Notice to Reader

Yangarra has refiled its Management's Discussion and Analysis for the year ended December 31, 2014 consolidating the “Disclosure Controls And Procedures” and “Internal Controls Over Financial Reporting” sections and revising the language within to more clearly explain the weakness in Disclosure Controls And Procedures and Internal Controls Over Financial Reporting.

Yangarra Resources Ltd.
Management's Discussion and Analysis
For year ended December 31, 2014

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, 2014 audited 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 March 19, 2015.

The financial information presented herein has been prepared on the basis of International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. 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.*

Non–IFRS and Additional IFRS Measures

This document contains "funds from operations", which is an additional IFRS measure presented in the consolidated financial statements. The Company uses funds generated from operations as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. This document also contains the terms "net debt" and "netbacks", which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers.

Funds flow from (used in) operations

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 and decommissioning costs incurred. 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 income 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:

	Year Ended	
	2014	2013
Cash from operating activities	$ 31,663,428	$ 27,077,123
Decommissioning costs incurred	76,361	-
Changes in non-cash working capital	6,586,199	(1,428,457)
Funds flow from operations	$ 38,325,988	$ 25,648,666

<u>*Netbacks*</u>

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 income / (loss) netbacks. Operating netback is calculated as the average sales price of its commodities (including realized gains on financial instruments) 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. 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.

<u>*Net debt*</u>

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.

2014 Highlights

- Average daily production was 2,870 boe/d, a 30% increase from 2013.
- Oil and gas sales, after royalties, were $51.4 million with funds flow from operations of $38.3 million ($0.70 per share - basic). This represents a 48% increase and a 49% increase, respectively, from 2013.
- Net Income of $24.4 million ($0.45 per share - basic) or $33.4 million before future income taxes ($0.61 per share - basic).
- Earnings before interest, taxes, depletion & depreciation, amortization and changes in commodity contracts ("EBITDA") was $39.7 million ($0.73 per share - basic) or $52.7 million including changes in commodity contracts ($0.97 per share - basic).
- Operating costs were $8.47/boe (including $1.58/boe of transportation costs).
- Field net backs (operating netback excluding commodity contracts) were $41.10, an increase of 18% from 2013. Operating netbacks were $40.62 per boe, a 12% increase from 2013.
- G&A costs of $2.05/boe.
- Royalties were 6% of oil and gas revenue.
- Total capital expenditures were $79.9 million (including $2.6 million of property acquisition costs under the August 2013 farm-in and $1.7 million in exploration and evaluation assets). The Company drilled 29 gross (19.4 net) wells in 2014.
- Net debt, excluding the current portion of the fair value of commodity contracts, was $59.8 million ($51.4 million including the current portion of the fair value of commodity contracts).
- Year-end debt to 2014 cash flow ratio excluding the current portion of the fair value of commodity contracts was 1.56 : 1 (1.34 : 1 including the current portion of the fair value of commodity contracts).

Financial Information

	Year Ended		
	2014	2013	2012
Statements of Comprehensive Income (Loss)			
Petroleum & natural gas sales and royalty income	$ 54,582,213	$ 34,726,657	$ 21,327,157
Net income (before tax)	$ 33,413,237	$ 4,146,706	$ 21,174
Net income (loss)	$ 24,371,606	$ 2,585,699	$ (217,712)
Net income (loss) per share - basic	$ 0.45	$ 0.06	$ (0.01)
Net income (loss) per share - diluted	$ 0.44	$ 0.06	$ (0.01)
Statements of Cash Flow			
Funds flow from operating activities	$ 38,325,988	$ 25,648,666	$ 14,588,405
Funds flow from operating activities per share - basic	$ 0.70	$ 0.63	$ 0.41
Funds flow from operating activities per share - diluted	$ 0.69	$ 0.63	$ 0.38
Cash from operating activities	$ 31,663,428	$ 27,077,123	$ 17,016,431
Statements of Financial Position			
Property and equipment	$ 218,154,343	$ 152,971,016	$ 121,842,378
Total assets	$ 250,491,053	$ 169,798,021	$ 138,894,114
Working capital deficit	$ 51,399,838	$ 40,778,148	$ 34,241,989
Working capital deficit, excluding MTM on commodity contracts	$ 59,766,933	$ 36,794,243	$ 36,301,842
Subordinated Debt	$ -	$ 7,786,632	$ -
Non-Current Liabilities	$ 26,382,773	$ 7,523,351	$ 12,274,710
Shareholders equity	$ 147,838,197	$ 95,583,587	$ 79,689,765
Weighted average number of shares - basic	54,581,750	41,033,862	35,320,108
Weighted average number of shares - diluted	55,793,173	41,033,862	37,927,041

