Bonterra Energy Corp.

Annual Report 2013

Yield
Sustainability
Growth

Bonterra Energy Corp.

Bonterra is a high-yield, dividend paying Canadian oil and gas company with a proven history of driving per share growth and long-term value for shareholders. Bonterra's successful performance is due to it's experienced management team, conservative capital structure and sustainable pace of development.

Our formula for growth

A proven and committed team

The successful execution of Bonterra's long-term strategy has been dependent on the strength of its people. Bonterra's proven track record of success was made possible by its experienced management team, the Board of Directors, employees, consultants, and field staff who have all been instrumental in providing continued growth and above-average results and returns for shareholders.

Experienced Management Team

High quality asset

With more than 10.6 billion barrels of original oil in place, the Pembina Cardium field is the largest conventional oil pool in western Canada. Only 12.6% of the oil in place is estimated to have been recovered to date. Bonterra holds a large, concentrated land position, and is the area's third largest operator. The Pembina Cardium field is characterized by high quality, light sweet oil, features a long-reserve life index, and is located in close proximity to refining facilities. These characteristics result in high netbacks and positive returns on investment.

10+ year inventory of high-quality drilling locations

PEMBINA CARDIUM:
10.6 BILLION BARRELS
with approximately 87% remaining oil in place

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Disciplined financial management

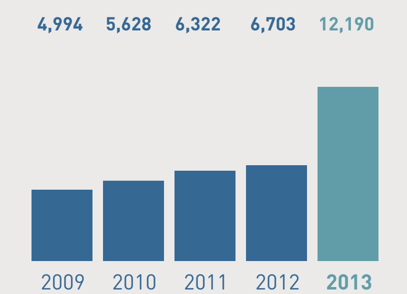
A conservative approach to the Company's capital structure has been a key factor in building financial strength and flexibility. Bonterra is committed to seeking new ways to strengthen its financial position that include capital cost-reduction initiatives, and exploring and implementing operational efficiencies across the Company. Bonterra ended the year with a net debt to cash flow ratio of 1.1 to 1, substantially lower than the 2012 year end. This successful approach allowed the Company to increase its dividend twice during the year while maintaining a pay-out ratio of 55% of funds flow, well within the Company's 2013 guidance range.

1.1 to 1 times
net debt to cash flow

55%
payout ratio

Evolving operations strategy

12,190 (BOE per day) **+82%**



Average daily production

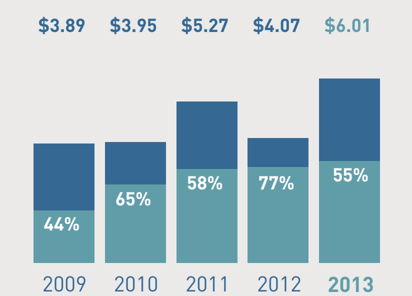
Bonterra's development of its Cardium assets continues to evolve in order to maximize recoveries and minimize costs. Bonterra continues to optimize its horizontal well design, moving from an intermediate casing to a mono-bore design; realizing a 43% reduction in drilling time, on average. Bonterra has also transitioned to cemented completions and subsequently increased frac densities by 31%. Cemented completions afford Bonterra the ability to precisely place fracs along the wellbore which is expected to improve overall recoveries. Bonterra's move to multi-well pad development within a concentrated area in 2014 is expected to further reduce costs and improve cycle times. Bonterra remains focused on reducing operating costs year over year.

Concentrated area development
+ new drilling & completion techniques
help reduce costs and improve recoveries
$12.77 per boe operating costs

Growth and income

Bonterra's track record of production, reserves and dividend growth on a total and per share basis remains unparalleled in the Canadian energy industry. The Company's asset base consists of stable producing properties located mainly in the Pembina field and are characterized by a long reserve life and low risk, predictable returns. In 2013, the Company posted new records for oil and gas revenues, production levels, funds flow from operations and net earnings.

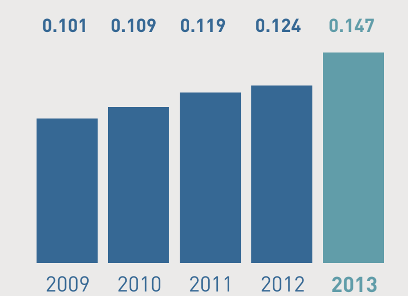
$3.33 per share paid in 2013



Cash dividends/ distributions to investors

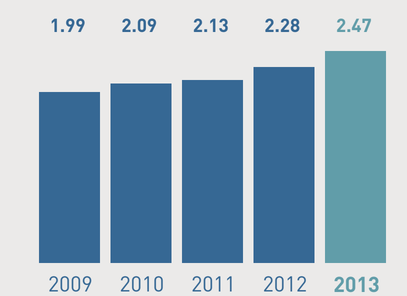
Dividends/distributions
Funds flow

18.5% growth over 2012



Production per share

8.3% growth over 2012



Reserves per share
based on proved + probable reserves

Annual Highlights

As at and for the year ended ($ 000s except $ per share)		December 31, 2013 [1]	December 31, 2012	December 31, 2011
FINANCIAL				
Revenue – realized oil and gas sales		**295,675**	142,770	162,277
Funds flow [2]		**181,574**	80,429	101,988
Per share – basic		**6.01**	4.07	5.27
Per share – diluted		**5.99**	4.06	5.22
Payout ratio		**55%**	77%	58%
Funds flow [2]		**185,393** [3]	80,429	101,988
Per share – basic		**6.14**	4.07	5.27
Per share – diluted		**6.11**	4.06	5.22
Payout ratio		**54%**	77%	58%
Cash flow from operations		**173,896**	74,325	97,409
Per share – basic		**5.76**	3.75	5.04
Per share – diluted		**5.74**	3.75	4.98
Payout ratio		**58%**	83%	61%
Cash dividends per share		**3.33**	3.12	3.06
Net earnings		**62,758**	33,211	43,608
Per share – basic		**2.08**	1.68	2.25
Per share – diluted		**2.07**	1.68	2.23
Capital expenditures and acquisitions, net of dispositions		**109,227** [4]	98,130 [5]	62,686
Total assets		**1,000,531**	419,933	364,176
Working capital deficiency		**35,895**	29,876	51,576
Long-term debt		**156,764**	166,808	69,916
Shareholders' equity		**667,641**	163,277	181,640
OPERATIONS				
Oil	– barrels per day	**7,787**	4,035	4,075
	– average price ($ per barrel)	**89.26**	82.04	92.76
NGLs	– barrels per day	**744**	476	386
	– average price ($ per barrel)	**52.41**	52.18	60.89
Natural gas	– MCF per day	**21,954**	13,157	11,163
	– average price ($ per MCF)	**3.46**	2.60	3.86
Total barrels of oil equivalent per day (BOE) [6]		**12,190**	6,703	6,322

(1) Annual figures for 2013 include the results of Spartan Oil Corp. (Spartan) for the period of January 25, 2013 to December 31, 2013. Production includes 341 days for Spartan and 365 days for Bonterra.

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

(3) Annual figures for 2013 include the results of Spartan for the period of January 1, 2013 to December 31, 2013. Production includes 365 days for Spartan and Bonterra.

(4) Includes the Spartan acquisition that closed on January 25, 2013 that included $10,000,000 of acquired cash that reduced capital expenditures from $121,641,000 excluding dispositions.

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

(6) 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)		2013 Q4	Q3	Q2	Q1 [1]
FINANCIAL					
Revenue – realized oil and gas sales		**70,917**	78,946	79,344	66,468
Funds flow [2]		**43,359**	46,874	50,566	40,726
Per share – basic		**1.39**	1.50	1.65	1.47
Per share – diluted		**1.38**	1.50	1.65	1.46
Payout ratio		**61%**	56%	51%	53%
Cash flow from operations		**47,772**	43,953	41,445	40,726
Per share – basic		**1.53**	1.41	1.35	1.47
Per share – diluted		**1.52**	1.40	1.35	1.46
Payout ratio		**56%**	60%	62%	53%
Cash dividends per share		**0.85**	0.84	0.84	0.80
Net earnings		**15,254**	19,690	15,119	12,695
Per share – basic		**0.50**	0.63	0.49	0.46
Per share – diluted		**0.49**	0.63	0.49	0.46
Capital expenditures and acquisitions, net of dispositions		**25,965**	34,025	9,731	39,506 [3]
Total assets		**1,000,531**	1,002,773	987,067	1,016,594
Working capital deficiency		**35,895**	43,681	26,824	31,519
Long-term debt		**156,764**	147,189	179,379	189,509
Shareholders' equity		**667,641**	671,528	648,574	658,062
OPERATIONS					
Oil	– barrels per day	**7,964**	7,310	8,414	7,459
	– average price ($ per barrel)	**80.88**	103.30	89.38	84.20
NGLs	– barrels per day	**691**	772	782	732
	– average price ($ per barrel)	**56.48**	55.30	44.64	53.75
Natural gas	– MCF per day	**22,802**	22,274	20,554	22,176
	– average price ($ per MCF)	**3.85**	2.71	4.13	3.21
Total barrels of oil equivalent per day (BOE) [4]		**12,456**	11,794	12,621	11,887

(1) Quarterly figures for Q1 2013 include the results of Spartan Oil Corp. (Spartan) for the period of January 25, 2013 to March 31, 2013. Production includes 66 days for Spartan and 90 days for Bonterra.

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

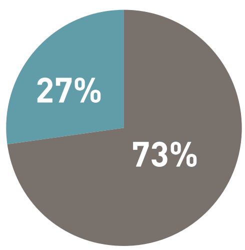
(3) Includes the Spartan acquisition that closed on January 25, 2013 that included $10,000,000 of acquired cash that reduced capital expenditures from $49,506,000 excluding dispositions.

(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.

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, 2013.

73% Oil and NGLs **27%** Natural Gas



Reserves by commodity 2013
*based on proved plus probable reserves

2013 Highlights Include:

- Shareholder rate of return in 2013 of approximately 25 percent from share price appreciation and dividends;
- Cash received by the Company from the sale of commodities, share issuance from treasury, exercising of stock options and the sale of investments totalling approximately $215 million; cash paid out by the Company for capital expenditures (net of land sales and $10 million cash received from the Spartan acquisition) and dividends totalled approximately $209 million;
- Increased the monthly dividend by $0.03 during the year;
- Net debt to funds flow ratio was 1.1 to 1 at December 31, 2013;
- Annual production averaged 12,190 BOE per day; a volume increase of 82 percent over the same period in 2012 and an increase of 18.5 percent on a per share basis;
- Proved plus probable (P & P) reserves of 75 million BOE (approximately 73 percent oil and liquids), a 67 percent volume increase over 2012 and an increase of 8 percent on a per share basis;
- Corporate netback increased to $40.58 per BOE from $31.36 per BOE in 2012;
- Drilled 55 gross (35 net) horizontal wells with a 100 percent success rate; and
- Production costs decreased to $12.77 per BOE compared to $16.88 per BOE in 2012.

2014 Guidance and Objectives:

- Projected cash receipts from the sale of commodities, exercising of stock options and the sale of investments and land is estimated to total $245 million; cash outlays for capital expenditures and dividends is estimated to total $231 million;
- Projected corporate netback is estimated to be $41.33 per BOE using the following assumptions: Cdn $85.50 per bbl average realized oil price, $3.50 per MCF average realized natural gas price ($3.25 per MCF plus $0.25 premium for heat adjustment); a 12 percent royalty; $13.00 per BOE production cost; $3.75 per BOE for administrative and interest costs and a Cdn/US dollar $0.96 exchange rate;
- Production estimate is expected to average between 12,400 and 12,700 BOE per day (67 percent oil, 5 percent liquids and 28 percent natural gas);
- Increasing the dividend by $0.01 per month would be approximately $3.8 million in additional annual expenditure; and

+ 12% increase in dividend

+ 82% increase in annual production

+ 29% increase in corporate netback

- Estimated 2014 annualized sensitivity analysis on cash flow:

	Change $	$000s	$ per Share
Realized crude oil price ($/bbl)	1.00	2,546	0.08
Realized natural gas price ($/MCF)	0.10	757	0.02
Cdn $/US $ exchange rate	0.01	2,164	0.07

Outlook

The future for Bonterra continues to be positive. The Company holds an enviable amount of light oil properties in the Cardium formation located in the Pembina and Willesden Green fields in west central Alberta. Technological advances for horizontal drilling continue to revitalize these fields and such changes may result in higher recoveries of original oil in place, resulting in future drilling programs that are even more optimistic.

