Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the September 30, 2012 unaudited consolidated financial statements and the December 31, 2011 audited consolidated financial statements of Yangarra Resources Ltd ("Yangarra" or "the Company"), together with the accompanying notes.

Additional information about Yangarra filed with Canadian securities commissions is available on-line at www.sedar.com.

The MD&A has been prepared using information that is current to November 16, 2012.

The financial information presented herein has been prepared on the basis of International Financial Reporting Standards ("IFRS"). Throughout this discussion, percentage changes are calculated using numbers rounded to the decimal to which they appear. All references to dollar amounts are in Canadian dollars.

***BOE Presentation** – Production information is commonly reported in units of barrel of oil equivalent ("boe"). For purposes of computing such units, natural gas is converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalent wellhead value for the individual products. Such disclosure of boe may be misleading, particularly if used in isolation. Readers should be aware that historical results are not necessarily indicative of future performance.*

***Special Note Regarding Non-IFRS Measures** This MD&A contains the terms "funds from (used in) operations" and "funds from (used in) operations per share", which should not be considered an alternative to or more meaningful than cash flow from (used in) operating activities as determined in accordance with IFRS. These terms do not have any standardized meaning as prescribed by IFRS. Yangarra's determination of funds from (used in) operations and funds from (used in) operations per share may not be comparable to that reported by other companies. Management uses funds from (used in) operations to analyze operating performance and leverage, and considers funds from (used in) operations to be a key measure as it demonstrates the Company's ability to generate cash necessary to fund future capital investments and to repay debt, if applicable. Funds from (used in) operations is calculated using cash flow from (used in) operating activities as presented in the statement of cash flows before changes in non-cash working capital. Yangarra presents funds from (used in) operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.*

The following table reconciles funds from (used in) operations to cash flow from (used in) operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	Three Months ended September 30		Nine Months ended September 30,	
	2012	2011	2012	2011
Cash flow from (used in) operating activities	$ 5,902,746	$ 3,611,162	$ 12,853,084	$ 7,410,422
Changes in non-cash working capital	(3,122,226)	1,356,691	(1,433,007)	3,244,347
Funds from (used in) operations	$ 2,780,520	$ 4,967,853	$ 11,420,077	$ 10,654,769

The Company considers corporate netbacks to be a key measure as they demonstrate Yangarra's profitability relative to current commodity prices. Corporate netbacks are comprised of operating, funds flow and net loss netbacks. Operating netback is calculated as the average sales price of its commodities and then subtracts royalties, operating costs and transportation expenses. Funds flow netback starts with the operating netback and further deducts general and administrative costs, finance expense and adds finance income as well as realized gains on financial instruments. To calculate the net income (loss) netback, Yangarra takes the funds flow netback and deducts share-based compensation expense as well as *depletion and depreciation charges, accretion expense, unrealized gains on financial instruments, any impairment or exploration and evaluation expense and deferred income taxes. There is no IFRS measure that is reasonably comparable to netbacks.*

Net debt and working capital (deficit), which represent current assets less current liabilities, excluding current derivative financial instruments, are used to assess efficiency, liquidity and the general financial strength of the Company. There is no IFRS measure that is reasonably comparable to net debt or working capital (deficit).

Forward-looking Statements *– Certain information regarding the Company set forth in this report, including management's assessment of the Company's future plans and operations, contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks and uncertainties, many of which are beyond the Company's control, include the impact of general economic conditions and specific industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. The Company's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits the Company can derive from such events.*

Company Description and Outlook

Yangarra is a junior oil and gas company engaged in the exploration, development and production of natural gas and oil with operations in Western Canada, with a main focus on Central Alberta, where the Company has extensive infrastructure and land holdings.

Yangarra is dedicated to creating value for its shareholders through its commitment to a clear business strategy and performance objectives. The Company's strategy is to increase the value of its corporate assets through the drill bit and by assembling a large focused land base in Central Alberta that features high-quality, long-life light oil and liquids-rich gas reserves. The Company has assembled a significant future drilling inventory and will strive to grow this inventory through drilling, geology and strategic acquisitions.

Highlights of the quarter ended September 30, 2012 are as follows:

- Production averaged 1,800 boe/d during the third quarter which is a 44% increase from the third quarter of 2011.
- Oil and NGL production was 37% of total production in the third quarter compared with 42% in the third quarter of 2011.
- Oil and gas sales including royalty income and realized hedging was $5.8 million with cash flow from operations of $2.8 million ($0.02 per share basic).
- Operating costs for the third quarter, including $0.80/boe of transportation costs, were $6.81/boe which represents a 9% decrease from the comparable period in 2011.
- G&A was $2.93/boe and royalties were 6% of oil and gas revenue.
- Capital expenditures of $4.7 million were for the drilling, completion and work-over operations conducted during the third quarter.
- As at September 30, 2012, the Company had a working capital deficit of $35 million (excluding mark to market on commodity contracts) compared to $34 million at December 31, 2011.

