Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the December 31, 2012 audited consolidated financial statements and the September 30, 2013 unaudited consolidated financial statements, 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 19, 2013.

The financial information presented herein has been prepared on the basis of International Accounting Standard 34 ("Interim Financial Reporting"). 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 flow from (used in) operations" and "funds flow from (used in) operations per share", which should not be considered an alternative to or more meaningful than cash 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 flow from (used in) operations and funds flow from (used in) operations per share may not be comparable to that reported by other companies. Management uses funds flow from (used in) operations to analyze operating performance and leverage, and considers funds flow 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 flow from (used in) operations is calculated using cash from (used in) operating activities as presented in the statement of cash flows before changes in non-cash working capital. Yangarra presents funds flow 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 flow from (used in) operations to cash from (used in) operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Cash from operating activities	$ 3,683,552	$ 8,183,515	$ 5,902,746	$ 16,319,945	$ 12,853,084
Changes in non-cash working capital	2,694,655	(1,702,826)	(3,122,226)	1,353,133	(1,433,007)
Funds flow from operations	$ 6,378,207	$ 6,480,689	$ 2,780,520	$ 17,673,078	$ 11,420,077

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.*

Overview

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.

Third Quarter Highlights

- Production averaged 2,238 boe/d (46% oil and NGL's).
- Operating costs including $1.47/boe of transportation costs were $6.92/boe which represents a 3% decrease from Q2 of 2013.
- Oil and gas sales including royalty income and realized commodity contracts was $9.2 million with funds flow from operations of $6.4 million ($0.05 per share - basic).
- Netback of $34.56 per boe is a 14% decrease from the $40.30 per boe reported in the second quarter of 2013. Realized prices were $44.89/boe down 8% from $48.95/boe in the second quarter of 2013 primarily due to realized hedging losses.
- G&A expenses were $1.76/boe which represents a 10% decrease from the second quarter of 2013.
- Capital expenditures of $8.6 million focused on drilling and infrastructure in Central Alberta.
- As at September 30, 2013, the Company was in a net debt position of $43 million compared to $34 million at December 31, 2012.
- The debt to annualized third quarter cash flow ratio was 1.7 to 1.0.
- Closed a 47 section Cardium Farm-In Agreement in the Willesden Green Area with an industry major.
- Completed a subordinated term loan facility of up to $20 million with Alberta Treasury Branches.

Operations Update

The Company drilled and completed 10 gross (5.5 net) wells during the first three quarters of 2013 (1 gross, 0.14 net were non-operated), in addition 2 gross (0.6 net) wells that were drilled in 2012 were completed in 2013. With the reduced drilling times the Company now expects 6 gross (5.7 net) wells to be drilled during the fourth quarter of 2013.

Yangarra continues to experience lower drilling costs with average costs of $490/meter in 2013 compared with average drilling costs of $614/meter in 2012 and $691/meter in 2011. The Company drilled its two most recent Cardium wells at a cost of $450/meter. The Company's completion costs are also lower with a cost of $60,000 per stage in 2013 compared with $107,000 per stage in 2012 and $161,000 per stage in 2011.

During the third quarter, the Company encountered mechanical issues due to the failure of an activation sub, resulting in approximately 1.6 m^3 of cement entering the horizontal section on the first well of a two well Glauconite pad site which will delay the on-stream date of the first well from November 1st to December 15th. Due to the complexity of the completion operation, costs will increase by approximately $500,000. The Company placed the second well on-stream November 1st at 500 boe/d.

In the fourth quarter Yangarra purchased 1.5 sections of Cardium land, with six (6) net drilling locations indentified, bringing the Company's total Cardium inventory to 105 gross (78 net). Yangarra also has 40 gross (26 net) Hoadley Glauconite locations in inventory. In addition, Yangarra purchased one section of Duvernay rights land offsetting its existing land position in south Willesden Green.

