Bonterra
Energy Corp.

The Value of Bonterra

Income, Growth and Sustainability

BONTERRA ANNUAL REPORT 2009

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Energy Corp.

Bonterra Energy Corp. is a high-yield, dividend paying oil and gas company headquartered in Calgary, Alberta. Bonterra has paid a monthly dividend (formerly a distribution) since inception and intends to pay approximately 60 to 75 percent of funds flow to investors.

The Company's asset base consists of concentrated, stable and underdeveloped properties across western Canada with large amounts of remaining oil still in place, a long reserve life and low-risk, predictable returns. Bonterra's proven track record of success is due to its experienced management team, conservative capital structure and sustainable pace of development.

UNLOCKING ADDITIONAL VALUE

Bonterra has one of the highest-quality asset bases in the Canadian energy industry with approximately 90 percent of corporate reserves on a Proved plus Probable basis in the Pembina Cardium field, Canada's largest original-oil-in-place pool (17 percent recovered to date). The Company has a 14 year drilling inventory with 435 gross locations already identified including 80 gross horizontal locations in the Halo area of the Pembina field. The 2010 capital development program of $40 to $50 million will consist of a targeted drilling program of horizontal multi-stage fracs, vertical wells and land and corporate acquisitions allowing the Company the potential to continue to provide its investors with above average results and returns.

Annual Highlights

	2009	2008	2007
FINANCIAL ($ 000s, EXCEPT $ PER SHARE / UNIT)			
Revenue – realized oil and gas	**85,712**	121,730	96,431
Cash flow from operations	**38,893**	69,570	51,433
Per Share / Unit Basic	**2.16**	4.07	3.04
Per Share / Unit Diluted	**2.15**	4.06	3.04
Payout Ratio (1)	**79%**	77%	87%
Funds Flow (2)	**66,504**	70,448	53,815
Per Share / Unit Basic	**3.69**	4.13	3.18
Per Share / Unit Diluted	**3.67**	4.12	3.18
Payout Ratio (1)	**46%**	76%	83%
Cash payments per Share / Unit (1)	**1.70**	3.12	2.64
Net Earnings	**68,563**	55,426	30,350
Per Share / Unit Basic	**3.81**	3.25	1.79
Per Share / Unit Diluted	**3.78**	3.23	1.79
Capital Expenditures and Acquisitions (net of disposals)	**5,640**	45,407	19,300
Total assets	**293,987**	265,301	142,326
Working Capital Deficiency	**10,162**	23,878	58,766
Long-term Debt	**59,823**	79,910	-
Shareholders' / Unitholders' Equity	**118,874**	56,777	44,376
Shares / Units Outstanding	**18,620**	17,258	16,928
OPERATIONS			
Oil and Liquids (barrels per day)	**3,141**	3,073	3,113
Average Price ($ per barrel)	**59.82**	87.54	70.31
Natural Gas (MCF per day)	**11,120**	7,637	6,627
Average Price ($ per MCF)	**4.15**	8.21	6.75
Total BOE per day (3)	**4,994**	4,346	4,218
RESERVES			
Oil and Liquids (barrels in 000s)			
Proved Developed Prducing (Gross) (4)	**15,519**	15,534	14,468
Proved (Gross)	**19,220**	17,991	17,472
Proved plus Probable (Gross)	**27,568**	22,867	21,910
Natural Gas (MCF in 000s)			
Proved Developed Prducing (Gross)	**32,103**	32,108	19,863
Proved (Gross)	**36,642**	36,571	24,125
Proved plus Probable (Gross)	**49,539**	50,245	32,465
Reserve Life Index (5) (oil, liquids and natural gas at 6:1) (years)			
Proved Developed Prducing (Gross)	**11.7**	12.5	11.3
Proved (Gross)	**14.2**	14.4	13.7
Proved plus Probable (Gross)	**20.1**	18.7	17.4
Reserves per Weighted Average Outstanding Share / Unit (BOE)			
Proved Developed Prducing (Gross)	**1.16**	1.22	1.05
Proved (Gross)	**1.41**	1.41	1.27
Proved plus Probable (Gross)	**1.99**	1.83	1.62

Quarterly Highlights

2009	4th	3rd	2nd	1st
FINANCIAL ($ 000S, EXCEPT $ PER SHARE)				
Revenue – realized oil and gas sales	**24,946**	20,965	20,501	19,300
Cash flow from operations	**13,673**	9,350	9,238	6,632
Per Share Basic	**0.76**	0.50	0.52	0.38
Per Share Diluted	**0.75**	0.50	0.52	0.38
Payout Ratio (1)	**66%**	87%	77%	94%
Funds Flow (2)	**37,595**	10,753	9,780	8,376
Per Share Basic	**2.07**	0.58	0.55	0.49
Per Share Diluted	**2.06**	0.57	0.55	0.49
Payout Ratio (1)	**24%**	76%	73%	74%
Cash payments per share (1)	**0.50**	0.44	0.40	0.36
Net Earnings	**52,136**	5,790	4,544	6,093
Per Share Basic	**2.88**	0.32	0.26	0.35
Per Share Diluted	**2.85**	0.32	0.26	0.35
Capital Expenditures and Acquisitions	**(16,976)**	17,660	2,255	2,701
Total Assets	**293,987**	273,543	258,393	260,732
Working Capital Deficiency	**10,162**	14,455	13,989	14,909
Long-term debt	**59,823**	81,136	71,573	89383
Shareholders' Equity	**118,874**	74,025	72,332	56,377
OPERATIONS				
Oil and Liquids (barrels per day)	**3,182**	3,084	3,029	3,268
Natural Gas (MCF per day)	**10,193**	10,881	11,551	11,877
Total BOE per day	**4,881**	4,898	4,954	5,245

(1) Cash dividend / disbursement payments per share/unit are based on payments made in respect of production months as opposed to the month paid.

(2) Funds flow is not a recognized measure under GAAP. For these purposes, the Company defines funds flow as funds provided by operations before changes in non-cash operating working capital items but including gain on sale of property, adjustments of investment tax credit receivable, and excluding restricted cash and asset retirement obligations settled.

(3) Barrels of oil equivalent (BOE) are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation.

(4) Gross reserves relate to the Company's ownership of reserves deducting any royalties.

(5) The reserve life index is calculated by dividing the reserves (BOE) by the annualized fourth quarter average production rate (2009 – 4,881; 2008 – 4,587 BOE per day; 2007 – 4,295 BOE per day).

Report to Shareholders

Bonterra continues to focus on providing its investors with stable income in the form of a monthly dividend, a conservative growth profile, and sustainability through the internal development and expansion of its high-quality asset base.

Bonterra Energy Corp. (Bonterra or the Company) is pleased to report its operational and financial results for the year ending December 31, 2009.

Bonterra continues to focus on providing its investors with stable income in the form of a monthly dividend, a conservative growth profile, and sustainability through the internal development and expansion of its high-quality asset base.

SUSTAINABILITY AND GROWTH

In 2009, Bonterra focused its capital program on its Pembina Cardium property, most notably on the horizontal, multi-stage frac drilling program and achieved increased production and reserves on both a total and per share basis. Bonterra is the third largest land owner in the Pembina Cardium field with approximately 160 gross (117 net) sections of Cardium mineral rights including 27.5 gross (23.0 net) sections along the perimeter of the main pool (frequently referred to as the "Halo" area) and the adjacent Willesden Green field.

Bonterra is proud to be one of the first companies to realize and unlock further value from the Pembina Cardium field through the application of this advanced technology beginning with the drilling of its first successful horizontal well in late 2008 which has averaged 124 BOE per day during its first 12 months of production. Horizontal, multi-stage frac drilling is now being used by many companies in the area and the Pembina Cardium zone is recognized as one of the most exciting plays in the Canadian energy sector because of its significant potential upside.

In 2009, Bonterra spent approximately $35.2 million on its capital development program of which approximately $22.9 million was spent on drilling and completions with the remainder spent on land and corporate acquisitions in the Pembina area. During the year, the Company drilled seven Pembina Cardium horizontal wells (5.5 net), eight vertical Pembina Cardium wells (6.9 net), and two natural gas wells (0.4 net), recording a 100 percent success rate. In November, the Company engaged the services of a second drilling rig and in March added a third drilling rig. The Pembina Cardium horizontal well drilling program will continue until spring break-up and resume once again when road bans are lifted. Average daily production increased 15 percent in 2009 year over year to 4,994 BOE per day, a new record level for Bonterra.

The development of this play is important for future growth and for generating long-term value for shareholders. The success achieved in 2009 well-exceeded the Company's initial expectations. As such, Bonterra has continued to advance the program at an accelerated pace.

Bonterra is currently planning to drill 20 to 30 gross horizontal Cardium wells in 2010 with a capital development budget of $40 to $50 million. The majority of wells planned are in the Halo area but the Company will also conduct some drilling in the main portion of the pool with the objective of converting some potential vertical locations to horizontals. The Company currently forecasts 2010 production to average between 5,700 and 6,000 BOE per day. The future drill program may also be affected by the results of the Alberta government's competition review.

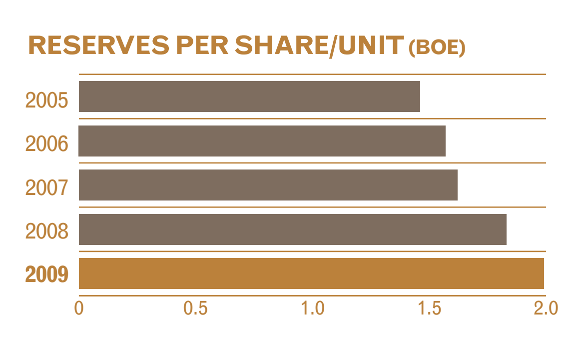
STRENGTHENING THE ASSET BASE

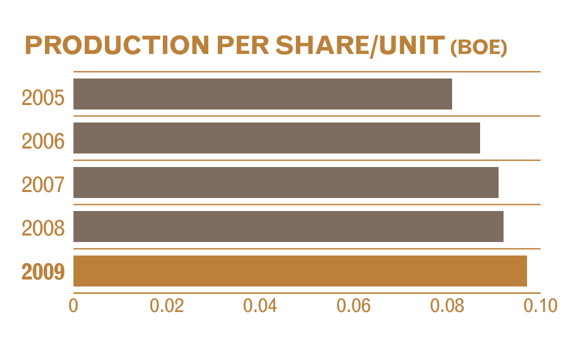
The Company was able to enhance its reserve base in 2009, increasing its reserve life index (RLI) to 20.1 years on a Proved plus Probable basis from 18.7 years in 2008. Bonterra's RLI continues to be one of the highest in the industry among conventional producers.

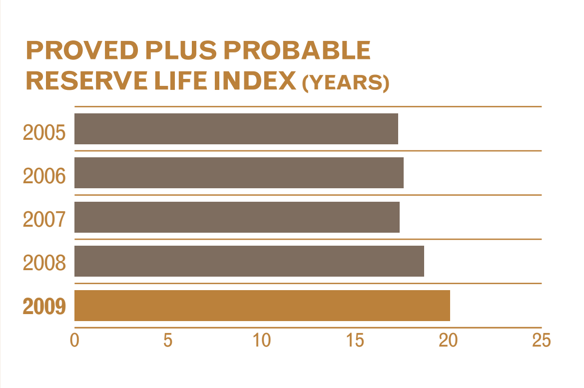
In 2009, Bonterra expanded its land holdings in the Pembina field with the acquisition of mineral rights at a cost of approximately $5.8 million. In addition, Bonterra acquired a small Canadian junior, Cobalt Energy Ltd., effective July 1, 2009. This acquisition resulted in only a modest increase in production but provided the Company with additional ownership in 11 gross Bonterra operated sections of land with potential Pembina Cardium horizontal drilling locations.

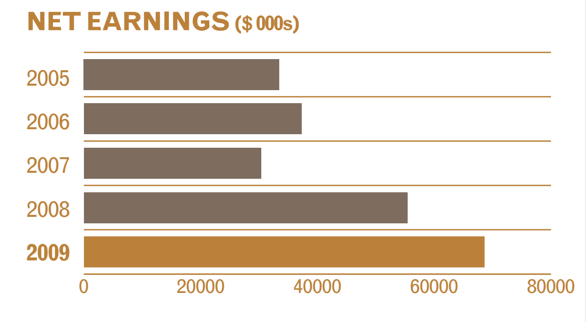
Results from Bonterra's operations, capital development program and acquisitions have resulted in increases in the independent engineering estimated recoverable reserves. This has contributed to Bonterra's low finding, development and acquisition (FD&A) costs. At $13.25 per BOE on a Total Proved basis and $8.93 on a Proved Plus probable basis, Bonterra continues to record FD&A costs that are significantly below industry average. With an average cash netback of $23.42 per BOE, Bonterra's 2009 proved plus probable recycle ratio was 2.6 times.

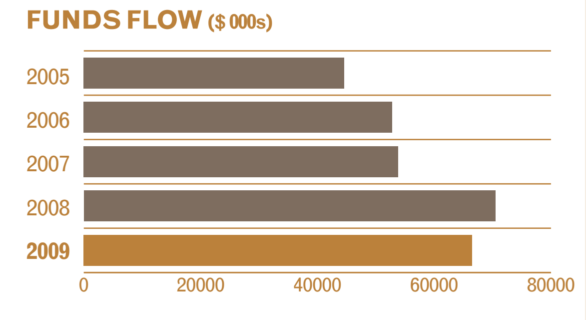
Bonterra completed asset sales in 2009 and in the first quarter of 2010, obtaining $35.8 million in dispositions from non-core assets in Saskatchewan. This included the divestment of approximately 270 BOE per day of producing oil and gas properties and an associated 1.4 million BOE of Proved plus Probable reserves. The proceeds from these sales will assist in accelerating the development of the Cardium assets.

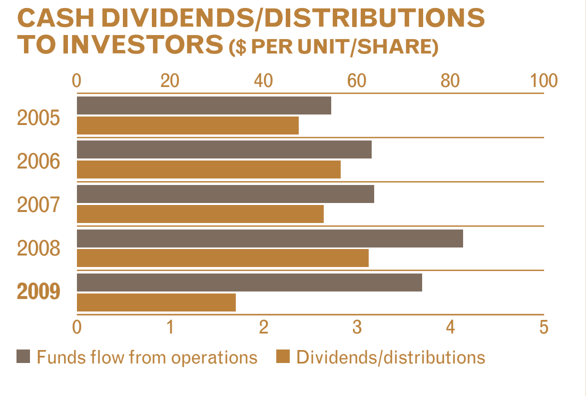












FINANCIAL STRENGTH

During the year, Bonterra took several steps towards improving its financial position. The Company entered into a new syndicated banking facility effective April 29, 2009 consisting of a $100 million syndicated revolving credit facility and a $20 million non-syndicated revolving credit facility. In addition, Bonterra completed an equity offering in May, 2009. The Company issued 1,068,000 common shares at a price of $16.85 per share for net proceeds of approximately $17 million. Funds were used for the Company's capital program and for general working capital purposes.

Bonterra is committed to seeking new ways to strengthen its financial position including cost-reduction initiatives, project reviews throughout the year and exploring and implementing operational efficiencies across the Company.

As a result of its strong financial position, Bonterra is sufficiently funded to execute the 2010 capital program and to pursue additional acquisition opportunities that may become available. It is the Company's goal to further decrease the debt to cash flow ratio by the end of 2010.

IMPROVING RETURNS TO INVESTORS

Financial results during 2009 were significantly impacted by the low commodity price environment. Revenue and funds flow from operations in 2009 decreased 30 percent and 6 percent, respectively when compared to the prior year primarily due to a 32 percent decrease in the Company's crude oil average realized price and a 50 percent decrease in the Company's natural gas average realized price partially offset by production increases and a gain on asset sale of $24.2 million in the fourth quarter of 2009. Commodity prices showed improvement during the latter half of the year, mainly in crude oil, and the fourth quarter numbers reflected a positive impact with a 250 percent increase in funds flow from operations in the fourth quarter of 2009 compared with the third quarter of 2009.

In 2009, Bonterra paid cash dividends to shareholders of $1.70 per share, a substantial decrease from the 2008 level of $3.12 per share. Bonterra had reduced its dividend in early 2009 to maintain its balance sheet strength and the financial flexibility necessary to continue developing the Pembina Cardium horizontal play. As pricing improved, Bonterra was able to increase the dividend twice during the year. Subsequent to year-end, Bonterra was able to once again increase the dividend to its current level of $0.18 per share which began with the dividend paid out in January, 2010.

