BORDER PETROLEUM CORP.

(formerly Border Petroleum Inc.)

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 20, 2013

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis of financial results and related data has been prepared by management, is reported in Canadian dollars and should be read in conjunction with Border's audited financial statements for the year ended March 31, 2012. The accompanying financial statements were approved by the Corporation's Audit Committee on behalf of the Board of Directors. The financial information presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS"), specifically International Accounting Standard 34, "Interim Financial Reporting". Additional information relating to Border is filed at www.sedar.com.

This Management's Discussion and Analysis is dated as of February 20, 2013.

BOE presentation** – **For the purposes of calculating unit costs, natural gas is converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one boe unless otherwise stated. A boe is a very approximate comparative measure that, in some cases, could be misleading, particularly if used in isolation.

FORWARD-LOOKING STATEMENTS

The information herein contains forward-looking statements and assumptions. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", continue", "estimate", "expect", "may", "will", "project", "predict", "potential, "targeting", "intend", "could", "might", "should", "believe" and other similar expressions. Such statements and assumptions also include those relating to guidance, results of operations and financial condition, capital spending, financing sources, commodity prices, cost of production and the magnitude of oil and gas reserves. By their nature, forward-looking statements are subject to numerous known and unknown risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. Border Petroleum Corp. is exposed to numerous operation, technical, financial and regulatory risks and uncertainties, many of which are beyond its control and may significantly affect anticipated future results.

Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, ability to attract and retain employees on a cost-effective basis, commodity and marketing risk and seasonality. Border Petroleum Corp. is subject to significant drill risks and uncertainties including the ability to find oil and natural gas reserves on an economic basis and the potential for technical problems that could lead to well blowouts and environmental damage. Border Petroleum Corp. is also exposed to risks relating to the inability to obtain timely regulatory approvals, surface access, access to third party gathering and processing facilities, transportation and other third party related operation risks. Furthermore, there are numerous uncertainties in estimating Border Petroleum Corp.'s reserve base due to the complexities in estimated future production, costs and timing of expenses and future capital. The financial risks Border Petroleum Corp. is exposed to include, but not limited to, access to debt or equity markets and fluctuations in commodity prices, interest rates and the Canadian/US dollar exchange rate. Border Petroleum Corp. is subject to regulatory legislation, the compliance with which may require significant expenditures and non-compliance with which may result in fines, penalties or production restrictions.

Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time preparation of, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Border Petroleum Corp. does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

NON-IFRS MEASURES

This MD&A includes references to financial measures commonly used in the oil and gas industry. The terms "net petroleum and natural gas revenue" (petroleum and natural gas sales less royalties, production expenses and transportation costs) and "funds from operations" (net loss for the period adjusted for non-cash items in the statement of operations) have no standardized meanings, are not defined by IFRS, and accordingly are referred to as non-IFRS measures.

Border Petroleum Corp. also uses "operating netbacks" as a key performance indicator of field results by commodity. "Operating netbacks" do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other companies. Operating netbacks are determined by deducting royalties, operating, processing and transportation expenses from petroleum and natural gas sales.

Funds from operations and operating netbacks are not intended to represent operating profits, nor should they be viewed as an alternative to cash flow provided by operating activities, net loss or other measures of financial performance calculated in accordance with IFRS.

CORPORATION OVERVIEW

The primary business of Border Petroleum Corp. ("Border" or the "Corporation") is the acquisition, development and production of crude oil, natural gas and natural gas liquids from properties located in the province of Alberta. The Corporation's shares are posted on the TSX Venture Exchange (the "TSXV") under the symbol "BOR". The Corporation changed its name from Border Petroleum Inc. to Border Petroleum Corp. on September 14, 2010.

HIGHLIGHTS

The following are the highlights of Border's operations for the quarter ended December 31, 2012:

- Border drilled, completed, and is currently testing its first long-leg Slave Point horizontal well.
- Border acquired and reprocessed 17 square kilometers of 3D seismic covering the southeast portion of lands under a federal permit granted to Border (the "Loon Block").
- Border currently has a positive working capital balance of approximately $10 million and an unutilized bank line of $3.5 million.
- Border's current production is approximately 192 boepd (45 percent oil weighted).
- Border is currently evaluating certain non-core asset dispositions and potential joint venture transactions with respect to its Red Earth assets.

OUTLOOK

Border's third quarter saw the commencement of the second phase of development of the 18,720 acre Loon Block at Red Earth with the drilling, completion and putting on production of its first long-leg horizontal well in December (the 10-15 Well"). The 10-15 Well was successfully drilled, completed, equipped and put on pump in December 2012 for a total cost of approximately $7 million. The 10-15 Well costs exceeded the pre-drill estimated costs of $5 million due to the drilling of a longer horizontal leg, which also led to additional completion costs.

On December 23, 2012, the 10-15 Well was put on pump using a pump jack with a maximum capacity of approximately 125 m3/d (786 bpd) of total fluid. The pump's maximum rate has proven insufficient to optimally produce the well's estimated inflow capacity of 257 m3/d (1,616 bpd) of total fluid as independently assessed by Fekete Associates Inc. ("Fekete") based on field production data to the end of January 2013.

To the end of January 2013, a total of 5,866 m3 (36,896 bbls) of fluid has been intermittently produced from the 10-15 Well consisting almost entirely of frac fluid and formation water, which is typical of the early stage production during the clean-up phase of wells in the Red Earth area.

At the beginning of February 2013, Border commenced isolated production testing to help ascertain inflow rates and water contribution along the horizontal wellbore. The pump's maximum capacity was insufficient to optimally handle the inflow capacity from both the heel to the middle of the horizontal wellbore as well as the toe of the wellbore.

Border is currently testing approximately 450 metres at the initial heel section of the well where porosities averaged approximately 6 percent as indicated on open-hole logs (porosities along the 1,630 m horizontal wellbore ranged from 6 percent to 33 percent). Based on field reports from February 15, 2013 this heel section has produced at an average rate of approximately 42 m3/d (264 bpd) of total fluid with an oil cut of 10 percent (26 bopd) on February 25, 2013.

Upon reviewing Fekete's analysis of the 10-15 Well's estimated inflow capacity, combined with the results of its isolated testing discussed above, management of Border has determined that a minimum 300 m3/d (1,887 bpd) capacity electrical submersible pump ("ESP") is required to handle the high fluid inflow rate and optimally produce the 10-15 Well along the entire length of the 1,630 horizontal wellbore. Management anticipates the installation of a high volume ESP will be complete within the next 2 weeks which it anticipates may result in increased oil cuts as experienced in the isolated testing of the heel section of the 10-15 Well.

Border expects to receive Alberta ERCB approval within the next 7 days to commence the initial steps required to convert a vertical well located on the 10-15 Well site into a water disposal well. Slave Point horizontal wells in the Red Earth area can produce between 50 to 90 percent water over a majority of their production life. Accordingly, the ability to dispose of water production from the 10-15 Well directly on-site, as well as from Border's two short-leg horizontal wells located at 5-1-85-10-W5 (the "5-1 Well") and 6-36-85-10W5 (the "6-36 Well"), will reduce Border's current and future operating costs related to these wells and any future wells in the area.

With respect to Border's 2 short-leg horizontal wells on the Loon Block, for the 6 months ended December 31, 2012, Border's 5-1 Well and 6-36 Well averaged approximately 15 bopd per well (producing day average). As previously reported, production from these short horizontal wells has been impeded by wax and asphaltene build up which Border continues to address using cost effective remediation efforts. The two wells are currently producing at a combined oil rate of approximately 25 bopd.