Financial Information

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Statements of Comprehensive Income (Loss)					
Petroleum & natural gas sales	$ 9,372,931	$ 7,747,389	$ 4,311,738	$ 23,638,701	$ 16,484,814
Net income (loss) for the period (before tax)	$ 39,646	$ 2,923,438	$ (3,037,649)	$ 2,569,798	$ 2,430,940
Net income (loss) for the period	$ 11,330	$ 2,082,942	$ (2,073,174)	$ 1,834,848	$ (558,335)
Net income (loss) per share - basic and diluted	$ 0.00	$ 0.02	$ (0.02)	$ 0.02	$ (0.00)
Statements of Cash Flow					
Funds flow from (used in) operating activities	$ 6,378,207	$ 6,480,689	$ 2,780,520	$ 17,673,078	$ 11,420,077
Funds flow from (used in) operating activities per share - basic and diluted	$ 0.05	$ 0.05	$ 0.02	$ 0.15	$ 0.09
Cash from (used in) operating activities	$ 3,683,552	$ 8,183,515	$ 5,902,746	$ 16,319,945	$ 12,853,084
Statements of Financial Position					
Property and equipment	$ 135,892,343	$ 130,846,089	$ 122,723,826	$ 135,892,343	$ 122,723,826
Total assets	$ 154,773,403	$ 144,353,167	$ 138,820,924	$ 154,773,403	$ 138,820,924
Working Capital (deficit), excluding MTM on commodity contracts	$ 42,594,542	$ 40,459,011	$ 35,450,284	$ 42,594,542	$ 35,450,284
Non-Current Liabilities	$ 13,971,180	$ 13,197,200	$ 14,557,606	$ 13,971,180	$ 14,557,606
Shareholders equity	$ 82,022,213	$ 81,826,383	$ 79,349,142	$ 82,022,213	$ 79,349,142
Weighted average number of shares - basic	121,718,245	121,711,723	121,711,723	121,713,921	120,311,001
Weighted average number of shares diluted	121,987,009	121,722,178	121,711,723	121,713,921	120,343,320

Pricing Environment

	2013 Q3	2013 Q2	2012 Q3	Nine Months Ended 2013	Nine Months Ended 2012
Realized Pricing (Including Hedging)					
Oil ($/bbl)	$ 96.51	$ 102.73	$ 84.35	$ 95.00	$ 84.45
NGL ($/bbl)	$ 53.33	$ 61.36	$ 42.24	$ 55.50	$ 52.95
Gas ($/mcf)	$ 3.05	$ 3.67	$ 2.52	$ 3.35	$ 2.37
Realized Pricing (Excluding Hedging)					
Oil ($/bbl)	$ 102.99	$ 102.73	$ 79.31	$ 93.59	$ 85.27
NGL ($/bbl)	$ 60.77	$ 61.36	$ 38.62	$ 53.69	$ 53.57
Gas ($/mcf)	$ 2.57	$ 3.67	$ 2.01	$ 3.07	$ 2.05
Oil Price Benchmarks					
West Texas Intermediate ("WTI") (US$/bbl)	$ 105.81	$ 94.23	$ 92.20	$ 98.20	$ 96.16
Edmonton (C$/bbl)	$ 103.65	$ 92.67	$ 84.33	$ 94.83	$ 97.04
Natural Gas Price Benchmarks					
AECO gas (Cdn$/GJ)	$ 2.82	$ 3.41	$ 2.19	$ 3.16	$ 2.18
Foreign Exchange					
U.S./Canadian Dollar Exchange	$ 0.963	$ 0.977	$ 1.005	$ 0.977	$ 0.998

Crude oil prices increased in the three months ended September 30, 2013, with the West Texas Intermediate ("WTI") reference price averaging US$105.81/bbl compared with US$92.20 per barrel in 2012. Demand for crude oil is generally tied to global economic growth, but is also influenced by factors such as infrastructure, political instability, market uncertainty, weather conditions and government regulations.