Operations Update

Yangarra delayed the resumption of its 2012 drilling program until September due to the extremely wet conditions in Central Alberta that prevailed after spring breakup.

The Company also changed the drilling program to mono-bore drilling from the previous intermediate casing method. The mono-bore wells provide significant cost savings as a result of much faster drilling times and substantially lower casing costs.

In September, a Cardium horizontal well was drilled in the Willesden Green area and the well was fractured using a slick water system with 500 tonnes of sand placed in 20 stages over a 1,230 meter horizontal leg. The fracture program was monitored using micro-seismic to assist Yangarra in determining optimal well spacing in the reservoir. The well is currently in clean up and flow testing with a flow rate over the first 15 days of 260 boe/d (IP 15) 85% liquids. The well will be shut in for a two week mandatory pressure buildup at the completion of the flow test.

Following the Cardium well, the Company drilled a SWS well from the same well pad and the well was fractured with 500 tonnes of sand placed in 14 stages. This well is the second horizontal SWS well drilled by Yangarra in the Willesden Green area. This fracture program was also observed with micro-seismic. The well was flowed through testers for 48 hours to recover flow- back water together with approximately 190 boe/d of oil and gas (60% liquids). The well is now shut-in for an estimated 30-45 days to "rest" allowing the water to be absorbed by the under saturated shales at which point the well will be placed on production.

In mid October, the Company drilled a Glauconite oil horizontal well in Westerose and this well was recently fractured using a foam based surfactant fluid with 500 tonnes placed in 16 stages. The well is currently flowing back through testers.

Landowner objections continue to delay installation of incremental compression in the Ferrier area and as a result 700 boe/d remains behind pipe waiting to be brought on-stream. In addition, the three wells recently drilled are expected to be on-stream by year end.

Current production is approximately 2,000 boe/d and fourth quarter production is expected to be 2,000 – 2,200 boe/d. Yangarra expects to average approximately 2,000 boe/d for 2012 which is a 65% increase from 2011 on an annualized per share basis.

Summary Financial Information

	Three Months ended September 30 2012	Three Months ended September 30 2011	Nine Months ended September 30, 2012	Nine Months ended September 30, 2011
Statements of Comprehensive Income (Loss)				
Net income (loss) for the period (before tax)	$ (3,037,649)	$ 5,424,074	$ 2,430,940	$ 8,015,045
Net income (loss) for the period	$ (2,073,174)	$ 4,106,091	$ (558,335)	$ 3,541,281
Net income (loss) per share - basic	$ (0.02)	$ 0.04	$ (0.00)	$ 0.03
Net income (loss) per share - fully diluted	$ (0.02)	$ 0.03	$ (0.00)	$ 0.03
Statements of Cash Flow				
Funds flow from (used in) operating activities	$ 2,780,520	$ 4,967,853	$ 11,420,077	$ 10,654,769
Funds flow from (used in) operating activities per share - basic	$ 0.02	$ 0.04	$ 0.09	$ 0.10
Funds flow from (used in) operating activities per share - fully diluted	$ 0.02	$ 0.04	$ 0.09	$ 0.10
Statements of Financial Position				
Property and equipment	$ 122,723,826	$ 104,908,393	$ 121,329,749	$ 104,908,393
Total assets	$ 138,820,924	$ 118,260,567	$ 142,907,001	$ 118,260,567
Working Capital (deficit), excluding MTM on commodity contracts and flow-through share obligation	$ (35,450,284)	$ (19,545,339)	$ (35,450,284)	$ (19,545,339)
Shareholders equity	$ 79,349,142	$ 78,375,411	$ 79,349,142	$ 78,375,411
Weighted average number of shares - basic	121,711,723	116,307,057	120,311,001	102,463,621
Weighted average number of shares - fully diluted	121,711,723	124,209,770	120,343,320	110,610,771

Business Environment

	Three Months ended September 30 2012	Three Months ended September 30 2011	Nine Months ended September 30, 2012	Nine Months ended September 30, 2011
West Texas Intermediate ("WTI") (US$/bbl)	$ 92.20	$ 89.81	$ 96.16	$ 95.52
AECO gas (Cdn$/GJ)	$ 2.19	$ 3.53	$ 2.18	$ 3.55

Crude oil prices strengthened in the third quarter of 2012, with the West Texas Intermediate ("WTI") reference price averaging US$92.20 per barrel compared to US$89.81 per barrel in the same period in 2011 however a further reduction to realized prices is due to Edmonton par to WTI differential. The average realized price of Yangarra's crude oil was $84.35/bbl for the third quarter of 2012 compared to $89.25/bbl a year ago, while NGLs averaged $38.62/bbl versus $54.00/bbl in 2011.