Management and the Board of Directors monitor production volumes, commodity prices, operating costs, payout ratios and capital expenditures on a monthly basis to determine the dividend amount. Bonterra currently intends to pay out between 60 and 75 percent of its cash flow and retain the remainder for capital expenditures.

Bonterra continues to maintain that the best assessment of an entity is its return to investors. On a one-year basis, Bonterra's total return to shareholders was 117 percent. The improving global economic outlook, increasing commodity prices and additional value attributed to the Pembina Cardium horizontal play have increased the share price substantially over the course of the year providing investors with one of its best returns since inception. Bonterra has also performed well over longer periods of time. Total return to shareholders over a three year period (2007 – 2009) was 87 percent and over a five year (2005 – 2009) period was 132 percent.

OUTLOOK

Bonterra continues to execute its business plan strategically and with discipline. Bonterra has spent considerable effort developing in-house technical skills and building strategic land positions in and around its core areas. The 2010 capital development program will continue to target these advantages and focus on maximizing shareholder returns through the allocation of capital to its high return Pembina Cardium horizontal drilling program, the active pursuit of improved reserve recovery and continued improvements in ongoing operations.

Taking this approach will allow Bonterra to maintain its strong dividend policy, providing investors with a solid income investment paid on a monthly basis while ensuring the long-term sustainability of its business.

Management would like to take this opportunity to thank the Board of Directors for its counsel and advice and its shareholders for their continued support. In addition, Bonterra's team of employees must be acknowledged for their hard work and dedication in executing Company strategy and maximizing shareholder returns. The Company looks forward to capitalizing on its many opportunities in 2010 and will continue to strive to add further value on behalf of investors.

Submitted on behalf of the Board of Directors,

George F. Fink
Chairman and Chief Executive Officer

Randy M. Jarock
President and Chief Operating Officer

PROVED PLUS PROBABLE RESERVES (MBOE)

2009 RESERVES BY COMMODITY

* based on proved plus probable reserves

AVERAGE DAILY PRODUCTION (BOE per day)

OPERATIONS OVERVIEW:

Bonterra's asset base consists of stable, producing properties located mainly in the Pembina field in central Alberta as well as northeast British Columbia and Saskatchewan. Its property portfolio is characterized by a long reserve life and low-risk, predictable returns.

In 2009, the Company developed and expanded its Pembina Cardium multi-stage frac program. Bonterra has been at the forefront of developing this new, exciting play and has been successful in capitalizing on a significant upside.

Bonterra's approach to its operations has been to strategically allocate capital, continue to add to its significant land base and use advanced industry technology to develop its best opportunities.

Production and Reserves

Bonterra's production volumes average 4,994 BOE per day in 2009, an increase of 15 percent over 2008 levels. Production was comprised of approximately 63 percent crude oil and natural gas liquids (NGLs) and 37 percent natural gas. Production increases can be attributed to the 2009 Pembina Cardium horizontal and vertical drill programs, improved operations and acquisitions offset by the disposition of a portion of its Shaunavon property (approximately 210 BOE per day). As well, the Company's capital development program was executed during the second half of the year. As such, new production came on later in the year and thus its impact on the annual average production rates was moderated.

Operations

2009 PRODUCTION BY COMMODITY

Bonterra's low decline production results from its high-quality reserve base. In 2009, Bonterra increased Total Proved (TP) reserves by 5.0 percent and Proved plus Probable (P+P) reserves by 14.7 percent to total 25.3 million BOE and 35.8 million BOE, respectively. The Company's reserve life index on a P+P basis is 20.1 years, well above industry-average.

A total of 2.2 million BOE on a TP basis and 6.6 million BOE on a P+P basis of net reserves have been assigned to 28.1 net (34 gross) horizontal wells in the company's Pembina Cardium horizontal project (almost all in the Halo area). Development has been intentionally located beyond existing Cardium

pool production, in what is termed the Halo area, to reduce the possibility of drainage of existing wells and in production without any water. There is minimal production history so reserves could only be assigned to a limited number of locations at this time.

Once further drilling is completed and additional production history becomes available, new reserves may be assigned as geological information appears to indicate that the undeveloped lands that have not been assigned reserves have similar characteristics to currently producing lands to which reserves have been assigned. Based on drilling four horizontal wells per section on the Halo area lands, up to 99 gross (88 net) total wells could be drilled and have reserves assigned.

Using the same horizontal technology, Bonterra will also be evaluating the main portion of the Pembina Cardium pool where the Company has a much larger land base. The Company has more than 1,000 gross vertical locations in the Pembina Cardium field based on 40 acre spacing. The Company will be converting some of these locations to horizontal locations after its evaluation is completed.

Capital Development Program

During 2009, Bonterra spent approximately $22.9 million on its drilling program focusing mainly on the Pembina Cardium play. The Company drilled seven Pembina Cardium horizontal wells (5.5 net), eight vertical Pembina Cardium wells (6.9 net) and two natural gas wells (0.4 net) with a 100 percent success rate.

Bonterra's first horizontal well was drilled in 2008 and was placed on production in early 2009. Bonterra completed and tied in three (2.1 net) horizontal Cardium oil wells and six (4.9 net) vertical oil wells in 2009. The additional four (3.4 net) horizontal Cardium oil wells and two (2.0 net) vertical wells were placed on production in the first week of January 2010.

Subject to commodity prices and regulatory policies such as the Alberta government's competition review, Bonterra is projecting 2010 capital expenditures of $40 to $50 million. Most of the capital will once again be focused on the Pembina Cardium horizontal drilling program with 20 to 30 gross additional wells planned in 2010. Production is expected to average between 5,700 to 6,000 BOE per day.

Acquisitions and Divestitures

A key part of the Company's business has been to acquire additional lands in its core areas through both corporate acquisitions or land sales. In July 2009, Bonterra completed its acquisition of Cobalt Energy Ltd. (Cobalt) for a total calculated accounting cost of $7,105,000. The acquisition of Cobalt resulted in only a modest increase in production but provided the Company with additional ownership in the Pembina Cardium Halo area play, providing additional horizontal drilling opportunities. In addition Bonterra acquired and paid $5,814,000 for mineral rights in the greater Pembina area of Alberta. These lands are located throughout the Halo area of the Pembina field and an adjacent small amount in the Willesden Green field, providing additional opportunities for the Company in developing its horizontal drilling program.

Bonterra divested a portion of its Shaunavon oil production to Eagle Rock in November 2009. The proceeds of disposition consisted of $23,729,000 cash and 30,769,200 common shares in Eagle Rock (representing approximately 4.2 percent of the outstanding common shares of that company at the time). The closing price of the Eagle Rock common shares on November 6, 2009 was $0.21 placing total consideration for the property at $30,191,000. The book value (net of abandonment provision) of the property to the Company was approximately $5,993,000 resulting in a gain on sale of $24,198,000.

Eagle Rock has since changed its name to Wild Stream Exploration Inc. (Wild Stream) (TSXV: WSX) and consolidated its common shares on a 30:1 basis resulting in Bonterra holding 1,025,640 common shares of Wild Stream.

The funds were used to retire debt and provided additional room for Bonterra to accelerate its horizontal drilling program at Pembina.

Subsequent to year-end, the Company divested its non-core Southeast Saskatchewan Pinto property. Production from this property was approximately 60 BOE per day consisting primarily of higher-cost, light, sweet crude oil production. The proceeds of disposition consisted of approximately $5.6 million and proceeds were applied to the Company's debt. The disposition closed in February, 2010.

Operational Excellence

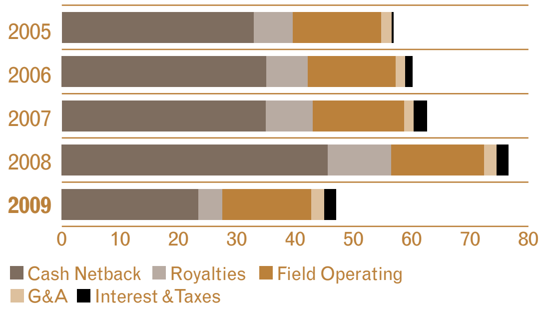
Bonterra's operating strategy continues to focus on reducing development risks, optimizing production volumes and lowering operating costs to maximize netbacks. On a per BOE basis, production costs have declined approximately 4.4 percent in 2009 compared to 2008 mainly due to field optimization and a general decline in service and material costs resulting from decreased industry demand.

Bonterra operates approximately 85 percent of its total production which allows the Company to better manage costs and efficiently invest capital through strategic scheduling of development programs, well workovers and facility upgrades.

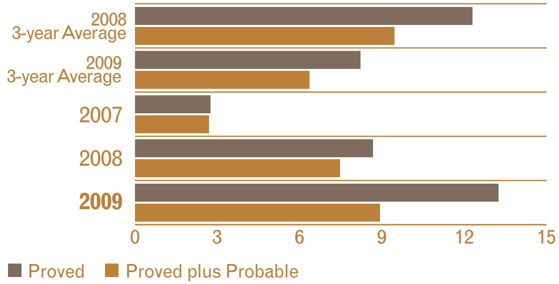
Finding, Development and Acquisition Costs

Finding, development and acquisition (FD&A) costs including future development costs in 2009 continue to be among the lowest in the industry. Results from Bonterra's ongoing operations, active capital development program and the successful drilling program continue to meet or exceed expectations. FD&A costs including acquisitions (and net of dispositions) in 2009 were $8.93 per BOE on a P+P basis compared with the previous three year average of $9.45 per BOE on a P+P basis (2006 – 2008).

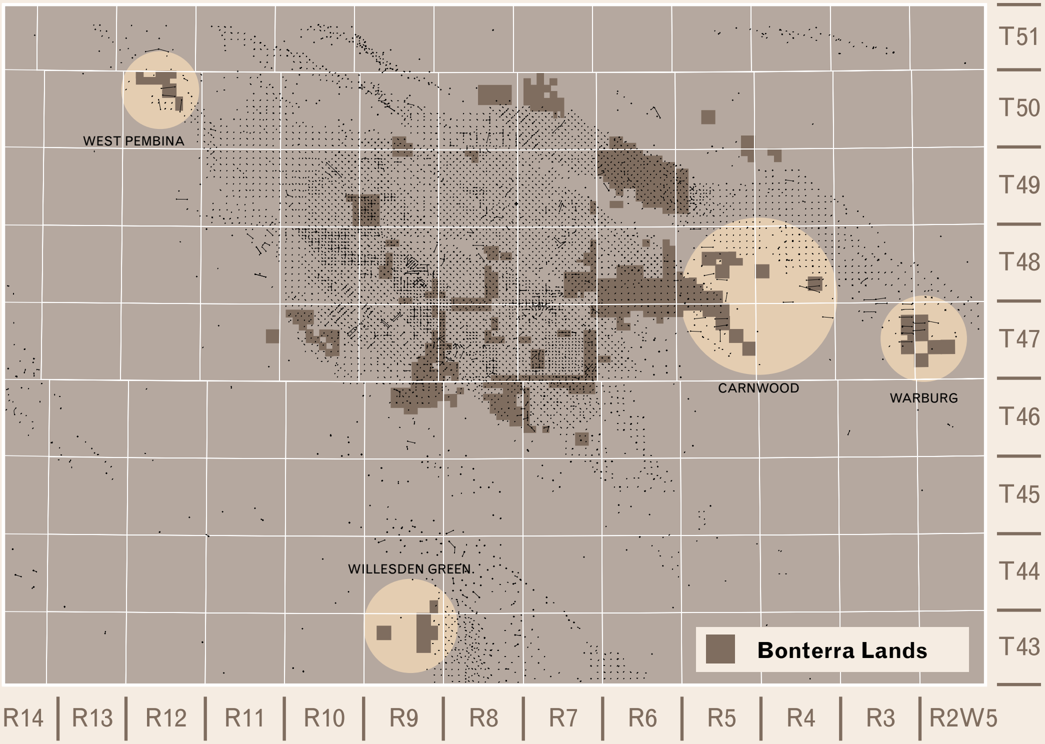
NETBACKS (AFTER REALIZED GAIN (LOSS) ON RISK MANAGEMENT CONTRACTS) ($ PER BOE)



FINDING, DEVELOPMENT & ACQUISITION COSTS (PROVED AND PROVED PLUS PROBABLE)



Pembina Cardium Horizontal Drilling



Overview

The Pembina Cardium field was discovered in 1953 and is now the largest conventional light oil field in Canada, currently covering 755,000 acres. This mature field has been historically exploited through infill drilling and waterflooding and has recently been further revitalized through the application of horizontal drilling and multi-stage frac technology.

As one of the largest, long-term players in the Pembina field, Bonterra has been on the forefront of successfully developing this play. The Company drilled the first successful Cardium Horizontal multi-stage fractured well in the Halo area of the Pembina field. The enormous resource potential, encouraging results and robust economics provide significant upside to the Company going forward.

Geology

The reservoir is a stratigraphic trap producing from the Cardium formation at a depth of 1,200 to 1,850 meters that contains neither bottom water nor a free gas cap. The Cardium formation consists of interbedded sandstone and shale which is capped in some areas with an effective higher permeability conglomerate. The Cardium sandstone is generally thicker, has higher porosity, lower permeability and therefore contains more of the original-oil-in-place than the conglomerate. The Cardium formation also exhibits a preferential southwest to northwest stress orientation that controls flow direction of fluids and hydraulic fracture orientation and therefore must be taken into account when selecting well locations in the Cardium.

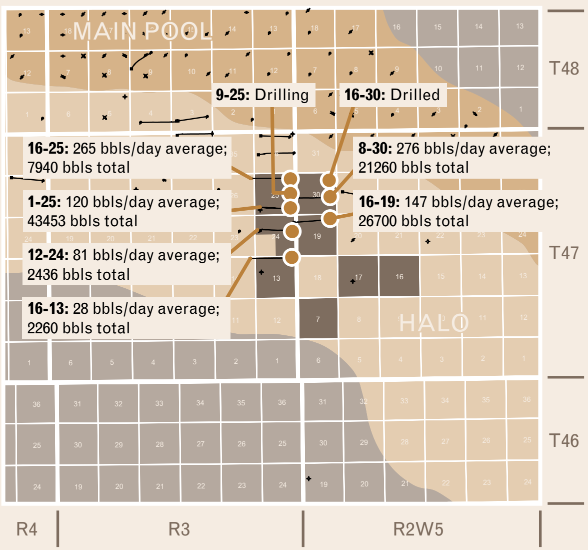
Economic vertical well production has historically been obtained in the main part of the Pembina Cardium pool and consists of clean, well-sorted sandstones which may or may not have had an effective conglomerate cap. Bonterra focused its initial horizontal development in the area surrounding the main part of the reservoir in what is referred to as the "Halo" area – an area in which vertical wells have been uneconomic to drill.

The Halo area consists mainly of extensively bioturbated, interbedded sand units that may have a thinner upper component of well sorted sandstone and generally does not have more than a thin inactive veneer of conglomerate overlying the formation. The application of the multi-stage fracture technology in the Halo area has allowed a portion of the reservoir that was once considered uneconomic to be actively developed into producing reserves.

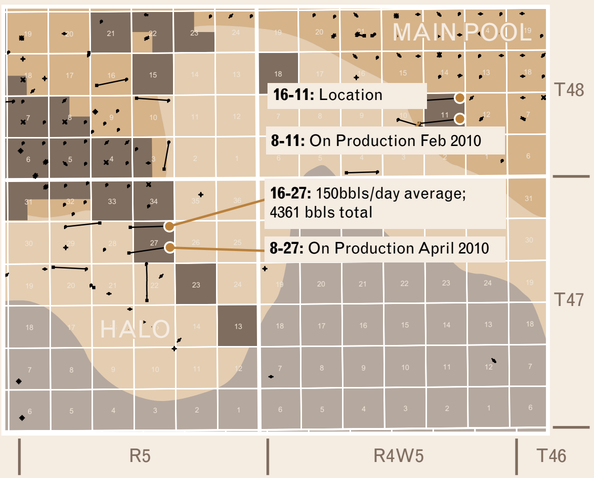
Land Base

Bonterra is the third largest land owner in the Pembina Cardium field with approximately 160 gross (117 net) sections of Cardium mineral rights. This includes 27.5 gross (23.0 net) sections in the Halo area and the adjacent Willesden Green field. The Halo area land holdings are particularly significant at this time as all Bonterra's wells have been drilled in this area and have experienced virgin pressures with no water production from waterflood.

