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 June 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 August 27, 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	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Cash from operating activities	$ 8,183,515	$ 4,452,879	$ 5,012,962	$ 12,636,393	$ 6,950,338
Changes in non-cash working capital	(1,702,826)	361,304	(1,519,959)	(1,341,522)	1,689,219
Funds flow from operations	$ 6,480,689	$ 4,814,183	$ 3,493,003	$ 11,294,871	$ 8,639,557

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.

Second Quarter Highlights

- Q2 2013 production averaged 2,005 boe/d (44% oil and NGL's) with production negatively impacted by approximately 200 boe/d shut-in due to the drilling of new wells on existing pad sites and turn-arounds at 3rd party processing facilities.
- Q2 2013 oil and gas sales including royalty income and realized commodity contracts was $8.9 million with funds flow from operations of $6.5 million ($0.05 per share - basic).
- 2013 First half year funds flow from operations was $11 million; therefore, with the anticipated increase in production for the second half of 2013, the Company expects to achieve its annual targeted funds flow of $24 million.
- Net income for Q2 2013 was $2.1 million ($2.9 million before future income tax).
- Operating costs for Q2 2013, including $1.29/boe of transportation costs, were $7.13/boe which represents a 21% decrease from Q1 of 2013.
- The Q2 2013 netback of $40.30 per boe is a 69% increase from the $23.81 per boe reported in the second quarter of 2012. Realized prices were $46.94/boe up 57% from $29.84/boe in the second quarter of 2012.
- G&A expenses for Q2 2013 were $1.96/boe which represents a 23% decrease from the first quarter of 2013.
- Q2 2013 capital expenditures of $3.7 million focused on drilling and infrastructure in Central Alberta.
- As at June 30, 2013, the Company was in a net debt position of $40 million compared to $34 million at December 31, 2012.
- The debt to annualized second quarter cash flow ratio was 1.5 : 1.
- Yangarra completed construction of an 11 mmcf/d gas processing facility (100% working interest) and the facility came online April 10, 2013 which brought on eight previously standing wells.

Operations Update

Following spring breakup, the Company has drilled 3 gross (1.5 net) Cardium wells at Ferrier. Productivity from the wells is exceeding expectations. The Company is continuing to improve drilling and completion costs due to pad drilling and reductions in drilling and completion times.

Starting in 2010, Yangarra has now drilled 53 horizontal wells in the Deep Basin using new horizontal multi-stage fracture technology. In that period, Yangarra has made significant advancement in drilling, completion and logistics which have had a significant impact on the Company's returns. The Company now expects returns from the combined 2013 drilling program to exceed 100%, with payouts of less than one year.

Financial Information

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Statements of Comprehensive Income (Loss)					
Petroleum & natural gas sales	$ 7,747,389	$ 6,518,381	$ 5,265,664	$ 14,265,770	$ 12,173,076
Net income (loss) for the period (before tax)	$ 2,923,438	$ (393,286)	$ 6,451,923	$ 2,530,152	$ 5,468,589
Net income (loss) for the period	$ 2,082,942	$ (259,424)	$ 3,305,628	$ 1,823,518	$ 1,514,839
Net income (loss) per share - basic and diluted	$ 0.02	$ 0.00	$ 0.03	$ 0.01	$ 0.01
Statements of Cash Flow					
Funds flow from (used in) operating activities	$ 6,480,689	$ 4,814,183	$ 3,493,003	$ 11,294,871	$ 8,639,557
Funds flow from (used in) operating activities per share - basic and diluted	$ 0.05	$ 0.04	$ 0.03	$ 0.09	$ 0.07
Cash from (used in) operating activities	$ 8,183,515	$ 4,452,879	$ 5,012,962	$ 12,636,393	$ 6,950,338
Statements of Financial Position					
Property and equipment	$ 130,846,089	$ 130,356,002	$ 121,329,749	$ 130,846,089	$ 121,329,749
Total assets	$ 144,353,167	$ 148,761,517	$ 142,907,001	$ 144,353,167	$ 142,907,001
Working Capital Deficit	$ 39,989,839	$ 42,469,266	$ 33,456,912	$ 39,989,839	$ 33,456,912
Non-Current Liabilities	$ 13,197,200	$ 12,482,223	$ 15,451,799	$ 13,197,200	$ 15,451,799
Shareholders equity	$ 81,826,383	$ 79,430,341	$ 81,125,416	$ 81,826,383	$ 81,125,416
Weighted average number of shares - basic	121,711,723	121,711,723	121,711,152	121,711,723	119,602,943
Weighted average number of shares diluted	121,722,178	121,711,723	121,711,152	121,711,723	119,602,943