During the three months ended September 30, 2012, benchmark natural gas prices in Canada fell 38% from the same period last year. AECO prices averaged $2.19/GJ throughout the third quarter of 2012 compared to $3.53/GJ a year ago. Yangarra's average realized gas price during the three-month period was $2.57/mcf versus $3.93/mcf last year.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	Three Months ended September 30 2012	Three Months ended September 30 2011	Nine Months ended September 30, 2012	Nine Months ended September 30, 2011
Daily production volumes				
Natural gas (mcf/d)	5,617	4,161	5,915	3,582
Oil (bbl/d)	273	384	327	303
NGL's (bbl/d)	317	132	354	107
Royalty income				
Natural gas (mcf/d)	1,228	172	1,380	86
Oil (bbl/d)	2	2	6	5
NGL's (bbl/d)	67	13	84	6
Combined (boe/d 6:1)	1,800	1,253	1,986	1,032
Product pricing (includes royalty income & realized hedging)				
Oil ($/bbl)	$ 84.35	$ 89.25	$ 84.45	$ 92.34
NGL ($/bbl)	42.24	54.00	$ 52.95	61.64
Gas ($/mcf)	2.52	3.93	2.37	3.90
Combined ($/boe)	$ 31.47	$ 55.09	$ 34.30	$ 51.74
Revenue				
Petroleum & natural gas sales - Gross	$ 4,885,957	$ 5,378,932	$ 16,857,092	$ 13,186,832
Royalty income	323,947	137,243	1,808,126	277,521
Realized hedging	574,219	834,284	372,278	1,107,912
Total sales	5,784,122	6,350,459	19,037,496	14,572,265
Royalty expense	(324,279)	(209,529)	(1,054,227)	(409,444)
Petroleum & natural gas sales - Net	$ 5,459,843	$ 6,140,930	$ 17,983,269	$ 14,162,821

Total revenue decreased by 9% in the third quarter of 2012 to $5.8 million from $6.4 million in the same period 2011, the decrease is made up of:

- a 43% decrease in average product prices and;
- a 44 % increase in production (on a boe basis).

The decreased production in the third quarter of 2012 can be attributed to natural declines and limited drilling during spring break-up. As at September 30, 2012 there continue to be significant volumes remaining behind pipe due to continued facility constraints and recent drilling waiting for pipeline tie-in.

The overall average price earned by the Company was lower when compared to the same period in 2011 due to significant decreases in the natural gas price.

The price received for oil decreased from the second quarter 2012 as well, due to decreases in WTI prices and increases in the Edmonton Par to WTI differential.

Oil and NGL production was 37% of total production in the third quarter compared with 42% in the third quarter of 2011. The decrease in liquids production was a result of lower than expected declines in several gas-weighted Glauconite wells and down time related to a turnaround at a third party deep cut plant.

The delays related to landowner objections to adding increased compression in a third party facility to which four new tested wells are tied into and to which new two additional shut in wells were tied into continued during the third quarter. Rather than expend additional capital to accelerate the process the Company continues to be patient and will let declines create room in the existing facility. One well has come on-stream as room became available in the existing compressor and the operator advises that the landowner objection is working its way through the regulatory process.

Royalty Income

	Three Months ended September 30		Nine Months ended September 30,	
	2012	2011	2012	2011
Royalty Income	$ 323,947	$ 137,243	$ 1,808,126	$ 277,521

Royalty income increased in third quarter of 2012 to $323,947 from $137,243 in the comparable period in 2011. The majority of royalty income is a result of the 15% sliding scale royalty purchased in the Willesden Green area in March 2010. At the end of 2010 four wells had been drilled on the royalty lands and during 2011 an additional eight wells were added bringing to the total to 12 wells generating the 15% royalty income.

Royalty Expense

	Three Months ended September 30		Nine Months ended September 30,	
	2012	2011	2012	2011
Royalty Expense	$ 324,279	$ 209,529	$ 1,054,227	$ 409,444
Per boe	$ 1.96	$ 1.82	$ 1.94	$ 1.45
As a % of sales	6%	4%	6%	3%

Royalties increased to $324,279 in the third quarter 2012 from $209,529 for the comparable period in 2011. The increased in the third quarter royalties is from additional wells reaching payout on the 5% royalty regime. The increase from the comparable period in 2011 is due to increased production rates. Generally, royalty rates in Western Canada are sensitive to prevailing commodity prices and individual well production rates. The crown royalty rate on the new horizontal wells in Central Alberta is 5% for the earlier of 2 years or 60,000 boe of production.

