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, 2013 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 24, 2014.

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.*

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	Year Ended	
	Q4	Q2	Q3	2013	2012
Cash from operating activities	$ 10,757,178	$ 3,683,552	$ 4,163,347	$ 27,077,123	$ 17,016,431
Changes in non-cash working capital	(2,781,590)	2,694,655	(995,019)	(1,428,457)	(2,428,026)
Funds flow from operations	$ 7,975,588	$ 6,378,207	$ 3,168,328	$ 25,648,666	$ 14,588,405

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 (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.*

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.

2013 Significant Events

During the year ended December 31, 2013 the Company completed the following significant milestones:

- Average daily production was 2,206 boe/d, a 15% increase from 2012.
- Funds flow from operations were $26 million ($0.21 per share - basic), a 76% increase from 2012.
- Earnings before interest, taxes, depletion & depreciation, amortization and changes in commodity contracts ("EBITDA") was $27.2 million.
- Operating costs, including $1.26/boe of transportation costs, were $7.56/boe.
- Operating netback of $36.18 per boe, a 42% increase from the $25.48 per boe reported in 2012.
- G&A costs of $2.06/boe, which represents an 18% decrease from 2012.
- Royalties at 5% of oil and gas revenue.
- $1.2 million of realized hedging gains.
- Fourth quarter 2013 production was 2,764 boe/d with funds flow from operations of $8 million ($0.06 per share - basic).
- Total capital expenditures were $47 million versus $19.8 million in 2012. With the equity raise late in 2013 the Company accelerated the fourth quarter capital expenditures to $26 million.
- As at December 31, 2013, the Company had a current bank debt, subordinated debt and working capital deficit, excluding mark to market on commodity contracts and flow-through share obligations, of $44.6 million compared to $36.3 million at December 31, 2012.
    - The annualized fourth quarter debt to cash flow ratio was 1.4 : 1.

Operations Update

2013 Operations Summary

The Company has successfully drilled and completed 15 gross (10.6 net) wells during 2013, in addition to completing 2 gross (0.6 net) wells that were drilled in 2012. All of the wells drilled in 2013 were completed by December 31, 2013, with the last 3 wells (2.75 net) tied in the last week of December 2013.

In January 2013 Yangarra began construction of an 11 mmcf/d gas processing facility in the Ferrier area (100% working interest) that was put in service April 10, 2013 and provided for the tie-in of 8.0 gross (2.4 net) standing wells, six of which had been drilled in 2011 and 2012.

In September 2013 Yangarra entered into a farm-in agreement with an industry major adding 61 gross (37 net) Cardium locations. Yangarra has drilled 7 gross (5.35 net) wells (4 of which were earning wells) which exceeded its initial drilling obligation under the terms of the farm-in agreement, to drill 2 earning wells by the end of March 31, 2014.

Late in 2013 Yangarra negotiated a swap with an industry partner to concentrate their respective interests in the Ferrier area. In the swap arrangement Yangarra exchanged its Glauconite interest in 2 wells and 3 sections (average 17% working interest) for Cardium interests in 4 wells and 1.5 sections (average 30.6% working interest). The swap resulted in $3 million of additional drilling and completions costs as the Company acquired an additional working interest in two Cardium wells.

Yangarra spent $3.4 million on land and acquisitions which included 1,760 acres (1,760 net) of land in Central Alberta during 2013 purchased at crown land sales.

2014 Operations Update

During the first quarter of 2014 the Company drilled 6 gross (5.9 net) wells in the Cardium formation. A total of 4 gross (3.9 net) wells were put on production during the quarter with the final 2 (2.0 net) expected to be on stream at quarter end. The Company experienced 11 days of shut-in production (approximately 1,200 boe/d) due to the TransCanada pipeline rupture near Rocky Mountain House and an additional 150 boe/d average for the quarter of Keyera curtailments at other facilities. The Company expects first quarter production to be approximately 2,800 boe/d and full year guidance remains at 3,200 boe/d. The Company will continue to drill through break-up as conditions permit, with 6 gross (5.2 net) wells planned for the second quarter.