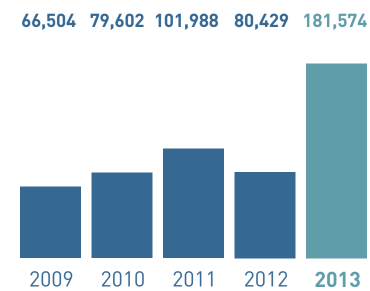
It is difficult to predict commodity prices, oil differentials, production volumes and declines for new wells and whether water or gas injections will be successful. All of the companies in the Pembina area are experimenting to determine how long the horizontal well distance should be; how many wells should be drilled per section, what is the appropriate frac spacing, what type of frac should be used, and the size of the fracs. The additional knowledge that is accumulated by the industry generally can lead to positive economic results. Bonterra has many years of undrilled locations, and as technological advances continue, we will be able to apply these to our assets and improve the amount of oil and gas recovered.

A conservative approach has been a key factor in Bonterra's corporate culture. The Company retains its strong financial position by maintaining a sustainable growth strategy, minimizing the amount and cost of debt and increasing its dividends in a cautious manner.

The Board of Directors wish to thank the employees and consultants for the Company's very successful results in 2013 and the shareholders for their continued support and understanding of Bonterra's cautious and controlled strategy.

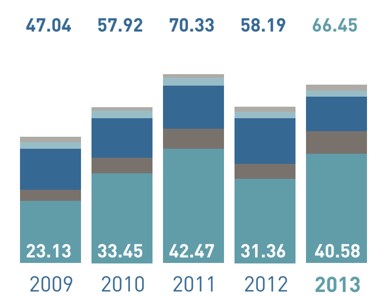
George F. Fink
Chief Executive Officer
and Chairman of the Board

181,574 ($ thousands) **+126%**



Funds flow

$40.58 ($ per BOE) **+29%**



Netbacks

Cash netback
Royalties
Field operating
G&A
Interest & other

The evolution of operations

Bonterra holds a large, concentrated position in the Pembina and Willesden Green Cardium fields in central Alberta. The Company's asset base in the Cardium totals 250.3 gross (193.7 net) sections and is characterized by high amounts of original oil-in place with low recoveries. The evolution of Cardium development from conventional vertical development to horizontal development has facilitated improved recoveries and decreased costs. The Company will continue to concentrate its efforts on maintaining a sustainable pace development, capturing operational efficiencies and improving production rates to increase profitability across its operations.

Drilling innovations

The Company continues to advance its drill program with longer horizontal lengths and a mono-bore well design resulting in decreased capital costs and increased per well recoveries.

43% reduction in average drill days

2013

Average Daily Production
12,190 BOE per day

Production Profile
70% oil and liquids;
30% natural gas

Capital Budget
$110 million

Average Well Cost
$2.7 million

Wells Drilled
30 gross (29.7 net) operated;
25 gross (5.3 net) non-operated
horizontal wells

New completion techniques

Bonterra continues to refine its completion techniques with different frac placement methods and fluid types. Bonterra has shifted to cemented completions, increased frac densities and slick water fracs. These improvements allow for greater control on fracture placement which improves overall recoveries.

31% increase in frac densities:
from 80m to 55m intervals between fracs

Future development

Future development will be more concentrated to specific areas within Bonterra's land base. Multi well pads will reduce overall development costs by improving efficiencies, reducing overall infrastructure requirements, and reducing the number of required equipment mobilization and demobilization.

Bonterra will also continue to front end load its drilling program by running two rigs in the first quarter of the year to offset the effects of downtime related to spring break up and plant turnarounds.

Bonterra's continued success in exploiting its Cardium position provides Bonterra with a strong platform for future growth. Over the last four years, the Company's operations have been concentrated on delineating the land base while improving drilling and completion techniques to reduce well cost and increase productivity. In 2014, Bonterra's capital development program of $120.0 million will mainly target light oil prospects in the Pembina Cardium Field, most notably focused on development in its Carnwood area holdings.

Bonterra plans to drill 56 gross (41.05 net) wells in 2014 with approximately $72 million of its capital budget spent drilling 26 gross (25.5 net) wells and completing 30 wells (includes four wells which were drilled in 2013) in the Carnwood area.

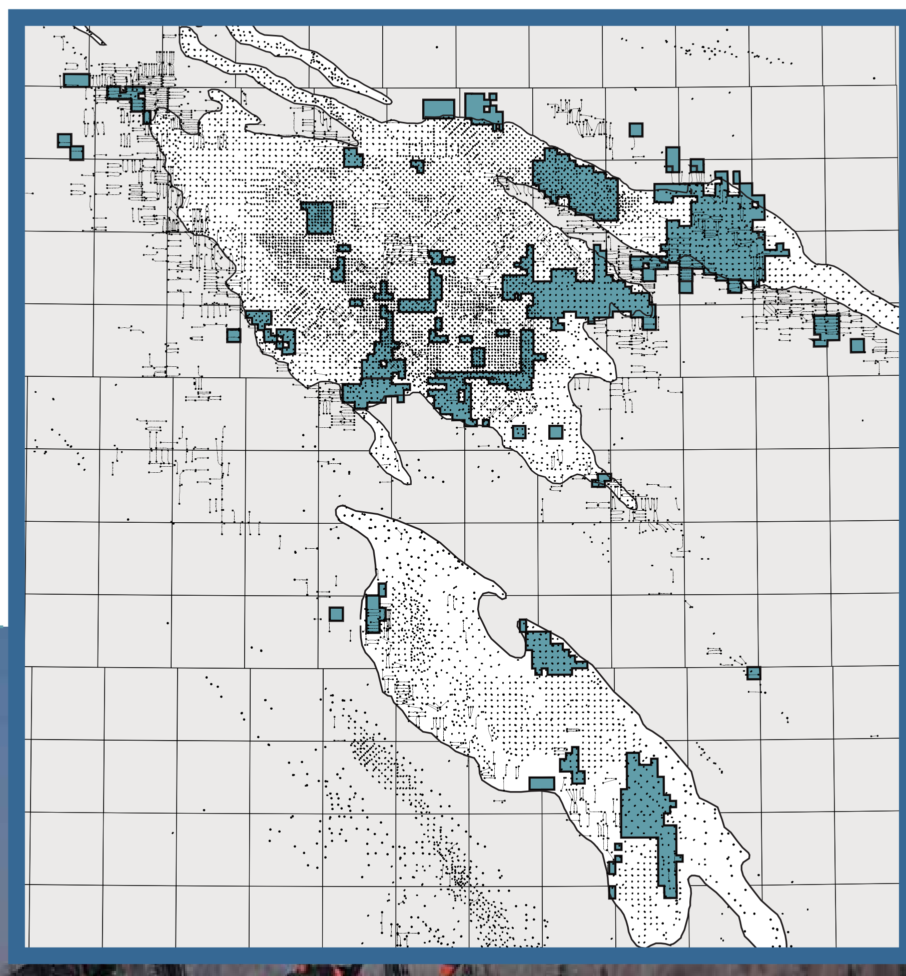
Bonterra's land position in the Carnwood area includes 38 gross (35 net) sections which are expected to be developed with up to eight horizontal wells per section. This represents a drilling inventory of approximately 305 gross (280 net) locations. Carnwood is a key focus in 2014 for the company as Bonterra looks to capture operational efficiencies and economies of scale. The Company is well-positioned as its total Cardium drilling inventory in excess of 10 years will provide significant future upside.

In 2014, the Company will continue to execute its disciplined approach to operations to improve efficiencies. Pad development has been an important evolution to the Company's exploitation strategy as it geographically concentrates the capital development program. This has resulted in decreased pad cycle times (start of drilling to all wells on production) and overall well capital costs. In 2014, drilling times are expected to average 10-12 days for 1.5 mile lateral length wells and 6-7 days for one mile lateral length wells, while the average well cost will be $2.7 million.

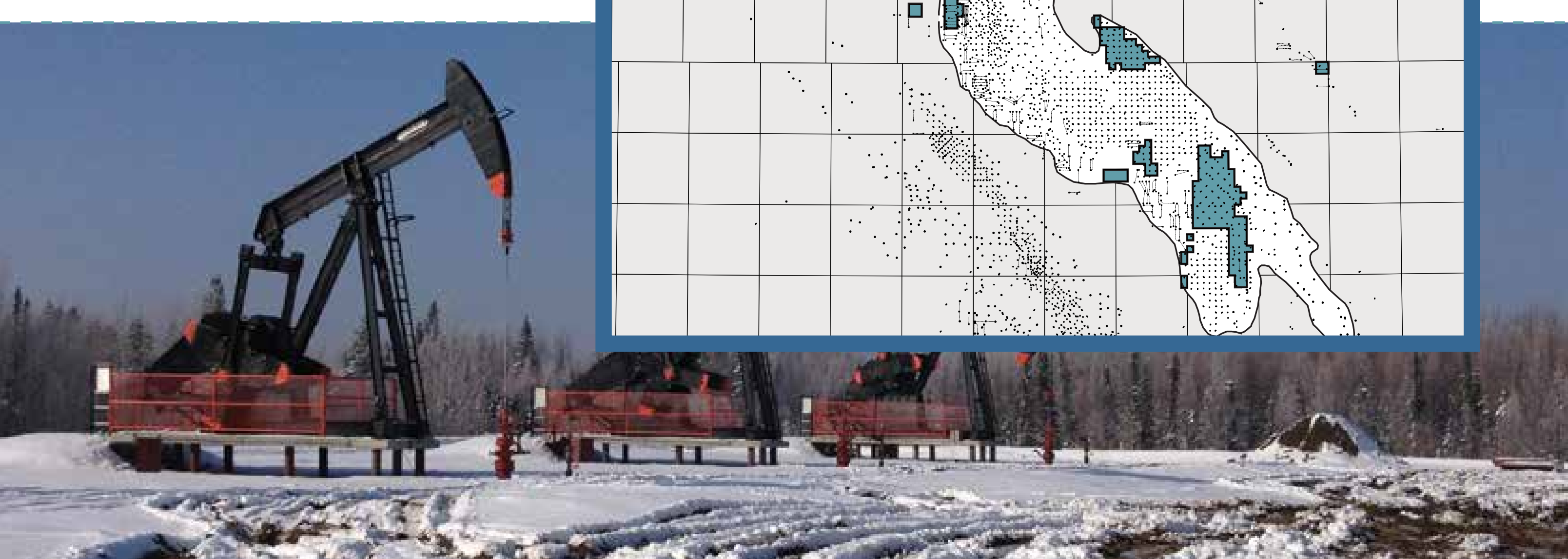
As the Company's operations continue to grow, Bonterra maintains its focus on ensuring it has the necessary infrastructure in place to accommodate new production. Bonterra has begun work on the reactivation of the 11-17 gas plant. This project is expected to reduce operating costs and increase gas handling capacity as it will allow the Company to redirect gas production from the Carnwood area to this plant. Additionally, the Company has increased its battery treating capacity in the Carnwood area to 5,000 barrels of oil per day.