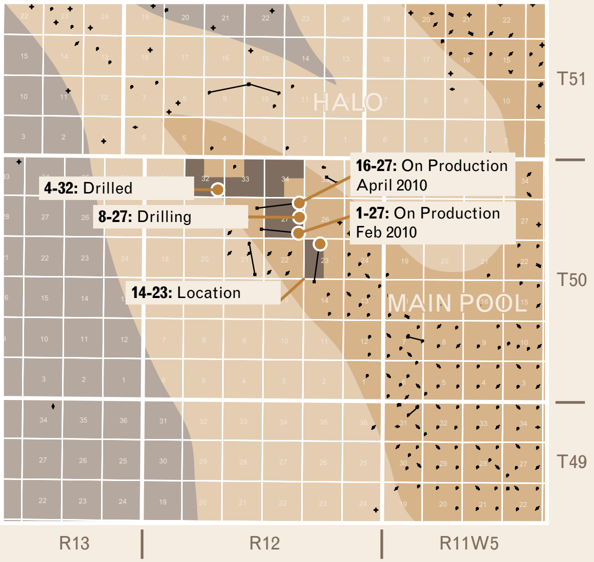
WARBURG



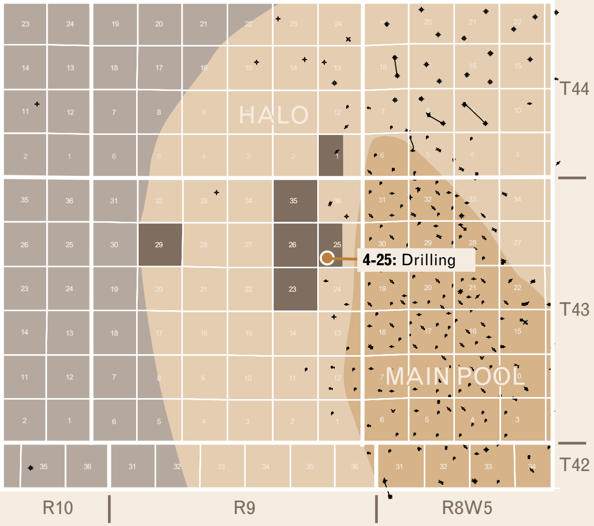
CARNWOOD



WEST PEMBINA



WILLESDEN GREEN LANDS



Bonterra's lands in the main part of the Pembina Cardium reservoir are generally underdeveloped when compared to other operators in the field who have typically drilled the Cardium down to 40 acre spacing (16 wells per section). Bonterra has over 1,000 gross additional vertical locations on existing lands if drilled to this spacing and the Company is currently evaluating converting at least some of these potential vertical locations to horizontals.

Drilling and Completion

Bonterra has applied conventional horizontal drilling technology to maximize the amount of Cardium reservoir accessed in each lateral leg. Depending on the well location, surface locations are chosen which both minimize the environmental footprint as well as optimize the section of the well for the area spacing requirements and future pumping equipment. Intermediate casing is set one meter into the Cardium sand which allows the lateral to begin traversing the sand from the top to find the most optimal placement within the sand according to area geology and reservoir simulation. The utilization of best drilling practices including bit selection and hydraulics, mud system design and maintenance and directional drilling combined with experienced wellsite supervision are key factors in achieving operational success. In 2009, Bonterra drilled eight (gross) horizontal wells averaging 1,220 meters in horizontal length without operational failure. The ongoing drilling target is to achieve between 1,200 to 1,300 meters of lateral length in each well.

Reserves

The Pembina Cardium field represents Canada's single largest conventional petroleum reservoir with an immense volume of original-oil-in-place estimated at over 7.8 billion barrels with an average recovery to date of approximately 17 percent. These original-oil-in-place and recovery numbers do not include the large Halo area.

Approximately 89.2 percent of the Company's Proved plus Probable (P+P) reserves and 84.6 percent of Total Proved (TP) reserves are assigned to the Cardium. Bonterra's reserves are very stable and its reserve life index at 14.2 years on a TP basis and 20.1 years on a P+P basis is one of the longest in the Canadian energy sector.

A total of 2.2 million BOE on TP basis and 6.6 million BOE on a P+P basis of reserves net to the company have been assigned to 28.1 net (34 gross) horizontal Cardium wells in this year's reserves report. The following table shows that reserves as high as 145 MBOE on a TP basis and 250 MBOE on a P+P basis have been assigned in our independent engineering evaluation.

	Mbbl / Well		MBOE / Well	
(Typical 100% Gross)	Proved	P+P	Proved	P+P
'Halo' Area with Successful Hz Producers	145	250	158	272
'Halo' Edge with Hz Production	66	125	72	136
'Halo' Area with Limited Hz Production History	0	250	0	272
'Halo' Area with Offsetting Vertical Well Production History	50-75	125-250	54-82	136-272
Wells in Waterflooded Portion of Main Pembina Cardium Pool	75	125	82	136

Reserves assigned varied for each well and was dependent upon the geology, development in the area and production history. Since there is minimal production history and the development in the Halo area is intentionally located beyond existing Cardium pool production to reduce the possibility of depletion and water production, reserves could only be assigned to a limited number of horizontal well locations at this time as per NI 51-101 standards. Once additional drilling is completed and additional production history is available, additional reserves could be assigned. Management believes that geological information indicates that the undeveloped lands that have not been assigned reserves have similar characteristics to currently producing lands to which reserves has been assigned.

A reserves simulation was conducted by Bonterra's independent engineering firm as part of the 2009 reserve evaluation. The simulation was based on limited production history conducted on the east portion of the Company's Halo area lands and indicated that lands could be developed at four wells per section without a reduction in reserves assigned for each well. Additional drilling density of up to seven wells per section was shown to result in a reduced recovery per well of 17.5 percent but still resulted in significant increased total reserves and an increased recovery factor.

Capital Development Program

Subject to commodity prices and regulatory and royalty policy, Bonterra is planning to drill approximately 20 to 30 gross horizontal Cardium wells in 2010. The majority of the horizontal wells will be in the Halo area. The Company has identified up to 65 gross (60 net) potential additional Cardium horizontal locations presently not included in the independent engineering evaluation based on drilling at four wells per section on Halo lands with no reserves currently assigned for a total of 99 gross wells (88 net wells).

Bonterra will also conduct some drilling in the main portion of the pool with the objective of converting some of the 1,000 gross potential vertical wells to horizontal locations.

Statistical Review

STATISTICAL REVIEW

Reserves

Bonterra engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of December 31, 2009. The reserves are located in the provinces of Alberta, British Columbia (BC) and Saskatchewan. Bonterra's largest producing area is located in the Pembina Field of Alberta, which contains 89.3 percent of the Company's reserves on a Proved plus Probable basis. The gross reserve figures for 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 Oil and Gas Reserves as of December 31, 2009

Reserve Category:	Light and Medium Oil Gross (Mbbl)	Natural Gas Gross (MMcf)	Natural Gas Liquids Gross (Mbbl)	BOE Gross (MBOE)
PROVED				
Developed Producing	14,248	32,103	1,271	20,869
Developed Non-Producing	220	760	7	354
Undeveloped	3,284	3,779	190	4,104
TOTAL PROVED	17,752	36,642	1,468	25,327
PROBABLE	7,923	12,896	425	10,497
TOTAL PROVED PLUS PROBABLE	25,675	49,539	1,893	35,824

Reconciliation of Company Gross Reserves by Principal Product Type as of December 31, 2009

	Light and Medium Oil and Natural Gas Liquids		Natural Gas		BOE	
	Gross Proved (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mmcf)	Gross Proved Plus Probable (Mmcf)	Gross Proved (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2008	17,991	22,867	36,571	50,246	24,086	31,241
Extension	1,983	6,062	1,024	2,540	2,154	6,485
Improved recovery	0	0	0	0	0	0
Technical revisions	2,138	1,579	3,350	1,034	2,696	1,751
Discoveries	0	0	0	0	0	0
Acquisitions	142	253	53	96	151	269
Dispositions	(1,010)	(1,151)	(7)	(9)	(1,011)	(1,152)
Economic factors	(877)	(895)	(290)	(309)	(925)	(947)
Production	(1,146)	(1,146)	(4,059)	(4,059)	(1,823)	(1,823)
December 31, 2009	19,220	27,568	36,642	49,539	25,327	35,824

Summary of Net Present Values of Future Net Revenue as of December 31, 2009

Net Present Values of Future Net Revenue
Before Income Taxes
Discounted at (% per Year)

($ Millions)	0%	5%	10%	15%	20%
Reserve Category:					
PROVED					
Developed Producing	1,045.3	580.8	407.6	319.1	264.8
Developed Non-Producing	15.8	13.0	11.2	9.9	9.0
Undeveloped	135.5	102.4	79.2	62.3	49.7
TOTAL PROVED	1,196.6	696.2	498.1	391.4	323.4
PROBABLE	702.9	260.6	135.6	84.7	58.4
TOTAL PROVED PLUS PROBABLE	1,899.5	956.9	633.7	476.1	381.8

Net Present Values of Future Net Revenue
After Income Taxes
Discounted at (% per Year)

($ Millions)	0%	5%	10%	15%	20%
Reserve Category:					
PROVED					
Developed Producing	903.8	533.5	387.5	309.1	259.4
Developed Non-Producing	11.8	10.6	9.6	8.9	8.3
Undeveloped	101.4	79.4	63.3	51.1	41.6
TOTAL PROVED	1,017.0	623.4	460.4	369.1	309.3
PROBABLE	527.4	195.8	102.5	64.5	44.9
TOTAL PROVED PLUS PROBABLE	1,544.5	819.2	562.9	433.7	354.2

Commodity prices used in the above calculations of reserves are as follows:

Year	Edmonton Par Price	Alberta Gas AECO-C Spot	Edmonton Propane	Edmonton Butane	Edmonton Pentane
	(Cdn $ per bbl)	(Cdn $ per MMBtu)	(Cdn $ per bbl)	(Cdn $ per bbl)	(Cdn $ per bbl)
2010	84.25	5.36	52.74	59.65	86.28
2011	89.99	6.21	56.33	63.72	92.16
2012	92.61	6.44	57.97	65.57	94.84
2013	96.19	7.23	60.21	68.11	98.51
2014	98.13	7.98	61.43	69.48	100.50
2015	100.11	8.16	62.67	70.89	102.53
2016	102.13	8.34	63.94	72.32	104.60
2017	104.19	8.52	65.23	73.78	106.71
2018	106.30	8.71	66.54	75.27	108.86
2019	108.44	8.90	67.89	76.79	111.06
2020	110.63	9.10	69.26	78.34	113.30

Crude oil, natural gas and liquid prices escalate at two percent per year thereafter.

2009 Finding and Development Costs (F&D) and Finding, Development and Acquisitions Costs (FD&A)

The Company has been active in its capital development program over the past three years. Over this time period Bonterra has incurred the following F&D and FD&A[3] Costs:

	2009 F&D Costs per BOE (1)(2)	2008 F&D Costs per BOE (1)(2)	2007 F&D Costs per BOE (1)(2)	**2009 Three Year Average**	2008 Three Year Average
Proved Reserve Additions	**$ 16.23**	$ 7.00	$ 2.15	**$ 8.46**	$ 11.55
Proved plus Probable Reserve Additions	**$ 11.01**	$ 6.82	$ 2.02	**$ 6.62**	$ 9.02

	2009 FD&A Costs per BOE (1)(2)(3)	2008 FD&A Costs per BOE (1)(2)(3)	2007 FD&A Costs per BOE (1)(2)(3)	**2009 Three Year Average**	2008 Three Year Average
Proved Reserve Net Additions	**$ 13.25**	$ 8.67	$ 2.74	**$ 8.22**	$ 12.30
Proved plus Probable Reserve Net Additions	**$ 8.93**	$ 7.47	$ 2.68	**$ 6.36**	$ 9.45

The above figures have been calculated in accordance with National Instrument 51-101 (NI 51-101) where the 2009 F&D Costs equate to the total exploration and development costs incurred by the Company of $28,726,000 (includes $5,814,000 for undeveloped land) as calculated according to GAAP plus or minus the yearly change in estimated future development costs as calculated by Sproule Associates Limited ($34,960,000 for Proved and $51,538,000 for Proved plus Probable). FD&A costs include acquisition costs of $7,105,000 as well as proceeds of disposition of $30,191,000.

The following precautionary notes have been provided as required by NI 51-101.

(1) Barrels of Oil Equivalent may be misleading, particularly if used in isolation. A BOE conversion ratio of 6MCF:1bbl 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.

All reserve numbers provided in the preceding tables are Bonterra's interest before royalties. It should not be assumed that the estimates of future net revenue presented in the above tables represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. Estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.

Production

The following table provides a summary of production volumes from the Company's main producing areas:

	2009		2008	
	Oils and NGLs (Bbls per day)	Natural Gas (MCF per day)	Oils and NGLs (Bbls per day)	Natural Gas (MCF per day)
Pembina area, AB	2,595	6,419	2,520	6,376
Shaunavon area, SK	318	-	313	-
Prespatou area, BC [1]	27	3,706	3	526
Other	201	995	237	735
	3,141	11,120	3,073	7,637

(1) The Northeast BC properties were acquired in the Silverwing acquisition which closed on November 12, 2008 and thus had little impact on 2008 production volumes.

Land Holdings

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

	2009		2008	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	168,749	106,785	152,917	92,438
Saskatchewan	14,483	12,793	31,182	28,000
British Columbia	73,910	30,373	73,910	30,373
	257,142	149,951	258,009	150,811

Petroleum and Natural Gas Capital 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:

	2009	2008
Land	$ 5,814,000	$ 376,000
Acquisitions	7,105,000	15,347,000
Disposals	(30,191,000)	-
Exploration and development costs	22,912,000	29,684,000
Net petroleum and natural gas capital expenditures	$ 5,640,000	$ 45,407,000

Drilling History

The following table summarizes the Company's gross and net drilling activity and success:

	2009					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	15.0	12.4	-	-	15.0	12.4
Natural gas	2.0	0.4	-	-	2.0	0.4
Dry	-	-	-	-	-	-
Total	17.0	12.8	-	-	17.0	12.8
Success rate	100%	100%	-	-	100%	100%

	2008					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	35.0	25.5	1	0.2	36.0	25.7
Natural gas	8.0	5.1	-	-	8.0	5.1
Dry	-	-	-	-	-	-
Total	43.0	30.6	1	0.2	44.0	30.8
Success rate	100%	100%	100%	100%	100%	100%

	2007					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	22.0	15.3	-	-	22.0	15.3
Natural gas	2.0	0.7	-	-	2.0	0.7
Dry	-	-	-	-	-	-
Total	24.0	16.0	-	-	24.0	16.0
Success rate	100%	100%			100%	100%

Tax Pools

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:

($000)	Rate of Utilization (%)	Amount
Undepreciated capital costs	20-100	$ 21,671
Eligible capital expenditures	7	7,363
Share issue costs	20	2,973
Canadian oil and gas property expenditures	10	26,282
Canadian development expenditures	30	59,141
Canadian exploration expenditures	100	11,174
SR&ED expenditures	100	80,357
Federal income tax losses carried forward(1)	100	223,629
		$ 432,590

(1) Federal income tax losses carried forward expire in the following years; 2013 – $1,069,000, 2024 – $3,347,000, 2025 – $7,532,000, 2026 – $46,670,000, 2027 – $117,189,000, 2028 – $34,726,000, 2029 – $13,096,000.

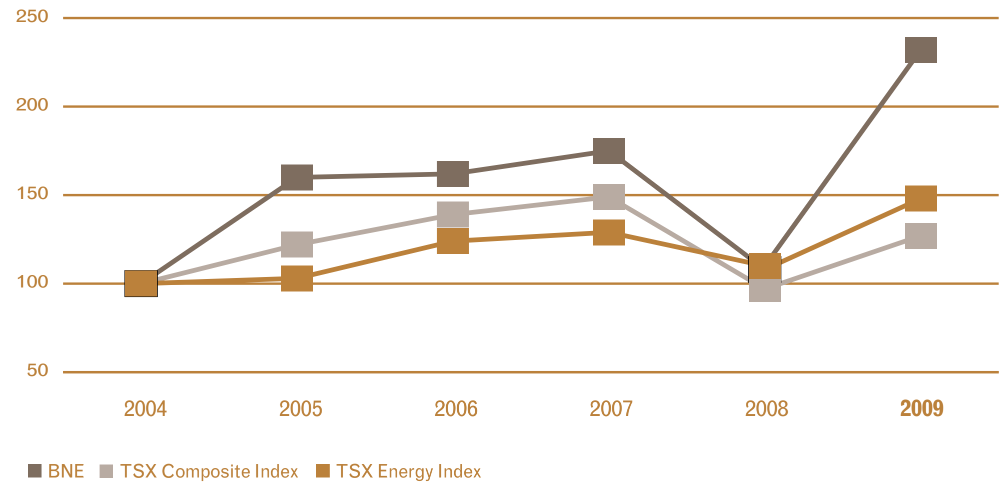
The Company has $27,670,000 (2008 – $27,670,000) remaining of investment tax credits that expire in the following years; 2019 – $3,469,000, 2020 – $3,059,000, 2021 – $4,667,000, 2022 – $3,909,000, 2023 – $3,155,000, 2024 – $1,995,000, 2025 – $2,257,000, 2026 – $2,405,000, 2027 – $2,009,000, 2028 – $745,000.