At Leduc, Border is currently planning to conduct an acid stimulation on its 13-33-49-26W4M Nisku horizontal oil well with a view to optimizing its current production base of approximately 114 boepd (15 percent oil weighted). Border has a high working interest in 6,405 net acres in the Leduc area of central Alberta.

Following the payment for the drilling, completion, equipping and testing of the 10-15 Well, acquiring the Loon Seismic, fulfilling its CDE Flow-Through commitment, and paying off a note related to the acquisition of the Leduc properties, as at February 14, 2013, Border had a positive working capital balance of approximately $10 million and an unutilized bank line of $3.5 million.

Border's current total production is approximately 192 boepd (45 percent oil weighted). With the conversion of the water disposal well at Red Earth, and the anticipated production adds from the 10-15 well following installation of an ESP, Border's expects its operating cash flow will be sufficient to cover its ongoing general and administrative costs. Border also currently holds approximately $32 million in tax pools as at December 31, 2012.

The management and Board of Directors of Border continue to assess various options at its disposal to maximize the value for its shareholders. To that end, the Corporation is currently evaluating certain non-core asset dispositions, as well as investigating various unsolicited inquiries regarding potential joint venture transactions with respect to its Red Earth assets.

OPERATIONS

The Corporation's average net daily production was 211 boe/d for the nine months ended December 31, 2012 compared to 213 boe/d for the same period last year. Average net daily production was 211 boe/d for the three months ended December 31, 2012 compared to 371 boe/d for the same period last year. Although new wells were drilled and brought on production over this period, the production profile remains flat due to decline, waxing and asphaltene issues in the Red Earth area and the shutting in of gas producing wells.

Producing Properties

Red Earth/Dawson, Alberta

The Corporation has a working interest in 22,017 gross acres (21,975 net) in the Red Earth and Dawson area of northwestern Alberta ("Non-Reserve Lands"). The Corporation re-entered five wells on these lands in its fiscal year ended March 31, 2011.

In the Red Earth area, Border has a 100% working interest in the wells 100/11-06-87-11W5M, 00/9-06-86-10W5M, 00/13-36-85-11W5M, 100/4-15-88-12W5M, 00/08-28-88-11W5M and 100/16-36-085-11 W5M/2. Four of the wells have been fracture stimulated and put on production to date. The Corporation has a well in the Dawson field located at 6-23-80-17W5M that produces as a single well battery.

All wells operate as single well batteries with effluent trucked to local processing facilities. The 11-06-87-11W5M well has been shut in due to high op costs and the 9-06-86-10W5M was down intermittently for pump maintenance. The Corporation continues to treat the wells for asphaltene and waxing issues.

On November 30, 2011, IOGC, with the approval of the Nation, issued an IOGC permit now covering more than 29.25 sections (18,720 acres) of the Nation's Lands in the Red Earth area of northwestern Alberta including rights in the Slave Point formation. The Corporation drilled its first two appraisal wells on the Loon Block and put them both on production mid April 2012. The wells continue to produce at a reduced inflow because of waxing/asphaltene restrictions common to the Red Earth area. Border is currently working with various chemical companies to find a solution to this issue.

In October 2012 Border successfully drilled its first long-leg Slave Point horizontal well located at 10-15-85-10W5M (the “10-15 Well”) The 10-15 Well was drilled to a total depth of 3,250 meters, including a 1,630 meter horizontal leg. The horizontal leg of the well was extended by approximately 250 meters to test the extent of the higher porosity formation encountered at the toe of the well.

The well was fracture stimulated over 23 zones and put on production December 23 2012. The Corporation has also secured 3D seismic coverage over the area around the 10-15 Well and has now had it reprocessed. This seismic will be used to pick future drill locations on the south portion of the Loon Block.

The Red Earth/Dawson production during the three and nine months ended December 31, 2011, averaged 33 bbls/d and 24 bbls/d respectively. This year, the three and nine months ended December 31, 2012, averaged 32 bbls/d and 41 bbls/d, respectively.

Leduc, Alberta

The Corporation has an interest in 6,727 gross acres (6,405 net) in the Leduc area of central Alberta. The Corporation has a 100% working interest in the wells 15-19-49-26W4M, 10-29-49-26W4M, 8-32-49-26W4M, 14-32-49-26W4M and 13-33-49-26W4M and 60% in 11-33-49-26W4M.

The Corporation did not proceed with any further work on the horizontal wells drilled in the Leduc area as capital was directed to the Red Earth area for this period. The 14-32-49-26W4M gas well remains shut in due to low gas prices and high op costs associated with water trucking from the well. The Leduc production during the three and nine months ended December 31, 2011, averaged 241 boe/d and 132 boe/d, respectively. This year, the Leduc production for the three and nine months ended December 31, 2012, averaged 130 boe/d and 123 boe/d, respectively.

Norris, Alberta

The Corporation has various working interests varying from 57.5% to 100% in 520 gross acres (452 net acres) in the Norris area of central Alberta which also consists of five producing oil wells and one water disposal well. The Corporation has a 57.5% working interest in the well 100/16-21-53-18W4M and 100.0% working interest in wells 102/16-21-53-18W4M, 00/01-28-53-18W4M, 102/01-28-53-18W4M and 100/04-27-053-18W4M which all produce from the Mannville formation. Several Norris wells had pump optimization performed during this reporting period with good results and are now in the midst of optimizing surface equipment. The Norris production during the three and nine months ended December 31, 2011, averaged 31 bbls/d and 14 bbls/d, respectively. This year, the Norris production for the three and nine months ended December 31, 2012, averaged 15 bbls/d and 10 bbls/d, respectively.

Cherhill/Majeau, Alberta

Border has a 37.5% to 100% working interest in 3,170 acres (2,770 net acres) in the Cherhill area of southwestern Alberta. The wells, 100/03-25-56-04W5 and the 6-26-56-04W5M, produce from the Glauconite formation. The Cherhill/Majeau production during the three and nine months ended December 31, 2011, averaged 10 bbls/d and 8 bbls/d, respectively. This year, the Cherhill/Majeau production for the three and nine months ended December 31, 2012, averaged 9 bbls/d and 9 bbls/d, respectively.

Cardiff, Alberta

No production, as the 14-34-55-01W5M well remains shut in

Pembina/Brazeau, Alberta

The Pembina shallow gas production from the acquisition of Canflame Energy Ltd. commencing July 14, 2011 had production to the end of December 31, 2011, averaging 49 boe/d, and 51 boe/d for the three months ended December 31, 2011. This year, the Pembina production for the three and nine months ended December 31, 2012, averaged 24 boe/d and 27 boe/d, respectively.

<u>Non-Producing Properties</u>

Phat City, Montana, USA

The Corporation is party to a sub-participation agreement with Triangle USA Petroleum Corporation Ltd. (“Triangle”), which assigned Triangle’s rights in an exploration agreement between Triangle and Hunter Energy LLC (“Hunter”). The agreement requires the Corporation to pay 33 1/3% of the cost to drill one vertical test well on certain joint participation lands consisting of a 33,831 gross acre land position in Montana, United States to earn a 25% non-operating working interest. Hunter has issued a notice of termination of the exploration agreement to Border dated July 25, 2011, with respect to a cash call regarding the drilling of the initial vertical test well under the exploration agreement.