Edmonton par differentials to WTI tightened in the three months ended September 30, 2013 when compared to the same period in 2012, moving from a $7.87/bbl differential in 2012 to $2.16/bbl in 2013. The closest reference price point for Yangarra's oil is Edmonton par and therefore the narrowing differential has had a significant impact on the Company realized pricing.

AECO natural gas prices increased for the three months ended September 30, 2013 by 29% to $2.82/GJ from $2.19/GJ in 2012. However natural gas prices weakened from the second quarter of 2013.

At September 30, 2013, Yangarra had contracted 900 bbl/day of 2013 oil production utilizing WTI fixed price contracts at an average price of $100.37 per bbl. Since the benchmark price was higher than our contracted value the realized prices were negatively impacted. Since the product is intended to provide protection to both the oil and NGL revenue streams the hedge impact is split between the two products.

In addition, Yangarra has contracted approximately 4,500 GJ/day of 2013 natural gas production utilizing AECO fixed price contracts at an average price of $3.46 per GJ. These contracts positively impacted the realized natural gas price.

The Company also has entered into 1,000 bbl/day for expected 2014 oil production utilizing WTI fixed price contracts at an average price of $94.03 per bbl and 800 bbl/day for expected 2015 oil production utilizing WTI fixed price contracts at an average price of $90.59 per bbl. The Company's commodity risk program helps sustain Cash Flow during periods of lower prices. For additional information, see the Financial Instruments and Financial Risks Management section of this MD&A.

Results of Operations

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Daily production volumes					
Natural gas (mcf/d)	6,983	5,915	5,617	6,003	5,915
Oil (bbl/d)	547	492	273	513	327
NGL's (bbl/d)	450	339	317	361	354
Royalty income					
Natural gas (mcf/d)	299	832	1,228	609	1,380
Oil (bbl/d)	1	1	2	1	6
NGL's (bbl/d)	26	49	67	41	84
Combined (boe/d 6:1)	2,238	2,005	1,800	2,018	1,986
Revenue					
Petroleum & natural gas sales - Gross	$ 9,372,931	$ 7,747,389	$ 4,885,957	$ 23,638,701	$ 16,857,092
Royalty income	195,468	366,609	323,947	931,415	1,808,126
Commodity contract settlement	(326,435)	805,711	574,219	909,693	372,278
Total sales	9,241,964	8,919,709	5,784,122	25,479,809	19,037,496
Royalty expense	(701,597)	(276,865)	(324,279)	(1,239,554)	(1,054,227)
Petroleum & natural gas sales - Net	$ 8,540,367	$ 8,642,844	$ 5,459,843	$ 24,240,255	$ 17,983,269
Change in fair value of contracts	$ (2,411,102)	$ (114,736)	$ (2,071,172)	$ (4,711,321)	$ 4,099,253
Total Revenue - Net	$ 6,129,265	$ 8,528,108	$ 3,388,671	$ 19,528,934	$ 22,082,522

Total sales in Q3 2013 were $8.5 million compared to $5.5 million in the same period 2012. The increase in sales is attributable to:

- a 43% increase in average product prices; and
- a 24% increase in production (on a boe basis).

The composite price received by the Company was higher when compared to 2012 due to higher natural gas and oil benchmark pricing.

The oil and NGL's split during the second quarter was 46% versus 37% in the third quarter of 2012. The increase in the oil and NGL weighting is due to the focus on oil weighted Cardium wells.

Compared to the second quarter 2013, total revenue increased by 4%. The increase in sales is attributable to:

- a 8% decrease in average product prices; and
- a 12% increase in production (on a boe basis).