Production and Transportation Costs

	Three Months ended September 30		Nine Months ended September 30,	
	2012	2011	2012	2011
Production costs	$ 995,004	$ 742,035	$ 3,262,317	$ 2,016,356
Per boe	$ 6.01	$ 6.44	$ 6.00	$ 7.16
Transportation costs	$ 132,603	$ 116,075	$ 436,511	$ 277,158
Per boe	$ 0.80	$ 1.01	$ 0.80	$ 0.98

Production and transportation costs increased in the third quarter of 2012 to $1,127,607 however decreased by 11% on a per boe basis when compared to the comparable period in 2011.

The decrease in operating costs from the comparable period in 2011 is due to the completion of maintenance work and various field projects during the quarter and the return to normal operating conditions.

Depletion, depreciation and accretion

	Three Months ended September 30		Nine Months ended September 30,	
	2012	2011	2012	2011
Depletion and depreciation	$ 3,581,413	$ 2,253,782	$ 12,518,151	$ 5,025,020
Per boe	$ 21.63	$ 19.55	$ 23.00	$ 17.84
Accretion	$ 21,984	$ 30,067	$ 70,515	$ 83,865

Depletion and depreciation increased in the third quarter 2012 versus the comparable period in 2011 due increased production levels.

General and administrative expenses ("G&A")

	Three Months ended September 30 2012	2011	Nine Months ended September 30, 2012	2011
Gross G&A expenses	$ 541,839	$ 539,781	$ 1,786,694	$ 1,732,846
G&A recoveries	(56,233)	(294,355)	(371,236)	(747,366)
Net G&A expenses	$ 485,606	$ 245,426	$ 1,415,458	$ 985,480
Per boe	$ 2.93	$ 2.13	$ 2.60	$ 3.50

Gross G&A costs in the third quarter are consistent with the comparable period in 2011. On a net basis G&A was higher than the comparable period in 2011 due to lower recoveries in the three months ended September 30, 2012.

Other expenses

	Three Months ended September 30 2012	2011	Nine Months ended September 30, 2012	2011
Interest and financing fees	$ 491,892	$ 69,541	$ 1,076,628	$ 220,097
Dividends on preferred shares	$ -	$ -	$ -	$ 8,960
Stock-based compensation	$ 143,600	$ 148,828	$ 499,724	$ 1,424,283

Interest and financing fees for the three months ended September 30, 2012 is for interest on the revolving operating demand loan for which the average amount drawn in 2012 was $34 million.

During the three months ended September 30, 2012, the Company granted a total of 1,770,000 stock options which vested immediately. The total fair value of the options was estimated at $296,900 of which $153,300 was capitalized.

Deferred Taxes

	Three Months ended September 30 2012	2011	Nine Months ended September 30, 2012	2011
Deferred Income Tax (recovery) expense	$ (964,475)	$ 1,317,983	$ 2,989,275	$ 4,473,764

During the three months ended September 30, 2012, the Company recorded a deferred income tax recovery of $964,475 compared to an expense of $1,317,983 in the same period last year. For 2012, this expense is a function of the overall net loss adjusted for tax related to the eligible capital expenditures being spent in relation to the June 2011 flow-through share issuance. As these eligible costs are incurred, the Company reverses the flow-through share premium liability and recognizes the deferred income tax expense at that time.

Yangarra does not have current income taxes payable and does not expect to pay current income taxes in 2012 as the Company had estimated tax pools of $88 million available at September 30, 2012.

Commodity price risk contracts

	Three Months ended September 30		Nine Months ended September 30,	
	2012	2011	2012	2011
Commodity contract settlement	$ 574,219	$ 834,284	$ 372,278	$ 1,107,912
Change in fair value of commodity contracts	(2,071,172)	2,888,898	4,099,253	3,893,444
	$ (1,496,953)	$ 3,723,182	$ 4,471,531	$ 5,001,356

As at September 30, 2012, the Company was committed to the following commodity price risk contracts for the sale of oil:

2012 Hedges:

- 100 bbl/d from January 1 to December 31, 2012 at a fixed price of $99.00 CAD/bbl;
- 200 bbl/d from January 1 to December 31, 2012 at a fixed price of $97.00 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2012 at a fixed price of $93.25 CAD/bbl; and
- 100 bbl/d from January 1 to December 31, 2012 at a fixed price of $100.00 CAD/bbl.

2013 Hedges:

- 200 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.00 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $97.50 CAD/bbl;
- 200 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.30 USD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.00 USD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $104.80 CAD/bbl and;
- Sold calls on 200 bbl/d d from January 1 to December 31, 2013 at $110 USD/bbl.

2014 Hedges:

- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $98.30 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $100.00 CAD/bbl; and
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $101.05 CAD/bbl.

As at September 30, 2012, the Company was committed to the following commodity price risk contracts on the AECO basis:

- 1,000 GJ/d at $5.25/GJ for April 2012 – October 2012;
- 1,000 GJ/d at $2.22/GJ for July 2012 – October 2012; and
- 1,000 GJ/d at $2.40/GJ for August 2012 – December 2012.