In addition, it is anticipated that a portion of the 2014 capital development program will be allocated to a waterflood enhanced recovery pilot project, in the Carnwood area, to examine the potential for secondary recovery methods on Bonterra's Cardium lands. The Company is also evaluating a gas flood enhanced recovery project in the Carnwood area. Enhanced recovery methods have the ability to increase reserve recovery and incremental value across a large portion of the Company's asset base.

Bonterra is encouraged by its progress on evolving its operations strategy and will continue to pursue the disciplined development of its light oil targets in the Cardium zone to drive future growth.



BONTERRA LANDS



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, 2013. 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, 2013

Reserve category:	Light and medium oil (Mbbl)	Natural gas (Mmcf)	Natural gas liquids (Mbbl)	BOE[1] (MBOE)
PROVED				
Developed producing	20,015.2	51,518	1,904.8	30,506.3
Developed non-producing	457.1	1,180	38.6	692.2
Undeveloped	16,654.8	30,372	1,180.2	22,897.1
TOTAL PROVED	37,127.0	83,070	3,123.6	54,095.7
PROBABLE	14,173.9	33,120	1,191.0	20,884.8
TOTAL PROVED PLUS PROBABLE	51,300.9	116,190	4,314.6	74,980.5

Reconciliation of Company Gross Reserves by Principal Product Type as of December 31, 2013

	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, 2012	24,924.6	33,661.7	49,258	68,221	33,134.3	45,031.9
Extension	826.0	1,207.4	1,839	2,727	1,132.5	1,661.9
Improved Recovery	3,154.9	4,114.9	5,140	6,658	4,011.5	5,224.6
Infill Drilling	-	-	-	-	-	-
Technical Revisions	(422.7)	(1,481.5)	12,832	15,563	1,715.9	1,112.3
Discoveries	-	-	-	-	-	-
Acquisitions	14,751.2	21,077.4	22,116	31,115	18,437.3	26,263.3
Dispositions	-	-	-	-	-	-
Economic Factors	130.5	149.5	(102)	82	113.6	135.9
Production	(3,113.9)	(3,113.9)	(8,013)	(8,013)	(4,449.4)	(4,449.4)
DECEMBER 31, 2013	**40,250.6**	**55,615.5**	**83,070**	**116,189**	**54,095.7**	**74,980.5**

Summary of Net Present Values of Future Net Revenue as of December 31, 2013

($ Millions)	Net present value before income taxes discounted at (% per year)		
Reserve category:	0%	5%	10%
PROVED			
Developed producing	1,390.4	931.0	711.4
Developed non-producing	32.9	25.6	21.5
Undeveloped	897.7	487.5	288.1
TOTAL PROVED	2,321.0	1,444.1	1,021.0
PROBABLE	1,203.1	485.1	249.4
TOTAL PROVED PLUS PROBABLE	3,524.1	1,929.2	1,270.4

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:

	2013 FD&A costs per BOE[1][2][3]	2012 FD&A costs per BOE[1][2][3]	2011 FD&A costs per BOE[1][2][3]	Three year average[4]
Proved reserve net additions	$ 23.63	$ 13.64	$ 33.22	$ 22.01
Proved plus probable reserve net additions	$ 20.12	$ 16.05	$ 15.38	$ 19.11

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

	2013 FD&A costs per BOE[1][2][3]	2012 FD&A costs per BOE[1][2][3]	2011 FD&A costs per BOE[1][2][3]	Three year average[5]
Proved reserve net additions	$ 24.80	$ 20.91	$ 57.53	$ 23.26
Proved plus probable reserve net additions	$ 21.06	$ 21.62	$ 35.40	$ 20.22

(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 ($US/$Cdn)
2014	92.64	4.00	69.05	103.50	1.5	0.9400
2015	89.31	3.99	66.57	99.78	1.5	0.9400
2016	89.63	4.00	66.81	100.14	1.5	0.9400
2017	101.62	4.93	75.74	113.53	1.5	0.9400
2018	103.14	5.01	76.88	115.24	1.5	0.9400
2019	104.69	5.09	78.03	116.97	1.5	0.9400

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

Production

	2013		
	Oils and NGLs (Bbl per day)	Natural Gas (Mcf per day)	Total (Boe per day)
Alberta	**8,330**	**20,083**	**11,678**
Saskatchewan	**178**	**53**	**186**
British Columbia	**23**	**1,818**	**326**
	8,531	**21,954**	**12,190**

Land Holdings

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

	2013		2012	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	**230,885**	**149,466**	186,389	109,837
Saskatchewan	**38,750**	**36,525**	6,585	5,416
British Columbia	**62,045**	**22,639**	62,045	22,639
	331,680	**208,630**	255,019	137,892

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)	2013	2012
Land	**36**	182
Acquisitions	**(10,000)**	17,108
Disposals	**(2,414)**	(3,753)
Exploration and development costs	**121,605**	84,593
Net petroleum and natural gas capital expenditures	**109,227**	98,130

Drilling History

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

	2013					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	**55.0**	**35.0**	**-**	**-**	**55.0**	**35.0**
Natural gas	**-**	**-**	**-**	**-**	**-**	**-**
Dry	**-**	**-**	**-**	**-**	**-**	**-**
Total	**55.0**	**35.0**	**-**	**-**	**55.0**	**35.0**
Success rate	**100%**	**100%**	**-**	**-**	**100%**	**100%**

	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%

Management's Discussion and Analysis

The following report, dated March 20, 2014, is a review of the operations and current financial position for the year ended December 31, 2013 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. These terms 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: "WTI" refers to West Texas Intermediate, a grade of light sweet crude oil used as a benchmark price in the United States; "MSW Stream Index" refers to the mixed sweet blend that is the benchmark price for conventionally produced light sweet crude oil in Western Canada; "bbl" refers to barrel; "NGL" refers to natural gas liquids; "MCF" refers to thousand cubic feet; "MMBTU" refers to million British thermal units 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.

Financial and Operational Discussion

Annual Comparisons

As at and for the year ended ($ 000s except $ per share)		**December 31, 2013** [1]	December 31, 2012	December 31, 2011
FINANCIAL				
Revenue – realized oil and gas sales		**295,675**	142,770	162,277
Cash flow from operations		**173,896**	74,325	97,409
Per share – basic		**5.76**	3.75	5.04
Per share – diluted		**5.74**	3.75	4.98
Payout ratio		**58%**	83%	61%
Cash dividends per share		**3.33**	3.12	3.06
Net earnings		**62,758**	33,211	43,608
Per share – basic		**2.08**	1.68	2.25
Per share – diluted		**2.07**	1.68	2.23
Capital expenditures and acquisitions, net of dispositions		**109,227** [2]	98,130 [3]	62,686
Total assets		**1,000,531**	419,933	364,176
Working capital deficiency		**35,895**	29,876	51,576
Long-term debt		**156,764**	166,808	69,916
Shareholders' equity		**667,641**	163,277	181,640
OPERATIONS				
Oil	– barrels per day	**7,787**	4,035	4,075
	– average price ($ per barrel)	**89.26**	82.04	92.76
NGLs	– barrels per day	**744**	476	386
	– average price ($ per barrel)	**52.41**	52.18	60.89
Natural gas	– MCF per day	**21,954**	13,157	11,163
	– average price ($ per MCF)	**3.46**	2.60	3.86
Total barrels of oil equivalent per day (BOE)		**12,190**	6,703	6,322

(1) Annual figures for 2013 include the results of Spartan Oil Corp. (Spartan), for the period of January 25, 2013 to December 31, 2013. Production includes 341 days for Spartan and 365 days for Bonterra.

(2) Includes the Spartan acquisition that closed on January 25, 2013 that included $10,000,000 of acquired cash that reduced capital expenditures from $121,641,000 excluding dispositions.

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

Quarterly Comparisons

As at and for the periods ended ($ 000s except $ per share)	2013 **Q4**	Q3	Q2	Q1 [1]
FINANCIAL				
Revenue – oil and gas sales	**70,917**	78,946	79,344	66,468
Cash flow from operations	**47,772**	43,953	41,445	40,726
Per share – basic	**1.53**	1.41	1.35	1.47
Per share – diluted	**1.52**	1.40	1.35	1.46
Payout ratio	**56%**	60%	62%	53%
Cash dividends per share	**0.85**	0.84	0.84	0.80
Net earnings	**15,254**	19,690	15,119	12,695
Per share – basic	**0.50**	0.63	0.49	0.46
Per share – diluted	**0.49**	0.63	0.49	0.46
Capital expenditures and acquisitions, net of dispositions	**25,965**	34,025	9,731	39,506 [2]
Total assets	**1,000,531**	1,002,773	987,067	1,016,594
Working capital deficiency	**35,895**	43,681	26,824	31,519
Long-term debt	**156,764**	147,189	179,379	189,509
Shareholders' equity	**667,641**	671,528	648,574	658,062
OPERATIONS				
Oil (barrels per day)	**7,964**	7,310	8,414	7,459
NGLs (barrels per day)	**691**	772	782	732
Natural gas (MCF per day)	**22,802**	22,274	20,554	22,176
Total BOE per day	**12,456**	11,794	12,621	11,887

(1) Quarterly figures for Q1 2013 include the results of Spartan Oil Corp. (Spartan), for the period of January 25, 2013 to March 31, 2013.Production includes 65 days for Spartan and 90 days for Bonterra.

(2) Includes the Spartan acquisition that closed on January 25, 2013 that included $10,000,000 of acquired cash that reduced capital expenditures from $49,506,000.

As at and for the periods ended ($ 000s except $ per share)	2012 Q4	Q3	Q2	Q1 [1]
FINANCIAL				
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
Per share – basic	**1.08**	0.83	0.74	1.10
Per share – diluted	**1.08**	0.83	0.74	1.10
Payout ratio	**72%**	94%	105%	71%
Cash dividends per share	**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 [1]	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) Includes an acquisition that closed on June 7, 2012 for $17,108,000.

Business Environment and Sensitivities

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.

	Q4-2013	Q3-2013	Q2-2013	Q1-2013	Q4-2012	Q3-2012	Q2-2012	Q1-2012
Crude oil								
WTI (U.S.$/bbl)	**97.44**	105.82	94.22	94.37	88.18	92.22	93.49	102.93
WTI to MSW Stream Index Differential (U.S.$/bbl) [1]	**(14.93)**	(4.72)	(3.67)	(6.95)	(3.32)	(7.21)	(10.12)	(10.49)
Bonterra average realized price (Cdn$/bbl)	**80.88**	103.30	89.38	84.20	78.58	80.54	80.93	88.48
Natural gas								
AECO (Cdn$/mcf)	**3.52**	2.43	3.52	3.18	3.20	2.31	1.89	2.15
Bonterra average realized price (Cdn$/mcf)	**3.85**	2.71	4.13	3.21	3.43	2.41	1.96	2.32
Foreign exchange Cdn$/U.S.$	**1.0498**	1.0385	1.0234	1.0089	0.9913	0.9948	1.0102	1.0012

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

WTI crude oil prices averaged $98 U.S. for the year, four percent higher than in 2012. Canadian crude oil differentials remained volatile throughout 2013 as a result of higher North American crude oil production, refinery outages, and constrained takeaway and infrastructure capacity. Bonterra average realized prices of $89.44 per barrel in 2013 was eight percent higher than 2012.The differential averaged a discount of $7.57 U.S. per barrel for the year and widened in the fourth quarter to a discount of $14.93 U.S. per barrel. Certain pipeline and infrastructure projects and additional crude oil rail capacity are scheduled to come on stream in 2014, which are expected to alleviate takeaway capacity which negatively impacts Canadian crude oil differentials. In the meantime, it is expected that differentials will remain volatile throughout 2014.