Business Environment

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
West Texas Intermediate ("WTI") (US$/bbl)	$ 94.23	$ 94.36	$ 93.50	$ 94.28	$ 98.22
Edmonton (C$/bbl)	$ 92.67	$ 87.43	$ 83.95	$ 90.43	$ 88.38
AECO gas (Cdn$/GJ)	$ 3.41	$ 2.92	$ 1.74	$ 3.16	$ 2.06
U.S./Canadian Dollar Exchange	$ 0.977	$ 0.992	$ 0.990	$ 0.984	$ 0.994

Crude oil prices remained relatively constant in the three months ended June 30, 2013, with the West Texas Intermediate ("WTI") reference price averaging US$94.23/bbl compared with US$93.50 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 decreased significantly in the three months ended June 30, 2013 when compared to the same period in 2012, moving from a $9.55/bbl differential in 2012 to $1.56/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 June 30, 2013 by 96% to $3.41/GJ from $1.74/GJ in 2012.

Results of Operations

	2013 Q2	2013 Q1	2012 Q2	Six Months Ended 2013	Six Months Ended 2012
Daily production volumes					
Natural gas (mcf/d)	5,915	5,090	6,115	5,505	6,066
Oil (bbl/d)	492	502	269	497	354
NGL's (bbl/d)	339	291	397	315	372
Royalty income					
Natural gas (mcf/d)	832	709	1,432	766	1,456
Oil (bbl/d)	1	2	3	2	8
NGL's (bbl/d)	49	48	94	48	93
Combined (boe/d 6:1)	2,005	1,809	2,022	1,906	2,080
Product pricing (includes royalty income & realized gains/losses on commodity contracts)					
Oil ($/bbl)	$ 102.73	$ 86.80	$ 81.97	$ 94.16	$ 87.56
NGL ($/bbl)	$61.36	52.62	55.22	56.95	59.81
Gas ($/mcf)	3.67	3.41	2.05	3.53	2.07
Combined ($/boe)	$ 48.95	$ 44.95	$ 32.13	$ 47.06	$ 36.07
Revenue					
Petroleum & natural gas sales - Gross	$ 7,747,389	$ 6,518,381	$ 5,265,664	$ 14,265,770	$ 12,173,076
Royalty income	366,609	369,338	645,002	735,947	1,484,179
Commodity contract settlement	805,711	430,418	223,840	1,236,128	(201,941)
Total sales	8,919,709	7,318,137	6,134,506	16,237,845	13,455,314
Royalty expense	(276,865)	(261,092)	(283,131)	(537,957)	(729,948)
Petroleum & natural gas sales - Net	$ 8,642,844	$ 7,057,045	$ 5,851,375	$ 15,699,888	$ 12,725,366
Change in fair value of contracts	$ (114,736)	$ (2,185,484)	$ 7,989,633	$ (2,300,219)	$ 6,170,425
Total Revenue - Net	$ 8,528,108	$ 4,871,561	$ 13,841,008	$ 13,399,669	$ 18,895,791

Total sales in Q2 2013 were $8.9 million compared to $6.1 million in the same period 2012. The increase in sales is attributable to:

- a 52% increase in average product prices; and
- a 1% decrease in production (on a boe basis).