Business Environment

	Year Ended	
	2014	2013
Realized Pricing (Including realized commodity contracts)		
Oil ($/bbl)	$ 84.40	$ 92.08
NGL ($/bbl)	$ 52.93	$ 54.32
Gas ($/mcf)	$ 4.06	$ 3.53
Realized Pricing (Excluding commodity contracts)		
Oil ($/bbl)	$ 88.41	$ 90.93
NGL ($/bbl)	$ 56.50	$ 52.91
Gas ($/mcf)	$ 4.53	$ 3.25
Oil Price Benchmarks		
West Texas Intermediate ("WTI") (US$/bbl)	$ 93.00	$ 97.95
Edmonton (C$/bbl)	$ 86.10	$ 93.90
Natural Gas Price Benchmarks		
AECO gas (Cdn$/GJ)	$ 4.50	$ 3.15
Foreign Exchange		
U.S./Canadian Dollar Exchange	$ 0.91	$ 0.97

Crude oil prices decreased for the year ended December 31, 2014, with the West Texas Intermediate ("WTI") reference price averaging US$93.00/bbl compared with US$97.95/bbl in 2013. 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. In the fourth quarter of 2014, there was a significant decrease in crude oil benchmark prices primarily due to slowing global economic conditions outside of the U.S. combined with strong growth in North American crude oil supply and the unexpected return of Libyan crude oil supply.

Edmonton par differentials to WTI remained relatively flat for the year ended December 31, 2014 when compared to the same period in 2013, moving from a $7.60/bbl differential in 2013 to $7.94/bbl in 2014. The US/CDN foreign exchange rate moved from $0.97 in 2013 to $0.91 for 2014. The Edmonton par reference price is denominated in Canadian dollars so the change in the foreign exchange rate has increased the Edmonton par price relative to WTI. Edmonton par is the closest reference price point for Yangarra's oil are therefore is the closest proxy to realized pricing.

When compared to 2013 realized pricing on oil decreased by 3%, excluding commodity contracts, and decreased by 8% when the effects of commodity contracts are included. The decrease in oil pricing is a direct result of the decreased WTI pricing.

When compared to 2013 liquids pricing increased by 7%, excluding commodity contracts, and decreased by 3% when the effects of commodity contracts are included.

For the year ended December 31, 2014, Yangarra had contracted 1,200 bbl/day of oil production utilizing WTI fixed price contracts at an average price of $95.20 per bbl. Since the benchmark price was higher than our contracted value the realized prices were negatively impacted. As the product is intended to provide protection to both the oil and NGL revenue streams the commodity contracts impact is split between the two products based on their relative production.

AECO natural gas prices increased for the year ended December 31, 2014 by 43% to $4.50/GJ from $3.15/GJ in 2013.

Yangarra had contracted 5,000 GJ/day of 2014 natural gas production utilizing AECO fixed price contracts at an average price of $3.39 per GJ. These contracts negatively impacted the realized natural gas price.

When compared to 2013 realized pricing on natural gas increased by 39%, excluding commodity contracts and by 15% when the effects of commodity contracts are included.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	Year Ended	
	2014	2013
Daily production volumes		
Natural gas (mcf/d)	8,514	6,583
Oil (bbl/d)	1,022	556
NGL's (bbl/d)	364	422
Royalty income		
Natural gas (mcf/d)	271	557
Oil (bbl/d)	1	1
NGL's (bbl/d)	20	37
Combined (boe/d 6:1)	2,870	2,206
Revenue		
Petroleum & natural gas sales - Gross	$ 54,582,213	$ 34,726,657
Royalty income	853,203	1,108,750
Commodity contract settlement	(510,369)	1,181,080
Total sales	54,925,047	37,016,487
Royalty expense	(3,505,935)	(1,796,832)
Petroleum & natural gas sales - Net	51,419,112	35,219,655
Change in fair value of contracts	13,024,535	(6,928,607)
Total Revenue - Net of royalties	$ 64,443,647	$ 28,291,048

Total sales increased by 48% in 2014 to $54.9 million from $37.0 million in 2013. The increase is attributable to:

- a 21% increase in average product prices; and
- a 30 % increase in production (on a boe basis).