The mark-to market on the hedges was in a gain position of $2,607,378 as at September 30, 2012 (December 31, 2011 – a loss position of $1,491,875).

Company Netbacks ($/boe)

	Three Months ended September 30 2012	2011	Nine Months ended September 30, 2012	2011
Sales Price	$ 29.51	$ 53.54	$ 30.98	$ 50.75
Royalty income	1.96	1.55	3.32	0.99
Royalty expense	(1.96)	(1.82)	(1.94)	(1.45)
Production costs	(6.01)	(6.44)	(6.00)	(7.16)
Transportation costs	(0.80)	(1.01)	(0.80)	(0.98)
Operating netback	**22.70**	45.82	25.57	42.15
G&A and other (excludes non-cash items)	(2.93)	(2.13)	(2.60)	(3.50)
Finance expenses	(2.97)	(0.60)	(1.98)	(0.81)
Cash flow netback	**16.79**	43.09	**20.99**	**37.84**
Depletion and depreciation	(21.63)	(19.55)	(23.00)	(17.84)
Accretion	(0.13)	(0.26)	(0.13)	(0.30)
Stock-based compensation	(0.87)	(1.29)	(0.92)	(5.05)
Unrealized gain (loss) on financial instruments	(12.51)	25.06	7.53	13.82
Deferred income tax	5.83	(11.43)	(5.49)	(15.88)
Net Income (loss) netback	**$ (12.52)**	$ 35.61	**$ (1.03)**	**$ 12.59**

The third quarter 2012 operating netback of $22.85 per boe is a 50% decrease from the same period in 2011. The decrease in operating netbacks from the comparable period in 2011 is due to primarily a reduction in commodity prices.

Liquidity and Capital Resources

The following table summarizes the change in working capital during the three and nine months ended September 30, 2012:

	Three Months Ended September 30, 2012	Nine months Ended September 30, 2012
Working capital (deficit) - beginning of period (1)	$ (33,428,709)	$ (34,028,162)
Cash flow from (used in) operating activities	2,780,520	11,420,077
Capital expenditures	(4,802,095)	(15,394,532)
Issuance of shares	-	2,552,333
Working capital (deficit) - end of period (1)	$ (35,450,284)	$ (35,450,284)
Credit facility limit	$ 42,000,000	$ 42,000,000

(1) Excludes non-cash change in fair value of commodity contracts

As at September 30, 2012, the Company had a working capital deficit of $35 million (excluding mark to market on commodity contracts) which is higher than the working capital deficit of $33 million at June 30, 2012 due to the resumption of the drilling program.

During the three months ended September 30, 2012, the Company generated $2.8 million of cash flow from operations compared to $3.5 million in the second quarter of 2012. Cash flow from operations was lower for the third quarter when compared to the second quarter of 2012 due to natural declines, the limited drilling during spring break-up and significant shut-in volumes.

As at September 30, 2012, the $35,686,781 (December 31, 2011 – $26,245,533) reported amount of bank debt was comprised of $23,800,000 (December 31, 2011 – $24,450,000) drawn on the revolving operating demand loan, $9,977,551 (December 31, 2011 – $nil) of guaranteed notes and $1,909,218

(December 31, 2011 – $1,795,533) of bank overdraft. The Company is subject to a financial covenant with respect to working capital, which the Company was in compliance with at September 30, 2012. The facility is secured by a fixed and floating charge on the assets of the Company and is secured by a general security agreement.

As at September 30, 2012, the maximum amount available under the revolving operating demand loan was $42,000,000 (December 31, 2011 – $40,000,000) at an interest rate of bank prime plus 1.5% per annum, payable monthly. The Company is compliant with all debt covenants as at September 30, 2012.

Capital Spending

Capital spending is summarized as follows:

	Three Months ended September 30		Nine Months ended September 30,	
	2012	2011	2012	2011
Land and lease rentals	$ 362,010	$ 953,884	$ 494,133	$ 3,041,601
Drilling and completion	4,042,124	14,892,270	13,047,822	34,080,733
Geological and geophysical	183,178	359,277	665,004	785,045
Equipment	92,311	2,799,884	1,054,208	6,383,254
	$ 4,679,623	$ 19,005,315	$ 15,261,167	$ 44,290,633

Capital expenditures of $4.7 million were focused Central Alberta with capital spent on drilling a Cardium Horizontal well, the first four days of drilling on a Second White Specks horizontal well, preparation work for completions and multiple work-overs.

Decommissioning Liabilities

As at September 30, 2012, the undiscounted fair value of the asset retirement obligation associated with the Company's existing properties was estimated to be $6,266,813 for which $5,174,579 has been recorded using a discount rate of 1.46% - 1.74%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 8.3 years.