Border Petroleum Corp.
Management's Discussion & Analysis

By correspondence dated August 2, 2011, the Corporation has contested the notice on grounds that the cash call is improper and does not comply with the exploration agreement. This is an exploration project for Nisku and Bakken oil on the west side of Williston Basin.

PRODUCTION SUMMARY

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31		%
	2012	2011	CHANGE	2012	2011	CHANGE
Total Production						
Oil - bbls	**6,517**	9,021	(28)	**20,642**	17,651	17
Natural gas liquids - bbls	**1,676**	3,063	(45)	**4,088**	4,538	(10)
Natural Gas - Mcf	**67,152**	132,040	(49)	**199,632**	217,764	(8)
Total boe	**19,385**	34,091	(43)	**58,002**	58,483	(1)
Daily Production						
Oil - bbls per day	**71**	98	(28)	**75**	64	17
Natural gas liquids - bbls per day	**18**	33	(45)	**15**	17	(12)
Natural Gas - Mcf per day	**730**	1,435	(49)	**726**	792	(8)
Total boe per day	**211**	371	(43)	**211**	213	(1)

For the nine months ended December 31, 2012, oil production increased 17% to 20,642 bbls compared to 17,651 bbls for the same period last year. Natural gas production for the nine months ended December 31, 2012, was down 8% to 199,632 mcf compared to 217,764 mcf for the comparable period last year. Natural gas liquids (“NGLs”) decreased 10% to 4,088 bbls during the nine months ended December 31, 2012 compared to 4,538 bbls for the same period last year. Total production expressed in boe for the nine months ended December 31, 2012, decreased 1% to 58,002 boe compared to 58,483 boe last year. Border has five key producing areas; Majeau, Norris, Red Earth Leduc and Pembina.

For the three months ended December 31, 2012, oil production decreased 28% to 6,517 bbls compared to 9,021 bbls for the comparable period last year. Natural gas production for the three months ended December 31, 2012, decreased 49% to 67,152 mcf compared to 132,040 mcf for the comparable period last year. Natural gas liquids (“NGLs”) decreased 45% to 1,676 bbls during the three months ended December 31, 2012 compared to 3,063 bbls for the same period last year. Total production expressed in boe for the three months ended December 31, 2012, decreased 43% to 19,385 boe compared to 34,091 boe last year.

PRICING SUMMARY

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31		%
	2012	2011	CHANGE	2012	2011	CHANGE
Oil - $ per bbl	**$ 66.83**	$ 94.23	(29)	**$ 71.92**	$ 88.09	(18)
Natural gas liquids - $ per bbl	**$ 46.87**	$ 68.60	(32)	**$ 50.11**	$ 65.67	(23)
Natural Gas - $ per Mcf	**$ 3.22**	$ 3.34	(4)	**$ 2.54**	$ 3.51	(27)
$ per boe	**$ 37.68**	$ 44.04	(14)	**$ 37.88**	$ 44.75	(15)

During the nine months ended December 31, 2012, and the comparable period last year, Border sold all its oil, natural gas and natural gas liquids at spot prices and did not enter into any long-term, fixed price marketing contracts or derivative financial instruments. The Corporation’s oil production is currently comprised of three different densities, classified as light, medium and heavy (844.2 to 949.1 kg/m3) and as such receives average prices that are lower than the light WTI spot price that is the most common oil reference price.

During the nine months ended December 31, 2012, the average boe price was $37.88 compared to $44.75 last year. This drop in average boe price is the result of lower prices during the nine months ended December 31, 2012, compared to the prices realized for the comparable nine months last year. The percentage of natural gas production to oil and liquids production was 57% compared to 62% last year. Natural gas prices fell 27% to average $2.54 per mcf compared to $3.51 per mcf for the same nine months last year. The boe price will vary due to two key components, the first is the current market price of the products and the second is the Corporation’s mix of products.

During the three months ended December 31, 2012, the average boe price was $37.68 compared to $44.04 last year. This drop in average boe price is the result of lower prices during the three months ended December 31, 2012, compared to the prices realized for the comparable three months last year. The percentage of natural gas production to oil and liquids production was 58%, compared to 65% last year. Natural gas prices fell 4% to $3.22 per mcf compared to $3.34 per mcf for the same three months last year.

REVENUE

	THREE MONTHS ENDED DECEMBER 31 2012	THREE MONTHS ENDED DECEMBER 31 2011	% CHANGE	NINE MONTHS ENDED DECEMBER 31 2012	NINE MONTHS ENDED DECEMBER 31 2011	% CHANGE
Oil	**$ 435,550**	$ 850,094	(49)	**$ 1,484,481**	$ 1,554,881	(5)
Natural gas liquids	**78,556**	210,136	(63)	**204,847**	298,030	(31)
Natural Gas	**216,244**	441,222	(51)	**507,587**	764,132	(34)
Total Working Interest Revenue	**$ 730,350**	$ 1,501,452	(51)	**$ 2,196,915**	$ 2,617,043	(16)
$ per boe	**$ 37.68**	$ 44.04	(14)	**$ 37.88**	$ 44.75	(15)

Total revenue for the nine months ended December 31, 2012, decreased 16% totaling $2,196,915 compared to $2,617,043 last year. This decrease was due primarily to the 15% drop in the average boe sales price from $44.75 per boe to $37.88 as sales volumes only fell 1% between the two years. Compared to last year, total revenue when expressed as dollars per boe fell 15% during the nine months ended December 31, 2012, due to the overall decrease in product prices. During the nine months ended December 31, 2012, natural gas sales volumes accounted for 57% of the total sales and 62% of total sales last year. Currently the Corporation has greater natural gas sales than oil and NGLs that drive the average price per boe downwards. Future drilling plans continue to target light oil production.

Total revenue for the three months ended December 31, 2012, decreased 51% totaling $730,350 compared to $1,501,452 last year. Border has five key producing areas; Majeau, Norris, Red Earth, Leduc and Pembina. During this quarter, the $771,102 decrease in revenues from the same quarter last year was due to lower sales volumes (71%) and lower product prices (29%). Decreases in price and volumes for oil accounted for 54% of the total decrease in revenue, while natural gas accounted for 29% of the decrease and natural gas liquids accounted for the remaining 17% drop in revenues.

Compared to last year, total revenue when expressed as dollars per boe fell 14% to average $37.68 per boe from $44.04 during the three months ended December 31, 2012, due to the overall decrease in product and prices.

ROYALTY SUMMARY

	THREE MONTHS ENDED DECEMBER 31 2012	THREE MONTHS ENDED DECEMBER 31 2011	% CHANGE	NINE MONTHS ENDED DECEMBER 31 2012	NINE MONTHS ENDED DECEMBER 31 2011	% CHANGE
Crown	**$ 17,701**	$ 52,780	(66)	**$ 44,067**	$ 102,198	(57)
Overriding and Freehold	**66,325**	87,862	(25)	**153,653**	123,918	24
Total Royalty Expense	**$ 84,026**	$ 140,642	(40)	**$ 197,720**	$ 226,116	(13)
$ per boe	**$ 4.33**	$ 4.13	5	**$ 3.41**	$ 3.87	(12)
Expense rate - % of total working interest revenue	**12**	9	33	**9**	9	-

Total royalties paid for the nine months ended December 31, 2012, decreased by 13% to $197,720 compared to $226,116 for the same nine months last year. On a $ per boe basis, total royalties fell by 12% to $3.41 for the nine months ended December 31, 2012, compared to $3.87 per boe for the comparable nine months last year. This royalty increase is the combination of two distinct categories of royalty costs incurred. As indicated in the table above, Crown royalties for the nine months ended December 31, 2012 have decreased 57% from last year, whereas the Overriding and freehold royalties have increased 24% this year versus the same nine months last year. Border’s Crown royalties are primarily paid on the oil and natural gas sales from the Leduc area. This producing property was acquired through a merger with Canflame Energy Ltd. in July 2011 and since that time declining production and extremely low natural gas prices have impaired the development of this area, resulting in a decrease in Crown royalties.