The increased production in 2014 can be attributed to additional wells that were brought on production during the year. The Company drilled or participated in 29 gross (19.4 net) horizontal wells during 2014.

Company Netbacks ($/boe)

	Year Ended 2014	Year Ended 2013
Sales price	$ 52.10	$ 43.12
Royalty income	0.81	1.38
Royalty expense	(3.35)	(2.23)
Production costs	(6.89)	(6.30)
Transportation costs	(1.58)	(1.26)
Field operating netback	**41.10**	**34.71**
Commodity contract settlement	(0.49)	1.47
Operating netback	**40.62**	**36.18**
G&A and other (excludes non-cash items)	(2.05)	(2.06)
Finance expenses	(2.36)	(2.32)
Cash flow netback	**36.21**	**31.80**
Depletion and depreciation	(15.88)	(17.50)
Accretion	(0.16)	(0.18)
Stock-based compensation	(0.70)	(0.36)
Unrealized gain (loss) on financial instruments	12.43	(8.60)
Deferred income tax	(8.63)	(1.94)
Net Income netback	**$ 23.26**	**$ 3.21**

The overall average price earned by the Company was higher when compared to 2013 as natural gas prices increased by 39% and oil prices decreased by 3%. The net affect was positive to pricing as the Company has a 51% gas weighting. The average sales price increased by 21% for the year ended December 31, 2014 when compared to 2013.

Royalty Income

	Year Ended 2014	Year Ended 2013
Royalty income	$ 853,203	$ 1,108,750

Royalty income decreased in 2014 to $853,203 as no new wells have been drilled on the royalty lands, leaving the existing royalty production subject to regular decline rates. The majority of royalty income is a result of the 15% sliding scale royalty purchased in the Willesden Green area in March 2010. At the end of 2014, there were a total of 12 wells generating the 15% royalty income.

Royalty Expense

	Year Ended 2014	Year Ended 2013
Royalty expense	$ 3,505,935	$ 1,796,832
Per boe	$ 3.35	$ 2.23
As a % of sales (including commodity contracts)	6%	5%
As a % of sales (excluding commodity contracts)	6%	5%

Royalties increased to $3,505,935 for the year ended December 31, 2014 or 6% as a percentage of sales (excluding commodity contact settlements). The increase is a result of higher production volumes during the year as the percentage of sales remained relatively constant.

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

	Year Ended 2014	Year Ended 2013
Production costs	$ 7,218,786	$ 5,074,900
Per boe	$ 6.89	$ 6.30
Transportation costs	$ 1,651,072	$ 1,016,247
Per boe	$ 1.58	$ 1.26
Combined ($/boe)	$ 8.47	$ 7.56

Production and transportation costs increased in 2014 to $8,869,858 on a dollar basis due to additional production and increased by 12% on a per boe basis when compared to 2013. The change is due to the additional third party processing charges and higher processing and transportation fees charged by the mid-stream operators.

Depletion, depreciation, impairment and accretion

	Year Ended 2014	Year Ended 2013
Depletion and depreciation	$ 16,635,642	$ 14,091,803
Per boe	$ 15.88	$ 17.50
Accretion	$ 170,409	$ 148,714

Depletion, depreciation increased when compared 2013 as a result of increased production. The DD&A rate per boe decreased in 2014 as the reserve base increased at a faster pace than the 2014 capital additions.

General and administrative expenses ("G&A")

	Year Ended 2014	Year Ended 2013
Gross G&A expenses	$ 3,462,309	$ 2,588,674
G&A recoveries	(1,316,433)	(929,708)
Net G&A expenses	$ 2,145,876	$ 1,658,966
Per boe	$ 2.05	$ 2.06

On a net basis, general and administrative expenses increased by 29% in 2014 as a result of increased head office costs due to the growth in production and the graduation to the TSX. On a per boe basis, G&A decreased due to higher production and increased recoveries.