Off Balance Sheet Arrangements

There were no off balance sheet arrangements, other than the office and truck lease commitment which is accounted for as an operating lease.

Related Party Transactions

During the three and nine months ended September 30, 2012 and 2011, the Company was charged or invoiced the following amounts by certain of its officers and directors and by companies controlled by certain of the Company's officers and directors:

	Three Months ended September 30		Nine Months ended September 30,	
	2012	2011	2012	2011
Administration and consulting fees	$ 47,458	$ 51,284	$ 141,963	$ 190,775
Production and capital expenditures	27,736	113,886	80,077	316,187
	$ 75,194	$ 165,170	$ 222,040	$ 506,962

Included in accounts payable and accrued liabilities at September 30, 2012 is $nil (December 31, 2011 – $117,020) relating to the above transactions. These transactions were in the normal course of operations and were measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Share Capital

Details of changes in the number of outstanding equity instruments are detailed in the following table:

	Common Shares	Preferred Shares	Warrants	Stock Options
Balance - December 31, 2011	**116,607,057**	**-**	**8,955,500**	**11,353,800**
Grant of options	-	-	-	3,155,000
Forfeiture of options	-	-	-	(2,500,800)
Expiry of options	-	-	-	(168,000)
Exercise of warrants	5,104,666	-	(5,104,666)	-
Expiry of warrants	-	-	(2,430,834)	-
Balance - September 30, 2012 and Date of MD&A	**121,711,723**	**-**	**1,420,000**	**11,840,000**

Contingency

In December 2009, the Company terminated the Standstill Agreement that it had with an industry partner regarding a joint producing property and served that industry partner with a Statement of Claim issued from The Court of Queen's Bench of Alberta, by which the Company claims breach of the agreements between the parties, gross negligence and default of operator. The Company seeks judgment for specified and such further damages to be determined by the Court, as well as appointment as operator. The Company significantly increased the statement of claim based on the information provided by the defendant expects the matter to go to trial during 2012. The potential outcome of the lawsuit and claims are undetermined, however, they may be material. As the likely outcome of this litigation cannot be determined at this time, no provision has been made in the consolidated financial statements.

Commitments

The Company had until December 31, 2012 to incur $10,000,000 of qualifying flow-through expenditures related to flow-through shares issued in June 2011. The flow-through commitment was fully spent in 2011and during first quarter of 2012.

The Company has entered into lease agreements for office premises, field equipment and Company vehicles with estimated minimum annual payments as follows:

2012	$	63,787
2013	$	244,745
2014	$	241,277

Financial Instruments and Financial Risk Management

The Company's financial instruments include accounts receivable, accounts payable and accrued liabilities, bank debt, other long term debt, commodity contracts and preferred shares. The carrying values of accounts receivable, accounts payable and accrued liabilities and bank debt approximate their fair values due to their relatively short periods to maturity.

The Company is required to classify fair value measurements using a hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy is as follows:

- Level 1 - quoted prices in active markets for identical assets or liabilities;
- Level 2 - inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly; and
- Level 3 - inputs for the asset or liability that are not based on observable market data.

The fair value of bank debt is level 1 it is determined using amounts held at/lent by financial institutions.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities. The Company has exposure to credit risk, liquidity risk and market risk as a result of its use of financial instruments. This note presents information about the Company's exposure to each of the above risks and the Company's objectives, policies and processes for measuring and managing these risks. Further quantitative disclosures are included throughout these financial statements. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with the risk management policies as set out herein:

a. Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. A substantial portion of the Company's accounts receivable are with natural gas and liquids marketers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks.

Purchasers of the Company's natural gas and liquids are subject to credit review to minimize the risk of non-payment. As at September 30, 2012, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of $6,691,126 (2011 – $16,109,194). As at September 30, 2012, the Company's receivables consisted of $4,748,378 from joint venture partners and other trade receivables and $1,942,748 of revenue receivable from petroleum and natural gas marketers.

Receivables from petroleum and natural gas marketers are typically collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any significant collection issues with its petroleum and natural gas marketers. To mitigate the risk associated with of dealing with a smaller marketer the Company has entered into an arrangement with Computershare to allow them to retain ownership of the product. All of the revenue accruals and receivables from petroleum and natural gas marketers were received in October and November 2012.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company mitigates the risk from joint venture receivables by obtaining partner approval of capital expenditures prior to starting a project. However, the receivables are from participants in the petroleum and natural gas sector, and collection is dependent on typical industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. Further risk exists with joint venture partners as disagreements occasionally arise which increases the potential for non-collection. For properties that are operated by the Company, production can be withheld from joint venture partners who are in default of amounts owing. In addition, the Company often has offsetting amounts payable to joint venture partners from which it can net receivable balances.

The Company did not provide for any doubtful accounts nor was it required to write-off any receivables during the nine months ended September 30, 2012. The Company would only choose to write-off a receivable balance after all reasonable avenues of collection had been exhausted.