Border Petroleum Corp.
Management's Discussion & Analysis

The increase in Overriding and freehold royalties are primarily due to royalty payments to Indian Oil and Gas Company ("ÏOGC") for the new production from the two horizontal wells in the Red Earth area completed in April and May 2012.

Total royalties paid for the three months ended December 31, 2012, decreased by 40% to $84,026 compared to $140,641 for the same three months last year. This decrease was primarily due to the drop in production from the wells in the Norris area, as well as the production declines in the Leduc and Pembina areas. On a $ per boe basis, total royalties increased by 5% to $4.33 for the three months ended December 31, 2012, compared to $4.13 per boe for the comparable three months last year.

OPERATING AND TRANSPORTATION EXPENSES

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Production expenses	**$ 350,914**	$ 780,880	(55)	**$ 1,320,778**	$ 1,533,013	(14)
Transportation and gathering	**200,695**	120,103	67	**793,522**	242,028	228
	551,609	900,983	(39)	**2,114,300**	1,775,041	19
Workover expenses	**-**	3,565	(100)	**30,068**	106,301	(72)
Total Production Expenses	**$ 551,609**	$ 904,548	(39)	**$ 2,144,368**	$ 1,881,342	14
$ per boe Total production expenses	**$ 28.46**	$ 26.53	7	**$ 36.97**	$ 32.17	15
Production expenses	**$ 18.11**	$ 22.91	(21)	**$ 22.77**	$ 26.21	(13)
Transportation & gathering	**$ 10.35**	$ 3.52	194	**$ 13.68**	$ 4.14	231
Workover expenses	**$ -**	$ 0.10	(100)	**$ 0.52**	$ 1.82	(71)
Expense rate - % of total working interest revenue	**76**	60	25	**98**	72	36

Production expenses, excluding workovers, for the nine months ended December 31, 2012, increased 19% to total $2,114,300 compared to $1,775,041 for the comparable period last year. The transportation and gathering expense component of the production costs for the nine months ended December 31, 2012, increased 228% to $793,522 compared to $242,028 for the same period last year due to trucking of produced water from the Leduc field, and increased production in the Red Earth field which resulted in higher cost transportation arrangements. The Leduc area incurs high transportation and gathering costs and the costs at December 31, 2012 includes nine months of the Leduc operations, whereas the nine months ended September 30, 2011 only includes the Leduc operations for 5.5 months commencing on July 14, 2011 when it was acquired from Canflame Energy Ltd.

Total production expenses for the nine months ended December 31, 2012, increased 14% to $2,144,368 compared to $1,881,342 for the same nine months last year. This is the result of acquisition of properties from Canflame Energy Ltd. and the additional operating costs associated with these properties; the first quarter last year did not reflect these additional costs. This resulted in total day-to-day production expenses, excluding workovers, expressed as a $ per boe during the nine months ended December 31, 2012, to average $36.45 per boe increasing 20% from last year's average of $30.35 per boe.

Production expenses, excluding workovers, for the three months ended December 31, 2012, fell 39% to total $551,609 compared to $900,983 for the same quarter last year. The transportation and gathering expense component of the production costs for the quarter ended December 31, 2012, increased 67% to $200,695 compared to $120,103 for the same quarter last year due primarily to trucking of produced water from the Leduc field, and increased production in the Red Earth field which resulted in higher cost transportation arrangements. Total production expenses for the three months ended December 31, 2012, fell 39% to $551,609 from $904,548 for the same three months last year due primarily to lower production volumes. Total day-to-day production expenses, excluding workovers, expressed as a $ per boe during the quarter ended December 31, 2012, averaged $28.46 per boe increasing 8% from last year's average of $26.43 per boe due to lower production volumes and fixed operating costs.

GENERAL AND ADMINISTRATIVE EXPENSES

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
General and administration	**$ 443,173**	$ 528,364	(16)	**$ 1,386,515**	$ 1,224,996	13
Transaction costs	**-**	142,799	(100)	**-**	294,603	(100)
	443,173	671,163	(34)	**1,386,515**	1,519,599	(9)
$ per boe	**$ 22.86**	$ 19.69	16	**$ 23.90**	$ 25.98	(8)
Expense rate - % of total working interest revenue	**61**	45	36	**63**	58	9

General and administrative expenses for the nine months ended December 31, 2012, increased by 13% totaling $1,386,515 compared to routine general and administrative costs of $1,224,996 for the same nine months last year. The additional "transaction costs" last year were legal fees and associated costs of $294,603 that were incurred due to the business combination with Canflame Energy Ltd. that closed on July 13, 2011. Increased costs this year included costs for specialized technical consultants and services for the two exploratory Red Earth wells drilled and completed in March, April and the long-leg horizontal well drilled in December 2012.

General and administrative expenses for the quarter ended December 31, 2012, decreased by 16% totaling $443,173 compared to routine general and administrative costs of $528,364 for the same quarter last year. Additional legal fees and associated costs totaling $142,799 were incurred in the second quarter of last year due to the business combination with Canflame Energy Ltd. that closed on July 13, 2011.

FINANCE INCOME AND EXPENSES

Finance income, consisting of interest income, is recognized as it accrues in the statement of income, using the effective interest method. Finance expense comprises interest expense on convertible debentures and note payable and accretion on the convertible note payable and of decommissioning provisions.

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Finance income						
Interest income	**$ 34,164**	$ 40,740	(16)	**$ 133,309**	$ 109,159	22
	34,164	40,740	(16)	**133,309**	109,159	22
Finance expenses						
Interest expense	**2,139**	370	478	**14,318**	4,047	254
Interest expense on note payable	**9,608**	27,741	(65)	**63,594**	79,604	(20)
Accretion on convertible note payable	**21,348**	26,610	(20)	**66,388**	76,358	(13)
Accretion of decommissioning provisions	**4,887**	10,697	(54)	**17,877**	17,441	2
Asset retirement expenses - non-CGU	**61**	-	n/a	**61**	-	n/a
	38,043	65,418	(42)	**162,238**	177,450	(9)
Net finance income (expense)	**(3,879)**	(24,678)	(84)	**(28,929)**	(68,291)	(58)
Finance income (expense) cash items	**32,025**	40,370	(21)	**16,421**	2,542	546
Finance expense non-cash items	**(35,904)**	(65,048)	(45)	**(45,350)**	(70,833)	(36)
Net finance income (expense)	**(3,879)**	(24,678)	(84)	**(28,929)**	(68,291)	(58)
$ per boe - finance income (expense) cash items	**$ 1.65**	$ 1.19	39	**$ 0.28**	$ 0.04	600
$ per boe - finance expense non-cash items	**$ (1.85)**	$ (1.91)	(3)	**$ (0.78)**	$ (1.21)	(36)
$ per boe - net finance income (expense)	**$ (0.20)**	$ (0.72)	(72)	**$ (0.50)**	$ (1.17)	(57)