Annual Financial Information

	2013 Q4	2013 Q3	2012 Q4	Year ended 2013	Year ended 2012	Year ended 2011
Statements of Comprehensive Income (Loss)						
Petroleum & natural gas sales	$ 11,087,956	$ 9,372,931	$ 4,842,343	$ 34,726,657	$ 21,327,157	$ 20,742,259
Net income (loss) for the period (before tax)	$ 1,576,908	$ 39,646	$ (2,409,766)	$ 4,146,706	$ 21,174	$ 4,872,697
Net income (loss) for the period	$ 750,851	$ 11,330	$ 340,623	$ 2,585,699	$ (217,712)	$ 1,385,698
Net income (loss) per share - basic and diluted	$ 0.01	$ 0.00	$ 0.00	$ 0.02	$ (0.00)	$ 0.01
Statements of Cash Flow						
Funds flow from (used in) operating activities	$ 7,975,588	$ 6,378,207	$ 3,168,328	$ 25,648,666	$ 14,588,405	$ 16,341,180
Funds flow from (used in) operating activities per share - basic and diluted	$ 0.06	$ 0.05	$ 0.03	$ 0.21	$ 0.12	$ 0.15
Cash from (used in) operating activities	$ 10,757,178	$ 3,683,552	$ 4,163,347	$ 27,077,123	$ 17,016,431	$ 6,664,849
Statements of Financial Position						
Property and equipment	$ 152,971,016	$ 135,892,343	$ 121,842,378	$ 152,971,016	$ 121,842,378	$ 119,374,219
Total assets	$ 169,798,021	$ 154,773,403	$ 138,894,114	$ 169,798,021	$ 138,894,114	$ 141,291,043
Working Capital (deficit), excluding MTM on commodity contracts	$ 36,794,243	$ 42,594,542	$ (36,301,842)	$ 36,794,243	$ (36,301,842)	$ (34,028,162)
Subordinated Debt	$ 7,786,632	$ -	$ -	$ 7,786,632	$ -	$ -
Non-Current Liabilities	$ 7,523,351	$ 13,971,180	$ 12,274,710	$ 7,523,351	$ (12,274,710)	$ (9,752,766)
Shareholders equity	$ 95,583,587	$ 82,022,213	$ 79,689,765	$ 95,583,587	$ (79,689,765)	$ (76,627,244)
Weighted average number of shares - basic	127,219,336	121,718,245	121,711,723	123,101,587	120,663,095	105,960,324
Weighted average number of shares diluted	128,322,269	121,987,009	121,711,723	123,101,587	120,663,095	113,781,122

Business Environment

	2013 Q4	2013 Q3	2012 Q4	Year Ended 2013	Year Ended 2012
Realized Pricing (Including commodity contracts)					
Oil ($/bbl)	$ 85.56	$ 96.51	$ 83.76	$ 92.08	$ 84.09
NGL ($/bbl)	$ 52.08	$ 53.33	25.09	$ 54.32	$ 46.78
Gas ($/mcf)	$ 3.92	$ 3.05	3.02	$ 3.53	$ 2.49
Realized Pricing (Excluding commodity contracts)					
Oil ($/bbl)	$ 84.98	$ 102.99	$ 77.78	$ 90.93	$ 83.07
NGL ($/bbl)	$ 51.45	$ 60.77	$ 18.27	$ 52.91	$ 45.92
Gas ($/mcf)	$ 3.67	$ 2.57	$ 2.94	$ 3.25	$ 2.23
Oil Price Benchmarks					
West Texas Intermediate ("WTI") (US$/bbl)	$ 97.46	$ 105.81	$ 88.22	$ 97.97	$ 94.21
Edmonton (C$/bbl)	$ 86.58	$ 103.65	$ 83.99	$ 93.11	$ 87.02
Natural Gas Price Benchmarks					
AECO gas (Cdn$/GJ)	$ 3.15	$ 2.82	$ 3.06	$ 3.65	$ 2.79
Foreign Exchange					
U.S./Canadian Dollar Exchange	$ 0.953	$ 0.963	$ 1.009	$ 0.971	$ 1.000

Crude oil prices increased in the year ended December 31, 2013, with the West Texas Intermediate ("WTI") reference price averaging US$97.97/bbl compared with US$94.21 per barrel in 2012. Demand for crude oil is generally tied to global economic growth, but is also influenced by factors such as infrastructure, political instability, market uncertainty, weather conditions and government regulations.