The Company also has $143,061,000 of capital loss carry forwards which can only be claimed against taxable capital gains.

SHARE/TRUST UNIT TRADING STATISTICS

(Based on daily closing price)		2009		2008
High	$	36.44	$	30.80
Low	$	13.50	$	15.50
Close	$	35.14	$	17.27
Daily Average Trading Volume		22,704		23,031

BONTERRA VS. THE INDICES



Management's Discussion and Analysis

This report dated March 9, 2010 is a review of the operations, current financial position, and outlook for Bonterra Energy Corp. ("Bonterra" or the "Company") (formerly Bonterra Oil & Gas Ltd.) and should be read in conjunction with the audited financial statements for the year ended December 31, 2009, together with the notes related thereto.

NON-GAAP MEASURES

Throughout this Management's Discussion and Analysis (MD&A) we use the terms "payout ratio" and "cash netback" to analyze operating performance. We calculate payout ratio by dividing cash dividends/distributions to shareholders/unitholders by cash flow from operating activities both of which are measures prescribed by GAAP which appear on our consolidated statements of cash flows. We calculate cash netback by dividing various operation and deficit statement items as determined by GAAP by total production on a barrel of oil equivalent basis.

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, statements 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; dividends; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

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

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 so, what benefits will be derived therefrom. Except as required by law, the Company 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.

ANNUAL COMPARISONS

	2009	2008	2007
Financial ($ 000s, except $ per share/unit)			
Revenue – realized oil and gas	**85,712**	121,730	96,431
Cash flow from operations	**38,893**	69,570	51,433
Per share / unit basic	**2.16**	4.07	3.04
Per share / unit diluted	**2.15**	4.06	3.04
Cash payments per share/unit (1)	**1.70**	3.12	2.64
Payout ratio (1)	**79%**	77%	87%
Net earnings	**68,563**	55,426	30,350
Per share / unit basic	**3.81**	3.25	1.79
Per share / unit diluted	**3.78**	3.23	1.79
Capital expenditures and acquisitions (net of disposals)	**5,640**	45,407	19,300
Total assets	**293,987**	265,301	142,326
Working capital deficiency	**10,162**	23,878	58,766
Long-term debt	**59,823**	79,910	-
Shareholders'/unitholders' equity	**118,874**	56,777	44,376
Operations			
Oil and liquids *(barrels per day)*	**3,141**	3,073	3,113
Natural gas (MCF per day)	**11,120**	7,637	6,627
Total BOE per day	**4,994**	4,346	4,218

(1) Cash dividend/disbursement payments per share/unit are based on payments made in respect of production months as opposed to the month paid.

QUARTERLY COMPARISONS

	2009			
	4th	3rd	2nd	1st
Financial ($ 000s, except $ per share)				
Revenue – realized oil and gas sales	24,946	20,965	20,501	19,300
Cash flow from operations	13,673	9,350	9,238	6,632
Per share basic	0.76	0.50	0.52	0.38
Per share fully diluted	0.75	0.50	0.52	0.38
Cash payments per share (1)	0.50	0.44	0.40	0.36
Payout ratio (1)	66%	87%	77%	94%
Net earnings	52,136	5,790	4,544	6,093
Per share basic	2.88	0.32	0.26	0.35
Per share fully diluted	2.85	0.32	0.26	0.35
Capital expenditures and acquisitions (net of disposals)	(16,976)	17,660	2,255	2,701
Total assets	293,987	273,543	258,393	260,732
Working capital deficiency	10,162	14,455	13,989	14,909
Long-term debt	59,823	81,386	71,573	89,383
Shareholders' equity	118,874	74,025	72,332	56,377
Operations				
Oil and liquids *(barrels per day)*	3,182	3,084	3,029	3,268
Natural gas *(MCF per day)*	10,193	10,881	11,551	11,877
Total BOE per day	4,881	4,898	4,954	5,245

(1) Cash dividend/disbursement payments per share/unit are based on payments made in respect of production months as opposed to the month paid.

	2008			
	4th	3rd	2nd	1st
Financial ($ 000s, except $ per share/unit)				
Revenue – realized oil and gas sales	22,613	34,226	34,398	30,493
Cash flow from operations	10,336	22,492	20,530	16,212
Per share / unit basic	0.59	1.31	1.21	0.96
Per share / unit fully diluted	0.59	1.30	1.20	0.96
Cash payments per share/unit (1)	0.62	0.96	0.84	0.70
Payout ratio (1)	105%	73%	69%	73%
Net earnings	10,585	21,125	12,912	10,804
Per share / unit Basic	0.62	1.23	0.76	0.64
Per share / unit fully diluted	0.62	1.22	0.75	0.64
Capital expenditures and acquisitions (net of disposals)	30,405	6,038	2,543	6,421
Total assets	265,301	150,120	153,247	150,169
Working capital deficiency	23,878	47,499	57,148	57,810
Long-term debt	79,910	-	-	-
Shareholders/unitholders' equity	56,777	57,623	46,612	48,136
Operations				
Oil and liquids *(barrels per day)*	3,055	2,998	3,009	3,153
Natural gas *(MCF per day)*	8,817	7,233	7,272	7,139
Total BOE per day	4,525	4,204	4,221	4,343

(1) Cash dividend/disbursement payments per share/unit are based on payments made in respect of production months as opposed to the month paid.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures (DC&P) are defined under National Instrument 52-109 – Certification of Disclosure Controls in Issuers' Annual and Interim Filings (NI 52-109) as "…controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers as appropriate to allow timely decisions regarding required disclosure." The Company has conducted a review and evaluation of its DC&P, with the conclusion that as at December 31, 2009 the Company has an effective system of DC&P as defined under NI 52-109. In reaching this conclusion, the Company recognizes that two key factors must be and are present:

1. the Company is very dependent upon its advisors and consultants (principally its legal counsels) to assist in recognizing, interpreting, understanding and complying with the various securities regulations disclosure requirements; and
2. the Company has an active Board and management with open lines of communication.

Bonterra has a small staff with varying degrees of knowledge concerning the various regulatory disclosure requirements. In many circumstances, the various regulatory requirements are relatively new, subject to interpretation, and complex. The Company is not of sufficient size to justify a separate department or one or more staff member specialists in this area. Therefore the Company must rely upon its advisors/consultants to assist it and as such they form part of the disclosure controls and procedures.

Proper disclosure necessitates that a person not only be aware of the pertinent disclosure requirements, but must also be sufficiently involved in the affairs of the Company and/or receives the communication of information to assess any necessary disclosure requirements. Accordingly, it is essential that there be proper communication among those people who manage and govern the affairs of the Company, this being the Board of Directors and senior management. The Company believes this communication exists.

While Bonterra believes it has adequate DC&P in place, lapses in the disclosure controls and procedures could occur and/or errors could occur. Should such occur, the Company intends to take whatever steps it deems necessary to minimize the consequences thereof.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls over financial reporting (ICFR) are defined in NI 52-109 as "… a process designed by, or under the supervision of, an issuer's certifying officers and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's Generally Accepted Accounting Practices (GAAP) and includes those policies and procedures that:

1. pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;
2. are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and
3. are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisitions, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial statements."

The Company has conducted a review and evaluation of its ICFR, with the conclusion that as of December 31, 2009 the Company's system of ICFR as defined under NI 52-109 is adequately designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. In addition, the Company has concluded that sufficient mitigating controls exist that the below mentioned weaknesses have resulted in no material impact on the Company's financial reporting or ICFR.

The control framework the Company used to design and evaluate its ICFR was COSO. In its evaluation, the Company identified certain weaknesses in internal controls over financial reporting:

1. due to the limited number of staff at the Company, it is not feasible to achieve the complete segregation of incompatible duties; and
2. due to the limited number of staff, the Company relies upon third parties as participants in the Company's internal controls over financial reporting.

The Company believes these weaknesses are mitigated by: the active involvement of senior management and the board of directors in the affairs of the Company; open lines of communication within the Company; the present levels of activities and transactions within the Company being readily transparent; the thorough review of the Company's financial statements by management, the board of directors and by the Company's auditors (annual statements only); and the establishment of a whistle-blower policy. Based on the above identified weaknesses, the Company has concluded that the Company's ICFR are ineffective. The mitigating factors will not necessarily prevent a misstatement occurring as a result of the aforesaid weaknesses in the Company's internal controls over financial reporting. A system of internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the internal controls over financial reporting are met. The Company has no plans for remediating the above weaknesses.

INTERNAL CONTROL CHANGES

The Company is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX (C-Sox). The 2009 certificate requires that the Company disclose in the MD&A any changes in the Company's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect the Company's internal control over financial reporting. The Company confirms that no such changes were made to the internal controls over financial reporting during 2009.

PRODUCTION

	Three months ended			Twelve months ended	
	December 31, 2009	September 30, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
Crude oil and NGLs (barrels per day)	**3,182**	3,084	3,055	**3,141**	3,073
Natural gas (MCF per day)	**10,193**	10,881	8,817	**11,120**	7,637
Average BOE per day	**4,881**	4,898	4,525	**4,994**	4,346

Barrels of oil equivalent (BOE) are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation.

Bonterra's 2009 average production increased 14.9 percent on a per BOE basis over 2008 despite the sale of the Shaunavon property of 210 BOE per day. Crude oil production increased by 2.2 percent while gas production increased by 45.6 percent. The natural gas increase was due primarily to the acquisition of Silverwing Energy Inc. (Silverwing) on November 12, 2008 which resulted in approximately 3,600 MCF per day being added to production.

On November 6, 2009, the Company disposed of a portion of its Shaunavon property for gross proceeds of $30,191,000. The production from this property was averaging approximately 210 BOE per day consisting entirely of medium grade crude oil.

In 2009, Bonterra drilled seven Pembina Cardium horizontal wells (5.5 net), eight vertical Pembina Cardium wells (6.9 net) and participated in drilling two natural gas wells (0.4 net). Bonterra recorded a 100 percent success rate with its 2009 drilling program. The Company's first horizontal well was drilled in 2008 and was placed on production in Q1 2009. Bonterra has completed and tied in three (2.1 net) horizontal Cardium oil wells and six (4.9 net) vertical oil wells in 2009. The additional four (3.4 net) horizontal Cardium oil wells and two (2.0 net) vertical wells were placed on production in the first week in Q1 2010.

In November, the Company engaged the services of a second drilling rig and in March a third drilling rig was added and will continue its Pembina Cardium horizontal well drilling program with all rigs until road bans are imposed in March 2010. The acquisition of Cobalt Energy Ltd. (Cobalt) effective July 1, 2009 resulted in only a modest increase in production but provided the Company with additional ownership in potential Pembina Cardium horizontal drilling opportunities.

Even with the above mentioned disposition, the company was able to increase its Q4 crude oil production through its 2009 Pembina Cardium horizontal and vertical drill programs. The Company's fourth quarter production in 2009 saw increases in crude oil of 98 barrels per day and a decline in natural gas of 688 MCF per day production over Q309. Exit production for the four (2.73 net) producing Pembina Cardium horizontal wells was approximately 456 (311 net) BOE per day. The Q4 natural gas decline is mainly due to shut in and restricting production of some of the Company's gas wells as well as natural production declines.

Bonterra expects 2010 production to average between 5,700 and 6,000 BOE per day.

REVENUE

	Three months ended			Twelve months ended	
(Cdn $)	**December 31, 2009**	September 30, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
Revenue – oil and gas sales (000s)	**24,946**	20,965	22,613	**85,712**	121,730
Average Realized Prices:					
Crude oil and NGLs (per barrel)	**68.40**	65.38	58.91	**59.82**	87.54
Natural gas (per MCF)	**4.76**	3.13	7.00	**4.15**	8.21

Revenue from petroleum and natural gas sales decreased 29.6 percent in 2009 compared to 2008 primarily due to a 31.7 percent drop in crude oil prices and a 49.5 percent drop in natural gas prices. The drop in commodity prices was partially offset with the above mentioned production increases. During 2009 the Company did not enter into any risk management contracts.

Quarter over quarter the Company saw an increase in revenues of $3,981,000 due to improved crude oil and natural gas prices in the fourth quarter of 2009.

ROYALTIES

	Three months ended			Twelve months ended	
($ 000s) except $ per BOE	**December 31, 2009**	September 30, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
Crown royalties	**1,451**	1,248	2,337	**4,737**	13,736
Freehold royalties, gross overriding royalties and net carried interests	**892**	697	558	**2,677**	3,479
Total royalty expense	**2,343**	1,945	2,895	**7,414**	17,215
Percentage of Revenue	**9.4**	9.3	12.8	**8.6**	14.1
$ per BOE	**5.22**	4.32	6.86	**4.07**	10.82

Royalties paid by the Company consist primarily of Crown royalties paid to the Provinces of Alberta, Saskatchewan and British Columbia. The majority of the Company's wells are low productivity wells and therefore have lower Crown royalty rates. The Company's average Crown royalty rate was approximately 5.5 percent (2008 – 10.6 percent) and approximately 3.1 percent (2008 – 2.7 percent) for other royalties. The increase in other royalty rates is due to the new horizontal oil wells being drilled on freehold mineral rights land.

The recently announced new Alberta Crown royalty rates vary by prices as well as productivity levels. With lower commodity prices in 2009 compared to 2008 and the Silvering acquisition (mostly BC production with lower Crown royalty rates) the Company has experienced a significant reduction in Crown royalties in 2009.

The fourth quarter royalties have increased $398,000 over third quarter due primarily to higher crude oil and natural gas pricing and an increased proportion of the Company's production coming from the new horizontal oil wells which are subject to freehold royalties at approximately 17 percent compared to a 5 percent royalty rate on Crown wells.

INVESTMENT TAX CREDIT RECOVERY

As part of the Company's conversion from a trust to a corporation in 2008, Bonterra assumed approximately $27,670,000 of investment tax credits (ITC's) from SRX Post Holdings Inc. Due to the depressed commodity prices as of December 31, 2008, the Company was not able to justify the ability to claim these ITC's prior to their expiration. The continued recovery in the price of crude oil as well as the Company's success in its horizontal crude oil development has resulted in significantly higher future anticipated cash flow from Bonterra's oil and gas operations and in the justification that the ITC's are likely to be claimed.

GAIN ON SALE OF PROPERTY

On November 6, 2009, the Company closed the sale of a portion of its Shaunavon oil production to Eagle Rock Exploration Ltd. (Eagle Rock) (TSXV: ERX). The proceeds of disposition consisted of $23,729,000 cash and 30,769,200 common shares in Eagle Rock (representing approximately 4.2 percent of the outstanding common shares of that company at the time). The closing price of the Eagle Rock common shares on November 6 was $0.21 placing total consideration for the property at $30,191,000. The book value (net of asset retirement provision) of the property to the Company was approximately $5,993,000 resulting in a gain on sale of $24,198,000.

Eagle Rock has since changed its name to Wild Stream Exploration Inc. (Wild Stream) (TSXV: WSX) and consolidated its common shares on a 30:1 basis resulting in Bonterra holding 1,025,640 common shares of Wild Stream.

PRODUCTION COSTS

	Three months ended			Twelve months ended	
($ 000s) except $ per BOE	**December 31, 2009**	September 30, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
Production costs	**6,870**	6,585	6,859	**27,848**	25,413
$ per BOE	**15.30**	15.79	16.25	**15.28**	15.98

Total production costs in 2009 have increased by $2,435,000 over 2008. The increase is due to increased production volumes (see Production). On a per BOE basis, production costs have declined in 2009 compared to 2008 mainly due to field optimization and a general decline in service and material costs resulting from decreased industry demand.

Total operating costs increased slightly in the fourth quarter of 2009 compared to the prior quarter due primarily to the billing of prior year gas processing charge adjustments in 2009 of approximately $200,000 by the operator of several of the Company's non-operated gas plants. On a per-unit-of-production basis, the 2009 rates were $0.49 lower than in 2008.