Border Petroleum Corp.
Management's Discussion & Analysis

DEPLETION AND DEPRECIATION

	THREE MONTHS ENDED DECEMBER 31 2012	2011	% CHANGE	NINE MONTHS ENDED DECEMBER 31 2012	2011	% CHANGE
Depletion, depreciation	**$ 386,101**	$ 517,757	(25)	**$ 1,147,727**	$ 889,725	29
	$ 386,101	$ 517,757	(25)	**$ 1,147,727**	$ 889,725	29
$ per boe - Depletion, depreciation	**$ 19.92**	$ 15.19	31	**$ 19.79**	$ 15.21	30
Expense rate - % of working interest revenue	**53**	34	56	**52**	34	54

Depletion and depreciation expense for the nine months ended December 31, 2012, totaled $1,147,727 or $19.79 per boe compared to $889,725 or $15.21 per boe for the same period last year. The depletion cost per boe increased 30% from the comparable period last year due to increased capital spending during the year and the write-down of the Leduc reserves at March 31, 2012.

Depletion and depreciation expense for the three months ended December 31, 2012, totaled $386,101 or $19.92 per boe compared to $517,757 or $15.19 per boe for the same period last year. The depletion cost per boe increased 31% from the comparable period last year due to additional capital costs during the quarter and the adjustment to the reserve base due to the impairment of the Leduc reserves at March 31, 2012.

SHARE CAPITAL

Issued and Outstanding Common Shares

	DECEMBER 31, 2012 Number	Stated Value
Balance, at March 31, 2012	224,537,953	$ 50,352,701
Issuance of common shares	48,335,000	7,250,250
Issuance of flow-through shares	60,106,000	10,750,830
Flow-through share premium		(1,734,930)
Share issue costs		(1,241,587)
Balance, at December 31, 2012	**332,978,953**	**$ 65,377,264**

On September 28, 2012, the Corporation completed a bought deal offering with a syndicate of Underwriters for the issuance of 48,335,000 common shares of the Corporation at a price of $0.15 per common share, 55,556,000 Canadian Exploration Expense (“CEE”) flow-through shares of the Corporation at a price of $0.18 per flow-through share and 4,550,000 Canadian Development Expense (“CDE”) flow-through shares of the Corporation at a price of $0.165 for aggregate gross proceeds of $18,001,080. The Underwriters were paid a cash commission of 6% of the gross proceeds of the offering.

Warrants

At December 31, 2012, the Corporation had no warrants outstanding.

Border Petroleum Corp.
Management's Discussion & Analysis

STOCK BASED COMPENSATION

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Stock based compensation	**$ 257,304**	$ 102,074	152	**$ 780,224**	$ 144,277	441
$ per boe	**$ 13.27**	$ 2.99	344	**$ 13.45**	$ 2.47	445
Expense rate - % of working interest revenue	**35**	7	417	**36**	6	543

The Corporation has established a stock option plan (the "Plan") which is administered by the Board of Directors, allowing the Board of Directors to grant stock options. The Plan allows for the granting of stock options for the purchase of up to 10% of the outstanding common shares of the Corporation.

Options may not be granted to any one person, any one consultant or any persons performing investor relations duties in any twelve month period which could, when exercised, result in the issuance of shares exceeding 5%, 2% or 2%, respectively, of the issued and outstanding common shares of the Corporation. All options granted under the Plan shall expire as determined by the Board of Directors not later than the tenth anniversary of the date the options were granted.

The exercise price of the options is to be determined by the Board of Directors, but shall not be less than the market price of the common shares of the Corporation on the TSXV on the last business day before the date on which the options are granted, less any discount permitted by the rules of the TSXV. Vesting of the options is at the discretion of the Board of Directors but generally will occur over a two to three year period following the grant date.

As at December 31, 2012 and March 31, 2012, the Corporation had 14,861,250 stock options outstanding with a weighted average exercise price of $0.23 and 2,130,000 of these stock options were exercisable at a weighted average price of $0.24. There were no stock options granted during the nine months ended December 31, 2012.

Compensation costs of $780,224 for the nine months ended December 31, 2012, (2011 - $144,277) have been expensed and have resulted in a corresponding increase in contributed surplus.

AVERAGE SHARES OUTSTANDING

The weighted average number of shares outstanding ended December 31, 2012, totaled 261,605,059 compared to 224,537,953 at March 31, 2012.

Common shares and other equity instruments outstanding as at the date of this MD&A is as follows:

Common shares	332,978,953
Stock options	14,861,250

NET LOSS AND COMPREHENSIVE LOSS

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31	
	2012	**2011**	**CHANGE**	**2012**	**2011**
Net income (loss) for period	**$ 228,843**	$ (859,411)	(127)	**$ (2,263,983)**	$ (2,077,892)
Income (Loss) per share	**$ -**	$ (0.01)	(100)	**$ (0.01)**	$ (0.01)

A net loss and comprehensive loss of ($2,263,983) was recorded for the nine months ended December 31, 2012, compared to a net loss and comprehensive loss of ($2,077,892) for the comparable period last year. This was due primarily to lower sales volumes, higher operating costs, higher general and administrative costs and an increase in stock-based compensation and depletion expense.

Border Petroleum Corp.
Management's Discussion & Analysis

NET PETROLEUM AND NATURAL GAS REVENUE

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31		%
	2012	2011	CHANGE	2012	2011	CHANGE
Petroleum & Natural Gas Revenue	**$ 730,350**	$ 1,501,452	(51)	**$ 2,196,915**	$ 2,617,043	(16)
Less:						
Royalties	**84,026**	140,642	(40)	**197,720**	226,116	(13)
Production expenses	**551,609**	900,983	(39)	**2,114,300**	1,775,041	19
Workover expenses	**-**	3,565	(100)	**30,068**	106,301	(72)
Net Petroleum & Natural Gas Revenue	**$ 94,715**	$ 456,262	(79)	**$ (145,173)**	$ 509,585	128
$ per boe	**$ 4.89**	$ 13.38	(63)	**$ (2.50)**	$ 8.71	129

Gross revenue from petroleum and natural gas decreased 16% to total $2,196,915 for the nine months ended December 31, 2012, compared to $2,617,043 for the comparable nine months last year. The net petroleum and natural gas loss after royalties, production and workover expenses for the nine months ended December 31, 2012 was ($145,173) compared to net petroleum and natural gas revenue of 509,585 for the comparable period last year.

Gross revenue from petroleum and natural gas fell 51% to total $730,350 for the three months ended December 31, 2012, compared to $1,501,452 for the comparable three months last year. Net petroleum and natural gas revenue after royalties, production and workover expenses for the three months ended December 31, 2012 decreased 79% to $94,717 compared to net petroleum and natural gas revenue of $456,262 for the comparable period last year.