Other expenses

	Year Ended 2014	Year Ended 2013
Finance		
Interest (includes released losses on interst rate contracts)	$ 2,077,390	$ 1,820,876
Change in fair value of interest rate contracts	396,551	43,236
Accretion	170,409	$ 148,714
	$ 2,644,350	$ 2,012,826
Stock-based compensation	$ 734,684	$ 289,600

Interest and financing fees for the year ended December 31, 2014 include interest on the revolving operating demand loan (the average amount drawn in 2014 was $47 million), the subordinated term facility and the change in fair value of the interest rate contracts.

The Company had the following interest rate contracts in place at December 31, 2014:

- Pay a floating rate to receive a 2.35% (plus a 2.50% credit spread) fixed rate on $10 million (January 2015 - June 2018)
- Pay a floating rate to receive a 2.15% (plus a 2.50% credit spread) fixed rate on $10 million (January 2015 - May 2018)

The fair value on the interest rate contracts was in a loss position of ($439,786) as at December 31, 2014 (2013 – $43,236).

During the year ended December 31, 2014, the Company granted options to purchase 1,291,677 common shares, (400,002 of the options vested immediately and 891,675 of the options will vest equally over three years with the first tranche vesting one year after the grant date). The fair value of the options was estimated at $1,683,600 ($1.32 per option) using the Black-Scholes pricing model.

Deferred Taxes

	Year Ended	
	2014	2013
Deferred income tax expense	$ 9,041,631	$ 1,561,007

The Company's effective tax rate for 2014 was 25%, however, Yangarra did not pay income taxes in 2014 and does not expect to pay income taxes in 2015 as it has sufficient tax pools to cover taxable income.

The Company has the following estimated tax pools as at December 31:

	Year Ended	
	2014	2013
Canadian exploration expenses	$ 10,247,874	$ 13,023,280
Canadian development expenses	103,782,030	71,317,286
Canadian oil and gas property expenses	15,493,336	8,516,809
Undepreciated capital costs	22,328,502	20,909,028
Non-capital losses (various expiry dates)	1,568,775	1,592,090
Share issuance costs	2,471,312	1,983,594
	$ 155,891,829	$ 117,342,087

Commodity price risk contracts

	Year Ended	
	2014	2013
Realized (loss) gain on contract settlement	$ (510,369)	$ 1,181,080
Change in fair value of commodity contracts	13,024,535	(6,928,607)
	$ 12,514,166	$ (5,747,527)

As at December 31, 2014, the Company was committed to the following commodity price risk contracts for the sale of oil:

2015 Oil
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
100 bbl/d from January 1 to December 31, 2015 at a fixed price of $92.25 CDN/bbl
200 bbl/d from January 1 to December 31, 2015 at a fixed price of $92.45 CDN/bbl
200 bbl/d from January 1 to December 31, 2015 at a fixed price of $100.00 CDN/bbl

As at December 31, 2014 the Company was committed to the following commodity price risk contracts on the AECO basis:

2015 Gas
2,000 GJ/d from January 1 to December 31, 2015 at a fixed price of $4.11/GJ

The fair value of the commodity contracts was $8,494,039 as at December 31, 2014 (2013 – $4,530,496).

Subsequent to year end the Company monetized 400 bbl/d of commodity contracts (the $91.20/bbl, $92.25/bbl and $92.45/bbl contracts) for proceeds of $4,016,652 The Company then entered into 500 bbl/d of costless collars at a floor of C$65.00 WTI per barrel and a ceiling of C$73.50 WTI per barrel, for the remainder of 2015. The Company also added 800 bbl/d of Edmonton par to WTI differential contracts at US$6.75/bbl for 2015.

The Company's commodity contract position for 2015 now consists of the 500 bbl/d costless collar, 300 bbl/d crude oil swap at an average price of C$102.56 WTI per barrel, 800 bbl/d of differential at US$6.75/bbl and 2,000 GJ/d of gas at $4.11 AECO per GJ.