Company Netbacks ($/boe)

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Sales Price	$43.94	$ 46.94	$ 29.51	$44.56	$ 30.98
Royalty income	0.95	2.01	1.96	1.69	3.32
Royalty expense	(3.41)	(1.52)	(1.96)	(2.25)	(1.94)
Production costs	(5.45)	(5.84)	(6.01)	(6.35)	(6.00)
Transportation costs	(1.47)	(1.29)	(0.80)	(1.26)	(0.80)
Operating netback	**$ 34.56**	**$ 40.30**	**$ 22.70**	**$ 36.39**	**$ 25.57**
G&A and other (excludes non-cash items)	(1.76)	(1.96)	(2.93)	(2.05)	(2.60)
Finance expenses	(2.32)	(2.00)	(2.97)	(2.19)	(1.98)
Cash flow netback	**30.49**	**36.34**	**16.79**	**32.15**	**20.99**
Depletion and depreciation	(18.05)	(18.38)	(21.63)	(18.21)	(23.00)
Accretion	(0.15)	(0.13)	(0.13)	(0.20)	(0.13)
Stock-based compensation	(0.38)	(1.15)	(0.87)	(0.53)	(0.92)
Unrealized gain (loss) on financial instruments	(11.71)	(0.63)	(12.51)	(8.55)	7.53
Deferred income tax	(0.14)	(4.61)	5.83	(1.33)	(5.49)
Net Income (loss) netback	**$ 0.06**	**$ 11.44**	**$ (12.52)**	**$ 3.33**	**$ (1.03)**

The third quarter 2013 operating netback of $34.56 per boe is a 52% increase from the $22.70 per boe reported in the third quarter of 2012. The improvements in netbacks were due to a higher reference price and a narrowing in the WTI to Edmonton par differential combined with lower operating costs in the quarter.

When compared to the second quarter of 2013 netback decreased by 14% due to a decrease in realized pricing and an increase in royalties.

Royalty Income

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Royalty Income	$ 195,468	$ 366,609	$ 323,947	$ 931,415	$ 1,808,126

Royalty income decreased in the third quarter of 2013 and year over year as no additional wells were drilled in the area covered by the 15% sliding scale royalty in 2013 and the existing wells continue to decline. There are currently a total of 12 wells generating the 15% royalty income.

Royalty Expense

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Royalty Expense	$ 701,597	$ 276,865	$ 324,279	$ 1,239,554	$ 1,054,227
Per boe	$ 3.41	$ 1.52	$ 1.96	$ 2.25	$ 1.94
As a % of sales	8%	3%	6%	5%	6%

Royalties increased to $701,597 for the three months ended September 30, 2013 or $3.41/boe and 8% as a percentage of sales. The increase results from wells reaching the two year cut-off on the reduced royalty rate and annual GCA deductions that were claimed in the previous quarter.

Generally, royalty rates in Western Canada are sensitive to prevailing commodity prices, individual well depth and 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. Deep natural gas wells have a royalty rate of 5% for the first 5 years of production.

Production and Transportation Costs

	2013 Q3	2013 Q2	2012 Q3	Nine Months Ended 2013	Nine Months Ended 2012
Production costs	$ 1,122,452	$ 1,065,010	$ 995,004	$ 3,497,260	$ 3,262,317
Per boe	$ 5.45	$ 5.84	$ 6.01	$ 6.35	$ 6.00
Transportation costs	$ 302,408	$ 234,440	$ 132,603	$ 692,521	$ 436,511
Per boe	$ 1.47	$ 1.29	$ 0.80	$ 1.26	$ 0.80
Combined ($/boe)	$ 6.92	$ 7.13	$ 6.81	$ 7.61	$ 6.80

Production and transportation costs increased in the third quarter of 2013 to $1,122,452 on a dollar basis due to increased production levels. On a per boe basis production and transportation costs increased by 1% when compared to the same period in 2012 and decreased by 3% when compared to the second quarter of 2013. Overall production and transportation costs remained relatively consistent and is in our usual range of below $8.00/boe.