As at September 30, 2012, the Company considers its receivables to be aged as follows:

Not past due	$	4,305,896
Past due by less than 90 days		307,939
Past due by more than 90 days		2,077,291
	$	6,691,126

b. Liquidity risk

Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they are due. The Company’s approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company’s reputation.

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures.

To facilitate the capital expenditure program, the Company has a credit facility agreement, as disclosed in note 5, which is regularly reviewed by the lender. The Company monitors its total debt position monthly. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month. The Company anticipates it will have adequate liquidity to fund its financial liabilities through its future cash flows. The Company’s financial liabilities are comprised of accounts payable and accrued liabilities, bank debt and the credit facility, which have expected maturities of less than one year resulting in their current classification on the statement of financial position.

c. Market risk

Market risk consists of interest rate risk, currency risk and commodity price risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with a risk management policy as set out herein:

i. 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 Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate. For the three months ended September 30, 2012, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been $83,033 (2011 - $14,579) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amount. The Company had no interest rate swap or financial contracts in place at September 30, 2012.

ii. Currency risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. All of the Company's petroleum and natural gas sales are denominated in Canadian dollars, however, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. The Company had no outstanding forward exchange rate contracts in place at September 30, 2012.

iii. Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand as well as the relationship between the Canadian and United States dollar, as outlined above.

Selected Historical Financial Information

	2012 Q3($)	2012 Q2($)	2012 Q1($)	2011 Q4($)
Petroleum and natural gas sales	**4,311,738**	5,265,664	6,907,412	7,555,427
Net petroleum and natural gas revenue	**4,311,406**	5,627,535	7,299,772	7,327,783
Net income (loss)	**(2,073,174)**	3,305,628	(1,790,789)	(2,155,583)
Net income (loss) per share – basic	**(0.02)**	0.03	(0.02)	(0.02)
Net income (loss) per share – diluted	**(0.02)**	0.03	(0.02)	(0.02)
Funds flow from operations	**2,780,520**	3,493,003	5,146,554	5,686,411
Funds flow from operations per share – basic	**0.02**	0.03	0.04	0.05
Funds flow from operations per share – fully diluted	**0.02**	0.03	0.04	0.05
Net capital expenditures	**4,679,623**	3,006,024	7,575,520	19,735,557

	2011 Q3($)	2011 Q2($)	2010 Q1($)	2010 Q4($)
Petroleum and natural gas sales	5,378,932	4,283,356	3,524,544	2,864,802
Net petroleum and natural gas revenue	5,306,646	4,262,657	2,844,144	2,017,879
Net loss	4,106,091	1,665,821	(2,230,631)	(183,574)
Net loss per share – basic	0.04	0.02	(0.03)	(0.00)
Net loss per share – diluted	0.03	0.01	(0.02)	(0.00)
Funds flow from operations	4,967,853	3,151,665	2,535,251	1,567,756
Funds flow from operations per share – basic	0.04	0.03	0.03	0.02
Funds flow from operations per share – fully diluted	0.04	0.03	0.03	0.02
Net capital expenditures	19,005,315	7,160,655	18,124,663	16,760,003

Business Risks and Uncertainties

The Company is exposed to several operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given current market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of environment impact; and credit risk of non-payment for sales contracts and joint venture partners.

The Company attempts to control operating risks by maintaining a disciplined approach to implementation of its exploration and development programs. Exploration risks are managed by hiring experienced technical professionals and by concentrating the exploration activity on specific core regions that have multi-zone potential where the Company has experience and expertise. The Company also generates internal prospects and participates in projects where ownership interest is considered sufficient to minimize risk. Operational control allows the Company to manage costs, timing and sales of production and to ensure new production is brought on-stream in a timely manner. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach could result in the imposition of fines and penalties, some of which could be material. Senior management continually assesses new and existing regulatory requirements and environmental risks and determines the impact these risks might have on the Company, as well as the appropriate actions necessary to manage those risks. These assessments and the resulting policy decisions are discussed quarterly with the Board of Directors which evaluates the performance and effectiveness of the Company's environmental policies and programs.

The Company's environmental responsibilities includes removing property, plant and equipment as well as reclaiming land and property to its original state, subsequent to the completion of oil and natural gas extraction activities. This requirement results in an asset retirement obligation that provides current recognition of estimated expenditures that will be incurred in the future. The Company's decommissioning liabilities are discussed in further detail under "Critical Accounting Estimates" below, as well as in note 6 to the Company's Condensed Interim Consolidated Financial Statements.

Disclosure Controls and Procedures

The Company's certifying officers will file a Venture Issuer Basic Certificate with respect to the information contained in its financial statements and respective accompanying Management's Discussion and Analysis. The Venture Issuer Basic Certification includes a 'Notice to Reader' stating that the certifying officers do not make any representations relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting, as defined in National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings.