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at December 31, 2014 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 ($0.27/mcf for natural gas and $5.65/bbl for oil). Fluctuations in commodity prices potentially could have resulted in unrealized gains (losses) impacting income before tax as follows:

Sensitivities	Impact on Income Before Tax	
	Increase 10%	Decrease 10%
Crude oil	(1,698,324)	1,698,324
Natural Gas	(193,450)	193,450

Liquidity and Capital Resources

The following table summarizes the change in working capital during the year ended December 31, 2014 and December 31, 2013:

		2014		2013
Working capital (deficit) - beginning of year [1]	$	(36,794,243)	$	(36,301,842)
Funds flow from operating activities		38,325,988		25,648,666
Additions to property and equipment		(78,125,708)		(45,023,600)
Additions to E&E Assets		(1,680,941)		(2,461,506)
Issuance of shares		26,408,338		13,593,273
Issuance (repayment) of Subordinated Debt		(7,786,632)		7,786,632
Decommissioning costs incurred		(76,361)		-
Other Debt		(37,374)		(35,866)
Working capital (deficit) - end of year [1]	$	(59,766,933)	$	(36,794,243)
Subordinated Debt Outstanding	$	-	$	(7,786,632)
Total Debt	$	(59,766,933)	$	(44,580,875)
Credit facility limit	$	70,000,000	$	45,000,000
Subordinated debt facility limit	$	20,000,000	$	20,000,000

(1) Excludes current portion of fair value of commodity contracts

As at December 31, 2014, the 55,602,093 (2013 – $32,112,455) reported amount of bank debt with Alberta Treasury Branches ("ATB") was comprised of $29,150,000 (2013 – $9,850,000) drawn on the revolving operating demand loan, $24,940,715 (2013 – $19,963,177) of guaranteed notes and $1,511,378 (2013 – $2,299,280) of outstanding cheques. The Company is subject to a financial covenant requiring an adjusted working capital ratio above 1 : 1 (current assets plus the undrawn availability under the revolving facility, divided by the current liabilities less the drawn portion of the revolving facility, excluding unrealized commodity contracts and flow-through share premium liability). The facility is secured by a general security agreement.

As at December 31, 2014, the maximum amount available under the revolving operating demand loan was $70,000,000 (December 31, 2013 – $45,000,000) at an interest rate of bank prime plus 0.75% per annum on the operating demand loan, payable monthly, or a credit spread of 2.0% on guaranteed notes. The next scheduled review is May 31, 2015. A decrease in the borrowing base could result in a reduction to the credit facility, which may require repayment to the lenders. During the period, the weighted average effective interest rate for the bank debt was approximately 4.1% (2013 – 4.9%).

As at December 31, 2014 nil (2013 – $7,786,632) was drawn on the $20,000,000 subordinated term loan facility 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). There are two tranches ($9,000,000 to be drawn on or before October 1, 2014 and $11,000,000 to be drawn on or before January 1, 2015) at an interest rate of bank prime plus 7.0% per annum, payable monthly, or a credit spread of 8.0% on guaranteed notes. Full payment of the principal is due on September 3, 2015. The second tranche was not drawn on January 1, 2015 and the current balance outstanding is $nil.

The Company is subject to financial covenants on the subordinated term facility requiring an adjusted working capital ratio greater than 1 : 1 (calculation consistent with the calculation disclosed above) and a debt to EBITDA ratio below 4 : 1 (debt is defined as all obligations, liabilities and indebtedness on the statement of financial position less asset retirement obligation, future income taxes, flow-through share premium liability and commodity\interest contracts and EBITDA is defined as net income plus interest expense and other financing costs, depletion and depreciation and income taxes). In addition the Company is required to comply with a PV-10 proved developed producing ("PDP") to debt ratio of not less than 0.92 : 1 on specified dates and a PV-10 total proved to debt ratio of not less than 1.5 : 1 on specified dates. This facility is secured with a pledge of a general demand debenture and a general security agreement.

The Company is in compliance with all covenants as at December 31, 2014.

The 2014 cash flow ratio as at December 31, 2014 was 1.56 : 1, excluding the current portion of the fair value of commodity contracts (1.34 : 1 including the current portion of the fair value of commodity contracts).

Yangarra intends to fund the 2015 budget with cash flow from operations and the availability on the revolving operating demand loan. There are no drilling commitments for 2015.