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

The oil and NGL's split during the second quarter was 44% versus 38% in the second quarter of 2012. The increase in the oil and NGL weighting is due to the focus on oil weighted Cardium wells.

Compared to the first quarter 2013, total revenue increased by 22%. The increase in sales is attributable to:

- a 9% increase in average product prices; and
- a 11% increase in production (on a boe basis).

The production increase in 2013 can be attributed to the new Ferrier gas processing facility (100% working interest), being put into service on April 10, 2013, which brought on eight previously standing wells. The increased production from the facility was partially offset by approximately 200 boe/d shut in due to the drilling of new wells on existing pad sites and turn-arounds at 3rd party processing facilities.

As a means of managing commodity price volatility and its impact on cash flows, Yangarra enters into various financial commodity agreements. Unsettled derivative financial contracts are measured at the date of the financial statements based on the fair value of the contracts. Changes in fair value result from volatility in forward curves of commodity prices and changes in the balance of unsettled contracts between periods. The changes in fair value are recognized in revenue as unrealized commodity contract gains and losses. Realized commodity contract gains and losses are recognized in revenue when derivative financial contracts are settled.

At June 30, 2013, Yangarra had contracted 700 bbl/day of 2013 oil production utilizing WTI fixed price contracts at an average price of $98.99 per bbl, 900 bbl/day for expected 2014 oil production utilizing WTI fixed price contracts at an average price of $93.57 per bbl and 500 bbl/day for expected 2015 oil production utilizing WTI fixed price contracts at an average price of $89.62 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 $3.45 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

Royalty Income

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Royalty Income	$ 366,609	$ 369,338	$ 645,002	$ 735,947	$ 1,484,179

Royalty income decreased in the second 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. There are currently a total of 12 wells generating the 15% royalty income.

Royalty Expense

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Royalty Expense	$ 276,865	$ 261,092	$ 283,131	$ 537,957	$ 729,948
Per boe	$ 1.52	$ 1.60	$ 1.55	$ 1.56	$ 1.93
As a % of sales	3%	4%	5%	3%	5%

Royalties remained relatively constant at $276,865 for the three months ended June 30, 2013, however decreased to $1.52/boe and 3% as a percentage of sales. The decrease results from new wells being brought online at the new plant which are subject to the reduced royalty rate. 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		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Production costs	$ 1,065,010	$ 1,309,798	$ 1,314,640	$ 2,374,808	$ 2,267,313
Per boe	$ 5.84	$ 8.04	$ 7.14	$ 6.88	$ 5.99
Transportation costs	$ 234,440	$ 155,673	$ 156,536	$ 390,113	$ 303,908
Per boe	$ 1.29	$ 0.96	$ 0.85	$ 1.13	$ 0.80
Combined ($/boe)	$ 7.13	$ 9.00	$ 7.99	$ 8.01	$ 6.79

Production and transportation costs decreased in the second quarter of 2013 to $1,065,010 on a dollar basis and decreased by 11% on a per boe basis when compared to the same period in 2012 and by 21% when compared to the first quarter of 2013. 2013 Q1 costs were impacted by the installation of a new facility Once the facility was brought online operating costs returned to the usual range of below $8.00/boe.

Depletion, depreciation and impairment and accretion

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Depletion and depreciation	$ 3,349,411	$ 2,968,665	$ 4,880,246	$ 6,318,076	$ 8,936,738
Per boe	$ 18.38	$ 18.23	$ 26.53	$ 18.31	$ 23.61
Accretion	$ 24,209	$ 53,320	$ 25,343	$ 77,529	$ 48,531

Depletion and depreciation decreased in the second quarter 2013 compared to the same period in 2012 due to 2012 Q1 impairment charge at regarding the assets at Jaslan. When compared to the first 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		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Gross G&A expenses	$ 526,544	$ 717,190	$ 604,584	$ 1,243,734	$ 1,244,993
G&A recoveries	(169,075)	(304,340)	(45,063)	(473,415)	(315,003)
Net G&A expenses	$ 357,469	$ 412,850	$ 559,521	$ 770,319	$ 929,990
Per boe	$ 1.96	$ 2.54	$ 3.04	$ 2.23	$ 2.46

On a net basis, general and administrative expenses decreased by 36% when compared to the same period in 2012, due to reduced staffing levels in the Calgary office. On a per boe basis G&A decreased by 23% when compared to the first quarter of 2013 as the first quarter included non-recurring charges for severances related to the reduction in head office staff.