Edmonton par differentials to WTI tightened in the year ended December 31, 2013 when compared to the same period in 2012, moving from a $7.19/bbl differential in 2012 to $4.86/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.

Realized pricing on oil increased by 9%, excluding commodity contracts and by 10% when the effects of commodity contracts are included. The increase in oil pricing is a direct result of the increased Edmonton par pricing.

Liquids pricing increased by 15%, excluding commodity contracts and by 16% when the effects of commodity contracts are included. Significant improvements in propane prices were the largest factor in the improved liquids price.

During the year ended December 31, 2013, Yangarra had contracted 900 bbl/day of oil production utilizing WTI fixed price contracts at an average price of $100.37 per bbl. Since the benchmark price was lower than our contracted value the realized prices were positively impacted. Since 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.

AECO natural gas prices increased for the year ended December 31, 2013 by 31% to $3.65/GJ from $2.79/GJ in 2012.

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

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2013		2012	Year Ended	
	Q4	Q3	Q4	2013	2012
Daily production volumes					
Natural gas (mcf/d)	8,303	6,983	4,607	6,583	5,586
Oil (bbl/d)	683	547	418	556	350
NGL's (bbl/d)	605	450	304	422	341
Royalty income					
Natural gas (mcf/d)	405	299	956	557	1,273
Oil (bbl/d)	1	1	(7)	1	3
NGL's (bbl/d)	24	26	57	37	77
Combined (boe/d 6:1)	2,764	2,238	1,700	2,206	1,914
Revenue					
Petroleum & natural gas sales - Gross	$ 11,087,956	$ 9,372,931	$ 4,842,343	$ 34,726,657	$ 21,327,157
Royalty income	177,335	195,468	216,693	1,108,750	2,024,819
Commodity contract settlement	271,387	(326,435)	535,585	1,181,080	907,863
Total sales	11,536,678	9,241,964	5,594,621	37,016,487	24,259,839
Royalty expense	(557,278)	(701,597)	(3,370)	(1,796,832)	(1,057,597)
Petroleum & natural gas sales - Net	$ 10,979,400	$ 8,540,367	$ 5,591,251	$ 35,219,655	$ 23,202,242
Change in fair value of contracts	$ (2,217,286)	$ (2,411,102)	$ (209,267)	$ (6,928,607)	$ 3,889,986
Total Revenue - Net of royalties	$ 8,762,114	$ 6,129,265	$ 5,381,984	$ 28,291,048	$ 27,092,228

Total sales increased by 53% in 2013 to $37.0 million from $24.3 million in 2012, the increase is attributable to:

- a 40% increase in average product prices; and
- an 15 % increase in production (on a boe basis).

The increased production in 2013 can be attributed to additional wells that were brought on production during 2013. The Company drilled or participated in 15 gross (10.6 net) horizontal wells during 2013.

Company Netbacks ($/boe)