Contractual Obligations and Commitments

As at December 31, 2014	Carrying Amount	Contractual Cash Flows	Less than 1 year	1-2 Years	2-5 Years	More than 5 years
A/P and accrued liabilities	20,541,046	20,541,046	20,541,046	-	-	-
Bank debt [(1)]	55,602,093	55,602,093	55,602,093	-	-	-
Other long-term liabilities	720,874	720,874	-	40,167	680,707	
Interest rate contract	439,786	439,786	126,944	126,944	185,898	-
Estimated interest payments [(1)]	-	588,147	588,147	-	-	-
	77,303,799	77,891,946	76,858,230	167,111	866,605	-

Capital Spending

Capital spending is summarized as follows:

	Year Ended	
Cash additions	2014	2013
Land, acquisitions and lease rentals	$ 1,188,777	$ 184,606
Property acquisitions (Farm-in drilling)	2,627,312	-
Drilling and completion	65,125,540	35,705,499
Geological and geophysical	1,612,737	756,870
Equipment	7,569,877	7,595,294
Other asset additions	1,465	318,233
	$ 78,125,708	$ 44,560,502
Exploration & evaluation assets additions	$ 1,680,941	$ 2,461,506

The Company drilled 29 gross (19.4 net) horizontal wells during 2014, including a Duvernay horizontal well. The drilling resulted in increased production.

In 2014 excluding the Duvernay well, the average drill cost per well was $1.8 million and the average completion cost per well was $1.2 million.

Outlook

Yangarra continues to manage the balance sheet and is targeting debt to cash flow of 2 to 1 or less in 2015 (assuming current strip pricing). The hedging program has provided excellent coverage in this low commodity environment which together with many other cost cutting initiatives will assist with keeping the balance sheet strong. Yangarra continues to make all capital allocation decisions based on maximizing full cycle economics.

Decommissioning Liabilities

As at December 31, 2014, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $11,922,672 for which $8,250,475 has been recorded using a discount rate of 1.46% - 2.33%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 15 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 year ended December 31, 2014 and 2013, the Company was charged or invoiced the following amounts by certain of its officers and directors through controlled companies:

	Year Ended 2014	Year Ended 2013
Administration and consulting fees	$ 424,085	$ 540,043
Production and capital expenditures	$ 114,291	203,023
	$ 538,376	$ 743,065

Included in accounts payable and accrued liabilities at December 31, 2014 is $6,478 (December 31, 2013 – $7,727) 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 $291,172 (December 31, 2013 - $328,545) 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, 2013	49,039,002	473,335	3,545,031
Equity financing	8,333,417	-	-
Expiry of warrants	-	(473,335)	
Grant of options	-	-	1,291,677
Exercise of options	383,335	-	(383,336)
Share consolidation	50	-	-
Balance - December 31, 2014	57,755,804	-	4,113,370
Grant of options	-	-	-
Exercise of options	-	-	-
Balance - Date of MD&A	57,755,804	-	4,113,370

In May 2014, the Company consolidated its outstanding common shares, stock options and warrants on a 1 for 3 basis (the "Share Consolidation"). As a result, the number of outstanding common shares, stock options and warrants of comparative periods have been reduced by a factor of three, in order for the comparative common share, stock options, warrants, per share amounts and diluted per share amounts to be equivalent.

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 satisfied its full CEE commitment related to the CEE flow-through shares issued in December 2013 as at December 31, 2014.

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

2015	$	241,277
2016	$	241,277
2017	$	241,277

Financial Instruments and Financial Risk Management

The Company's financial instruments include accounts receivable, bank debt, subordinated debt, accounts payable and accrued liabilities, other long term liabilities, interest rate contracts and commodity contracts. The carrying values of accounts receivable, accounts payable and accrued liabilities, other long term liabilities and bank debt approximate their fair values due to their relatively short periods to maturity. The fair value of the subordinated debt is approximately equal to the carrying value as the debt is subject to a floating interest rate.

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

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

The fair value of the interest rate contracts and the commodity contracts is classified at level 2. The fair value is calculated using the forward price curves as at December 31, 2014 for the period the contract is outstanding.

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 December 31, 2014, the maximum credit exposure is the carrying amount of the accounts receivable of $13,609,036 (December 31, 2013 – $8,846,547).

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

Oil and natural gas marketers	$	2,644,221
Joint venture partners		8,258,199
Realized Commodity Contracts		1,063,489
Other		1,643,127
	$	13,609,036

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 (Computershare). 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 January 2015.

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 year ended December 31, 2014.

As at December 31, 2014, the Company considers its receivables to be aged as follows:

Not past due	$	6,609,455
Past due by less than 90 days		3,710,806
Past due by more than 90 days		3,288,775
	$	13,609,036

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, commodity contracts, interest rate contracts, bank debt and subordinated debt, which are classified as current or non-current on the statement of financial position based on their maturity dates.