As discussed above, Bonterra's production comes primarily from low productivity wells. These wells generally result in higher operating costs on a per-unit-of-production basis as costs such as municipal taxes, surface leases, power and personnel costs are not variable with production volumes. The Company is continually examining ways to reduce operating costs.

GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended			Twelve months ended	
($ 000s) except $ per BOE	**December 31, 2009**	September 30, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
G&A Expense	**1,623**	788	824	**4,458**	3,401
$ per BOE	**3.61**	1.75	1.95	**2.45**	2.14

General and administrative (G&A) expenses increased 31 percent in 2009 compared to 2008. The Company provides administrative services to Comaplex Minerals Corp. (Comaplex) (TSX: CMF) and Pine Cliff Energy Ltd. (Pine Cliff) (TSXV: PNE), companies that share common directors and management. Please refer to discussion under Related Party Transactions for details.

The Company's significant general and administrative costs are employee compensation; professional services such as legal, engineering and accounting; computer services and bank charges. Employee compensation expense decreased by approximately 7 percent ($279,000) in 2009 from 2008 due to a smaller bonus accrual. The Company's bonus plan consists of cash payments equal to three percent of before tax net earnings (excluding the investment tax credit recovery) to be paid to employees and key consultants based on performance throughout the year. Costs associated with professional services increased by approximately $115,000 due to additional accounting (new production accounting software) and engineering services (horizontal well evaluations).

Computer services increased by $367,000 due to significant increases in the cost of new licensing agreements for the Company's engineering and accounting software and the contracting of an external manager of IT. The largest increase to G&A was bank charges of $678,000 relating to the cost of establishing a new bank facility as well as increased standby fees on the unused portion of the Company's credit facility.

The quarter over quarter increase of $835,000 was primarily due to a special bonus accrual of approximately $532,000 on the gain on sale of the Shaunavon property, legal and accounting costs increase of approximately $80,000 associated with the amalgamation of the various Bonterra entities in December of 2009 and $55,000 of engineering costs associated with various horizontal well evaluations.

During the year the Company capitalized $359,000 (2008 – $426,000) of general and administrative costs.

INTEREST EXPENSE

	Three months ended			Twelve months ended	
($ 000s) except $ per BOE	**December 31, 2009**	September 30, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
Interest Expense	**738**	815	746	**3,294**	2,740
$ per BOE	**1.64**	1.81	1.77	**1.81**	1.72

Bank debt at December 31, 2009 was $59,823,000 (December 31, 2008 – $93,235,000). The Company's banking arrangements allow it to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one half percent lower than that charged on the general loan account.

The Company has also borrowed $23,500,000 from two related parties. Please see Related Party Transactions section for further details.

Interest charges increased in 2009 as the average outstanding debt balance (including related party balances) increased by approximately $22 million over 2008. The acquisitions of Silverwing and Cobalt as well as the reorganization costs to change Bonterra into a corporation resulted in approximately $47 million of additional debt. In addition the Company has incurred approximately $28 million in capital expenditures during this period. These increases were partially offset by net proceeds of approximately $17,000,000 from a 2009 second quarter private equity issue and approximately $24 million cash on the sale of the Shaunavon property in November. Offsetting the increased debt balance was an average reduction of 0.3 percent (4.3 percent in 2008 to 4.0 percent in 2009) in interest rates paid on the outstanding debt balances.

Quarter over quarter saw a decrease in interest charges due to reduced debt balances resulting from proceeds of the Shaunavon sale being applied to the bank debt.

Effective April 29, 2009, the Company entered into a new bank facility with new terms and conditions. The new facility consists of a $100,000,000 syndicated revolving credit facility and a $20,000,000 non-syndicated revolving credit facility.

The interest rate on the credit facility is calculated as follows:

	Level I	Level II	Level III	Level IV	Level V
Consolidated Total Funded Debt (1) to Consolidated Cash flow Ratio	Under 1.0:1	Over 1.0:1 to 1.5:1	Over 1.5:1 to 2.0:1	Over 2.0:1 to 2.5:1	Over 2.5:1
Canadian Prime Rate Plus (2)	125	150	175	200	250
Bankers' Acceptances Rate Plus (2)	275	300	325	350	400

(1) Consolidated total funded debt excludes related party amounts but includes working capital.
(2) Numbers in table represent basis points.

Consolidated total funded debt to consolidated cash flow ratio shall be adjusted effective as of the first day of the next fiscal quarter following the end of each fiscal quarter, with each such adjustment to be effective until the next such adjustment.

As of December 31, 2009 the Company will qualify for the Level I interest rates. The revised rates will apply commencing April 1, 2010 resulting in a reduction of 50 basis points in the cost of the Company's bank borrowings.

REORGANIZATION COSTS

Based on accounting principles, costs associated with the Trust's 2008 reorganization into Bonterra Oil and Gas Ltd. must be expensed. The costs consisted of a $1,000,000 finders fee paid to a company that facilitated the reorganization, $931,000 of professional fees, $150,000 stock exchange fees and $40,000 of costs associated with the distribution of the reorganization document. These costs were all one-time costs and no further costs were incurred by the Company in direct relation to the reorganization.

STOCK-BASED COMPENSATION

Stock-based compensation is a statistically calculated value representing the estimated expense of issuing employee stock options. The Company records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. The Company issued only 33,000 stock options during 2009 resulting in a reduction of stock-based compensation by $296,000.

The 33,000 common share options were issued with an exercise price of $14.90 per share and a fair value of $1.58 per option. The fair value of the options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 1.4 percent (2008 – 2.2 percent), expected weighted average volatility of 33 percent (2008 – 31 percent), expected weighted average life of 3.0 years (2008 – 3.5 years) and an annual dividend/distribution rate based on the dividends paid to the shareholders during the year.

DEPLETION, DEPRECIATION, ACCRETION AND DRY HOLE COSTS

The Company follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. For intangible capital costs that result in the addition of reserves, the Company depletes its oil and natural gas intangible assets using the unit-of-production basis by field.

For tangible assets such as well equipment, a life span of ten years is estimated and the related tangible costs are depreciated at one tenth of original cost per year. The use of a ten year life span instead of calculating depreciation over the life of reserves was determined to be more representative of actual costs of tangible property. Given the Company's long production life of its wells, the wells generally require replacement of tangible assets more than once during their life time. Most of the Company's wells have been producing since the 1960's and are expected to continue to produce for at least another twenty years.

Provisions are made for asset retirement obligations through the recognition of the fair value of obligations associated with the retirement of tangible long-life assets being recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is adjusted over time for changes in the value of the liability through accretion charges which are included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

At December 31, 2009, the estimated total undiscounted amount required to settle the asset retirement obligations was $64,482,000 (2008 – $58,903,000). Of the $5,579,000 increase, the majority is due to increases in anticipated costs of abandoning the Company's producing and non producing wells.

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 credit-adjusted risk-free interest rate of five percent. The discount rate is reviewed annually and adjusted if considered necessary. A change in the rate would have a significant impact on the amount recorded for asset retirement obligations. Based on the current provision, a one percent increase in the risk adjusted rate would decrease the asset retirement obligation by $2,870,000. While a one percent decrease in the risk adjusted rate would increase the asset retirement obligation by $3,949,000.

The above calculation requires an estimation of the amount of the Company's petroleum reserves by field. This figure is calculated annually by an independent engineering firm and is used to calculate depletion. This calculation is to a large extent subjective. Reserve adjustments are affected by economic assumptions as well as estimates of petroleum products in place and methods of recovering those reserves. To the extent reserves are increased or decreased, depletion costs will vary.

For the fiscal year ending December 31, 2009, the Company expensed $19,277,000 (2008 – $14,749,000) for the above-described items. The increase is predominately due to increased production volumes resulting from the Silverwing acquisition and higher per BOE depletion charges on the Company's horizontal Cardium oil wells compared to Bonterra's other production. The higher BOE depletion charges on the horizontal wells are primarily due to lack of production history on these wells resulting in lower proved reserve being assigned but with substantial probable reserves being assigned. The Company's policy is to deplete the cost of the wells based on proved reserves. It is anticipated that as there is more production history on the horizontal wells there will be a conversion of the probable reserves to proven reserves resulting in a reduction of depletion charges per BOE in future years.

The Company continues to have relatively low finding and development costs (see discussion under Finding and Development Costs). Based on year end reserves, the Company's average cost of proved reserves is $6.62 (2008 – $6.40) per BOE.

The Company currently has an estimated reserve life for its proved developed producing reserves of 11.7 (2008 – 12.5) years calculated using the Company's gross reserves (prior to allowance for royalties) based on the third party engineering report dated December 31, 2009 and using fourth quarter 2009 average production rates of 4,879 BOE per day (2008 – 4,587 BOE per day). Based on total proved reserves the Company has a 14.2 (2008 – 14.4) year reserve life and on a proved and probable basis the reserve life increases to 20.1 (2008 – 18.7) years. These figures are some of the longest reserve life indexes (excluding oil sands) in the Canadian oil and gas industry.

INCOME TAXES

On November 12, 2008, Bonterra Energy Income Trust converted to a corporation. As a result of the reorganization, the Company has recorded a future income tax asset and a corresponding deferred tax credit. These amounts will be amortized into future tax expense as the associated tax pools are consumed.

The current tax provision of $551,000 consists of a resource surcharge of $282,000 payable to the Province of Saskatchewan and a tax amount of $269,000 payable to the Province of Quebec. The resource surcharge is calculated as a flat percent of revenues generated from the sale of petroleum products produced in Saskatchewan. The resource surcharge rate was three percent in 2009. The tax payable to the Province of Quebec is a one-time charge that resulted from the Company's conversion to a corporation.

The Company and its subsidiaries have 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	$	21,671
Eligible capital expenditures	7		7,363
Share issue costs	20		2,973
Canadian oil and gas property expenditures	10		26,282
Canadian development expenditures	30		59,141
Canadian exploration expenditures	100		11,174
SR&ED expenditures	100		80,357
Income tax losses carried forward (1)	100		223,629
		$	432,590

(1) Federal income tax losses carried forward expire in the following years; 2013 – $1,069,000, 2024 – $3,347,000, 2025 – $7,532,000, 2026 – $46,670,000, 2027 – $117,189,000, 2028 – $34,726,000, 2029 – $13,096,000.

The Company has $27,670,000 (2008 – $27,670,000) remaining of investment tax credits that expire in the following years; 2019 – $3,469,000, 2020 – $3,059,000, 2021 – $4,667,000, 2022 – $3,909,000, 2023 – $3,155,000, 2024 – $1,995,000, 2025 – $2,257,000, 2026 – $2,405,000, 2027 – $2,009,000, 2028 – $745,000.

The Company also has $143,061,000 of capital loss carry forwards which can only be claimed against taxable capital gains.

NET EARNINGS

	Three months ended			Twelve months ended	
($ 000s) except $ per share	**December 31, 2009**	September 30, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
Net Earnings	**52,136**	5,790	10,585	**68,563**	55,426
$ per share- Basic	**2.88**	0.32	0.62	**3.81**	3.25
$ per share- Fully Diluted	**2.85**	0.32	0.62	**3.78**	3.23

Bonterra's net earnings for the year ended December 31, 2009 represents a 23.7 percent increase over the Company's 2008 net earnings. The Company recorded net earnings per share in 2009 of $3.81 compared to $3.25 in the 2008 year. This represents a return on Shareholders' equity of approximately 57.7 percent (2008 – 97.6 percent) based on year end Shareholders' equity.

Two significant factors contributing to net earnings were the Company's recordings of the investment tax credit recovery of $27,670,000 and the sale of a portion of the Company's Shaunavon production for a gain of $24,198,000 all of which occurred in the fourth quarter of 2009. Excluding these items (net of 29.15 percent tax effect), 2009 net earnings decreased by $23,611,000 from $55,426,000 in 2008 to an adjusted net earnings of $31,815,000 in 2009. Reduced revenues resulting from decreased commodity prices were the main reason for the reduction. This reduction was partially offset by production volume gains. The Company continues to return in excess of 25 percent of its gross realized oil and gas revenues in net earnings. The Company's low capital costs per BOE of reserves combined with the Company's low production decline rates should allow for continued positive earnings.

COMPREHENSIVE INCOME

Other comprehensive income for 2009 consists of an unrealized gain on investments (including investments in a related party) of $600,000 (2008 loss of $1,611,000) including a fourth quarter loss of $478,000 relating to a reduction in the investments fair value. Other comprehensive income varies from net earnings by changes in the fair value of Bonterra's holdings of investments including the investment in Comaplex.

CASH FLOW FROM OPERATIONS

	Three months ended			Twelve months ended	
($ 000s) except $ per share	**December 31, 2009**	September 30, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
Cash flow from operations	**13,673**	9,350	10,336	**38,893**	69,570
$ per share-basic	**0.76**	0.50	0.59	**2.16**	4.07
$ per share-fully diluted	**0.75**	0.50	0.59	**2.15**	4.06

Cash flow from operations decreased 44 percent year over year, mainly due to decreased commodity prices received in 2009. Fourth quarter cash flow increased by $4,325,000 over Q3 due to recovering commodity prices. The Company has not entered into any risk management agreements and as such is fully exposed to changes in commodity prices and exchange rates.

CASH NETBACKS

The following table illustrates the Company's cash netback:

$ per Barrel of Oil Equivalent (BOE)	2009	2008
Production volumes (BOE)	1,822,628	1,590,666
Gross production revenue	$ 47.04	$ 81.15
Realized gain (loss) on risk management contracts	-	(4.62)
Royalties	(4.07)	(10.82)
Production costs	(15.28)	(15.98)
Field netback	27.69	49.73
General and administrative (1)	(2.16)	(2.14)
Interest and taxes	(2.11)	(2.00)
Cash netback	$ 23.42	$ 45.59

The following table illustrates the Company's cash netback for the three months ended:

$ per Barrel of Oil Equivalent (BOE)	December 31, 2009	September 30, 2009
Production volumes (BOE)	448,892	450,616
Gross production revenue	$ 55.50	$ 47.81
Royalties	(5.22)	(4.32)
Production costs	(15.30)	(15.79)
Field netback	34.98	27.70
General and administrative (1)	(2.43)	(1.75)
Interest and taxes	(1.80)	(1.99)
Cash netback	$ 30.75	$ 23.96

(1) General and administrative costs have been reduced by $532,000 relating to the bonus payment on the gain on sale of property as the benefit has not been included in the above cash net back calculation.

RELATED PARTY TRANSACTIONS

The Company holds 689,682 (2008 – 689,682) common shares in Comaplex which have a fair market value as of December 31, 2009 of $4,827,000 (2008 – $2,131,000). Comaplex is a publically traded mineral company on the Toronto Stock Exchange. The Company's ownership in Comaplex represents less than one percent of the issued and outstanding common shares of Comaplex. The Company has common directors and management with Comaplex.

Comaplex paid a management fee to the Company of $330,000 (2008 – $330,000). Comaplex also shares office rental costs and reimburses the Company for costs related to employee benefits and office materials. In addition, Comaplex owns 204,633 (December 31, 2008 – 204,633) common shares in the Company. Services provided by the Company include executive services (president and vice president, finance duties), accounting services, oil and gas administration and office administration. In addition, Bonterra allocated $102,000 of drilling tax credits to Comaplex for $51,000. All services performed are charged at estimated fair value. At December 31, 2009, Comaplex owed the Company $105,000 (December 31, 2008 – $56,000).

As of December 31, 2009, Comaplex has loaned the Company $12,000,000 (December 31, 2008 – Nil). The loan is unsecured and it has no set repayment terms. Until June 30, 2009 the Company paid interest at Canadian chartered bank prime plus one quarter of a percent. Effective July 1, 2009, the interest rate was reduced to Canadian chartered bank prime less 0.25 percent. The reduction in rate was due to the lowering of the Company's bank interest rate with its banking syndicate resulting from an improved debt to cash flow ratio (see Interest Expense and Liquidity and Capital Resources sections) and since the benefits of this loan are shared with Comaplex, the interest rate was reduced accordingly.

In 2008, in order to facilitate the acquisition of Silverwing, the Company borrowed on a short-term basis $20,000,000 from Comaplex to allow time to finalize documentation for its new bank line of credit. The funds were repaid on November 21, 2008.

Interest paid on these loans during 2009 and 2008 was $194,000 and $21,000, respectively. The loans result in a substantial benefit to Bonterra and to Comaplex. The interest paid to Comaplex by Bonterra is substantially lower than bank interest and the amount drawn on the bank line of credit is lower reducing the bank interest rate. For Comaplex, the interest earned is substantially higher than Comaplex would receive by investing in bank instruments such as BA's or GIC's.