Natural gas prices increased substantially in 2013 with AECO prices averaging approximately 33 percent higher than 2012 levels. An increase in firm shipping contracts on the Trans Canada Mainline and extreme cold weather throughout North America in the fourth quarter of 2013 alleviated the natural gas inventory buildup and led to increased gas prices.

The following chart shows the Company's sensitivity to key commodity price variables. The sensitivity calculations are performed independently showing the effect of the change of one variable; with all other variables being held constant.

Annualized sensitivity analysis on cash flow, as estimated for 2014 [1]

Impact on cash flow	Change ($)	$000s	$ per share [2]
Realized crude oil price ($/bbl)	1.00	2,546	0.08
Realized natural gas price ($/mcf)	0.10	757	0.02
Canadian $/ U.S. $ exchange rate	0.01	2,164	0.07

(1) This analysis uses current royalty rates, annualized estimated average production of 12,500 BOE per day and no changes in working capital.

(2) Based on annualized basic weighted average shares outstanding of 31,573,960.

Business Overview, Strategy and Key Performance Drivers

Bonterra is a focused and growing petroleum and natural gas Canadian energy corporation that actively develops, produces and sells crude oil, natural gas and natural gas liquids. 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 Cardium properties using primary recovery techniques. Starting in late 2012, the Company has focused more of its infill drilling opportunities in the main pool, specifically the Carnwood area. Although the focus is still to use primary recovery techniques, the Company continually looks at adding reserves and production volumes by acquisition, drilling existing locations or exploring the possibilities of secondary recovery methods.

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 in which Spartan became a wholly owned subsidiary. 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. The Spartan Transaction added 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. On March 1, 2013, Spartan amalgamated with Bonterra.

Since acquisition, the Spartan assets contributed total revenue (primarily oil and gas sales, net of royalties) of $92,213,000 and production of 5,394 BOE per day for the 2013 year. In addition, the Spartan assets contributed operating and administrative expenses of $11,949,000 for the year ended December 31, 2013. If Bonterra had acquired Spartan as of January 1, 2013, the combined annual production for the Company would have increased by 304 BOE per day to 12,494 BOE per day. Producing assets acquired in the Spartan Transaction are approximately 80 percent crude oil and natural gas liquids.

The Company incurred expenditures of $121,605,000, before dispositions and cash received on acquisitions, related to its capital program for the year, of which $25,965,000 was incurred in the fourth quarter.

Operational success is dependent upon several factors, including but not limited to, the price of energy commodity products, efficiently managing capital and operating spending, the ability to maintain desired levels of production, control over infrastructure, efficiency in developing and operating properties and 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

($000s)	December 31, 2013 Gross [1]	December 31, 2013 Net [2]	September 30, 2013 Gross [1]	September 30, 2013 Net [2]	December 31, 2012 Gross [1]	December 31, 2012 Net [2]	Year ended December 31, 2013 Gross [1]	Year ended December 31, 2013 Net [2]	Year ended December 31, 2012 Gross [1]	Year ended December 31, 2012 Net [2]
	Three months ended						Year ended			
Crude oil horizontal-operated	**6**	**5.9**	9	9.0	6	4.6	**30**	**29.7**	24	20.0
Crude oil horizontal-non-operated	**13**	**2.6**	10	2.4	6	1.6	**25**	**5.3**	10	2.9
Total	**19**	**8.5**	19	11.4	12	6.2	**55**	**35.0**	34	22.9
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 2013, the Company placed three gross (3.0 net) wells on production that were drilled in the later part of 2012 and drilled 30 gross (29.7 net) wells in 2013, of which 26 gross (25.8 net) were placed on production. The remaining four wells will be placed on production in the first quarter of 2014. In addition, 25 gross (5.3 net) non-operated wells were drilled and placed on production during 2013.

Prior to the acquisition, Spartan drilled six (5.8 net) wells in late 2012 and into 2013, all of which were placed on production in the first quarter of 2013. Spartan also had four (1.0 net) non-operated wells that were drilled prior to the acquisition and placed on production in the first quarter of 2013.

Production

	Three months ended December 31, 2013	Three months ended September 30, 2013	Three months ended December 31, 2012	Year ended December 31, 2013 [1]	Year ended December 31, 2012
Crude oil (barrels per day)	**7,964**	7,310	4,400	**7,787**	4,035
NGLs (barrels per day)	**691**	772	595	**744**	476
Natural gas (MCF per day)	**22,802**	22,274	16,009	**21,954**	13,157
Average BOE per day	**12,456**	11,794	7,663	**12,190**	6,703

(1) In 2013, average daily production included 365 days of Bonterra production and 341 days of Spartan production.

Production volumes during 2013 increased to 12,190 BOE per day compared to 6,703 BOE per day, an increase of 82 percent over the same period in 2012. The increase in production is primarily due to the Spartan Transaction and the Company's 2013 drilling program in the Pembina Cardium area.

Production volumes for Q4 2013 increased by six percent compared to Q3 2013, which was primarily due to 10.9 net wells that were placed on production late in the third quarter and into the fourth quarter of 2013. Fourth quarter production was negatively affected by pipeline apportionments, non-operated facility maintenance programs and well and facility shut-ins due to cold weather issues. These negative factors however, did not prevent the Company from reaching its targeted annual average production volumes.

Cash Netback

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

	Three months ended			Year ended	
$ per BOE	**December 31, 2013**	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
Production volumes (BOE)	**1,145,918**	1,085,030	705,001	**4,449,280**	2,453,474
Gross production revenue [1]	**$61.89**	$72.76	$56.20	**$66.45**	$58.19
Royalties [2][4]	**(7.97)**	(9.44)	(4.90)	**(8.52)**	(5.61)
Field operating costs	**(12.11)**	(14.71)	(19.02)	**(12.77)**	(16.88)
Field netback	**$41.81**	$48.61	$32.28	**$45.16**	$35.70
General and administrative [3][4]	**(1.85)**	(2.65)	(2.31)	**(2.35)**	(2.48)
Interest and other	**(2.12)**	(2.76)	(2.51)	**(2.23)**	(1.86)
Cash netback	**$37.84**	$43.20	$27.46	**$40.58**	$31.36

(1) For the fourth quarter of 2013 the WTI to MSW Stream Index Differential was $14.93 (U.S. $/bbl) compared to $4.72 (U.S. $/bbl) for the third quarter of 2013;

(2) Includes non-recurring royalties of $0.92 per BOE for the three months ended September 30, 2013 and $0.67 per BOE for the year ended December 31, 2013 due to prior period royalties not paid by Spartan.

(3) Includes non-recurring general and administrative expenses of $0.31 per BOE for the three months ended September 30, 2013 and $0.30 per BOE for the year ended December 31, 2013 due to the Spartan Transaction.

(4) The non-recurring items combined to reduce cash flow in 2013 by $4,331,000.

Cash netbacks have increased in 2013 compared to 2012 primarily due to higher realized commodity prices and lower operating costs. Fourth quarter 2013 over third quarter 2013 cash netbacks decreased due to a decrease in realized commodity prices due in part to a higher crude oil differential in the fourth quarter.

Oil and Gas Sales

	Three months ended			Year ended	
($ 000s)	**December 31, 2013**	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
Revenue – oil and gas sales	**70,917**	78,946	39,624	**295,675**	142,770
Average Realized Prices ($):					
Crude oil (per barrel)	**80.88**	103.30	78.58	**89.26**	82.04
NGLs (per barrel)	**56.48**	55.30	50.41	**52.41**	52.18
Natural gas (per MCF)	**3.85**	2.71	3.43	**3.46**	2.60
Average (per BOE)	**61.89**	72.76	56.20	**66.45**	58.19

Revenue from oil and gas sales increased by $152,905,000 in 2013 or 107 percent compared to 2012. This increase was primarily due to an 89 percent increase in production due to the Spartan Transaction and the successful results of Bonterra's 2013 drilling program. Average realized price per BOE increased in 2013 compared to the same period a year ago, due to higher realized prices received for crude oil and natural gas. The increase in Bonterra's realized price for crude oil was primarily due to an increase in WTI.

The quarter over quarter oil and gas revenues decreased due to lower realized prices for crude oil mainly due to a much higher crude oil differential, partially offset by higher production volumes and higher realized prices for natural gas in the fourth quarter.

The Company's product split on a revenue basis for 2013 is approximately 90 percent weighted towards crude oil and NGLs. This ratio will likely remain similar or increase as the Company continues to develop its Cardium (mainly oil) properties.

Royalties

($ 000s)	Three months ended December 31, 2013	September 30, 2013	December 31, 2012	Year ended December 31, 2013	December 31, 2012
Crown royalties	**4,546**	4,598	2,436	**18,031**	9,727
Freehold, gross overriding and other royalties	**4,583**	5,639	1,017	**19,867**	4,033
Total royalties	**9,129**	10,237	3,453	**37,898**	13,760
Crown royalties – percentage of revenue	**6.4**	5.8	6.1	**6.1**	6.8
Freehold, gross overriding and other royalties – percentage of revenue	**6.5**	7.1	2.6	**6.7**	2.8
Royalties – percentage of revenue	**12.9**	12.9	8.7	**12.8**	9.6
Royalties $ per BOE	**7.97**	9.44	4.90	**8.52**	5.61

Royalties paid by the Company consist of crown royalties paid to the Provinces of Alberta, Saskatchewan and British Columbia. The Company's average crown royalty rate is approximately 6.1 percent for 2013 compared to 6.8 percent for 2012. The decrease is primarily due to a lower ratio of crown versus freehold wells acquired from Spartan and horizontal Cardium wells that are still eligible for the initial five percent royalty rate until accumulated production thresholds are met or the expiry of time allowed to reach the threshold levels. A significant portion of those initial five percent royalty rate wells are from wells acquired or drilled in the first half of 2013. Quarter over quarter the crown royalty rate increased, which caused the crown royalties expense to be static despite the decrease in oil and gas sales. The crown royalty rate increase was due primarily to Alberta crown royalties on crude oil, which is calculated from the Alberta Crown Reference price, which increased 10 percent from Q3 2013.This increase was partially offset by the new crown wells that were placed on production in the fourth quarter that are eligible for the initial five percent royalty rates.

Non-crown royalties increased in 2013 compared to 2012 primarily due to a $3,000,000 onetime payment for non-crown royalties owed for prior years by Spartan and additional oil and gas revenue from wells subject to non-crown royalties from the Spartan Transaction and recent non-operated freehold wells drilled in the Tomahawk area. The percent decrease in non-crown royalties quarter over quarter is primarily due to a negative $1,000,000 gross overriding royalty adjustment in the third quarter of 2013 for prior years, related to Spartan acquired wells.

Production Costs

($ 000s except $ per BOE)	Three months ended December 31, 2013	September 30, 2013	December 31, 2012	Year ended December 31, 2013	December 31, 2012
Production costs	**13,877**	15,963	13,407	**56,810**	41,408
$ per BOE	**12.11**	14.71	19.02	**12.77**	16.88

On a BOE basis, production costs have decreased by 24 percent compared to the prior year. Total production costs for 2013 increased 37 percent compared to 2012 due to the 82 percent increase in production volumes compared to the prior year.

The decrease on a BOE basis is primarily due to the Spartan Transaction, as Spartan had more horizontal wells than vertical wells, which have lower operating costs per BOE, due to higher production volumes over the same fixed costs. In addition, the Company, through the Spartan Transaction, acquired a wholly owned gas plant facility that has lower compression, gathering and processing costs. These factors have significantly reduced combined operating costs on a BOE basis.

Quarter over quarter operating costs on a BOE basis decreased 13 percent primarily due to increased production and lower operating costs in the fourth quarter. During the third quarter the Company experienced additional seasonal costs for facility start up and turnaround costs, which are generally conducted after spring breakup. Repair and maintenance costs for Q2 are completed in Q3 due to road bans in Q2 preventing access for these activities.