Yangarra intends to fund the 2015 budget with cash flow from operations and the availability on the revolving operating demand loan.

c. Market risk

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

i. Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate and to mitigate this risk, the Company has entered into interest rate contracts. For the year ended December 31, 2014, if interest rates had been 1% lower with all other variables held constant, income for the period would have been $465,573 (December 31, 2013 - $308,150) 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 December 31, 2014.

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 commodity price risk contracts are listed in the commodity price risk contracts section.

Capital Resources

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 and debt:

	December 31, 2014	*December 31, 2013*
Shareholders' equity	$ 147,838,197	$ 95,583,587
Bank debt	$ 55,602,093	$ 32,112,455
Subordinated debt	$ –	$ 7,786,632

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 December 31, 2014, the Company's capital structure was not subject to external restrictions. No changes have been made to the capital policy in 2014.

Selected Quarterly Financial Information

	2014 Q4($)	2014 Q3($)	2014 Q2($)	2014 Q1($)
Petroleum & natural gas sales and royalty income	**10,524,238**	14,796,645	14,106,137	16,008,396
Net petroleum and natural gas revenue	**9,774,426**	13,845,994	13,238,221	15,070,840
Net income (loss)	**12,833,554**	7,967,369	2,851,233	719,450
Net income (loss) per share – basic	**0.22**	0.14	0.05	0.03
Net income (loss) per share – diluted	**0.22**	0.13	0.05	0.03
Funds flow from operations	**10,339,008**	9,346,927	8,180,361	10,459,692
Funds flow from operations per share – basic	**0.18**	0.16	0.15	0.21
Funds flow from operations per share –diluted	**0.18**	0.16	0.15	0.21
Net capital expenditures	**18,783,353**	19,588,859	19,445,229	21,989,208

	2013 Q4($)	2013 Q3($)	2013 Q2($)	2013 Q1($)
Petroleum & natural gas sales and royalty income	11,265,291	9,568,399	8,113,998	6,887,719
Net petroleum and natural gas revenue	10,708,013	8,866,802	7,837,133	6,626,627
Net income (loss)	750,851	11,330	2,082,942	(259,424)
Net income (loss) per share – basic	0.03	0.00	0.06	0.00
Net income (loss) per share – diluted	0.03	0.00	0.06	0.00
Funds flow from operations	7,975,588	6,378,207	6,480,689	4,814,183
Funds flow from operations per share – basic	0.18	0.16	0.15	0.16
Funds flow from operations per share –diluted	0.18	0.16	0.15	0.16
Net capital expenditures	23,483,590	8,567,226	3,708,601	11,262,592

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. The Company has focused capital expenditures on drilling and completions, with major infrastructure costs for a facility built in the first quarter of 2013. Production has grown steadily over the two year period with revenue and cash increasing when accounting for changes in commodity pricing.

Fourth Quarter Activities

Fourth quarter 2014 production of 3,035 boe/d is an increase of 10% compared to the 2,764 boe/d in the comparable period in 2013. Petroleum and natural gas sales decreased by 5% when compared to the same period in 2013 and funds flow from operations increased by 30%, due to the effect of commodity contracts. Production increased by 10% however realized pricing (excluding commodity contracts) decreased by 21% due to the drop in oil and liquids pricing.

Capital expenditures were $19 million in the fourth quarter of 2014 compared to $23 million in the same period in 2013. The Company drilled three Cardium wells in the fourth quarter, satisfied its CEE commitment by drilling a Duvernay well in the South Block, and participated in four non-operated wells.

Business Risks and Uncertainties

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

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

Environmental Risks

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

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

Disclosure Controls And Procedures and Internal Controls Over Financial Reporting

Disclosure controls and procedures ("DC&P") as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, means controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

Additionally, pursuant to NI 52-109, the Company's CEO and CFO are responsible for designing and evaluating the internal controls over financial reporting ("ICFR") or causing them to be designed or evaluated under their supervision. ICFR is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information resulting in the preparation of financial statements for external purposes which are in accordance with IFRS. Because of their inherent limitations, ICFR may not prevent or detect misstatements, errors or fraud.

Control systems, no matter how well designed, have inherent limitations. Moreover, any control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance, that the objectives of the control system are met.