NETBACKS

	THREE MONTHS ENDED DECEMBER 31		%	NINE MONTHS ENDED DECEMBER 31		%
	2012	2011	CHANGE	2012	2011	CHANGE
$ per boe						
Working Interest Revenue	**$ 37.68**	$ 44.04	(14)	**$ 37.88**	$ 44.75	(15)
Royalties	**4.33**	4.13	5	**3.41**	3.87	(12)
Production expense	**18.11**	22.91	(21)	**22.77**	26.21	(13)
Gather/transportation	**10.35**	3.52	194	**13.68**	4.14	230
Workover expenses	**-**	0.10	(100)	**0.52**	1.82	(71)
Total after royalties and production expenses	**$ 4.89**	$ 13.38	(62)	**$ (2.50)**	$ 8.71	(129)
General and administration and transaction costs	**22.86**	19.69	16	**23.90**	25.98	(8)
Finance income cash items	**1.65**	1.19	39	**0.28**	0.04	600
Total Corporate Netbacks	**$ (16.32)**	$ (5.12)	219	**$ (26.12)**	$ (17.23)	52
Non-Cash Items						
Depletion, depreciation and accretion	**19.92**	15.19	31	**19.79**	15.21	30
Stock based compensation	**13.27**	2.99	344	**13.45**	2.47	445
Finance expense non-cash items	**(1.85)**	(1.91)	(3)	**(0.78)**	(1.21)	(36)
Deferred tax expense (recovery)	**(63.17)**	-	n/a	**(21.11)**	(0.59)	3,478
Total Netbacks after non-cash items	**$ 11.81**	$ (25.21)	(147)	**$ (39.03)**	$ (35.53)	10

Field netback for the nine months ended December 31, 2012, was a loss of ($2.50) per boe compared to a gain of $8.71 per boe for the comparable period last year. Total netbacks after non-cash items for the nine months ended December 31, 2012, were losses of ($39.03) per boe compared to ($35.53) per boe for the comparable period last year.

Border Petroleum Corp.
Management's Discussion & Analysis

Field netback for the three months ended December 31, 2012, was a gain of $4.89 per boe compared to a gain of $13.38 per boe for the comparable period last year. Total netbacks after non-cash items for the three months ended December 31, 2012, were gains of $11.81 per boe compared to a loss of ($25.21) per boe for the comparable period last year.

CAPITAL ADDITIONS

	THREE MONTHS ENDED DECEMBER 31 2012	THREE MONTHS ENDED DECEMBER 31 2011	% CHANGE	NINE MONTHS ENDED DECEMBER 31 2012	NINE MONTHS ENDED DECEMBER 31 2011	% CHANGE
Exploration and evaluation assets	**$ 7,514,708**	$ 4,319,355	74	**$ 7,497,314**	$ 4,673,005	60
Property and equipment						
Land and lease costs	**-**	-	n/a	**457,765**	-	n/a
Drilling and completions	**745,162**	180,010	314	**1,741,360**	2,832,357	(39)
Production equipment and facilities	**453,912**	114,960	295	**1,065,842**	729,610	46
Property acquisitions	**-**	-	n/a	**54,907**	17,326,419	(100)
Furniture & computers	**-**	22,158	(100)	**8,581**	24,304	(65)
Asset retirement	**102,521**	3,109	n/a	**111,171**	129,658	n/a
Total	**$ 8,816,303**	$ 4,639,592	90	**$ 10,936,940**	$ 25,715,353	(57)

Total asset additions were $10,936,940 for the nine months ended December 31, 2012, compared to $25,715,353 for the comparable period last year. Capital additions last year included the acquisition of Canflame Energy Ltd and the Leduc farm-in purchase. See details in Note 4 of the current financial statements. These additions included $ 111,171 of asset retirement decommissioning adjustments. The additions to capital expenditures during the nine months ended December 31, 2012 relate primarily to the drilling, completion and equipping of the long-leg horizontal Red Earth well drilled during December 2012 and the completion and equipping of the two short-leg Red Earth horizontal wells drilled in March 2012.

BANK DEBT

The Corporation has no bank debt outstanding under a demand revolving operating loan at September 30, 2012, (September 30, 2011 - $2,670,000). This facility provides that advances be made by way of prime-based loans and letters of credit to an aggregate maximum of $3,500,000. The facility bears interest of prime plus 1.25% per annum on prime-based loans and 2.00% per annum with a minimum fee of $200 for letters of credit. There is also a non-refundable facility fee calculated at a rate of 0.25% per annum, payable monthly, calculated on the unused portion of the authorized amount of this facility.

Under the terms of the credit facility, the Corporation must maintain a working capital ratio no less than 1:1 adjusted for any un-drawn portion of the revolving facility and excluding the mark to market impact of forward commodity contracts, if applicable.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2012, Border had working capital (current assets minus current liabilities) of $9,983,328 compared to working capital of $6,217,603 at March 31, 2012.

Pursuant to its joint venture with the Loon River Cree Nation, as well as its current land holdings at its Red Earth core areas, Border has a significant drilling portfolio. In this regard, Border plans to undertake new capital projects at Red Earth over the next 12 months. Current plans focus on the Red Earth area and include drilling two long leg horizontal wells and shooting 3D seismic over the next six months.

	DECEMBER 31 2012	MARCH 31 2012	% CHANGE
Cash	**$ 15,891,378**	$ 12,972,419	23
Accounts receivable and prepaid expenses	**1,207,344**	1,557,612	(22)
Accounts payable and accrued liablities	**(7,980,893)**	(9,075,357)	(12)
Investment in secured debt	**865,499**	762,929	13
	$ 9,983,328	$ 6,217,603	61

OFF-BALANCE SHEET ARRANGEMENTS

The Corporation has no off-balance sheet arrangements.

TRANSACTIONS WITH RELATED PARTIES

The Corporation utilizes the services of a law firm in which a Director of the Corporation is a Partner. During the nine months ended December 31, 2012, the Corporation incurred $109,925 (December 31, 2011 - $314,578) on legal services. These costs are recorded in share issuance costs and general legal fee expenses.

SUBSEQUENT EVENTS

At December 31, 2012, the total principal and interest remaining on the convertible note was $ 937,611. On January 15, 2013, the Corporation negotiated early repayment of the convertible note payable without penalty, realizing a savings of $71,014.

RISK FACTORS

The following are certain risk factors that relate to Border that the reader should consider. If any event arising from these factors occurs, the Corporation's business could be materially affected.

- Fluctuations in the prices of oil and gas will affect Border's revenue, cash flows and earnings and the value of the Corporation's oil and gas properties. These fluctuations could also affect the Corporation's ability to raise capital. These fluctuations in prices could be due to global economic and market conditions, weather conditions, the level of consumer and industrial demand, and governmental regulations.

- Drilling activities are subject to risks such as the possibility that commercially productive reservoirs will not be encountered, weather conditions, the ability to obtain regulatory approvals and shortages or delays in equipment and services.

- Estimates of oil and natural gas reserves involve a great measure of uncertainty as they depend on the reliability of available data, the costs to recover said reserves, and the ability to transport the product to market.

- There are operating risks that could affect the business of the Corporation. These include blowouts, equipment failures, spills or leaks, accidents and weather conditions.

- Compliance with and changes to environmental laws and regulations.

- The oil and gas industry is extremely competitive.

- The value of the Corporation's oil and gas properties.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Corporation has not entered into any marketing arrangements related to the selling of oil or natural gas production.

Fair Values

The fair values of cash, accounts receivable, deposits, investment in secured debt, bank debt, accounts payable and accrued liabilities, and note payable approximate their carrying value.

At December 31, 2012, the Corporation does not have any financial derivatives, including commodity contracts. Consequently, the Corporation's financial instruments were recorded at fair value on the balance sheet with changes to fair value being reported in the statement of loss and comprehensive loss.

The fair value of transactions are classified according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities.