The Company also has a management agreement with Pine Cliff. Pine Cliff has common directors and management with the Company. Pine Cliff trades on the TSX Venture Exchange. Pine Cliff paid a management fee to the Company of $120,000 (2008 – $238,000). Services provided by the Company include executive services (president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. The Company has no share ownership in Pine Cliff. As at December 31, 2009 the Company had an account receivable from Pine Cliff of $1,000 (December 31, 2008 – $1,000).

As of December 31, 2009, the Company's CEO and major shareholder has loaned the Company $11,500,000 (December 31, 2008 – $6,000,000). The loan is unsecured, bears interest at Canadian chartered bank prime and has no set repayment terms. Effective July 1, 2009, the interest rate was also decreased to Canadian chartered bank prime less .25 percent. Interest paid on this loan in 2009 was $209,000 (2008 – $7,000). This loan results in being a substantial benefit to Bonterra and to the CEO. The interest paid to the CEO by Bonterra is substantially lower than bank interest and for the CEO the interest earned is substantially higher than the CEO would receive by investing in bank instruments such as BA's or GIC's.

COMMITMENTS

The Company has no contractual obligations that last more than a year other than its office lease agreements which are as follows:

Lease Obligations ($ 000s)	
Year 1	$ 944
Year 2	932
Year 3	829
Year 4	496
Total	$ 3,201

FINANCIAL REPORTING UPDATE

On January 1, 2009, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3064, "Goodwill and Intangible Assets". The new section replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard had no impact on the Company's consolidated financial statements.

On January 20, 2009, the Company adopted the CICA's Emerging Issues Committee (EIC) EIC-173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". The EIC provides guidance on how to take into account credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of EIC-173 had no impact on the Company's consolidated financial statements.

In December 2008, the CICA issued Section 1582, "Business Combinations", which will replace former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011 with earlier adoption permitted.

In December 2008, the CICA issued Sections 1601, "Consolidated Financial Statements", and 1602, "Non-controlling Interests", which replaces existing Section 1600. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier adoption permitted. Section 1602 currently does not impact the Company as it has full controlling interest of all of its subsidiaries.

In 2009, the CICA issued amendments to CICA Handbook Section 3862, "Financial Instruments – Disclosures". The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009. The amendments are consistent with recent amendments to financial instrument disclosure standards in IFRS. The Company has included these additional disclosures in Note 16.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

The Accounting Standards Board has confirmed the convergence of Canadian GAAP with International Financial Reporting Standards (IFRS) will be effective January 1, 2011. From that point onward the Company will be required to account for and report under IFRS.

Although the International Accounting Standards Board (IASB) intends to revise several standards between now and 2011, IFRS will be adopted in Canada utilizing a "big bang" approach, with the exception of some Canadian GAAP changes that have occurred or will occur in periods leading up to the transition date.

The IASB has undertaken a number of projects, many being joint projects with the Financial Accounting Standards Board in the U.S., that may significantly change existing international standards.

This degree of activity currently being undertaken by the standard setters makes the convergence from Canadian GAAP to IFRS a moving target. Due to these likely changes, careful monitoring of developments will be required in order to understand fully the accounting and business implications of the new requirements.

The Company in the fourth quarter of 2009 commenced phase two of the process of conversion to IFRS by engaging its external auditors to perform a detailed review of the of the implementation of IFRS on the Company's high impact and medium impact areas identified below:

High impact areas:

- IFRS 1 – First time adoption of IFRS
- IFRS 3 – Business combinations
- IAS 16 – Property and equipment
- IAS 36 – Impairment of assets

Medium impact areas include:

- IFRS 6 – Exploration and evaluation of mineral resources
- IFRS 2 – Share-based payments
- IAS 1 – Presentation of financial statements
- IAS 10 – Events after the balance sheet date
- IAS 12 – Income Taxes
- IAS 18 – Revenues
- IAS 23 – Borrowing costs
- IAS 39 – Financial instruments, recognition and measurement
- IAS 37 – Provisions, contingent liabilities and contingent assets

The Company in conjunction with its auditors are currently finalizing phase two with an anticipated completion date of June 3, 2010 to determine accounting policies and the resulting numerical changes to opening balance sheet items. The Company anticipates commencing phase three (financial statement and note compilation) during the third quarter of 2010. Key information will be disclosed as it becomes available during the transition period.

The impact of IFRS will be significant; however the Company has always maintained an accounting policy of successful efforts for property and equipment that will result in a major reduction in the level of conversion compared to most oil and gas companies who used the full cost accounting policy.

The Company has implemented a new financial accounting system that provides for sufficient detail to comply with the IFRS requirements. As the Company has been using successful efforts since its inception, detail at a well level has been maintained under its past and current financial accounting systems as well as procedures are in place to capture this information at the operational level.

Implications to the Company's controls for DC&P and ICFR are being reviewed; however the Company believes that the majority of the procedures in place will apply once IFRS is implemented. Training will be required and is ongoing. Individuals within the Company have been and will continue to attend courses, seminars and other training activities to ensure the Company is adequately prepared for IFRS. Use of external legal expertise will be used to ensure compliance is maintained with all contractual agreements.

LIQUIDITY AND CAPITAL RESOURCES

During 2009, Bonterra participated in drilling 17 gross wells (12.8 net) at a total cost of $22,912,000. Included in the above figure is approximately $1,300,000 of costs associated with the completion and tie-in of wells the Company drilled in 2008. The above capital cost is net of $3,836,000 in drilling tax credits. In addition, Bonterra acquired and paid $5,814,000 for mineral rights in the greater Pembina area of Alberta.

On July 2, 2009, Bonterra completed its acquisition of Cobalt. The Company issued 201,438 common shares and assumed $2,856,000 of negative working capital and incurred approximately $170,000 in acquisition costs for a total calculated accounting cost of $7,105,000. This acquisition resulted in acquiring an additional 40 BOE per day of production as well as increasing the Company's working interest in approximately 11 gross sections of land with potential Cardium horizontal locations in the Pembina area of Alberta.

As previously discussed, the Company closed a purchase and sale agreement to divest of a portion of its Shaunavon oil production to Eagle Rock. The proceeds of disposition included cash of $23,729,000 and 30,769,200 common shares. These funds were used to retire debt and therefore provide additional room in Bonterra's line of credit for additional 2010 drilling. In addition, the common shares received for the Shaunavon properties will provide further funds upon their ultimate sale.

Subsequent to December 31, 2009, the Company entered into a purchase and sale agreement to divest its Southeast Saskatchewan Pinto property. Production from this property was approximately 60 BOE per day consisting primarily of light sweet crude oil. The proceeds of disposition consist of approximately $5,600,000 cash. The disposition closed in February, 2010. The proceeds were applied to the Company's debt.

The government of Alberta announced drilling incentives and royalty reductions in respect of wells drilled after April 1, 2009 and prior to March 31, 2011. The Company is planning to maximize the crown royalty credits available under the new drilling incentive program which will result in a substantial reduction of capital costs on a per well basis. The Company currently has plans to spend between $40,000,000 and $50,000,000 (net of drilling incentives) in 2010 on development of its oil and gas properties. Any land, property or corporate acquisitions will be in addition to this amount.

Bonterra anticipates funding the 2010 capital program from cash flow, the Company's existing line of credit, sale of investments, proceeds from the above mentioned Pinto sale as well as proceeds received on the exercise of employee stock options.

Effective April 29, 2009, the Company entered into a new bank facility. The new facility consists of a $100,000,000 syndicated revolving credit facility and a $20,000,000 non-syndicated revolving credit facility. At December 31, 2009, the Company's bank loan was $59,823,000 (December 31, 2008 – $93,235,000). The terms of the new facility provides that the loan is revolving until April 28, 2011, is subject to annual review and has no fixed payment requirements.

The following is a list of the material bank covenants:

1) The Company is required to not exceed $120,000,000 in consolidated debt (includes negative working capital but excludes debt to related parties). As of December 31, 2009 the Company had consolidated debt of $46,485,000.

2) Dividends paid in any quarter shall not exceed 80 percent of the average of the previous four quarters' cash flow as defined under GAAP. The Company has received a waiver of this requirement for the fourth quarter 2009 and the first quarter of 2010 and instead is restricted to paying no more than the lesser of 80 percent of each quarters cash flow or $10,000,000 or $12,500,000 respectively. Quarter four dividends were $8,907,000 with 80 percent of Q4 cash flow being $10,718,000.

Bonterra is continuing with its efforts to acquire producing and non-producing properties through either property or entity acquisitions. Funding for any acquisition would depend on items such as the type of acquisition, quality of the assets, size of the purchase and Bonterra's trading price at the time of the acquisition.

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

	2009		2008	
Issued	Number	Amount ($ 000s)	Number	Amount ($ 000s)
Common Shares				
Balance, beginning of year	17,257,603	99,530	-	-
Issued pursuant to private placement	1,068,000	17,996	-	-
Issued on acquisition of Cobalt	201,438	3,207	-	-
Issued pursuant to Company share option plan	92,600	1,898	-	-
Transfer of contributed surplus to share capital	-	103	-	-
Issue costs for private placement	-	(1,046)	-	-
Future tax effect of share issue costs	-	267	-	-
Issued on reorganization to a corporation	-	-	17,257,603	99,530
Balance, end of year	18,619,641	121,955	17,257,603	99,530

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,861,964 common shares (2008 – 1,725,760). The exercise price of each option granted equals the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2009 and 2008, and changes during the twelve month periods ended on those dates is presented below:

	December 31, 2009		December 31, 2008	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	1,390,500	$ 20.50	-	$ -
Options granted	33,000	14.90	1,390,500	20.50
Options exercised	(92,600)	20.50	-	-
Outstanding at end of period	1,330,900	$ 20.36	1,390,500	$ 20.50
Options exercisable at end of period	370,900	$ 20.50	-	$ -

The following table summarizes information about options outstanding at December 31, 2009:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/09	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/09	Weighted-Average Exercise Price
$14.90	33,000	3.1 years	$ 14.90	-	$ -
20.50	1,297,900	2.9 years	20.50	370,900	20.50
$14.90-20.50	1,330,900	2.9 years	$ 20.36	-	$ 20.50

BUSINESS PROSPECTS, RISKS, AND OUTLOOKS

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry and increasing environmental controls and regulations. The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Company's cash flow or in the value of its producing and non-producing oil and natural gas properties.

The Company presently attempts to minimize these risks by pursuing both oil and natural gas activities and operates its oil and natural gas interests in areas which have long life reserves, where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

SENSITIVITY ANALYSIS

Sensitivity analysis, as estimated for 2010:

	Cash Flow	Cash Flow Per Share(1)
U.S. $1.00 per barrel	$ 1,124,000	$ 0.060
Canadian $0.10 per MCF	$ 347,000	$ 0.019
Change of Canadian $0.01/U.S. $ exchange rate	$ 834,000	$ 0.045

(1) Based on year end outstanding common shares of 18,619,641.

Additional Information

Additional information relating to the Company may be found on www.sedar.com as well as on the Company's 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. In the preparation of the statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

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

Deloitte & Touche LLP has been appointed by the Shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditors' 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
CEO
March 9, 2010

Garth E. Schultz
Vice President, Finance and CFO
March 9, 2010

Auditors' Report

To the Shareholders of Bonterra Energy Corp. (formerly Bonterra Oil & Gas Ltd.):

We have audited the consolidated balance sheets of Bonterra Oil & Gas Ltd. as at December 31, 2009 and 2008 and the consolidated statements of shareholders' equity, operations and deficit, comprehensive income and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Calgary, Alberta
March 9, 2010

Consolidated Financial Statements

Consolidated Balance Sheets

As at December 31 ($ 000s)	2009	2008
ASSETS		
CURRENT		
Restricted term deposit	-	20
Accounts receivable (Notes 4 & 15)	14,713	11,753
Crude oil inventory	431	845
Prepaid expenses (Note 4)	3,247	4,222
Future income tax asset (Note 11)	11,889	2,669
Investments (Note 8)	4,462	-
Investment in related party (Note 6)	4,827	2,131
	39,569	21,640
Restricted cash (Note 7)	812	1,252
Investment tax credit receivable (Note 11)	27,670	-
Future income tax asset (Note 11)	58,265	85,416
PROPERTY AND EQUIPMENT (Note 8)		
Petroleum and natural gas properties and related equipment	255,840	232,685
Accumulated depletion and depreciation	(88,169)	(75,692)
NET PROPERTY AND EQUIPMENT	167,671	156,993
	$ 293,987	$ 265,301
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities (Note 4)	18,868	23,888
Due to related parties (Note 9)	23,500	6,000
Deferred credit (Note 11)	7,363	2,305
Short-term bank debt (Note 10)	-	13,325
	49,731	45,518
Long-term bank debt (Note 10)	59,823	79,910
Deferred credit (Note 11)	47,769	64,758
Asset retirement obligations (Note 12)	17,790	18,338
	175,113	208,524
Commitments, Contingencies and Guarantees (Note 17)		
SHAREHOLDERS' EQUITY (Note 13)		
Share capital	121,955	99,530
Contributed surplus	3,350	2,542
	125,305	102,072
Deficit	(8,451)	(46,715)
Accumulated other comprehensive income (Note 14)	2,020	1,420
	(6,431)	(45,295)
Total Shareholders' Equity	118,874	56,777
	293,987	265,301

See the accompanying notes to the consolidated financial statements

On behalf of the Board:

George F. Fink
Director

Bill Woodward
Director

Consolidated Statements of Shareholders' Equity

For the Years Ended December 31 ($ 000s)	2009	2008
Unitholders' equity, beginning of year	-	44,218
Shareholders' equity, beginning of year	56,777	-
Comprehensive income for the year	69,163	53,815
Net capital contributions (Note 13)	22,322	8,135
Stock-based compensation	911	1,207
Conversion of the Trust to a Corporation (Note 4)	-	(64,715)
Distributions declared	-	(42,660)
UNITHOLDERS' EQUITY, END OF YEAR	-	-
Conversion of the Trust to a Corporation (Note 4)	-	64,715
Dividends declared	(30,299)	(7,938)
SHAREHOLDERS' EQUITY, END OF YEAR	118,874	56,777

Consolidated Statements of Operations and Deficit

For the Years Ended December 31 ($ 000s except $ per share)	2009	2008
REVENUE AND OTHER INCOME		
Oil and gas sales	85,712	129,083
Loss on risk management contracts-cash	-	(7,353)
Gain on risk management contracts – non-cash	-	3,085
Royalties	(7,414)	(17,215)
Investment tax credit recovery (Note 11)	27,670	-
Gain on sale of property (Note 8)	24,198	-
Interest and other	158	45
	130,324	107,645
EXPENSES		
Production costs	27,848	25,413
General and administrative (Note 8 and 15)	4,458	3,401
Interest on debt (Notes 9 and 10)	3,294	2,740
Reorganization costs (Note 4)	-	2,121
Stock-based compensation	911	1,207
Depletion, depreciation and accretion	19,277	14,749
	55,788	49,631
EARNINGS BEFORE TAXES	74,536	58,014
Taxes (Note 11)		
Current	551	437
Future	5,422	2,151
	5,973	2,588
NET EARNINGS FOR THE YEAR	68,563	55,426
Deficit, beginning of year	(46,715)	(51,543)
Distributions declared	-	(42,660)
Dividends declared	(30,299)	(7,938)
DEFICIT, END OF YEAR	(8,451)	(46,715)
NET EARNINGS PER SHARE – BASIC (Note 13)	3.81	3.25
NET EARNINGS PER SHARE – DILUTED (Note 13)	3.78	3.23

See the accompanying notes to the consolidated financial statements

Consolidated Statements of Comprehensive Income

For the Years Ended December 31 ($ 000s except $ per share)	2009	2008
NET EARNINGS FOR THE YEAR	**68,563**	55,426
OTHER COMPREHENSIVE INCOME, NET OF INCOME TAX		
Unrealized (loss) gain on investments (net of income taxes of (97), (2008-(272))	**600**	(1,611)
Other Comprehensive Income (Loss)	**600**	(1,611)
COMPREHENSIVE INCOME	**69,163**	53,815
COMPREHENSIVE INCOME PER SHARE – BASIC (Note 13)	**3.84**	3.15
COMPREHENSIVE INCOME PER SHARE – DILUTED (Note 13)	**3.81**	3.14