In accordance with the requirements of NI 52-109 an evaluation of the effectiveness of DC&P and ICFR was undertaken as at December 31, 2014 based upon the "Internal Control – Integrated Framework" published in 1992 by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, the Company's CEO and CFO conclude that its DC&P are not operating effectively as a result of the weakness in ICFR discussed hereafter:

- Due to the relative small number of employees at Yangarra, Management is aware that there are not multiple personnel to review complex and non-routine financial and tax issues that may arise. Management does not believe it is economically feasible at this time to have such additional personnel whom may remediate or correct such weakness.

As a result of these identified weakness in Yangarra's ICFR, there is a more than remote likelihood that a material misstatement would not be prevented or detected in a timely manner. Yangarra's management has processes in-place to mitigate, but not fully compensate, the financial reporting risks arising from the identified weakness, including CEO and CFO oversight of all material transactions and related accounting records and daily oversight by the senior personnel of the Company. In addition, Yangarra's Audit Committee reviews on a quarterly and annual basis the financial statements and key risks of the Company and queries management about significant transactions.

Until such time as it is economically feasible to hire additional qualified personnel, in order to remediate the identified weakness in the Company's ICFR, the Company intends to continue to engage third-party expert advisors in connection with corporate taxation, complex accounting matters or any non-routine accounting transactions that may arise.

New Accounting Standards

Financial Instruments

On July 24, 2014, the IASB issued the final version of IFRS 9, "Financial Instruments" ("IFRS 9") to replace IAS 39, "Financial Instruments: Recognition and Measurement" ("IAS 39").

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Yangarra does not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

IFRS 11 Accounting for Acquisitions of Interests in Joint Operations. The amendments clarify that business combination accounting is required to be applied to acquisitions of interests in a joint operation (e.g. oil and gas property) that constitutes a business. To be applied prospectively for annual periods beginning on or after January 1, 2016. Early adoption is permitted.

New and Amended Accounting Standards Adopted

The Company adopted the following new amendment:

Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2014, the Company adopted, as required, amendments to IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"). The amendments clarify that the right to offset financial assets and liabilities must be available on the current date and cannot be contingent on a future event. The adoption of IAS 32 did not impact the Consolidated Financial Statements.

Critical Accounting Estimates

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect reported amounts and presentation of assets, liabilities, revenues, expenses and disclosures of contingencies and commitments. Such estimates primarily relate to unsettled transactions and events at the statement of financial position date which are based on information available to management at each financial statement date. Actual results could differ from those estimated. Judgments, estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

<u>Critical judgments in applying accounting policies</u>

CGU Determination

The Company's assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing. CGUs are determined by similar geological structure, shared infrastructure and geographical proximity.

Impairment indicator assessment

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

Contingencies

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

<u>Key sources of estimation uncertainty</u>

Reserves

Reserves are used in the unit of production calculation for depletion and depreciation as well as impairment analysis. The quantity of reserves is subject to a number of estimates and projections including assessment of engineering data, projected future rates of production, commodity prices, regulatory changes, operating costs and sustaining capital expenditures. These estimates and projections are uncertain as the Company does not have a long commercial production history to assist in the development of these forward-looking estimates. However, all reserve and associated financial information is evaluated and reported on by a firm of qualified independent reserve evaluators in accordance with the standards prescribed by applicable securities regulators. The calculation of future cash flows based on these reserves is dependent on a number of estimates including: production volumes, facility performance, commodity prices, and royalties, operating costs, sustaining capital and tax rates. The price used in the Company's assessment of future cash flows is based on the Company's independent evaluator's estimate of future prices and evaluated for reasonability by the Company against other available information. The Company believes these prices are reasonable estimates for a long-term outlook.

Decommissioning liabilities

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

Impairment Estimate

The assessment for impairment for P&E and E&E assets involves comparing the carrying value of the CGU with the higher of value in use calculations and fair value less costs to sell. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for regional supply-and-demand conditions for crude oil, natural gas and liquids. Impairment is recognized in the statement of income (loss) and comprehensive income (loss) in the period in which carrying amount exceeded the recoverable amount.

Deferred taxes

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

Contingencies

When recognized, management makes its best estimate with respect to future cash outflows.

Other areas of estimates

The recognition of amounts in relation to stock-based compensation requires estimates related to valuation of stock options at the time of issuance including share price, risk free rate, volatility, expected life and dividend yield. The fair value of commodity contracts is calculated using valuation models that require estimates as to future market prices expected interest rates and expected volatility in these variables. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements for current and future periods could be significant.