Other expenses

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Finance					
Interest	$ 505,236	$ 364,541	$ 327,675	$ 869,777	$ 584,736
Change in fair value of commodity contracts	(141,505)	-	-	(141,505)	-
Accretion	24,209	53,320	25,343	77,529	48,531
	$ 387,940	$ 417,861	$ 353,018	$ 805,801	$ 633,267
Stock-based compensation	$ 210,400	$ -	$ 125,124	$ 210,400	$ 356,124

Interest and financing fees for the three months ended June 30, 2013 include interest on the revolving operating demand loan, (the average amount drawn in 2013 was $34 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 June 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 six months ended June 30, 2013, the Company granted options to purchase 1,905,000 common shares, with the options vesting immediately. The fair value of the options was estimated at $313,100 ($0.27 per option) using the Black-Scholes pricing model. $210,400 of the stock-based compensation was expensed and the remaining $102,700 was capitalized.

Deferred Taxes

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Deferred income tax expense	$ 840,496	$ (133,862)	$ 3,146,295	$ 706,634	$ 3,953,750

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 $97 million available at June 30, 2013.

Commodity price risk contracts

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Realized gain on contract settlement	$ 805,711	$ 430,418	$ 223,840	$ 1,236,128	$ (201,941)
Change in fair value of commodity contracts	(114,736)	(2,185,484)	7,989,633	(2,300,219)	6,170,425
	$ 690,975	$ (1,755,066)	$ 8,213,473	$ (1,064,091)	$ 5,968,484

As at June 30, 2013, the Company was committed to the following commodity price risk contracts for the sale of oil:

2013 Contracts:
- 200 bbl/d from July 1 to December 31, 2013 at a fixed price of $98.00 CAD/bbl;
- 100 bbl/d from July 1 to December 31, 2013 at a fixed price of $97.50 CAD/bbl;
- 200 bbl/d from July 1 to December 31, 2013 at a fixed price of $98.30 USD/bbl;
- 100 bbl/d from July 1 to December 31, 2013 at a fixed price of $98.00 USD/bbl;
- 100 bbl/d from July 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 Contracts:
- 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;
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $91.40 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $91.35 CAD/bbl
- 200 bbl/d from January 1 to December 31, 2014 at a fixed price of $92.00 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $90.00 USD/bbl;
- 200 bbl/d from January 1 to December 31, 2014 at a fixed price of $93.52 CAD/bbl and;
- Sold Swaption on 200 bbl/d @ $100.00 WTI/USD for January – December 2014.

2015 Contracts:
- 100 bbl/d from January 1 to December 31, 2015 at a fixed price of $86.05 USD/bbl;
- 100 bbl/d from January 1 to December 31, 2015 at a fixed price of $91.20 CDN/bbl;
- 200 bbl/d from January 1 to December 31, 2015 at a fixed price of $90.37 CDN/bbl and;
- 100 bbl/d from January 1 to December 31, 2015 at a fixed price of $90.10 CDN/bbl.

As at June 30, 2013, the Company was committed to the following commodity price risk contracts on the AECO basis:

- 2,000 GJ/d at $3.51/GJ for July – December 2013;
- 1,000 GJ/d at $3.35/GJ for July – December 2013;
- 500 GJ/d at $3.42/GJ for July – December 2013;
- 500 GJ/d at $3.42/GJ for July – December 2013 and;
- 500 GJ/d at $3.60/GJ for July – December 2013.

The fair value on the contracts was in a gain position of $97,892 as at June 30, 2013 (December 31, 2012: a gain position of $2,398,111).