Depletion, depreciation and impairment and accretion

	2013 Q3	2013 Q2	2012 Q3	Nine Months Ended 2013	Nine Months Ended 2012
Depletion and depreciation	$ 3,715,664	$ 3,349,411	$ 3,581,413	$ 10,033,740	$ 12,518,151
Per boe	$ 18.05	$ 18.38	$ 21.63	$ 18.21	$ 23.00
Accretion	$ 30,977	$ 24,209	$ 21,984	$ 108,506	$ 70,515

Depletion and depreciation increased in the third quarter 2013 compared to the same period in 2012 due increased production levels. When compared to the second quarter of 2013 the depletion rate remained relatively constant as the capital program resulted in equivalent additions to the reserve base.

General and administrative expenses ("G&A")

	2013 Q3	2013 Q2	2012 Q3	Nine Months Ended 2013	Nine Months Ended 2012
Gross G&A expenses	$ 459,801	$ 526,544	$ 541,839	$ 1,703,535	$ 1,786,694
G&A recoveries	(97,988)	(169,075)	(56,233)	(571,403)	(371,236)
Net G&A expenses	$ 361,813	$ 357,469	$ 485,606	$ 1,132,132	$ 1,415,458
Per boe	$ 1.76	$ 1.96	$ 2.93	$ 2.05	$ 2.60

On a net basis, general and administrative expenses decreased by 25% when compared to the same period in 2012 due to reductions in staff in late 2012. On a per boe basis G&A decreased by 10% when compared to the second quarter of 2013 due to increased production.

Other expenses

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Finance					
Interest	$ 375,487	$ 505,236	$ 491,892	$ 1,245,264	$ 1,076,628
Change in fair value of interest rate contracts	101,619	(141,505)	-	(39,887)	-
Accretion	30,977	24,209	21,984	108,506	70,515
	$ 508,082	$ 387,940	$ 513,876	$ 1,313,883	$ 1,147,143
Stock-based compensation	$ 79,200	$ 210,400	$ 125,124	$ 289,600	$ 356,124

Interest and financing fees for the three months ended September 30, 2013 include interest on the revolving operating demand loan, (the average amount drawn in 2013 was $38 million), renewal and servicing charges on the demand loan and the change in fair value of the interest rate contracts.

The Company had the following interest rate contracts in place at September 30, 2013:

- Pay a floating rate to receive a 2.35% (plus a 2.50% credit spread) fixed rate on $10 million (June 2014-June 2018)
- Pay a floating rate to receive a 2.15% (plus a 2.50% credit spread) fixed rate on $10 million (May 2014-May 2018)

During the nine months ended September 30, 2013, the Company granted options to purchase 2,540,000 common shares, with the options vesting immediately. The fair value of the options was estimated at $435,100 ($0.17 per option) using the Black-Scholes pricing model. $289,600 of the stock-based compensation was expensed and the remaining $145,500 was capitalized.

Deferred Taxes

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Deferred income tax expense	$ 28,316	$ 840,496	$ (964,475)	$ 734,950	$ 2,989,275

Yangarra does not have current income taxes payable and does not expect to pay current income taxes in 2013 as the Company had estimated tax pools of $103 million available at September 30, 2013.

Commodity price risk contracts

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Realized gain on contract settlement	$ (326,435)	$ 805,711	$ 574,219	$ 909,693	$ 372,278
Change in fair value of commodity contracts	(2,411,102)	(114,736)	(2,071,172)	(4,711,321)	4,099,253
	$ (2,737,537)	$ 690,975	$ (1,496,953)	$ (3,801,628)	$ 4,471,531

At September 30, 2013, Yangarra had contracted 900 bbl/day of 2013 oil production utilizing WTI fixed price contracts at an average price of $100.37 per bbl, 1,000 bbl/day for expected 2014 oil production utilizing WTI fixed price contracts at an average price of $94.03 per bbl and 800 bbl/day for expected

2015 oil production utilizing WTI fixed price contracts at an average price of $90.59 per bbl. In addition, Yangarra has contracted approximately 4,500 GJ/day of 2013 natural gas production utilizing AECO fixed price contracts at an average price of $3.46 per GJ.