- Level 2 – Inputs are other than quoted prices in Level 1 that are either directly or indirectly observable for the asset or liability.

- Level 3 – Inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level.

The Corporation’s cash has been valued using Level 1 inputs.

The Corporation is exposed to financial risks arising from its financial assets and liabilities. The Corporation manages its exposure to financial risks by operating in a manner that minimizes its exposure to the extent practical. The main financial risks affecting the Corporation are as follows:

Credit Risk

Credit risk is primarily related to the Corporation's receivables from oil and natural gas marketers and joint venture partners and the risk of financial loss if a customer, partner, or counterparty to a financial instrument fails to meet its contractual obligations. Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following production. Currently the Corporation sells the majority of its production to an oil and gas marketer. The Corporation historically has not experienced any collection issues with its oil and natural gas marketers. Joint venture receivables are typically collected within one to three-months of the joint venture bill being issued to the partner. The Corporation attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. The Corporation does not typically obtain collateral from joint venture partners; however, in certain circumstances, it may cash-call a partner in advance of the work and as well the Corporation has the ability in most cases to withhold production from joint venture partners in the event of non-payment. The Corporation establishes an allowance for doubtful accounts as determined by management based on their assessed collectability; therefore, the carrying amount of accounts receivable generally represents the maximum credit exposure.

The Corporation believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business. There were no receivables allowed for or written off during the period ended December 31, 2012 and there is $394,346 in accounts receivable outstanding greater than 90 days at December 31, 2012, which the Corporation would consider past due under normal conditions. Of this balance, $330,202 is due from one joint venture partner.

Cash balances consist of amounts on deposit with banks where bank overdraft consists of outstanding cheques issued in excess of cash. The Corporation manages the credit exposure of cash by selecting financial institutions with high credit ratings.

Total credit risk at December 31, 2012, is comprised of $1,091,050 in accounts receivable, $116,294 in deposits and prepaid expenses, $150,422 in lease reclamation deposits, $865,499 in investment in secured debt and $15,891,378 in cash and cash equivalents.

Market Risk

Market risk consists of commodity price, foreign exchange and interest rate risk, that may affect the value of the Corporation's financial instruments.

Commodity Price Risk

Commodity price risk is the risk that the future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by the world and continental/regional economy and other events that dictate the levels of supply and demand. The Corporation has not attempted to mitigate commodity price risk through the use of financial derivative contracts. The Corporation had no financial derivative sales contracts or working capital items denominated in foreign currencies as at or during the nine months ended December 31, 2012.

Foreign Currency Exchange Risk

Foreign currency exchange risk is the risk that future cash flows will fluctuate as a result of changes in foreign exchange rates. Although all the Corporation's oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian dollar and the United States dollars. The Corporation had no forward exchange rate contracts in place as at or during the period ended December 31, 2012.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate price risk to the extent that the note payable and investment in secured debt both bear interest at a fixed rate and interest rate cash flow risk to the extent that bank debt, if any, bears interest at a floating rate.

Operational Risks

Border's operational activities are focused in the Western Canadian Sedimentary Basin, a competitive environment with a number of companies exploring for hydrocarbons. Other operational risks include weather delays, mechanical or technical difficulties, and exploration risks associated with finding economically viable hydrocarbons reserves. Border attempts to manage these risks by maintaining an inventory of certain critical equipment; conducting advance planning to manage its drilling programs in an efficient and cost effective manner; and hiring experienced technical staff and personnel to conduct its exploration programs.

Border's field operations are also subject to health, safety and environmental risks. The Corporation maintains a Health, Safety and Environmental Policy and an Emergency Response Plan which are updated bi-annually or as needed to comply with current legislation. Both are designed to protect the health and safety of all concerned property, drilling, pollution, and commercial general liability.

Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they are due. The Corporation's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due without incurring unacceptable losses or risking harm to the Corporation's reputation. The Corporation prepares capital expenditure budgets which are regularly monitored and updated as considered necessary. As well, the Corporation utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. Also see below for a discussion on the Corporation's capital management policy.

Capital Management

The Corporation's policy is to maintain a strong capital base with the following objectives:

- Maintaining financial flexibility
- Maintaining creditor and investor confidence, and
- Sustaining the future development of the business.

The Corporation manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. Working capital and debt instruments (if any) are the components of the Corporation's capital structure to be managed. The most significant alternatives available for the management of the capital structure include adjusting capital spending to manage projected debt levels or to issue common shares or debentures when management and the Board of Directors feel the timing is appropriate. Management continually monitors the Corporation's projected capital spending and its net debt to maintain a sound capital position. Refer to the above section "Liquidity and Capital Resources".

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by Border are disclosed in Notes 2 and 3 to the year ended Financial Statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstance may result in actual results or changes to estimate amounts that differ materially from current estimates. The following discussion helps to assess the critical accounting policies and practices of the Corporation and the likelihood of materially different results from those reported.

CHANGES IN ACCOUNTING POLICIES AND NEW ACCOUNTING PRONOUNCEMENTS

Recent Accounting Pronouncements

Financial Instruments

The International Accounting Standards Board ("IASB") intends to replace IAS 39, "Financial Instruments: Recognition and Measurement" ("IAS 39") with IFRS 9, "Financial Instruments" ("IFRS 9"). IRFS 9 will be published in three phases, of which the first phase has been published.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 39 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used.

For financial liabilities, the approach to the fair value option may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is currently effective for annual periods beginning on or after January 1, 2015. The Corporation is currently assessing the impact of this standard.

Fair Value Measurements

In May 2011, the IASB issued IFRS 13, "Fair Value Measurement" which provides a consistent and less complex definition of fair value, established a single source of guidance for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. Prospective application of this standard is effective for fiscal periods beginning on or after January 1, 2013, with early adoption permitted. The Corporation is currently assessing the impact of this standard.

Reporting Entity

In May 2011, the IASB issued IFRS 10, "Consolidated Financial Statements" ("IFRS 10"), IFRS 11, "Joint Arrangements" ("IFRS 11"), IFRS 12, "Disclosers of Interest in Other Entities" ("IFRS 12") and amendments to both IAS 27, "Consolidated and Separate Financial Statement" and IAS 28 "Investments in Associates".

IFRS 10 creates a single consolidated model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and special purpose vehicles. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation to arrangements that meet the definition of a joint operation. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including joint arrangements, associates and special purpose vehicles.

Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013, with earlier adoption permitted if all of the standards are collectively adopted. The Corporation is currently assessing the impact of these standards.

BUSINESS RISKS AND UNCERTAINTIES

Border advises readers that this Report may contain a number of forward-looking statements that involve a number of risks and uncertainties. Such information, although considered reasonable by Border at the time, may ultimately prove incorrect, too optimistic or too pessimistic, and actual results may differ materially from those anticipated in the statements. For this purpose, any statements contained within this Report that are not statements of historical fact may be deemed forward looking.

In common with all public oil and gas companies, and especially smaller companies, Border is subject to considerable market volatility affecting the prices received for its production, foreign exchange and interest rates, the availability and cost of capital financing, and market liquidity for its common shares. Furthermore, high energy prices can lead to increased energy supplies, reduced economic activity, and increased conservation efforts, which then sow the seeds for lower energy prices. Border does not participate in hedging of oil and gas prices, foreign exchange or interest rates, as it considers such activities to be highly risky and a distraction from its primary areas of focus.