Critical Accounting Estimates

The preparation of the financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect reported amounts and presentation of assets, liabilities, revenues, expenses and disclosures of contingencies and commitments. Such estimates primarily relate to unsettled transactions and events at the statement of financial position date which are based on information available to management at each financial statement date. Actual results could differ from those estimated.

Judgments, estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

Property and equipment

The Company capitalizes costs in connection with the development of its oil and gas projects. The measurement of these costs at each financial statement date requires estimates to be made with respect to equipment and drilling activities. The estimate of the percentage of completion of various projects at the financial statement date affects P&E additions and the related accrued liability. An increase in the measurement amount of these items would increase P&E and accrued liabilities accordingly.

Reserves

Reserves and resources are used in the unit of production calculation for depletion and depreciation as well as impairment analysis. The quantity of reserves is subject to a number of estimates and projections including assessment of engineering data, projected future rates of production, commodity prices, regulatory changes, foreign exchange rates, operating costs and sustaining capital expenditures. These estimates and projections are uncertain as the Company does not have a long commercial production history to assist in the development of these forward-looking estimates. However, all reserve and associated financial information is evaluated and reported on by a firm of qualified independent reserve evaluators in accordance with the standards prescribed by applicable securities regulators.

The calculation of future cash flows based on these reserves is dependent on a number of estimates including: production volumes, facility performance, commodity prices, royalties, operating costs, sustaining capital, foreign exchange and tax rates. The price used in our assessment of future cash flows is based on the Company's independent evaluator's estimate of future prices and evaluated for reasonability by the Company against other available information. The Company believes these prices are reasonable estimates for a long-term outlook.

Impairment

The Company assesses its P&E and E&E assets for possible impairment if there are events or changes in circumstances that indicate the carrying values of the assets may not be recoverable. Such indicators include changes in the Company's business plans, changes in commodity prices, evidence of physical damage and significant downward revisions to estimated recoverable volumes or increases in estimated future development expenditures.

The assessment for impairment for P&E and E&E assets involves comparing the carrying value of the CGU with the higher of value in use calculations and fair value less costs to sell. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for regional supply-and-demand conditions for crude oil, natural gas and liquids. Impairment is recognized in earnings in the period in which carrying amount exceeded the recoverable amount. The Company has not recognized any impairment as at September 30, 2012.

Depletion and depreciation

Depletion of resource assets is measured over the life of proved and probable reserves on a unit-of-production basis and commences when the wells are substantially complete and after commercial production has begun. Reserve estimates and the associated future capital can have a significant impact on earnings, as these are key components to the calculation of depletion. A downward revision in the reserve estimate or an upward revision to future capital would result in increased depletion, reduced earnings and reduced carrying value of petroleum and natural gas property assets.

Decommissioning liabilities

The Company measures decommissioning liabilities at each financial statement date. The estimate is based on the Company's share of costs to reclaim the resource assets and certain facilities related to the projects as well as other resource assets associated with future expansions. To determine the future value of the liability, estimates of the amount, timing and inflation of the associated abandonment costs are made. The present value of the cost is recorded as the decommissioning liability using a risk-free discount rate. Due to the long-term nature of current and future project developments, abandonment costs will be incurred many years in the future. As a result of these factors, different estimates could be used for such abandonment costs and the associated timing. Assumptions of higher future abandonment costs, regulatory changes, higher inflation, lower risk-free rates or an assumption of earlier or specified timing of abandonment would cause the decommissioning liability of the corresponding asset to increase. These changes would also cause future accretion expenses to increase and future earnings to decrease.

Deferred taxes

Deferred income tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amount and the tax basis of assets and liabilities. An estimate is required for both the timing and corresponding tax rate for this reversal. Should these estimates change, it may impact the measurement of the Company's assets or liabilities as well as deferred tax recovery or expense recognized to earnings. Where unfavorable evidence exists, additional considerations and evidence for recognition of deferred tax assets is required. The Company has applied management's judgment and evaluated applicable factors necessary in making this determination and has concluded that the positive evidence in consideration of the estimated future cash flows based on reserve reports from the Company's independent engineers, does not sufficiently outweigh negative factors. The Company only recognizes deferred tax assets arising from unused tax losses to the extent that the Company has sufficient taxable temporary differences or it is probable that sufficient taxable profit will be available against which the unused tax losses can be utilized. The Company has not recognized a deferred tax asset.

Contingencies

By their nature, contingencies will only be resolved when one or more of the future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

Other areas of estimates

The recognition of amounts in relation to stock-based compensation requires estimates related to valuation of stock options at the time of issuance. The fair value of foreign exchange contracts is calculated using valuation models that require estimates as to future market prices. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements for current and future periods could be significant.