See the accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flow

For the Years Ended December 31 ($ 000s)	2009	2008
OPERATING ACTIVITIES		
Net earnings for the year	**68,563**	55,426
Items not affecting cash		
Gain on risk management contracts – non-cash	**-**	(3,085)
Stock-based compensation	**911**	1,207
Depletion, depreciation and accretion	**19,277**	14,749
Gain on sale of property	**(24,198)**	-
Future income taxes	**5,422**	2,151
	69,975	70,448
Change in non-cash working capital		
Accounts receivable	**(47)**	2,642
Crude oil inventory	**365**	(40)
Prepaid expenses	**1,057**	(360)
Accounts payable and accrued liabilities	**(4,654)**	(57)
Restricted cash	**440**	-
Investment tax credit receivable	**(27,670)**	-
Asset retirement obligations settled (Note 12)	**(573)**	(3,063)
	(31,082)	(878)
CASH PROVIDED BY OPERATING ACTIVITIES	**38,893**	69,570
FINANCING ACTIVITIES		
Increase (decrease) in debt	**(35,613)**	20,698
Due to related parties	**17,500**	6,000
Issue of shares pursuant to private placement	**17,996**	-
Share issue costs	**(1,046)**	-
Stock option proceeds	**1,898**	7,935
Unit distributions	**-**	(46,384)
Dividends	**(30,299)**	(7,938)
CASH USED IN FINANCING ACTIVITIES	**(29,564)**	(19,689)
INVESTING ACTIVITIES		
Property and equipment expenditures	**(28,726)**	(30,060)
Acquisition (Note 5)	**-**	(13,816)
Disposition of property and equipment (Note 5)	**23,729**	-
Reorganization (Note 4)	**-**	(11,257)
Restricted term deposit	**20**	(20)
Change in non-cash working capital		
Accounts receivable	**(3,613)**	-
Accounts payable and accrued liabilities	**(739)**	5,272
CASH USED IN INVESTING ACTIVITIES	**(9,329)**	(49,881)
Net cash inflow	**-**	-
Cash, beginning of year	**-**	-
CASH, END OF YEAR	**-**	-
Cash Interest Paid	**3,294**	2,740
Cash Taxes Paid	**616**	582

See the accompanying notes to the consolidated financial statements

Notes to the Consolidated Financial Statements

For the Years Ended December 31, 2009 and 2008

1. CHANGE OF ORGANIZATION

On November 12, 2008, Bonterra Energy Income Trust (the "Trust") was acquired by Bonterra Oil & Gas Ltd. (the "Company") through a reverse takeover by the Trust of SRX Post Holdings Inc. (SRX). In conjunction with the reorganization, the Trust acquired all the issued and outstanding shares of Silverwing Energy Inc. (Silverwing). Concurrently, all of the Company's subsidiaries, including Silverwing were amalgamated into Bonterra Energy Corp. (a subsidiary of Bonterra Energy Income Trust).

Prior to the reorganization on November 12, 2008, the consolidated financial statements included the accounts of the Trust and its subsidiaries. After giving effect to the reorganization, the consolidated financial statements have been prepared on a continuity of interests basis, which recognizes Bonterra Oil & Gas Ltd. as the successor entity to the Trust.

Effective January 1, 2010, the Trust was wound up into Bonterra Oil & Gas Ltd. and Bonterra Oil & Gas Ltd. was amalgamated with Bonterra Energy Corp. The continuing entity officially changed its name to Bonterra Energy Corp. subsequent to finalizing the reorganization.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) as described below.

Consolidation

These consolidated financial statements include the accounts of the Company, the Trust (wholly owned by the Company as of December 31, 2009) and its wholly owned subsidiary Bonterra Energy Corp. (Bonterra). Inter-company transactions and balances are eliminated upon consolidation.

Measurement Uncertainty

The preparation of financial statements in accordance with GAAP 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 balance sheets 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.

Amounts recorded for depletion, depreciation, accretion and amounts used for impairment calculations are based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves. Stock-based compensation is based upon expected volatility and option life estimates. Asset retirement obligations are based on estimates of abandonment costs, timing of abandonment, inflation and interest rates. The provision for income taxes is based on judgements in applying income tax law and estimates on the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. These estimates are subject to measurement uncertainty and changes in these estimates could materially impact the financial statements of future periods.

Revenue Recognition

Revenues associated with sales of petroleum and natural gas are recorded when title passes to the customer.

Joint Interest Operations

Significant portions of the Company's oil and gas operations are conducted jointly with other parties and accordingly the financial statements reflect only the Company's proportionate interest in such activities.

Inventories

Inventories consist of crude oil. Crude oil stored in the Company's tanks are 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, royalties and depletion and depreciation for the year and net realizable value is determined based on estimated sales price less transportation costs.

Investments

Investments are carried at fair value. Fair value is determined by multiplying the year end trading price of the investments by the number of common shares held as at period end.

Property and Equipment

Petroleum and Natural Gas Properties and Related Equipment

The Company follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of exploratory wells are initially capitalized pending determination of proved reserves. Costs of wells which are assigned proved reserves remain capitalized, while costs of unsuccessful wells are charged to earnings. All other exploration costs including geological and geophysical costs are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Producing properties are assessed annually or more frequently as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. If required, the impairment recorded is the amount by which the carrying value of the asset exceeds its fair value.

Costs related to undeveloped properties are excluded from the depletion base until it is determined whether or not proved reserves exist or if impairment of such costs has occurred. These properties are assessed at least annually to determine whether impairment has occurred.

Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the per-unit-of-production method. Development and exploration drilling and equipment costs are depleted over the remaining proved developed reserves. Depreciation of other plant and equipment is provided on the straight line method. Straight line depreciation is based on the estimated service lives of the related assets which is estimated to be ten years.

Furniture, Fixtures and Office Equipment

These assets are recorded at cost and depreciated over a three to ten year period representing their estimated useful lives.

Income Taxes

The Company accounts for income taxes using the liability method. Under this method, the Company records a future income tax asset or liability to reflect any difference between the accounting and tax basis of assets and liabilities, using substantively enacted income tax rates. The effect on future tax assets and liabilities of a change in tax rates is recognized in net earnings in the period in which the change occurs. Future income tax assets are only recognized to the extent it is more likely than not that sufficient future taxable income will be available to allow the future income tax asset to be realized.

Asset Retirement Obligations

The Company recognizes an Asset Retirement Obligation (ARO) 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, if any, will be applied prospectively. The fair value of the estimated ARO 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 reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the obligations are charged against the ARO to the extent of the liability recorded.

Stock-Based Compensation

The Company accounts for stock based compensation 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. Stock-based compensation expense is recorded over the vesting period with a corresponding amount reflected in contributed surplus. Stock-based compensation expense is calculated as the estimated fair value of the options at the time of grant, amortized over their vesting period. When stock options are exercised, the associated amounts previously recorded as contributed surplus are reclassified to common share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

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: held-for trading, loans and receivables, held-to-maturity investments, available-for-sale financial assets or other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. Held-for-trading financial instruments are measured at fair value and changes in fair value are recognized in net earnings. 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.

All risk management contracts are recorded in the balance sheet at fair value unless they qualify for the normal sale and normal purchase exemption. All changes in their fair value are recorded in net earnings unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the underlying hedged transaction is recognized in net earnings. Any hedge ineffectiveness is immediately recognized in net earnings. The Company has elected not to use cash flow hedge accounting on its risk management contracts with financial counterparties resulting in all changes in fair value being recorded in net earnings.

Cash and restricted cash are classified as held-for-trading and are measured at fair value which equals the carrying value and any gains or losses are recognized in earnings in the period they occur. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Investments are classified as available-for-sale which are 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 and amounts due to related parties are classified as other financial liabilities, which are measured at amortized cost.

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 earnings in the period they occur.

The Company may elect to use hedge accounting when there is a high degree of correlation between the price movements in the financial instruments and the items designated as being hedged and the Company has documented the relationship between the instruments and the hedged item as well as its risk management objective and strategy for undertaking hedge transactions. During the years ended December 31, 2009 and December 31, 2008, the Company did not designate any of its financial instruments as hedges. There are no risk management contracts outstanding as at December 31, 2009 and December 31, 2008.

Basic and Diluted per Share Calculations

Basic earnings per share are computed by dividing earnings by the weighted average number of shares outstanding during the year. Diluted per share amounts reflect the potential dilution that could occur if options to purchase shares were exercised. The treasury stock method is used to determine the dilutive effect of common share options, whereby proceeds from the exercise of common share options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

3. CHANGES IN ACCOUNTING POLICIES

On January 1, 2009, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3064, "Goodwill and Intangible Assets". The new section replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard had no impact on the Company's consolidated financial statements.

On January 20, 2009, the Company adopted the CICA's Emerging Issues Committee (EIC) EIC-173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". EIC-173 provides guidance on how to take into account credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of EIC-173 did not have a material impact on the Company's consolidated financial statements.

In 2009, the CICA issued amendments to CICA Handbook Section 3862, "Financial Instruments – Disclosures". The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009. The amendments are consistent with recent amendments to financial instrument disclosure standards in IFRS. The Company has included these additional disclosures in Note 16.

Recent Accounting Pronouncements

In December 2008, the CICA issued Section 1582, "Business Combinations", which will replace former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011 with earlier adoption permitted.

In December 2008, the CICA issued Sections 1601, "Consolidated Financial Statements", and 1602, "Non-controlling Interests", which replaces existing Section 1600. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on or after the beginning of the first annual reporting period beginning on or after January 1, 2011 with earlier adoption permitted. Section 1602 currently does not impact the Company as it has full controlling interest of all of its subsidiaries.

The Canadian Accounting Standards Board has confirmed that IFRS will replace Canadian GAAP effective January 1, 2011, including comparatives for 2010, for Canadian publicly accountable enterprises.

4. REORGANIZATION

As part of the 2008 reorganization of the Trust, SRX acquired all the issued and outstanding trust units of Bonterra Energy Income Trust on a basis of one Trust Unit for one Common Share of SRX. Immediately preceding the reorganization, SRX was under the protection of Companies' Creditors Arrangement Act (CCAA). Prior to the conversion, the Trust advanced $11,257,000 to SRX for settlement of claims pursuant to the CCAA proceedings. Upon completion of the CCAA procedures, SRX was owed $2,224,000 in outstanding tax and legal claims that have been used by the CCAA Monitor to settle secured creditor claims. This amount was recorded as an outstanding account receivable by the Company. As of December 31, 2009 the entire amount has been received.

In addition, SRX paid an advance of $1,800,000 to the CCAA Monitor for costs and payment of the unsecured creditors. This amount was recorded as a prepaid expense in the accounts of the Company. As of December 31, 2009, $791,000 remains unpaid to the unsecured creditors.

Included in accounts payable is $791,000 (December 31, 2008 – $4,024,000) to account for the amount due to the secured and unsecured creditors.

5. BUSINESS COMBINATIONS

On July 2, 2009, the Company acquired all of the issued common shares of Cobalt Energy Ltd. (Cobalt) for consideration of 201,438 common shares at a value of $15.92 per common share plus the assumption of $2,856,000 of negative working capital for total consideration of $6,063,000. Results of Cobalt's operations have been included in the consolidated financial statements commencing from that date.

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

Cost of acquisition ($ 000s)	
Value of common stock	3,207
Acquisition costs	170
	3,377

Allocation of purchase price:	
Property and equipment	7,105
Future income tax liability	(748)
Working capital deficiency	(2,856)
Asset retirement obligations	(124)
	3,377

On November 12, 2008, the Company acquired all the common shares of Silverwing for cash consideration of $13,816,000 (including acquisition costs of $334,000) plus the issuance of 7,745 common shares at a value of $25.85 per common share plus the assumption of $14,979,000 of negative working capital. The results of Silverwing's operations have been included in the consolidated financial statements since that date. The acquisition was funded through the Company's bank facility (see Note 10).

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

Cost of acquisition ($ 000s)	
Cash paid	13,482
Value of common stock	200
Acquisition costs	334
	14,016

Allocation of purchase price:	
Restricted cash	1,252
Future income tax benefit	18,325
Property and equipment	15,347
Working capital deficiency	(14,979)
Asset retirement obligations	(5,929)
	14,016

6. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2008 – 689,682) common shares in Comaplex Minerals Corp (Comaplex), a company with common directors and management with the Company and its subsidiaries. The investment is recorded at fair market value. The common shares trade on the Toronto Stock Exchange under the symbol CMF. The investment represents less than a one percent ownership in the outstanding shares of Comaplex.

7. RESTRICTED CASH

An escrow account was held by Silverwing prior to its acquisition by the Company. The escrow account was created to support eligible expenditures related to a farm-in agreement. The Company may access the funds upon completion and tie-in or abandonment and reclamation of 11 (December 31, 2008 – 21) wells. The funds are administered by the farmors' legal counsel. The funds in the escrow account are invested in interest bearing term deposits.

8. PROPERTY AND EQUIPMENT

	2009		2008	
($ 000s)	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Undeveloped land	7,992	-	2,295	-
Petroleum and natural gas properties and related equipment	246,387	87,153	229,136	74,844
Furniture, equipment and other	1,461	1,016	1,254	848
	255,840	88,169	232,685	75,692

On November 6, 2009, the Company divested of a portion of its Shaunavon oil production to Eagle Rock Exploration Ltd. (Eagle Rock) (TSXV: ERX). The proceeds of disposition consist of $23,729,000 cash and 30,769,200 common shares in Eagle Rock (representing approximately 4.2 percent of the outstanding common shares of that company). The Eagle Rock common shares were trading for $0.21 cents per share on November 6, 2009. The Company had a net book value (after effects of asset retirement obligations) of $5,993,000 attributable to the assets disposed of resulting in a gain on sale of the property of $24,198,000.

Eagle Rock has since changed its name to Wild Stream Exploration Inc. (Wild Stream) (TSXV: WSX) and consolidated its common shares on a 30:1 basis resulting in Bonterra holding 1,025,640 common shares of Wild Stream at December 31, 2009 with a quoted market value of $4,462,000.

During the year the Company capitalized $359,000 (2008 – $426,000) of general and administrative costs.

9. DUE TO RELATED PARTIES

As of December 31, 2009, the Company's CEO and major shareholder has loaned the Company $11,500,000 (December 31, 2008 – $6,000,000). The loan is unsecured, bore interest at Canadian chartered bank prime less one half of a percent and has no set repayment terms but is payable on demand. Effective July 1, 2009 the interest rate was adjusted to Canadian chartered bank prime less .25 percent. The interest rate was adjusted to keep the loan rate at approximately two percent below the Company's bank financing rate. Interest paid on this loan during 2009 was $209,000 (2008 – $7,000).

As of December 31, 2009, Comaplex has loaned the Company $12,000,000 (December 31, 2008 – Nil). The loan is unsecured, bore interest at Canadian chartered bank prime plus one quarter of a percent and has no set repayment terms but is payable on demand. Effective July 1, 2009 the interest rate was adjusted to Canadian chartered bank prime less 0.25 percent. The interest rate was adjusted to keep the loan rate at approximately two percent below the Company's bank financing rate. Interest paid on this loan during 2009 was $194,000.

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

Please refer to Notes 6 and 15 for additional related party transactions.

10. BANK DEBT

As of December 31, 2009, the Company has a bank facility consisting of a $100,000,000 syndicated and $20,000,000 non-syndicated revolving credit facility (December 31, 2008 – $80,000,000 syndicated and $20,000,000 non-syndicated demand credit facility). This new facility became effective April 29, 2009, when the Company agreed to new terms and conditions. Amounts drawn under the facility at December 31, 2009 was $59,823,000 (December 31, 2008 – $93,235,000). The interest rate on the outstanding debt during 2009 was approximately 4.0 percent. The Company at December 31, 2009 was in level III (see below) in respect of its various borrowing charges. The term of the new facility provides that the loan is revolving until April 28, 2011, is subject to annual review and has no fixed payment requirements.

The amount available for borrowing under the credit facility is reduced by outstanding letters of credit. Letters of credit totaling $285,000 were issued at December 31, 2009 (December 31, 2008 – $525,000). Security for the credit facilities consists of various fixed and floating demand debentures totaling $200,000,000 over all of the Company's assets, and a general security agreement with first ranking over all personal and real property.

The interest rate on the credit facility is calculated as follows:

	Level I	Level II	Level III	Level IV	Level V
Consolidated Total Funded Debt (1) to Consolidated Cash flow Ratio	Under 1.0:1	Over 1.0:1 to 1.5:1	Over 1.5:1 to 2.0:1	Over 2.0:1 to 2.5:1	Over 2.5:1
Canadian Prime Rate Plus (2)	125	150	175	200	250
Bankers' Acceptances Rate Plus (2)	275	300	325	350	400

(1) Consolidated total funded debt excludes related party amounts but includes working capital.
(2) Numbers in table represent basis points.