The oil and gas business is also subject to a number of operational risks and uncertainties relating to such matters as exploration and development success, technical drilling and production performance and equipment failure including blowouts and fires, reserve recovery rates and timing, availability of third-party natural gas transportation, environmental damage and competition with much larger and better-financed companies for scarce land, people and financial resources.

To manage these risks and uncertainties, Border relies upon the expertise and creativity of its human resources, the development of strategic relationships with industry partners, modern exploration, engineering and business technology, professional environmental sensitivity assessments, and public liability, property damage and business interruption insurance.

Furthermore, the oil and gas industry is subject to extensive regulatory environments and fiscal regimes, both in Canada and internationally, which are subject to changes and beyond the control of the Corporation. The Corporation takes a proactive approach with respect to environment and safety. An operational emergency and response plan and safety policy are in place and the Corporation is in compliance with current environmental legislation.

DATE

This Management Discussion and Analysis is dated as of February 20, 2012.

ADDITIONAL INFORMATION

Additional information regarding Border is available on SEDAR at www.sedar.com.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbls	Barrels
Mbbls	thousand barrels
bbls/d	barrels of oil per day
boe/d	barrels of oil equivalent per day
NGLs	natural gas liquids (consisting of any one or more of propane, butane and condensate thousand stock tank barrels of oil
bpd	barrels of production per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
m3	cubic meters

Other

boe means barrels of oil equivalent. A barrel of oil equivalent is determined by converting a volume of natural gas to barrels using the ration of six (6) mcf to one (1) barrel. "boe" may be misleading, particularly if used in isolation the boe conversion ration of six (6) mcf: one (1) bbl is based on an energy equivalency methods primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

GORR means gross overriding royalty

CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic meters	28.174
cubic meters	Cubic feet	35.494
bbls	Cubic meters	0.159
feet	meters	0.305
acres	hectares	0.405

Border Petroleum Corp.
Management's Discussion & Analysis

SUMMARY OF QUARTERLY RESULTS

The Corporation's results of operations for the eight most recent fiscal quarters are summarized as follows:

	THREE MONTHS ENDED DEC 31/2012	THREE MONTHS ENDED SEPT 30/2012	THREE MONTHS ENDED JUN 30/2012	THREE MONTHS ENDED MAR 31/2012
	Q3	Q2	Q1	Q4
Total Production Volumes				
Natural gas (Mcf)	67,152	56,705	75,775	108,283
Oil and NGL (bbl)	8,193	6,975	9,562	6,662
Combined (boe)	19,385	16,426	22,191	24,709
Daily Production				
Natural gas (Mcf per day)	730	616	833	1,190
Oil and NGL (bbl per day)	89	76	105	73
Combined (boe per day)	211	179	244	272
Gross Revenue				
Natural Gas	$ 216,244	$ 132,145	$ 159,198	$ 245,416
Oil and liquids	514,106	483,265	691,957	462,485
Total PNG Revenue	730,350	615,410	851,155	707,901
Royalty Expense				
Crown royalties	17,701	(304)	26,670	1,329
Freehold and overriding royalties	66,325	22,356	64,972	40,764
Total Royalty Expense	$ 84,026	$ 22,052	$ 91,642	$ 42,093
Net Revenue after Royalties	**$ 646,324**	**$ 593,358**	**$ 759,513**	**$ 665,808**
Operating, transportation & workover	551,609	613,551	979,206	825,429
General and administrative	443,173	478,566	464,776	615,246
Transaction costs	-	-	-	100,001
Stock based compensation	257,304	261,205	261,715	266,037
Depletion, depreciation and impairment	386,101	328,788	432,838	10,594,607
Income (loss) before finance expense and income taxes	$ (991,863)	$ (1,088,752)	$ (1,379,022)	$ (11,735,512)
Net finance (income) expense	$ (3,879)	$ (6,728)	$ (18,322)	$ (17,246)
Deferred income tax recovery	(1,224,585)	-	-	(960,000)
Net and Comprehensive Loss	**$ 228,843**	**$ (1,095,480)**	**$ (1,397,344)**	**$ (10,758,266)**
Basic income (loss) per share	$0.00	($0.01)	($0.01)	($0.05)
Average Price				
Natural gas ($ per Mcf)	$ 3.22	$ 2.33	$ 2.10	$ 2.27
Oil and NGL ($ per bbl)	$ 62.75	$ 69.29	$ 72.37	$ 69.42
$ per boe	$ 37.68	$ 37.47	$ 38.36	$ 28.65
Total Assets	**$ 54,799,601**	**$ 49,817,051**	**$ 36,246,204**	**$ 42,533,642**
Total Liabilities	**$ 11,294,161**	**$ 6,795,386**	**$ 7,417,197**	**$ 12,569,006**

Border Petroleum Corp.
Management's Discussion & Analysis

SUMMARY OF QUARTERLY RESULTS – continued

	THREE MONTHS ENDED DEC 31/2011	THREE MONTHS ENDED SEPT 30/2011	THREE MONTHS ENDED JUN 30/2011	THREE MONTHS ENDED MAR 31/2011
	Q3	**Q2**	**Q1**	**Q4**
Total Production Volumes				
Natural gas (Mcf)	132,040	83,296	2,428	2,222
Oil and NGL (bbl)	12,084	7,826	2,279	3,214
Combined (boe)	34,091	21,708	2,684	3,584
Daily Production				
Natural gas (Mcf per day)	1,435	905	27	25
Oil and NGL (bbl perday)	131	85	25	36
Combined (boe per day)	371	236	29	40
Gross Revenue				
Natural Gas	$ 441,222	$ 312,657	$ 10,253	$ 9,211
Oil and liquids	1,060,230	560,719	231,963	267,980
Total PNG Revenue	1,501,452	873,376	242,216	277,191
Royalty Expense				
Crown royalties	52,780	52,887	(3,468)	26,579
Freehold and overriding royalties	87,862	28,123	7,933	12,293
Total Royalty Expense	$ 140,642	$ 81,010	$ 4,465	$ 38,872
Net Revenue after Royalties	**$ 1,360,810**	**$ 792,366**	**$ 237,751**	**$ 238,319**
Operating and transportation	904,548	722,065	254,729	367,314
General and administrative	528,364	414,859	281,773	382,249
Transaction costs	142,799	61,426	90,378	-
Stock based compensation	102,074	23,443	18,759	127,769
Depletion, depreciation, accretion	517,757	315,062	56,906	101,502
Income (loss) before finance expense and income taxes	$ (834,732)	$ (744,489)	$ (464,794)	$ (740,515)
Net finance expense	$ 24,678	$ 27,744	$ 15,869	$ 46,911
Deferred income tax recovery	-	$ -	(34,415)	(70,267)
Net and Comprehensive loss	**$ (859,410)**	**$ (772,233)**	**$ (446,248)**	**$ (717,159)**
Basic income (loss) per share	($0.01)	($0.01)	($0.01)	($0.01)
Average Price				
Natural gas ($ per Mcf)	$ 3.34	$ 3.75	$ 4.22	$ 4.15
Oil and NGL ($ per bbl)	$ 87.74	$ 71.65	$ 101.78	$ 83.39
$ per boe	$ 44.04	$ 40.23	$ 90.24	$ 77.34
Total Assets	**$ 46,353,543**	**$ 26,961,591**	**$ 11,874,876**	**$ 9,004,471**
Total Liabilities	**$ 5,897,104**	**$ 8,601,864**	**$ 4,458,463**	**$ 1,335,998**