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at June 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	(5,677,194)	5,677,194
Natural Gas	(254,196)	254,196

Company Netbacks ($/boe)

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Sales Price	$ 46.94	$ 42.68	$ 29.84	$ 44.93	$ 31.62
Royalty income	2.01	2.27	3.51	2.13	3.92
Royalty expense	(1.52)	(1.60)	(1.55)	(1.56)	(1.93)
Production costs	(5.84)	(8.04)	(7.14)	(6.88)	(5.99)
Transportation costs	(1.29)	(0.96)	(0.85)	(1.13)	(0.80)
Operating netback	**$ 40.30**	**$ 34.34**	**$ 23.81**	**$ 37.49**	**$ 26.82**
G&A and other (excludes non-cash items)	(1.96)	(2.54)	(3.04)	(2.23)	(2.46)
Finance expenses	(2.00)	(2.24)	(1.78)	(2.11)	(1.54)
Cash flow netback	**36.34**	**29.57**	**18.99**	**33.14**	**22.82**
Depletion and depreciation	(18.38)	(18.23)	(26.53)	(18.31)	(23.61)
Accretion	(0.13)	(0.33)	(0.14)	(0.22)	(0.13)
Stock-based compensation	(1.15)	-	(0.68)	(0.61)	(0.94)
Unrealized gain (loss) on financial instruments	(0.63)	(13.42)	43.43	(6.67)	16.30
Deferred income tax	(4.61)	0.82	(17.10)	(2.05)	(10.44)
Net Income (loss) netback	**$ 11.43**	**$ (1.59)**	**$ 17.97**	**$ 5.28**	**$ 4.00**

The second quarter 2013 operating netback of $40.30 per boe is a 69% increase from the $23.81 per boe reported in the second 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.

Liquidity and Capital Resources

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

	2013	2012
Working capital (deficit) - beginning of period	$ (36,301,842)	$ (34,028,162)
Funds flow from operating activities	11,294,871	14,588,405
Purchase/Transfer of property and equipment	(15,434,292)	(24,448,531)
Sale of property and equipment	-	4,650,000
Issuance of shares	-	2,552,333
Bank Debt	(17,748)	384,113
Commodity Contract	469,172	-
Working capital (deficit) - end of period	$ (39,989,839)	$ (36,301,842)
Credit facility limit	$ 45,000,000	$ 42,000,000

As at June 30, 2013, the $41,398,550 (December 31, 2012 – $32,138,763) reported amount of bank debt with a Canadian chartered bank was comprised of $6,900,000 (December 31, 2012 – $21,950,000) drawn on the revolving operating demand loan, $29,975,510 (December 31, 2012 – $9,992,093) of guaranteed notes and $4,523,040 (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 June 30, 2013.

The facility is secured by a general security agreement.

As at June 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 loan, payable monthly, and a credit spread of 2.5% on the guaranteed notes. The next scheduled review is May 31, 2014.

During the three month ended June 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 June 30, 2012 was 1.5:1.

Capital Spending

Capital spending is summarized as follows:

	2013		2012	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Land and lease rentals	$ (226,665)	$ 1,060,280	$ (15,366)	$ 833,615	$ 132,123
Drilling and completion	$ 1,190,051	8,036,865	2,383,800	9,226,916	9,005,698
Geological and geophysical	$ 135,526	33,678	327,646	169,204	481,826
Equipment	$ 2,724,863	1,879,815	309,944	4,604,677	961,897
Other Asset Additions	$ (115,174)	251,954	-	136,780	-
	$ 3,708,601	$ 11,262,592	$ 3,006,024	$ 14,971,192	$ 10,581,544

The majority of capital costs in the three months ended June 30, 2013 are related to the completion of construction on the processing facility in the Ferrier area. The Company also restarted the drilling program in June and had the majority of a well completed at the end of the quarter. The negative amount for office additions relates to a credit received from the landlord for renovations completed on the corporate office.