The Company's commodity risk program helps sustain cash flow during periods of lower prices. For additional information, see the Financial Instruments and Financial Risks Management section of this MD&A.

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at September 30, 2013 to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Company believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices potentially could have resulted in unrealized gains (losses) impacting income before tax as follows:

	Impact on Income Before Tax	
	Increase 10%	Decrease 10%
Crude oil	(7,237,076)	7,237,076
Natural Gas	(115,092)	115,092

Liquidity and Capital Resources

The following table summarizes the change in working capital during the nine months ended September 30, 2013 and year ended December 31, 2012:

		2013		2012
Working capital (deficit) - beginning of period (1)	$	(36,301,842)	$	(34,028,162)
Funds flow from operating activities		17,673,078		14,588,405
Purchase/Transfer of property and equipment		(24,001,518)		(24,448,531)
Sale of property and equipment		-		4,650,000
Issuance of shares		62,500		2,552,333
Other Debt		(26,760)		384,113
Working capital (deficit) - September 30, 2013 (1)	$	(42,594,542)	$	(36,301,842)
Credit facility limit	$	45,000,000	$	42,000,000
Subordinated debt facility	$	20,000,000	$	-

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

As at September 30, 2013, the $44,202,319 (December 31, 2012 – $32,138,763) reported amount of bank debt with a Canadian chartered bank was comprised of $10,050,000 (December 31, 2012 – $21,950,000) drawn on the revolving operating demand loan, $29,925,033 (December 31, 2012 – $9,992,093) of guaranteed notes and $4,227,286 (December 31, 2012 – $196,658) of outstanding cheques. The Company is subject to a financial covenant requiring a working capital ratio of 1 : 1, which the Company was in compliance with at September 30, 2013. The facility is secured by a general security agreement.

As at September 30, 2013, the maximum amount available under the revolving operating demand loan was $45,000,000 (December 31, 2012 – $42,000,000) at an interest rate of bank prime plus 1.5% per annum on the operating demand load, payable monthly, and a credit spread of 2.5% on the guaranteed notes. The next scheduled review is May 31, 2014.

During the three months ended September 30, 2013 the Company entered into a subordinated term loan facility of up to $20,000,000 with Alberta Treasury Branches ("ATB"). The subordinated term loan has a two year committed term (subject to an extension for an additional year upon mutual consent) is available in three tranches ($7,800,000 on or before December 31, 2013, $6,420,000 on or before May 31, 2014 and $5,780,000 on or before July 31, 2014) at a floating rate (including all fees and closing costs) of currently less than 10% per annum. Full payment of the principal is due on maturity with reserve-based and financial covenants. Subsequent to September 30, 2013 the Company took down $7,800,000 of the subordinated term loan, leaving $12,200,000 undrawn. This facility is secured with a pledge of a general debenture under a general security agreement.

During the nine months ended September 30, 2013, the weighted average effective interest rate for the bank debt was approximately 4.18% (December 31, 2012 - 4.50 %).

Yangarra's debt to trailing year cash flow ratio as at September 30, 2013 was 1.7:1.

Capital Spending

Capital spending is summarized as follows:

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Land and lease rentals	$ 307,274	$ (226,665)	$ 362,010	$ 1,140,889	$ 494,133
Drilling and completion	$ 6,725,516	$ 1,190,051	4,042,124	15,952,432	13,047,822
Geological and geophysical	$ 417,101	$ 135,526	183,178	586,305	665,004
Equipment	$ 1,036,654	$ 2,724,863	92,311	5,641,331	1,054,208
Other Asset Additions	$ 80,681	$ (115,174)	-	217,461	-
	$ 8,567,226	$ 3,708,601	$ 4,679,623	$ 23,538,418	$ 15,261,167

The Company has drilled 11 gross (7.3 net) wells in 2013 with all wells targeting oil weighted reservoirs. The two most recent wells were part of the previously announced farm-in. The Company drilled 4 gross (2.4 net) wells in the third quarter and expects to drill an additional 6 gross (5.7 net) wells in the fourth quarter of 2013.