The consolidated total funded debt to consolidated cash flow ratio shall be adjusted effective as of the first day of the next fiscal quarter following the end of each fiscal quarter, with each such adjustment to be effective until the next such adjustment.

The following is a list of the material covenants:

- The Company is required to not exceed $120,000,000 in consolidated debt (includes negative working capital but excludes debt to related parties).
- Dividends paid in any quarter shall not exceed 80 percent of the average of the previous four quarters' cash flow as defined under GAAP. During the third quarter the Company received a waiver of this requirement for the fourth quarter and instead is restricted to paying no more than the lesser of 80 percent of quarter four cash flow or $10,000,000. In addition the Company received a waiver of this requirement for the first quarter of 2010 and instead is restricted to paying no more than the lesser of 80 percent of the first quarter 2010 cash flow or $12,500,000

At December 31, 2009, the Company is in compliance with all covenants.

11. INCOME TAXES

The Company has recorded a future income tax asset related to assets and liabilities and related tax amounts:

($ 000s)	2009	2008
Future tax liability related to investments:	**(824)**	(212)
Future tax liability related to property and equipment:	**(5,855)**	(7,097)
Future tax asset related to asset retirement obligations:	**4,474**	4,593
Future tax asset related to finance costs:	**802**	1,134
Future tax asset related to corporate tax losses and SR&ED claims	**59,668**	86,998
Future tax asset related to corporate capital tax losses	**17,883**	17,883
Valuation adjustment	**(17,883)**	(17,883)
Future Tax Asset – Long-term	**58,265**	85,416
Current portion of future income tax asset related to corporate tax losses and SR&ED claims:	**11,889**	2,669
Future Tax Asset-Current	**11,889**	2,669

As a result of the reorganization as described in Note 1 the Company recorded a deferred credit of $71,303,000 relating to the difference between the future income tax asset generated on the reorganization and the amount of the cash payment made to SRX immediately before the reorganization. This credit is being amortized (2009 – $12,356,000, 2008 – $4,240,000) on the same basis as the related future income tax asset (2009 – $14,306,000, 2008 – $4,909,000).

A reconciliation of the deferred credit is as follows:

($ 000s)	
Amount recorded on reorganization	71,303
Amortized in 2008	(4,240)
Rate adjustment	425
Amortized in 2009	(12,356)
Balance as of December 31, 2009	55,132
Current portion	7,363
Long-term portion	47,769
	55,132

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

($ 000s)	**2009**	2008
Earnings before income taxes	**74,536**	58,014
Combined federal and provincial income tax rates	**29.15%**	29.62%
Income tax provision calculated using statutory tax rates	**21,727**	17,184
Increase (decrease) in taxes resulting from:		
Saskatchewan resource surcharge	**282**	437
Quebec tax	**269**	-
Stock-based compensation	**266**	357
Deferred credit amortization	**(11,931)**	(4,240)
Change in effective tax rate	**(4,708)**	(499)
Trust income allocated to Unitholders prior to conversion	**-**	(10,291)
Others	**68**	(360)
Income tax expense	**5,973**	2,588

The Company and its subsidiaries have 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	21,671
Eligible capital expenditures	7	7,363
Share issue costs	20	2,973
Canadian oil and gas property expenditures	10	26,282
Canadian development expenditures	30	59,141
Canadian exploration expenditures	100	11,174
SR&ED expenditures	100	80,357
Income tax losses carried forward (1)	100	223,629
		432,590

(1) Federal income tax losses carried forward expire in the following years; 2013 – $1,069,000, 2024 – $3,347,000, 2025 – $7,532,000, 2026 – $46,670,000, 2027 – $117,189,000, 2028 – $34,726,000, 2029 – $13,096,000.

The Company has $27,670,000 (2008 – $27,670,000) remaining of investment tax credits that expire in the following years; 2019 – $3,469,000, 2020 – $3,059,000, 2021 – $4,667,000, 2022 – $3,909,000, 2023 – $3,155,000, 2024 – $1,995,000, 2025 – $2,257,000, 2026 – $2,405,000, 2027 – $2,009,000, 2028 – $745,000.

The Company also has $143,061,000 of capital loss carry forwards which can only be claimed against taxable capital gains.

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

12. ASSET RETIREMENT OBLIGATIONS

At December 31, 2009, the estimated total undiscounted amount required to settle the asset retirement obligations was $64,482,000 (2008 – $58,903,000). Costs for asset retirement have been calculated assuming a two 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 credit-adjusted risk-free interest rate of five percent (2008 – five percent).

Changes to asset retirement obligations were as follows:

($ 000s)	2009	2008
Asset retirement obligations, January 1	18,338	14,904
Adjustment to asset retirement obligations	(138)	(217)
Adjustment related to asset additions (net of disposals)	(750)	5,929
Liabilities settled during the year	(573)	(3,063)
Accretion	913	785
Asset retirement obligations, December 31	17,790	18,338

13. SHAREHOLDERS' EQUITY

Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value. The Company is also authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable preferred shares or Class "B" preferred shares.

Issued

	2009		2008	
	Number	Amount ($ 000s)	Number	Amount ($ 000s)
Common Shares				
Balance, beginning of year	17,257,603	99,530	-	-
Issued pursuant to private placement	1,068,000	17,996	-	-
Issued on acquisition of Cobalt (Note 5)	201,438	3,207	-	-
Issued pursuant to Company share option plan	92,600	1,898	-	-
Transfer of contributed surplus to share capital	-	103	-	-
Issue costs for private placement	-	(1,046)	-	-
Future tax effect of share issue costs	-	267	-	-
Issued on reorganization to a corporation	-	-	17,257,603	99,530
Balance, end of year	18,619,641	121,955	17,257,603	99,530

Issued	2008 Number	2008 Amount ($ 000s)
Trust Units		
Balance, beginning of year	16,928,158	90,590
Transfer of contributed surplus to unit capital	-	805
Issued pursuant to Trust unit option plan	321,700	7,935
Issued on acquisition of Silverwing (Note 5)	7,745	200
Cancelled on conversion to a corporation	(17,257,603)	(99,530)
Balance, end of 2008	-	-

On May 27, 2009, the Company completed a private placement for 1,068,000 common shares at a price of $16.85 per common share for aggregate proceeds of $17,996,000. The Company incurred issue costs of $1,046,000 in respect of the offering.

The number of common shares used to calculate diluted net earnings per share for the year ended December 31, 2009 of 18,131,085 shares (2008 – 17,119,517) included the basic weighted average number of common shares outstanding of 18,006,320 shares (2008 – 17,075,647) plus 124,765 shares (2008 – 43,870) related to the dilutive effect of common share options.

A summary of the changes of the Company's contributed surplus is presented below:

Contributed surplus ($ 000s)	2009	2008
Balance, beginning of year	**2,542**	2,140
Stock-based compensation expensed (non-cash)	**911**	1,207
Stock-based options exercised (non-cash)	**(103)**	(805)
Balance, end of year	**3,350**	2,542

The deficit balance is composed of the following items:

($ 000s)	2009	2008
Accumulated earnings	276,745	208,182
Accumulated cash dividends and distributions	(285,196)	(254,897)
Deficit	(8,451)	(46,715)

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,861,964 common shares (2008 – 1,725,760). The exercise price of each option granted equals the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2009 and 2008, and changes during the years ended on those dates is presented below:

	December 31, 2009		December 31, 2008	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	1,390,500	$ 20.50	-	$ -
Options granted	33,000	14.90	1,390,500	20.50
Options exercised	(92,600)	20.50	-	-
Outstanding at end of period	1,330,900	$ 20.36	1,390,500	$20.50
Options exercisable at end of period	370,900	$ 20.50	-	$ -

The following table summarizes information about options outstanding at December 31, 2009:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/09	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/09	Weighted-Average Exercise Price
$14.90	33,000	3.1 years	$14.90	-	$ -
20.50	1,297,900	2.9 years	20.50	370,900	20.50
$14.90-20.50	1,330,900	2.9 years	$20.36	370,900	$20.50

The Company records compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. In 2009, the Company granted 33,000 stock options with an estimated fair value of $52,000 ($1.58 per option) using the Black-Scholes option pricing model with the following key assumptions:

	2009	2008
Weighted-average risk free interest rate (%)	**1.4**	2.2
Expected life (years)	**3.0**	3.5
Weighted-average volatility (%)	**33.0**	31.3
Dividend yield 2009 and 2008	**based on the percentage of dividends (2008 – dividends or distributions) paid during the period granted**	

14. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ 000s)	**January 1, 2009**	**Other Comprehensive Income (Loss)**	**December 31, 2009**
Unrealized gains (losses) on available for sale financial assets	**1,420**	**600**	**2,020**

($ 000s)	January 1, 2008	Other Comprehensive Income (Loss)	December 31, 2008
Unrealized gains on available for sale financial assets	3,031	(1,611)	1,420

15. RELATED PARTY TRANSACTIONS

The Company received a management fee from Comaplex of $330,000 (2008 – $330,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses and represents the fair value of the services rendered. The Company also allocated $102,000 of drilling royalty credits to Comaplex for $51,000. As at December 31, 2009, the Company had an account receivable from Comaplex of $105,000 (December 31, 2008 – $56,000).

The Company received a management fee from Pine Cliff Energy Ltd., a company with common directors and management with the Company and its subsidiaries, of $120,000 (2008 – $238,000) for management services and office administration. This fee has been included in general and administrative expenses as a recovery and represents the fair value of the services rendered. As at December 31, 2009 the Company had an account receivable from Pine Cliff of $1,000 (December 31, 2008 – $1,000).

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

16. FINANCIAL AND CAPITAL RISK MANAGEMENT

Financial Risk Factors

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

- Receivables
- Restricted cash
- Payables
- Common share investments
- Due to related parties
- Bank loans

The Company's activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, foreign exchange risk), credit risk, and liquidity 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 management is carried out by senior management under the direction of the Directors of the Company.

The Company may enter into various risk management contracts in accordance with Board approval to manage the Company's exposure to commodity price fluctuations. Currently no risk management agreements are in place. The Company does not speculatively trade in risk management contracts. The Company's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities.

Capital Risk Management

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

The Company monitors capital on the basis of the ratio of debt to cash flow. This ratio is calculated using each quarter end net debt (total debt adjusted for working capital) and divided by the preceding twelve months cash flow. The Company believes that a debt level of approximately one and a half year's cash flow is an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its undeveloped resources by horizontal or vertical drill programs.

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 Table 1.

Table 1

	As at December 31, 2009		
($ 000s)	Carrying Value	Fair Value	Face Value
Financial assets			
Accounts receivable	14,713	14,713	14,873
Investments	4,462	4,462	N/A
Investment in related party	4,827	4,827	N/A
Restricted cash	812	812	812
Financial liabilities			
Accounts payable and accrued liabilities	18,868	18,868	18,868
Due to related parties	23,500	23,500	23,500
Long-term debt	59,823	59,823	59,823

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related parties and long-term debt carried on the consolidated balance sheet are carried at amortized cost. Restricted cash, 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 restricted cash, investments and investments in related party have been assessed on the fair value hierarchy described above and are all considered Level 1.

The net debt and cash flow from operations figures are presented in Table 2.

Table 2

($ 000s)	December 31, 2009
Long-term debt	59,823
Due to related parties	23,500
Accounts payable and accrued liabilities	18,868
Current assets (1)	(27,680)
Net Debt	74,511
Cash flow from operations(2)	38,893
Net debt to cash flow from operations	1.92

(1) Current assets include accounts receivable, crude oil inventory, prepaid expenses, investments and investment in related party.
(2) Cash flow from operations includes annual net earnings less adjustment for non-cash (gain) loss on risk management contracts, stock-based compensation, depletion, depreciation and accretion, gain on sale of property, future income taxes, changes in non-cash working capital items, asset retirement obligations settled and investment tax credit receivable.

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, recently 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 $100,000,000 revolving operating line, $20,000,000 demand operating line and $23,500,000 due to related parties. The borrowings under these facilities are at bank prime plus or minus various percentages as well as by means of bankers' acceptances (BA's) within the Company's credit facility. The Company manages its exposure to interest rate risk through entering into various term lengths on its BA's 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 net earnings and comprehensive income by $591,000 (increase by $591,000).

Foreign exchange risk

The Company has no foreign operations and currently sells all 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 discontinue the use of commodity price agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

Credit risk

Credit risk is the risk that a contracting party will not complete its obligations under a financial instrument and cause the Company to incur a financial loss. The Company is exposed to credit risk on all financial assets included on the balance sheet. 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;
- Agreements for product sales are primarily on 30 day renewal terms; and
- Investments are generally only with companies that have common management with the Company.

Of the accounts receivable balance of December 31, 2009 ($14,713,000) and December 31, 2008 ($11,753,000) over 87 (2008 – 82) percent relates to product sales with international oil and gas companies and drilling credits receivable from the province 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, 2009, there was no impairment provision required on any of the financial assets of the Company due to historical success of collecting receivables. The Company does have a credit risk exposure as the majority of the Company's accounts receivable are with counterparties having similar characteristics. However, payments from the Company's largest accounts receivable counterparties have consistently been received within 30 days and the sales agreements with these parties are cancellable with 30 days notice if payments are not received.

At December 31, 2009, approximately $244,000 or 1.6 percent of the Company's total accounts receivable are aged over 120 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, 2009 is $160,000 (December 31, 2008 – $85,000) with the difference being included in general and administrative expenses. There were no accounts written off during the year.

The carrying value of accounts receivable approximates their fair value due to the relatively short periods to maturity on this instrument. The maximum exposure to credit risk is represented by the carrying amount on the balance sheet. 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:

		Payments Due By Period		
($ 000s)	Recognized on Financial Statements	Less than 1 year	1-3 years	4-5 years
Accounts payable and accrued liabilities	Yes – Liability	18,868	-	-
Due to related party	Yes – Liability	23,500	-	-
Long-term bank debt	Yes – Liability	-	59,823	-
Office leases	No	944	1,761	496
Total		43,312	61,584	496

c) Risk management contracts

The Company has no outstanding risk management contracts.

17. COMMITMENTS, CONTINGENCIES AND GUARANTEES

The Company has no contractual obligations that last more than a year other than its office lease agreements which are as follows:

Lease Obligations ($ 000s)	
Year 1	944
Year 2	932
Year 3	829
Year 4	496
Total	3,201

18. SUBSEQUENT EVENTS-DIVIDENDS

Subsequent to December 31, 2009, the Company has declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 5, 2010	January 15, 2010	$0.18	January 29, 2010
February 3, 2010	February 16, 2010	$0.18	February 26, 2010
March 3, 2010	March 15, 2010	$0.18	March 31, 2010

19. SUBSEQUENT EVENT – DISPOSITION

Subsequent to December 31, 2009, the Company entered into a purchase and sale agreement to divest its Southeast Saskatchewan Pinto property. The proceeds of disposition consist of approximately $5,600,000 cash and resulted in a gain of approximately $5,800,000. The disposition closed on February 23, 2010.

Corporate Information

BOARD OF DIRECTORS

G.J. Drummond, Nassau, Bahamas
G.F. Fink, Calgary, Alberta
C.R. Jonsson, Vancouver, British Columbia
F. W. Woodward, Calgary, Alberta

OFFICERS

G.F. Fink – Chief Executive Officer
R.M. Jarock – President and Chief Operating Officer
G.E. Schultz – Vice President, Finance,
Chief Financial Officer & Secretary

REGISTRAR & TRANSFER AGENT

Olympia Trust Company, Calgary, Alberta

AUDITORS

Deloitte & Touche LLP, Calgary, Alberta

SOLICITORS

Borden Ladner Gervais LLP, Calgary, Alberta

BANKERS

CIBC, Calgary, Alberta
The Royal Bank of Canada, Calgary, Alberta
Alberta Treasury Branch, Calgary, Alberta

STOCK LISTING

The Toronto Stock Exchange, Toronto, Ontario
Trading symbol: BNE

HEAD OFFICE

901, 1015 – 4th Street SW
Calgary, Alberta T2R 1J4
PH 403.262.5307
FX 403.265.7488

WEBSITE

www.bonterraenergy.com

designed and produced by nonfiction studios inc.

Bonterra
Energy Corp.

901, 1015 – 4th Street SW
Calgary, Alberta T2R 1J4