The Company continually looks for field optimization opportunities, such as redirecting natural gas to its wholly owned gas facility for lower gas processing and transportation costs as well as decreasing downtime issues by owning its own infrastructure. In addition the Company will reactivate a second wholly owned gas plant in Q2 2014 to increase gas processing capacity and to further reduce gas processing and transportation costs.

Other Income

($ 000s)	Three months ended **December 31, 2013**	September 30, 2013	December 31, 2012	Year ended **December 31, 2013**	December 31, 2012
Realized gain on investments	**-**	-	943	**278**	2,705
Gain on sale of property	**-**	5	-	**217**	3,616
Administrative income (loss)	**117**	(17)	37	**161**	285
Investment income	**18**	19	39	**104**	161
	135	7	1,019	**760**	6,767

During 2013, the Company disposed of a portion of its investments for gross proceeds of $968,000 (December 31, 2012 - $3,485,000). The increase in carrying value of these publically traded securities is mainly due to increased share prices, partially offset by the investments sold in the period. The market value of the investments held by the Company is $6,804,000 at December 31, 2013 (December 31, 2012 - $5,046,000).

During 2013, the Company sold a portion of its non-core Southeast Saskatchewan property for cash proceeds of $2,406,000. At the time of disposition, the Company had a carrying value of $1,373,000 for exploration and evaluation expenditures, $954,000 for property plant and equipment and $133,000 of decommissioning liabilities resulting in a gain on sale of $212,000.

During 2012, the Company disposed of a portion of its Central Alberta Redwater and Tomahawk properties for proceeds of $1,109,000 and $2,500,000 respectively. At the time of disposition, the properties had no carrying value which resulted in an accounting gain on sale equal to its proceeds.

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

General and Administration (G&A) Expense

($ 000s except $ per BOE)	Three months ended **December 31, 2013**	September 30, 2013	December 31, 2012	Year ended **December 31, 2013**	December 31, 2012
Employee compensation expense	**1,403**	1,702	875	**5,986**	3,974
Office and administration expense (recurring)	**719**	838	755	**3,125**	2,121
	2,122	2,540	1,630	**9,111**	6,095
Office and administration expense (non-recurring) [1]	**-**	339	-	**1,331**	-
Total G&A expense	**2,122**	2,879	1,630	**10,442**	6,095
$ per BOE (recurring)	**1.85**	2.34	2.31	**2.05**	2.48
$ per BOE (total)	**1.85**	2.65	2.31	**2.35**	2.48

(1) Non-recurring office and administration costs relates to the Spartan Transaction.

Total G&A expense increased to $9,111,000 for the year ended December 31, 2013 compared to $6,095,000 in 2012.

The increase in employee compensation expense of $2,012,000 for 2013 compared to the prior year is primarily due to the increased number of staff required to accommodate the increased activity from the Spartan Transaction and an increase in accrued bonuses, due to higher net earnings before income taxes. The quarter over quarter decrease of $299,000 is due to a decrease in the amount of the accrued bonus. 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.

The increase in recurring office and administration expense for 2013 compared to 2012, related to an increase in bank renewal fees due to an increased credit facility, additional computer software costs and a general increase in office expenditures due to increased staffing of the Company. The quarter over quarter decrease relates primarily to a decrease in engineering fees, bank charges and a decrease in the allowance for doubtful accounts.

Finance Costs

	Three months ended			Year ended	
($ 000s except $ per BOE)	**December 31, 2013**	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
Interest on long-term debt	**1,332**	1,355	1,616	**6,165**	3,730
Other interest	**261**	261	225	**958**	1,279
Interest expense	**1,593**	1,616	1,841	**7,123**	5,009
$ per BOE	**1.39**	1.49	2.61	**1.60**	2.04
Unwinding of the discounted value of decommissioning liabilities	**284**	284	224	**1,088**	886
Total finance costs	**1,877**	1,900	2,065	**8,211**	5,895

Interest on long-term debt increased $2,435,000 in 2013 compared to 2012 due to the Company increasing its bank debt by $64,632,000 from the end of the second quarter of 2012 to the end of the second quarter of 2013. The increase was due to increased spending in the capital drilling program in the second half of 2012 and into the first quarter of 2013 and a $20,000,000 repayment of a short-term related party loan. The Company also experienced higher interest rates on its credit facilities in the first and second quarters of 2013. Interest rates are determined by net debt to cash flow ratios on a trailing quarterly basis. Increased cash flow and the $27,603,000 equity issuance on July 2, 2013 reduced the overall debt (see Shareholders' Equity section), resulting in lower interest rates in the second half of 2013.

Other interest relates to amounts paid to related parties (see related party transactions) and a $25,000,000 subordinated promissory note from a private investor.

From a sensitivity perspective on the estimated loan amounts, a one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by $1,265,000.

Share-based Payments

	Three months ended			Year ended	
($ 000s)	**December 31, 2013**	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
	773	1,055	1,264	**4,155**	4,241

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.

Based on outstanding options as of December 31, 2013, the Company anticipates that an expense of approximately $1,033,000 will be recorded for 2014, $364,000 for 2015 and $44,000 for 2016.

On January 31, 2014 the Company granted 677,000 stock options to employees, directors and consultants with an exercise price of $51.25, based on the market price immediately preceding the date of grant. The options vest between one to two years and expire between July 31, 2015 to August 31, 2016.

For more information about options issued and outstanding, refer to Note 16 of the December 31, 2013 audited annual financial statements.

Depletion and Depreciation, Exploration and Evaluation and Goodwill

	Three months ended			Year ended	
($ 000s)	**December 31, 2013**	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
Depletion and depreciation	**24,707**	18,929	10,585	**91,779**	33,521
Exploration and evaluation expense	**489**	391	-	**1,156**	-

Provision for depletion and depreciation increased by $58,260,000 for 2013 compared to 2012. The increase in depletion and depreciation was mainly the result of increased production volumes and increased property, plant and equipment costs from the Spartan Transaction. The quarter over quarter increase was primarily due to increased production levels from new wells and related capital costs, which initially have higher depletion rates.

Exploration and evaluation expense related to expired leases.

With the Spartan Transaction, Bonterra also recorded goodwill. Goodwill has been allocated to the primary cash generating unit that includes Pembina and Cardium assets in Alberta, Canada.

There was no impairment provisions recorded for the years ended December 31, 2013 and 2012.

Taxes

The Company recorded a deferred tax expense of $22,024,000 for 2013 (December 31, 2012 - $11,406,000). The deferred tax expense increase in 2013 compared to 2012 is primarily related to increased earnings before income taxes.

The Company has $562,911,000 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, 2012 - $27,670,000) remaining of investment tax credits that expire between the years 2018 to 2027. In addition, the Company has $134,938,000 (December 31, 2012 - $135,502,000) of capital loss carry forwards which can only be claimed against taxable capital gains. For additional information regarding income taxes, see Note 15 of the December 31, 2013 audited annual financial statements.

On November 14, 2013, the Company received a proposal letter from the Canada Revenue Agency (CRA) which stated its intent to challenge the tax consequences of Bonterra's reorganization from a trust to a corporation, which occurred on November 18, 2008. The CRA position is based on the acquisition and control rules in addition to the general anti-tax avoidance rules in the Income Tax Act. In 2014, if CRA issues a Notice of Reassessment for Bonterra's 2008, 2009, 2010, 2011, 2012 and 2013 taxation years, Bonterra would be required to make a payment of 50 percent of the tax liability claimed by the CRA in order to appeal this reassessment. If such reassessments are issued and maintained on appeal, Bonterra will owe total cash taxes of approximately $35 million for the six taxation years since the reorganization. Bonterra would have 90 days from the date of the Notice of Reassessment to prepare and file a Notice of Objection. If the CRA is not in agreement with Bonterra's Notice of Objection, Bonterra has the option to file its case with the Tax Court of Canada. Bonterra anticipates that legal proceedings through various tax courts would take approximately two to four years. If Bonterra receives a positive ruling then any taxes, interest and penalties paid to the CRA will be refunded plus interest. If Bonterra is unsuccessful then any remaining taxes payable plus interest and penalties will be remitted. No amount has been provided for in the financial statements.

The impact of the proposal on Bonterra's tax provision has been considered by management; however management remains of the opinion that after careful consideration and consultation at the time of the reorganization, Bonterra's subsequent tax filings were correct as filed. In management's view, the reassessment of companies with respect to the use of tax pools is part of an overall initiative by the CRA.

If the proposed reassessments are issued by CRA, management will vigorously defend Bonterra's tax filing position.

Net Earnings

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2013**	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
Net earnings	**15,254**	19,690	6,082	**62,758**	33,211
$ per share – basic	**0.50**	0.63	0.31	**2.08**	1.68
$ per share – diluted	**0.49**	0.63	0.31	**2.07**	1.68

Net earnings for 2013 increased by $29,547,000 or 89 percent compared to 2012. Increased net earnings resulted primarily from increased oil and gas production volumes and prices per BOE. This increase was partially offset by an increase in depletion and depreciation, deferred tax expense, production costs and royalty expenditures.

The decrease in net earnings for Q4 2013 compared to Q3 2013 resulted from decreased revenue from oil and gas sales and an increase in depletion and depreciation expense. This was partially offset by a decrease in production costs and deferred tax expense.

Other Comprehensive Income

Other comprehensive income for 2013 consists of an unrealized gain before tax on investments (including investments in a related party) of $2,725,000 relating to an increase in the investments' fair value (December 31, 2012 - unrealized gain of $1,514,000). The Company also disposed of a portion of these investments in 2013 for a realized gain before tax of $278,000 (December 31, 2012 - $2,705,000). Realized gains serve to 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, 2013**	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
Cash flow from operations	**47,772**	43,953	21,460	**173,896**	74,325
$ per share – basic	**1.53**	1.41	1.08	**5.76**	3.75
$ per share – diluted	**1.52**	1.40	1.08	**5.74**	3.75

In 2013, cash flow from operations increased by $99,571,000 compared to 2012. This was primarily due to increased production and lower production costs realized from the Spartan Transaction and the continued success of the Company's horizontal drilling program, which combined with higher commodity prices, resulted in increased net backs. The quarter over quarter increase was primarily due to a positive change in non-cash working capital and increased production, partially offset by lower netbacks in the fourth quarter.

Related Party Transactions

Bonterra holds 1,034,523 (December 31, 2012 - 1,034,523) common shares in Pine Cliff which represents less than one percent ownership in Pine Cliff's outstanding common shares. Pine Cliff's common shares have a fair market value as of December 31, 2013 of $1,076,000 (December 31, 2012 - $910,000). Pine Cliff paid a management fee to the Company of $60,000 plus administrative costs (December 31, 2012 - $225,000 plus administrative costs from Pine Cliff and its subsidiary Geomark Exploration Ltd.). 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, 2013, the Company had an accounts receivable from Pine Cliff of $217,000 (December 31, 2012 - $45,000).

As at December 31, 2013, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2012 - $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 2013 was $285,000 (December 31, 2012 - $286,000). 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

Net Debt to Cash Flow

Bonterra continues to focus on managing its cash flow, capital expenditures and dividend payments. The Company continues to meet its annual guidance range of 1 to 1 times to 1.5 to 1 times net debt to cash flow with a ratio of 1.1 to 1 times. The Company anticipates with a low net debt to cash flow ratio and continued successful drilling program, will allow the Company to sustain future cash flows and shareholder dividends.