Outlook

Yangarra's capital spending for 2013 is updated to $40 million versus the previously guided $35 million. Due to the drilling of additional oil targets versus liquids rich natural gas, the Company's 2013 annual production is now forecast to be 2,200 boe/d down from 2,400 boe/d; with cash flow expected to be within the previous guidance range of $25-30 million at $27 million for the year. The Company expects to exit the 2013 year at 3,000 boe/d with year-end debt forecast at $49 million resulting in a 1.4 to 1.0 debt to annualized fourth quarter cash flow ratio.

The Board of Directors has approved an initial capital budget for $45 million in 2014, drilling 15.5 net wells focused on the development of Yangarra's Cardium light oil play. The budget is expected to increase the Company's annual production to 3,200 boe/d with cash flow from operations estimated at $40 million. The Company expects year-end 2014 debt of $55 million resulting in a debt to annual cash flow ratio of 1.4 to 1.0. The budget assumes an average price of US$95.00/bbl for WTI crude oil (CDN$85.00/bbl Edmonton par) and an average price of $3.00/GJ for AECO natural gas.

Decommissioning Liabilities

As at September 30, 2013, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $7,646,972 for which $5,342,357 has been recorded using a discount rate of 1.56% - 2.54%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 8.1 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, 2013 and 2012, 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:

	2013		2012	Nine Months Ended	
	Q3	Q2	Q3	2013	2012
Administration and consulting fees	$ 88,500	$ 82,933	$ 47,458	$ 222,035	$ 141,963
Production and capital expenditures	52,033	36,633	27,736	175,952	80,077
	$ 140,533	$ 119,566	$ 75,194	$ 397,987	$ 222,040

Included in accounts payable and accrued liabilities at September 30, 2013 is $13,943 (December 31, 2012 – $11,221) 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.

Other long-term liabilities include a mortgage for $337,651 (December 31, 2012 - $361,411) held in the name of an officer of the Company for a property that is used as a field office. The Company is the beneficial owner through a trust agreement of the property against which the mortgage is secured. All mortgage payments are made by the Company.

Share Capital

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

	Common Shares	Warrants	Stock Options
Balance - December 31, 2012	**121,711,723**	**1,420,000**	**11,840,000**
Grant of options	-	-	2,540,000
Forfeiture of options	-	-	(2,215,000)
Exercise of options	200,000		(200,000)
Expiry of options	-	-	(380,000)
Balance - September 30 2013	**121,911,723**	**1,420,000**	**11,585,000**
Exercise of options	200,000		(200,000)
Forfeiture of options	-		(750,000)
Balance - Date of MD&A	**122,111,723**	**1,420,000**	**10,635,000**

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 increased the statement of claim based on the information provided by the defendant. The potential outcome of the lawsuit and claims are undetermined, however, they could be material.

In the normal conduct of operations, there are other pending claims by and against the Company. Litigation is subject to many uncertainties, and the outcome of individual matters is not predictable with assurance. In the opinion of management, based on the advice and information provided by its legal counsel, the final determination of these other litigations will not materially affect the Company's financial position or results of operations

Commitments

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

2013	$	60,319
2014	$	241,277
2015	$	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 liability and commodity contracts. 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 commodity contracts are classified as level 2.

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. 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, 2013, the maximum credit exposure is the carrying amount of the accounts receivable of $13,280,832 (December 31, 2012 – $8,398,042).

The maximum exposure to credit risk for receivables at the reporting date by type of customer was:

Oil and natural gas marketers	$	2,741,977
Joint venture partners		8,014,677
Other		2,524,178
	$	13,280,832

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. All of the revenue accruals and receivables from petroleum and natural gas marketers were received in October and November 2013.