	2013 Q4	2013 Q3	2012 Q4	Year Ended 2013	Year Ended 2012
Sales Price	$44.67	$43.94	$ 34.39	$44.59	$ 31.74
Royalty income	0.70	0.95	1.39	1.38	2.89
Royalty expense	(2.19)	(3.41)	(0.02)	(2.23)	(1.51)
Production costs	(6.20)	(5.45)	(9.65)	(6.30)	(6.81)
Transportation costs	(1.27)	(1.47)	(0.95)	(1.26)	(0.84)
Operating netback	**$ 35.70**	**$ 34.56**	**$ 25.16**	**$ 36.18**	**$ 25.48**
G&A and other (excludes non-cash items)	(2.07)	(1.76)	(2.25)	(2.06)	(2.52)
Finance expenses	(2.59)	(2.32)	(2.65)	(2.32)	(2.13)
Cash flow netback	**31.04**	**30.49**	**20.26**	**31.80**	**20.82**
Depletion and depreciation	(15.96)	(18.05)	(18.52)	(17.50)	(20.67)
Impairment	-	-	(19.82)	-	(5.76)
Gain on sale of property and equipment	-	-	4.15	-	0.93
Accretion	(0.16)	(0.15)	(0.14)	(0.18)	(0.13)
Stock-based compensation	-	(0.38)	-	(0.36)	(0.71)
Unrealized gain (loss) on financial instruments	(8.72)	(11.71)	(1.34)	(8.60)	5.55
Deferred income tax	(3.25)	(0.14)	17.59	(1.94)	(0.34)
Net Income (loss) netback	**$ 2.95**	**$ 0.06**	**$ 2.18**	**$ 3.21**	**$ (0.31)**

The overall average price earned by the Company was higher when compared to 2012 due higher natural gas reference pricing and oil prices caused by a narrowing in the Edmonton par differential to WTI and higher oil and liquids content in the product mix at 46% in 2013 versus 40% in 2012.

Operating netbacks increased by 42% when compared to the year ended 2012 with improved realized pricing causing the majority of the increase.

Royalty Income

	2013 Q4	2013 Q3	2012 Q4	Year Ended 2013	Year Ended 2012
Royalty Income	$ 177,335	$ 195,468	$ 216,693	$ 1,108,750	$ 2,024,819

Royalty income decreased in 2013 to $1,108,750 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 2013, there were a total of 12 wells generating the 15% royalty income.

Royalty Expense

	2013 Q4	2013 Q3	2012 Q4	Year Ended 2013	Year Ended 2012
Royalty Expense	$ 557,278	$ 701,597	$ 3,370	$ 1,796,832	$ 1,054,227
Per boe	$ 2.19	$ 3.41	$ 0.02	$ 2.23	$ 1.94
As a % of sales	5%	8%	0%	5%	6%

Royalties increased to $1,796,832 for the year ended 2013 or 5% as a percentage of sales. The increase results from higher production during 2013, however the royalty rate as a percentage of revenue decreased in 2013. 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 Q4	2013 Q3	2012 Q4	Year Ended 2013	Year Ended 2012
Production costs	$ 1,577,640	$ 1,122,452	$ 1,508,757	$ 5,074,900	$ 4,771,074
Per boe	$ 6.20	$ 5.45	$ 9.65	$ 6.30	$ 6.81
Transportation costs	$ 323,726	$ 302,408	$ 148,665	$ 1,016,247	$ 585,176
Per boe	$ 1.27	$ 1.47	$ 0.95	$ 1.26	$ 0.84
Combined ($/boe)	$ 7.48	$ 6.92	$ 10.60	$ 7.56	$ 7.65

Production and transportation costs increased in 2013 to $6,091,147 on a dollar basis due to additional production and decreased by 1% on a per boe basis when compared to 2012. As production volumes have increased the Company has implemented improvements to operating practices by hiring more experienced personal and streamlining operations across the Central Alberta area. Overall production and transportation costs remained relatively consistent and is in our usual range of below $8.00/boe.

Depletion, depreciation and impairment and accretion

	2013 Q4	2013 Q3	2012 Q4	Year Ended 2013	Year Ended 2012
Depletion and depreciation	$ 4,058,063	$ 3,715,664	$ 2,896,705	$ 14,091,803	$ 14,477,976
Per boe	$ 15.96	$ 18.05	$ 18.52	$ 17.50	$ 20.67
Impairment	$ -	$ -	$ 3,098,546	$ -	$ 4,035,426
Accretion	$ 40,208	$ 30,977	$ 22,096	$ 148,714	$ 92,611

Depletion, depreciation remained consistent when compared 2012 and on a per boe basis, the DD&A rate per boe increased in 2013 as the reserve base increased at a faster pace than the 2013 capital additions.