Working Capital Deficiency

($ 000s)	**December 31, 2013**	December 31, 2012
Working capital deficiency	**35,895**	29,876
Long-term bank debt	**156,764**	166,808
Net debt	**192,659**	196,684
Shareholders' equity	**667,641**	163,277
Total	**860,300**	359,961

Net Debt and Working Capital

Net debt is a combination of long-term bank debt and working capital. Net debt remained relatively unchanged from a year ago. This was primarily attributable to the Company's increased cash flow from the Spartan Transaction (see Note 6 of the December 31, 2013 audited annual financial statements), its successful 2013 drilling program and an equity raise in the third quarter, offset by increased capital spending, while at the same time increasing the dividends paid to shareholders on a per share basis.

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 non-core assets and investments.

Effective January 17, 2014, the Company increased its Subordinated Promissory Note by an additional $15,000,000, for a total of $40,000,000 under the same terms and conditions. See Note 12 of the December 31, 2013 audited annual financial statements.

During the third quarter of 2013 the Company completed a $27,603,000 equity issuance. These funds were used to temporarily reduce the outstanding bank debt, which also resulted in a reduction of the debt to cash flow ratio.

With the Spartan Transaction, the Company inherited a derivative financial instrument entered into by Spartan. The financial derivative was outstanding for the period January 1, 2013, to December 31, 2013 for a total 273,750 barrels of oil (approximately 750 barrels of oil per day) at a fixed price of Cdn $90.00 per barrel.

On October 18, 2013, the Company entered into a financial derivative for the period November 1, 2013 to December 31, 2013 for a total of 488,000 MMBTU of natural gas at NYMEX less $0.34 U.S. per MMBTU.

The Company does not currently have any financial derivative contracts.

Capital Expenditures

During the year ended December 31, 2013, the Company incurred capital costs of $119,227,000 (December 31, 2012 - $81,022,000) net of proceeds of $2,414,000 on disposal of property, plant and equipment (December 31, 2012 - $3,753,000). The Company spent $121,605,000 primarily on the drilling of 30 gross (29.7 net) Pembina and Willesden Green Cardium operated horizontal wells and 25 (5.3 net) non-operated wells, facilities and gathering and compression systems.

Long-term Debt

Long-term debt represents the outstanding draws from the Company's credit facilities as described in the notes to the Company's annual financial statements. As of December 31, 2013, the Company had bank facilities consisting of a $220,000,000 (December 31, 2012 - $160,000,000) syndicated revolving credit facility and a $30,000,000 (December 31, 2012 - $20,000,000) non-syndicated revolving credit facility, for total facilities of $250,000,000. Amounts drawn under these facilities at December 31, 2013 totaled $156,764,000 (December 31, 2012 - $166,808,000). The interest rates on the outstanding debt as of December 31, 2013 were 3.8 percent and 3.0 percent on the Company's Canadian prime rate loans and Banker's Acceptances, respectively. The loan is revolving to April 24, 2014, with a maturity date of April 25, 2015 and is subject to annual review. The revolving credit facilities have no fixed terms of repayment.

Advances drawn under the credit facilities are secured by a fixed and floating charge debenture over the assets of the Company. In the event the credit facilities 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 see Note 13 of the December 31, 2013 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, 2013		December 31, 2012	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**19,909,541**	**149,877**	19,571,316	142,567
Acquisition	**10,711,405**	**502,258**	-	-
Share issuance	**553,725**	**27,603**	-	-
Share issue costs, net of tax		**(996)**		-
Issued pursuant to the Company share option plan	**147,500**	**6,625**	338,225	6,934
Transfer from contributed surplus to share capital		**531**		376
Balance, end of year	**31,322,171**	**685,898**	19,909,541	149,877

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 3,132,217 (December 31, 2012 - 1,990,954) 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 three years. For additional information regarding options outstanding, see Note 16 of the December 31, 2013 audited annual financial statements.

On July 2, 2013, the Company announced the closing of a bought deal financing of 553,725 common shares at a price of $49.85 per common share, for aggregate gross proceeds of $27,603,000. The Company incurred issue costs of $1,325,000 in respect of the financing.

Dividend Policy

For 2013, Bonterra paid dividends of $100,180,000 ($3.33 per share) compared to $61,707,000 ($3.12 per share) in the same period in 2012. Bonterra's dividend policy is regularly monitored and is dependent upon production, commodity prices, cash flow from operations, debt levels and capital expenditures. With its large inventory of undrilled locations, Bonterra continues to be well positioned to provide its shareholders a combination of sustainable growth and meaningful 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 from the exercise of employee stock options, the sale of investments and 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 58 percent for the year ended December 31, 2013 (83 percent for the year ended December 31, 2012).

Quarterly Financial Information

For the periods ended ($ 000s except $ per share)	2013 Q4	Q3	Q2	Q1
Revenue – oil and gas sales	**70,917**	78,946	79,344	66,468
Cash flow from operations	**47,772**	43,953	41,445	40,726
Net earnings	**15,254**	19,690	15,119	12,695
Per share – basic	**0.50**	0.63	0.49	0.46
Per share – diluted	**0.49**	0.63	0.49	0.46

For the periods ended ($ 000s except $ per share)	2012 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

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, and operating and administrative costs. Revenue, cash flow and net earnings in 2013 were higher than the prior quarters in 2012 mainly due to the Spartan Transaction, increased production from new wells, increased commodity prices and reduced operating costs.

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, judgments and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets or liabilities 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 judgments 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 costs 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 than 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, property, plant and equipment and goodwill.

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, geographic 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 therefrom. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

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

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, 2013 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, 2013 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 1992). 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 year end 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 controls over financial reporting during the year ended December 31, 2013, that have materially affected, or are reasonably likely to materially affect, the internal controls 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, the Company adopted several new IFRS standards and amendments in accordance with the transitional provisions of each standard. A brief description of each new standard and its impact on the Company's financial statements follows below:

IAS 1 "Presentation of Financial Statements" which requires companies to group together items within other comprehensive income that may be reclassified to the net earnings section of the statement of comprehensive income. The retrospective adoption of this standard did not have any impact on the Company's financial statements.

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 establishes control as the determining factor when determining whether an interest in another entity should be included in the consolidated financial statements. The adoption of this standard is not applicable to the Company's 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. The Company performed a review of its interest in other entities and did not identify any significant interests for which it shares joint control; as such, there is no impact as a result of this standard.

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. None of these disclosure requirements are applicable for the financial statements, unless significant events and transactions in the period require that they are provided. Accordingly the Company has not made such disclosure.

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. There has been no change to the Company's methodology for determining the fair value for its financial assets and liabilities, and as such, the application of IFRS 13 has not resulted in any adjustments to the fair value measurements carried out by the Company.

IFRS 9 "Financial Instruments"

As of January 1, 2015, Bonterra will be required to adopt amendments to IFRS 9. 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. Bonterra is currently assessing the impact that the adoption of the amended standard could have on the Company's financial statements.

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

Management's Responsibility for Financial Statements

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

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

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 20, 2014

Robb D. Thompson
Chief Financial Officer and
Corporate Secretary

March 20, 2014

Independent Auditor's Report

To the Shareholders of Bonterra Energy Corp.

We have audited the accompanying financial statements of Bonterra Energy Corp. (the "Company"), which comprise the statements of financial position as at December 31, 2013 and 2012, 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, 2013 and 2012, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Accountants

March 20, 2014

Calgary, Canada

Financial Statements

Statement of Financial Position

As at ($ 000s)	Note	**December 31, 2013**	December 31, 2012
ASSETS			
CURRENT			
Accounts receivable		**27,247**	19,158
Crude oil inventory		**749**	797
Prepaid expenses		**1,642**	1,635
Investments	3	**5,728**	4,136
		35,366	25,726
Investment in related party	5	**1,076**	910
Exploration and evaluation assets	7	**7,674**	1,982
Property, plant and equipment	8	**835,935**	341,452
Investment tax credit receivable	15	**27,670**	27,670
Deferred tax asset	15	**-**	22,193
Goodwill	6, 9	**92,810**	-
		1,000,531	419,933
LIABILITIES			
CURRENT			
Accounts payable and accrued liabilities	10	**34,261**	28,602
Due to related party	11	**12,000**	12,000
Subordinated promissory note	12	**25,000**	15,000
		71,261	55,602
Bank debt	13	**156,764**	166,808
Decommissioning liabilities	14	**37,362**	34,246
Deferred tax liability	15	**67,503**	-
		332,890	256,656
COMMITMENTS AND SUBSEQUENT EVENTS	20, 21		
SHAREHOLDERS' EQUITY			
Share capital	16	**685,898**	149,877
Contributed surplus		**12,791**	9,167
Accumulated other comprehensive income		**3,761**	1,620
Retained earnings (deficit)		**(34,809)**	2,613
		667,641	163,277
		1,000,531	419,933

See accompanying notes to these financial statements.

On behalf of the Board:

George F. Fink
Director

Rodger A. Tourigny
Director

Statement of Comprehensive Income

For the years ended December 31 ($ 000s, except $ per share)	Note	2013	2012
REVENUE			
Oil and gas sales, net of royalties	17	**257,777**	129,010
Loss on risk management contract	19	**(1,202)**	-
Other income	18	**760**	6,767
		257,335	135,777
EXPENSES			
Production costs		**56,810**	41,408
Office and administration		**4,456**	2,121
Employee compensation		**5,986**	3,974
Finance costs	4	**8,211**	5,895
Share-based payments	16	**4,155**	4,241
Depletion and depreciation	8	**91,779**	33,521
Exploration and evaluation expenses	7	**1,156**	-
		172,553	91,160
EARNINGS BEFORE INCOME TAXES		**84,782**	44,617
DEFERRED INCOME TAXES	15	**22,024**	11,406
NET EARNINGS FOR THE YEAR		**62,758**	33,211
OTHER COMPREHENSIVE INCOME (LOSS)			
Unrealized gain on investments		**2,725**	1,514
Deferred taxes on unrealized gain on investments		**(341)**	(189)
Realized gain on investments transferred to net earnings		**(278)**	(2,705)
Deferred taxes on realized gain on investments transferred to net earnings		**35**	338
OTHER COMPREHENSIVE GAIN (LOSS) FOR THE YEAR		**2,141**	(1,042)
TOTAL COMPREHENSIVE INCOME FOR THE YEAR		**64,899**	32,169
NET EARNINGS PER SHARE – BASIC	16	**2.08**	1.68
NET EARNINGS PER SHARE – DILUTED	16	**2.07**	1.68
COMPREHENSIVE INCOME PER SHARE – BASIC	16	**2.15**	1.63
COMPREHENSIVE INCOME PER SHARE – DILUTED	16	**2.14**	1.63

See accompanying notes to these financial statements.

Statement of Cash Flow

For the years ended December 31 ($ 000s)	Note	2013	2012
OPERATING ACTIVITIES			
Earnings before income taxes		**84,782**	44,617
Items not affecting cash			
Share-based payments		**4,155**	4,241
Depletion and depreciation		**91,779**	33,521
Exploration and evaluation expenses		**1,156**	-
Unrealized gain on risk management contract		**(1,859)**	-
Unwinding of the fair value of decommissioning liabilities		**1,088**	886
Gain on sale of property		**(217)**	(3,616)
Gain on sale of investments		**(278)**	(2,705)
Investment income		**(104)**	(161)
Interest expense		**7,123**	5,009
Change in non-cash working capital			
Change in accounts receivable		**(1,492)**	1,580
Change in crude oil inventory		**116**	194
Change in prepaid expenses		**909**	53
Change in accounts payable and accrued liabilities		**(5,530)**	(3,743)
Decommissioning expenditures		**(609)**	(542)
Interest paid		**(7,123)**	(5,009)
CASH PROVIDED BY OPERATING ACTIVITIES		**173,896**	74,325
FINANCING ACTIVITIES			
Increase (decrease) in bank debt		**(10,044)**	96,892
Due to related parties		**-**	(20,000)
Subordinated promissory note		**10,000**	-
Issuance of common shares	16	**27,603**	-
Share issue costs		**(1,325)**	-
Stock option proceeds		**6,625**	6,934
Dividends		**(100,180)**	(61,707)
CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES		**(67,321)**	22,119
INVESTING ACTIVITIES			
Investment income received		**104**	161
Exploration and evaluation expenditures		**(36)**	(182)
Property, plant and equipment expenditures		**(121,605)**	(84,593)
Proceeds on sale of property		**2,414**	3,753
Purchase of investments		**-**	(185)
Proceeds on sale of investments		**968**	3,485
Cash acquired on acquisition	6	**10,000**	-
Acquisition		**-**	(17,108)
Change in non-cash working capital			
Change in accounts payable and accrued liabilities		**(2,408)**	1,629
Change in accounts receivable		**3,988**	(3,404)
CASH USED IN INVESTING ACTIVITIES		**(106,575)**	(96,444)
NET CASH INFLOW		**-**	-
Cash, beginning of year		**-**	-
CASH, END OF YEAR		**-**	-

See accompanying notes to these financial statements.