Outlook

The $25 million 2013 capital budget will focus on development of Yangarra's Cardium light oil play with a 4 year drillable inventory already identified. The budget is expected to generate funds flow from operations of $24 million ($0.20/share) and 2013 debt to cash flow ratio of 1.5.

Decommissioning Liabilities

As at June 30, 2013, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $7,239,328 for which $5,159,490 has been recorded using a discount rate of 2.13% - 2.44%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 8.4 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 six months ended June 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	Six Months Ended	
	Q2	Q1	Q2	2013	2012
Administration and consulting fees	$ 82,933	$ 50,602	$ 47,457	$ 133,535	$ 94,505
Production and capital expenditures	36,633	87,286	16,375	123,919	52,341
	$ 119,566	$ 137,888	$ 63,832	$ 257,454	$ 146,846

Included in accounts payable and accrued liabilities at June 30, 2013 is $15,273 (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 $346,663 (December 31, 2012 - $361,411) held in the name of an officer of the Company. The property against which the mortgage is secured is owned by the Company through a trust agreement and is used as a field office. 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	-	-	1,905,000
Forfeiture of options	-	-	(1,615,000)
Expiry of options	-	-	(380,000)
Balance - June 30 2013	**121,711,723**	**1,420,000**	**11,750,000**
Grant of options			535,000
Forfeiture of options			(300,000)
Balance - Date of MD&A	**121,711,723**	**1,420,000**	**11,985,000**

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 may 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	$	116,094
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 June 30, 2013, the maximum credit exposure is the carrying amount of the accounts receivable of $7,567,521 (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	$	3,068,218
Joint venture partners		2,490,917
Other		2,008,386
	$	7,567,521

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 July and August 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 six months ended June 30, 2013. The Company would only choose to write-off a receivable balance after all reasonable avenues of collection had been exhausted.

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

Not past due	$	4,787,643
Past due by less than 90 days		720,238
Past due by more than 90 days		2,059,640
	$	7,567,521

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 six months ended June 30, 2013, if interest rates had been 1% lower with all other variables held constant, income for the period would have been $164,485 (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 June 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:

	June 30, 2013	*December 31, 2012*
Shareholders' equity	$ 81,826,383	$ 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 June 30, 2013, the Company's capital structure was not subject to external restrictions.

Selected Historical Financial Information

	2013 Q2($)	2013 Q1($)	2012 Q4($)	2012 Q3($)
Petroleum and natural gas sales	**7,747,389**	6,518,381	4,842,343	4,311,738
Net petroleum and natural gas revenue	**7,837,133**	6,626,627	5,055,666	4,311,406
Net income (loss)	**2,082,942**	(259,424)	340,623	(2,073,174)
Net income (loss) per share – basic	0.02	0.00	0.00	(0.02)
Net income (loss) per share – diluted	0.02	0.00	0.00	(0.02)
Funds flow from operations	**6,480,689**	4,814,183	3,168,328	2,780,520
Funds flow from operations per share – basic	0.05	0.04	0.03	0.02
Funds flow from operations per share –diluted	0.05	0.04	0.03	0.02
Net capital expenditures	**3,708,601**	11,262,592	4,537,364	4,679,623

	2012 Q2($)	2012 Q1($)	2011 Q4($)	2011 Q3($)
Petroleum and natural gas sales	5,265,664	6,907,412	7,555,427	5,378,932
Net petroleum and natural gas revenue	5,627,535	7,299,772	7,327,783	5,306,646
Net income (loss)	3,305,628	(1,790,789)	(2,155,583)	4,106,091
Net income (loss) per share – basic	0.03	(0.02)	(0.02)	0.04
Net income (loss) per share – diluted	0.03	(0.02)	(0.02)	0.03
Funds flow from operations	3,493,003	5,146,554	5,686,411	4,967,853
Funds flow from operations per share – basic	0.03	0.04	0.05	0.04
Funds flow from operations per share –diluted	0.03	0.04	0.05	0.04
Net capital expenditures	3,006,024	7,575,520	19,735,557	19,005,315

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.