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 accounts receivable during the nine months ended September 30, 2013. The Company would only choose to write-off a receivable balance after all reasonable avenues of collection had been exhausted.

As at September 30, 2013, the Company considers its receivables to be aged as follows:

Not past due	$	4,097,785
Past due by less than 90 days		5,118,912
Past due by more than 90 days		4,064,135
	$	13,280,832

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 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 and bank debt, 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 financial derivatives 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, the Company has put interest rate contracts in pace to mitigate this risk. For the nine months ended September 30, 2013, if interest rates had been 1% lower with all other variables held constant, income for the period would have been $265,585 (December 31, 2012 - $287,000) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amount.

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, 2013.

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. The Company's commodity contracts are discussed in the "commodity price risk contract" section of the MD&A.

Capital disclosures

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute its capital expenditure program, which includes expenditures in oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include shareholders equity:

	September 30, 2013	*December 31, 2012*
Shareholders' equity	$ 82,022,213	$ 79,689,765

The Company monitors capital based on annual cash from operations before changes in non-cash working capital and capital expenditure budgets, which are updated as necessary and are reviewed and periodically approved by the Board of Directors.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions including the current economic conditions, the risk characteristics of the Company's petroleum and natural gas assets, the depth of its investment opportunities, current and forecasted net debt levels, current and forecasted commodity prices and other facts that influence commodity prices and funds from operations such as quality and basis differentials, royalties, operating costs and transportation costs.

In order to maintain or adjust the capital structure, the Company considers its forecasted cash from operations before changes in non-cash working capital while attempting to finance an acceptable capital expenditure program including acquisition opportunities, the current level of bank credit available from the Company's lender, the level of bank credit that may be attainable from its lender as a result of petroleum and natural gas reserve growth, the availability of other sources of debt with different characteristics than existing debt, the sale of assets, limiting the size of the capital expenditure program and the issue of new equity if available on favorable terms. At September 30, 2013, the Company's capital structure was not subject to external restrictions.

Selected Historical Financial Information

	2013 Q3($)	2013 Q2($)	2013 Q1($)	2012 Q4($)
Petroleum and natural gas sales	**9,372,931**	7,747,389	6,518,381	4,842,343
Net petroleum and natural gas revenue	**8,866,802**	7,837,133	6,626,627	5,055,666
Net income (loss)	**11,330**	2,082,942	(259,424)	340,623
Net income (loss) per share – basic	0.00	0.02	0.00	0.00
Net income (loss) per share – diluted	0.00	0.02	0.00	0.00
Funds flow from operations	**6,378,207**	6,480,689	4,814,183	3,168,328
Funds flow from operations per share – basic	0.05	0.05	0.04	0.03
Funds flow from operations per share –diluted	0.05	0.05	0.04	0.03
Net capital expenditures	**8,567,226**	3,708,601	11,262,592	4,537,364

	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 –diluted	0.02	0.03	0.04	0.05
Net capital expenditures	4,679,623	3,006,024	7,575,520	19,735,557

Fluctuations in quarterly revenues net income and funds flow from operations over the last eight quarters are due primarily to the volatility in commodity prices and changes in sales volumes due to production growth through successful drilling activity.

Business Risks and Uncertainties

Refer to the December 31, 2012 MD&A for a complete listing of Business Risks and Uncertainties.

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 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

Refer to the December 31, 2012 MD&A for a complete listing of critical accounting estimates.

Accounting standards newly adopted

On January 1, 2013 the Company adopted new standards with respect to consolidated (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), fair value measurements (IFRS 13) and amendments to financial instrument disclosures (IFRS 7). The adoption of these standards had no impact on the amounts recorded in the condensed consolidated interim financial statements as at January 1, 2013 or on the comparative periods.