Statement of Changes in Equity

For the years ended
($000s, except number of shares outstanding)

	Number of shares outstanding (Note 16)	Share capital (Note 16)	Contributed surplus [1]	Accumulated other comprehensive income [2]	Retained earnings (deficit)	Total shareholders' equity
JANUARY 1, 2012	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
Share-based payments			4,155			4,155
Acquisition (Note 6)	10,711,405	502,258				502,258
Share issuance	553,725	27,603				27,603
Share issue costs, net of tax		(996)				(996)
Exercise of options	147,500	6,625				6,625
Transfer to share capital on exercise of options		531	(531)			-
Comprehensive income				2,141	62,758	64,899
Dividends					(100,180)	(100,180)
DECEMBER 31, 2013	**31,322,171**	**685,898**	**12,791**	**3,761**	**(34,809)**	**667,641**

(1) Contributed surplus comprises share-based payments.

(2) Accumulated other comprehensive income comprises 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, 2013 and 2012.

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 20, 2014.

b) 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.

c) 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.

d) 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 and goodwill 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 market 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.

Risk Management Contract

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.

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 or expense related to deferred income tax assets or liabilities to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of 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.

e) Recent Accounting Pronouncements

As of January 1, 2013, the Company adopted several new IFRS standards and amendments in accordance with the transitional provisions of each standard. A brief description of each new standard and its impact on the Company's financial statements follows below:

IAS 1 "Presentation of Financial Statements" which requires companies to group together items within other comprehensive income that may be reclassified to the net earnings section of the statement of comprehensive income. The retrospective adoption of this standard did not have any impact on the Company's financial statements.

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. The adoption of this standard is not applicable to the Company's 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. The Company performed a review of its interest in other entities and did not identify any significant interests for which it shares joint control, as such, there is no impact as a result of this standard.

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. None of these disclosure requirements are applicable for the financial statements, unless significant events and transactions in the period require that they are provided. Accordingly the Company has not made such disclosure.

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. There has been no change to the Company's methodology for determining the fair value for its financial assets and liabilities, and as such, the application of IFRS 13 has not resulted in any adjustments to the fair value measurements carried out by the Company.

IFRS 9 "Financial Instruments"

As of January 1, 2015, Bonterra will be required to adopt amendments to IFRS 9.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. Bonterra is currently assessing the impact that the adoption of the amended standard could have on the Company's financial statements.

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 overrides (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 18).

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 the following: its purchase price or construction cost, including expenditures such as drilling costs; the present value of the initial estimate 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) Business Combinations and Goodwill

The purchase price used in a business combination is based on the fair value at the date of acquisition. The business combination is recorded or accounted for based on the fair value of the assets and liabilities acquired. All acquisition costs are expensed as incurred. Contingent liabilities are recognized at fair value at the date of the acquisition, and subsequently re-measured at each reporting period until settled. The excess of cost over fair value of the net assets and liabilities acquired is recorded as goodwill. Goodwill is allocated to the CGU expected to benefit from the synergies of the combination.

Goodwill is recorded at cost and is not amortized.

h) 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 flow 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 flow 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, PP&E and Goodwill) are grouped together into the smallest group of assets that generates cash flows from continuing use that are largely independent of the cash flow 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 and recorded in the statement of comprehensive income.

i) 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.

j) 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 sheet 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 or liability.

k) 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.

l) 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 amounts due to related party 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.

m) 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.

n) 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, 2013**	December 31, 2012
Interest expense on bank debt	**6,165**	3,730
Interest expense on amounts owing to related parties	**285**	683
Interest expense on subordinated promissory note and other	**673**	596
Unwinding of the fair value of decommissioning liabilities	**1,088**	886
	8,211	5,895

5. Investment in Related Party

The investment consists of 1,034,523 (December 31, 2012 - 1,034,523) common shares in Pine Cliff Energy Ltd. (Pine Cliff), a company with some common directors and some common management with Bonterra. The investment in Pine Cliff represents less than one percent ownership in the outstanding common shares of Pine Cliff and is recorded at fair market value. The common shares of Pine Cliff trade on the TSX Venture Exchange under the symbol PNE.

In addition, Geomark Exploration Ltd. (a wholly owned subsidiary of Pine Cliff) owns 204,633 (December 31, 2012 - 204,633) common shares in Bonterra.

6. 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. 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 assets contributed revenue (primarily oil and gas sales, net of royalties) of $92,214,000 and operating and administrative expenses of $11,949,000 for the period from January 25, 2013 to December 31, 2013. If the acquisition had occurred on January 1, 2013, total revenue (primarily oil and gas sales, net of royalties) would have been approximately $99,788,000 and operating and administrative expenses would have been $14,747,000 for the year ended December 31, 2013. The Spartan Transaction was accounted for as a business combination with Bonterra identified as the acquirer.

The 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	8,830
Property, plant and equipment	471,139
Goodwill	92,810
Working capital	
Cash	10,000
Accounts receivable	10,585
Prepaid expense	915
Accounts payable and accrued liabilities	(13,597)
Risk management contract	(1,859)
Decommissioning liabilities	(8,870)
Deferred tax liability	(67,695)
Total	502,258

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

On March 1, 2013, Spartan was amalgamated with Bonterra.

7. Exploration and Evaluation Assets

($ 000s)	
COST AND CARRYING AMOUNT	
Balance at January 1, 2012	1,989
Additions	182
Transfers to property, plant and equipment	(189)
BALANCE AT DECEMBER 31, 2012	**1,982**
Acquisition	8,830
Additions	36
Dispositions	(1,373)
Transfers to property, plant and equipment	(645)
Expiry of exploration and evaluation assets	(1,156)
BALANCE AT DECEMBER 31, 2013	**7,674**

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, 2012	344,193	77,611	1,510	423,314
Additions	70,480	13,931	182	84,593
Adjustment to decommissioning liabilities	(3,477)	-	-	(3,477)
Transfers from exploration and evaluation assets	189	-	-	189
Acquisition	16,117	3,486	-	19,603
Disposals	(261)	(126)	(31)	(418)
Balance at December 31, 2012	**427,241**	**94,902**	**1,661**	**523,804**
Additions	92,492	28,799	314	121,605
Adjustment to decommissioning liabilities	(6,100)	-	-	(6,100)
Disposals	(797)	(205)	(35)	(1,037)
Transfers from exploration and evaluation assets	645	-	-	645
Acquisition	378,685	92,454	-	471,139
Balance at December 31, 2013	**892,166**	**215,950**	**1,940**	**1,110,056**

Accumulated Depletion and Depreciation ($ 000s)	Oil and gas properties	Production facilities	Furniture, fixtures & other equipment	Total property, plant & equipment
Balance at January 1, 2012	(116,521)	(31,289)	(1,143)	(148,953)
Depletion and depreciation	(27,187)	(6,232)	(102)	(33,521)
Disposals and other	101	-	21	122
Balance at December 31, 2012	**(143,607)**	**(37,521)**	**(1,224)**	**(182,352)**
Depletion and depreciation	(73,885)	(17,766)	(128)	(91,779)
Disposals and other	(30)	9	31	10
Balance at December 31, 2013	**(217,522)**	**(55,278)**	**(1,321)**	**(274,121)**

Carrying amounts as at: ($ 000s)				
December 31, 2012	283,634	57,381	437	341,452
December 31, 2013	**674,644**	**160,672**	**619**	**835,935**

In June 2013, the Company sold a portion of its non-core Southeast Saskatchewan properties for cash proceeds of $2,406,000. At the time of disposition, the Company had a carrying value of $1,373,000 for exploration and evaluation expenditures, $954,000 for property, plant and equipment and $133,000 for decommissioning liabilities resulting in a gain on sale of $212,000.

Impairment

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 (2012 - 1.5 percent). The pre-tax discount rate applied to the cash flows for the Company's total proved and probable assets is ten percent.

There were no impairment provisions recorded for the years ended December 31, 2013 and 2012.

9. Goodwill

The amount recorded as goodwill, related to the Spartan Transaction (note 6), has all been allocated to the primary CGU, Alberta, Canada. There was no impairment loss recorded in the statement of comprehensive income for the year ended December 31, 2013.

10. Accounts Payable and Accrued Liabilities

($ 000s)	**December 31, 2013**	December 31, 2012
Accounts payable	**18,966**	20,181
Accrued liabilities	**15,295**	8,421
	34,261	28,602

11. Transactions with Related Parties

As at December 31, 2013, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2012 - $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 $285,000 (December 31, 2012 - $286,000). 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.

The Company received a management fee of $60,000 plus administrative costs for the year ended December 31, 2013 (December 31, 2012 - $225,000 plus administrative costs from Pine Cliff and Geomark) for management services and office administration from Pine Cliff. The management fee has been included in other income. As of December 31, 2013, the Company had an account receivable from Pine Cliff of $217,000 (December 31, 2012 - $45,000).

Compensation for Key Management Personnel

($ 000s)	**December 31, 2013**	December 31, 2012
Compensation	**1,542**	1,529
Share-based payments	**1,876**	2,445
Total compensation	**3,418**	3,974

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, 2013, Bonterra has borrowed $25,000,000 (December 31, 2012 - $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 $25,000,000 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 for the year ended was $673,000 (December 31, 2012 - $451,000).

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.

Effective January 17, 2014, the Company increased the Subordinated Promissory Note by an additional $15,000,000 for a total of $40,000,000 under the same terms and conditions as at December 31, 2013.

13. Bank Debt

As at December 31, 2013, the Company has bank facilities consisting of $220,000,000 (December 31, 2012 - $160,000,000) syndicated revolving credit facility and a $30,000,000 (December 31, 2012 - $20,000,000) non-syndicated revolving credit facility, for total facilities of $250,000,000. Amounts drawn under both credit facilities at December, 2013 were $156,764,000 (December 31, 2012 - $166,808,000). Amounts borrowed under the credit facilities at December 31, 2013 bear interest at a floating rate based on the applicable Canadian prime rate (currently three percent) or Banker's Acceptance rate plus a range between 0.75 percent and 3.50 percent. The percent increase within the range is dependent 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 24, 2014 and with a maturity date of April 25, 2015 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 $700,000 were issued as at December 31, 2013 (December 31, 2012 - $400,000). Security for credit facilities consists of various and floating demand debentures totaling $400,000,000 (December 31, 2012 - $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 $250,000,000 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, 2013, the Company is in compliance with all covenants.

14. Decommissioning Liabilities

At December 31, 2013, the estimated total undiscounted amount required to settle the decommissioning liabilities was $134,265,000 (December 31, 2012 - $67,684,000). The provision has been calculated assuming a 1.5 percent inflation rate (December 31, 2012 - 1.5 percent inflation rate). These obligations will be settled based on the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a risk-free interest rate of 3.2 percent (December 31, 2012 - 2.4 percent).

Changes to decommissioning liabilities were as follows:

($ 000s)	December 31, 2013	December 31, 2012
Decommissioning liabilities, January 1	**34,246**	34,904
Adjustment to decommissioning liabilities	**(6,100)**	(3,477)
Acquisition	**8,870**	2,735
Disposals	**(133)**	(260)
Liabilities settled during the period	**(609)**	(542)
Unwinding of the fair value of decommissioning liabilities	**1,088**	886
Decommissioning liabilities, end of year	**37,362**	34,246

15. Income Taxes

($ 000s)	December 31, 2013	December 31, 2012
Deferred tax asset (liability) related to:		
Investments	**(572)**	(302)
Exploration and evaluation assets and property, plant and equipment	**(114,027)**	(34,856)
Decommissioning liabilities	**9,348**	8,575
Corporate tax losses	**35,659**	48,474
Share issue costs	**1,517**	-
Corporate capital tax loss	**16,880**	16,964
Unrecorded benefit of capital tax losses	**(16,308)**	(16,662)
Deferred tax asset (liability)	**(67,503)**	22,193

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, 2013	December 31, 2012
Earnings before taxes	**84,782**	44,617
Combined federal and provincial income tax rates	**25.02%**	25.04%
Income tax provision calculated using statutory tax rates	**21,212**	11,172
Increase (decrease) in taxes resulting from:		
Share-based payments	**1,040**	1,062
Non-taxable portion of realized gains	**-**	(381)
Unrecorded benefit of capital losses	**(354)**	(242)
Change in effective tax rate and corporate tax filings	**207**	(178)
Others	**(81)**	(27)
Deferred income tax expense	**22,024**	11,406

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	81,098
Eligible capital expenditures	7	5,513
Share issue costs	20	6,063
Canadian oil and gas property expenditures	10	68,212
Canadian development expenditures	30	221,897
Canadian exploration expenditures	100	9,924
Income tax losses carried forward [1]	100	170,204
		562,911

(1) Federal income tax losses carried forward expire in the following years; 2026 - $112,524,000; 2027 - $35,248,000; 2028 - $13,131,000; 2031 - $9,301,000.

The Company has $27,670,000 (December 31, 2012 - $27,670,000) remaining of investment tax credits that expire in the following years; 2018 - $3,469,000; 2019 - $3,059,000; 2020 - $4,667,000; 2021 - $3,909,000; 2022 - $3,155,000; 2023 - $1,995,000; 2024 - $2,257,000; 2025 - $2,405,000; 2026 - $2,009,000; 2027 - $745,000.

The Company also has $134,938,000 (December 31, 2012 - $135,502,000) of capital loss carry forwards which can only be claimed against taxable capital gains.

On November 14, 2013, the Company received a proposal letter from the Canada Revenue Agency (CRA) which stated its intent to challenge the tax consequences of Bonterra's reorganization from a trust to a corporation, which occurred on November 18, 2008. The CRA position is based on the acquisition and control rules in addition to the general anti-tax avoidance rules in the Income Tax Act. In 2014, if CRA issues a Notice of Reassessment for Bonterra's 2008, 2009, 2010, 2011, 2012 and 2013 taxation years, Bonterra would be required to make a payment of 50 percent of the tax liability claimed by the CRA in order to appeal this reassessment. If such reassessments are issued and maintained on appeal, Bonterra will owe total cash taxes of approximately $35 million for the six taxation years since the reorganization. Bonterra would have 90 days from the date of Notice of Reassessment to prepare and file a Notice of Objection. If the CRA is not in agreement with Bonterra's Notice of Objection, Bonterra has the option to file its case with the Tax Court of Canada. Bonterra anticipates that legal proceedings through various tax courts would take approximately two to four years. If Bonterra receives a positive ruling then any taxes, interest and penalties paid to the CRA will be refunded plus interest. If Bonterra is unsuccessful then any remaining taxes payable plus interest and penalties will be remitted. No amount has been provided for in these financial statements.

The impact of the proposal on Bonterra's tax provision has been considered by management; however management remains of the opinion that after careful consideration and consultation at the time of the reorganization, Bonterra's subsequent tax filings were correct as filed.

If the proposed reassessments are issued by CRA, management will vigorously defend Bonterra's tax filing position.

16. Shareholders' Equity

Authorized

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

	December 31, 2013		December 31, 2012	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**19,909,541**	**149,877**	19,571,316	142,567
Acquisition	**10,711,405**	**502,258**	-	-
Share issuance	**553,725**	**27,603**	-	-
Share issue costs, net of tax		**(996)**		-
Issued pursuant to the Company share option plan	**147,500**	**6,625**	338,225	6,934
Transfer from contributed surplus to share capital		**531**		376
Balance, end of year	**31,322,171**	**685,898**	19,909,541	149,877

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;

	2013	2012
Basic shares outstanding	**30,210,710**	19,780,814
Dilutive effect of share options [1]	**108,315**	13,120
Diluted shares outstanding	**30,319,025**	19,793,934

(1) The Company did not include 226,000 share options (December 31, 2012 - 1,215,000) in the dilutive effect of share option calculation as these share options were anti-dilutive.

For the year ended December 31, 2013, the Company declared and paid dividends of $100,180,000 ($3.33 per share) (December 31, 2012 - $61,707,000 ($3.12 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 3,132,217 (December 31, 2012 - 1,990,954) 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 three years.

A summary of the status of the Company's stock option plan as of December 31, 2013, and changes during the year ended on those dates is presented below:

	Number of options	**Weighted average exercise price**
At January 1, 2012	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
Options granted	365,000	48.68
Options exercised	(147,500)	44.91
Options cancelled	(380,000)	57.76
Options forfeited	(89,000)	51.00
At December 31, 2013	**1,650,500**	**$48.31**

The following table summarizes information about options outstanding at December 31, 2013:

	Options outstanding			Options exercisable	
Range of exercise prices	Number outstanding at December 31, 2013	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable at December 31, 2013	Weighted-average exercise price
$ 40.00 – $ 49.50	1,028,500	1.2 years	$45.89	462,500	$44.86
50.00 – 59.00	622,000	1.5 years	52.31	494,500	51.76
$ 40.00 – $ 59.00	1,650,500	1.3 years	$48.31	957,000	$48.42

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 2013, the Company granted 365,000 stock options with an estimated fair value of $1,569,000 or $4.30 per option using the Black-Scholes option pricing model with the following key assumptions:

	December 31, 2013	December 31, 2012
Weighted-average risk free interest rate (%) [1]	**1.15**	1.12
Expected life (years)	**1.88**	1.42
Weighted-average volatility (%) [2]	**26.61**	28.23
Forfeiture rate (%)	**-**	-
Weighted average dividend yield (%)	**6.91**	6.90

(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 when the options were exercised in 2013 was $53.86 (2012 - $49.17).

17. Oil and Gas Sales, Net of Royalties

($ 000s)	**December 31, 2013**	December 31, 2012
Oil and gas sales	**295,675**	142,770
Less:		
Crown royalties	**(18,031)**	(9,727)
Freehold, gross overriding royalties and other	**(19,867)**	(4,033)
Oil and gas sales, net of royalties	**257,777**	129,010

18. Other Income

($ 000s)	**December 31, 2013**	December 31, 2012
Investment income	**104**	161
Administrative income	**161**	285
Realized gain on sale of property	**217**	3,616
Realized gain on investments	**278**	2,705
Other income	**760**	6,767

19. 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 party
- 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 related 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 as high as one and a half year's cash flow is still 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 achieved a net debt to cash flow of 1.1-1.

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 as follows.

	As at December 31, 2013			As at December 31, 2012		
($ 000s)	Carrying value	Fair value	Face value	Carrying value	Fair value	Face value
FINANCIAL ASSETS						
Accounts receivable	**27,247**	**27,247**	**27,661**	19,158	19,158	19,389
Investments	**5,728**	**5,728**	**N/A**	4,136	4,136	N/A
Investments in related party	**1,076**	**1,076**	**N/A**	910	910	N/A
FINANCIAL LIABILITIES						
Accounts payable and accrued liabilities	**34,261**	**34,261**	**34,261**	28,602	28,602	28,602
Due to related parties	**12,000**	**12,000**	**12,000**	12,000	12,000	12,000
Subordinated promissory note	**25,000**	**25,000**	**25,000**	15,000	15,000	15,000
Bank debt	**156,764**	**156,764**	**156,764**	166,808	166,808	166,808

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. Bonterra's risk management contract has been assessed at level 2.

The net debt and cash flow figures as of December 31, 2013 are as follows:

($ 000s)	
Bank debt	**156,764**
Accounts payable and accrued liabilities	**34,261**
Due to related parties	**12,000**
Subordinated promissory note	**25,000**
Current assets	**(35,366)**
Net debt	**192,659**
Cash provided by operating activities	**173,896**
Net debt to annual cash flow from operations	**1.1-1**

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 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 $220,000,000 syndicated revolving operating line, $30,000,000 non-syndicated operating line, $12,000,000 due to a related party and a $25,000,000 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 $1,265,000.

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 currency exchange rate 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 $27,247,000 accounts receivable balance at December 31, 2013 (December 31, 2012 - $17,094,000) over 85 percent (2012 - 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, 2013, 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, 2013, approximately $3,869,000 or 14.2 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, 2013 is $414,000 (December 31, 2012 - $231,000) 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	34,261	-	-
Risk management contract	Yes – Liability	-	-	-
Due to related parties	Yes – Liability	12,000	-	-
Subordinated promissory note	Yes – Liability	25,000	-	-
Bank debt	Yes – Liability	-	156,764	-
Office leases	No	1,251	2,445	1,630
Total		72,512	159,209	1,630

c) Risk Management Contracts

($ 000s)	**December 31, 2013**	December 31, 2012
Risk management contract		
Realized loss	**(3,061)**	-
Unrealized gain	**1,859**	-
	(1,202)	-

With the Spartan transaction, the Company inherited a derivative financial instrument. The financial derivative was outstanding for the period January 1, 2013 to December 31, 2013 for a total 273,750 barrels of oil (approximately 750 barrels of oil per day) at a fixed price of Cdn $90.00 per barrel.

On October 18, 2013, the Company entered into a financial derivative for the period November 1, 2013 to December 31, 2013 for a total of 488,000 MMBTU of natural gas at NYMEX less $0.34 U.S. per MMBTU.

20. Commitments

The Company has entered into leases for buildings and office equipment. These leases have an average life of 4.3 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, 2013 are as follows:

($ 000s)	
Within one year	1,251
After one year but not more than five years	4,075
Total	5,326

21. Subsequent Events

(I) Dividends

Subsequent to December 31, 2013, the Company has declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 2, 2014	January 15, 2014	0.29	January 31, 2014
February 3, 2014	February 14, 2014	0.29	February 28, 2014
March 3, 2014	March 14, 2014	0.29	March 31, 2014

(II) Options

On January 31, 2014 the Company granted 677,000 stock options to employees, directors and consultants with an exercise price of $51.25, based on the market price immediately preceding the date of grant. The options vest between one to two years and expire between July 31, 2015 to August 31, 2016.

Corporate Information

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Board of Directors

G. J. Drummond
G. F. Fink
R. M. Jarock
C. R. Jonsson
R. A. Tourigny
F.W. Woodward

Officers

B. A. Curtis, Vice President, Business Development
G. F. Fink, CEO and Chairman of the Board
A. Neumann, Chief Operating Officer
R. D. Thompson, CFO and Corporate Secretary

Registrar and 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
TD Securities, Calgary, Alberta
J.P. Morgan, Calgary, Alberta

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