General and administrative expenses ("G&A")

	2013 Q4	2013 Q3	2012 Q4	Year Ended 2013	Year Ended 2012
Gross G&A expenses	$ 885,139	$ 459,801	$ 697,379	$ 2,588,674	$ 2,484,072
G&A recoveries	(358,305)	(97,988)	(346,300)	(929,708)	(717,536)
Net G&A expenses	$ 526,834	$ 361,813	$ 351,079	$ 1,658,966	$ 1,766,537
Per boe	$ 2.07	$ 1.76	$ 2.25	$ 2.06	$ 2.52

On a net basis, general and administrative expenses decreased by 6% in 2013 due higher overhead recoveries, primarily from the newly constructed gas plant, with gross G&A remaining relatively consistent as there were no major changes to the total number of staff. On a per boe basis, G&A decreased by 18% due to higher production and increased recoveries.

Other expenses

	2013		2012	Year Ended	
	Q4	Q3	Q4	2013	2012
Finance					
Interest	$ 575,612	$ 375,487	$ 414,422	$ 1,820,876	$ 1,491,050
Change in fair value of interest rate contracts	83,123	101,618	-	43,236	-
Accretion	40,208	30,977	$ 22,096	148,714	$ 92,611
	$ 698,943	$ 508,082	$ 436,518	$ 2,012,826	$ 1,583,661
Stock-based compensation	$ -	$ 79,200	$ -	$ 289,600	$ 499,724

Interest and financing fees for the year ended December 31, 2013 include interest on the revolving operating demand loan (the average amount drawn in 2013 was $31 million) the subordinated term facility, 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 December 31, 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)

The interest rate contracts had a fair value of $43,236 at December 31, 2013.

During the year ended December 31, 2013, the Company granted options to purchase 2,540,000 common shares, with the options vesting immediately. The fair value of the options was estimated at $435,100 ($0.17 per option) using the Black-Scholes pricing model. $289,600 of the stock-based compensation was expensed and the remaining $145,500 was capitalized.

Deferred Taxes

	2013		2012	Year Ended	
	Q4		Q4	2013	2012
Deferred income tax expense	$ 826,057	$ 28,316	$ (2,750,389)	$ 1,561,007	$ 238,886

The Company's effective tax rate for 2013 was 25%, however, Yangarra did not pay income taxes in 2013 and does not expect to pay income taxes in 2014 as is has sufficient tax pools to cover taxable income.

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

		Year Ended December 31,	
	Rate %	2013	2012
Canadian exploration expenses	100	$ 13,023,280	$ 12,488,867
Canadian development expenses	30	71,317,286	52,019,745
Canadian oil and gas property expenses	10	8,516,809	10,392,075
Undepreciated capital costs	10-30	20,909,028	18,897,904
Non-capital losses (various expiry dates)	100	1,592,090	1,388,618
Share issuance costs	5 Years	1,983,594	1,907,526
		$ 117,342,087	$ 97,094,735

Commodity price risk contracts

	2013		2012	Year Ended	
	Q4	Q3	Q4	2013	2012
Realized gain on contract settlement	$ 271,387	$ (326,435)	$ 535,585	$ 1,181,080	$ 907,863
Change in fair value of commodity contracts	(2,217,286)	(2,411,102)	(209,267)	(6,928,607)	3,889,986
	$ (1,945,899)	$ (2,737,537)	$ 326,318	$ (5,747,527)	$ 4,797,849

As at December 31, 2013, the Company was committed to the following commodity price risk contracts for the sale of oil:

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 USD/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
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $98.20 CAD/bbl
- 100 bbl/d from January 1 to June 30, 2014 at a fixed price of $100.00 CAD/bbl
- Sold Swaption on 100 bbl/d @ $100.00 WTI/CAD for July – 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
- 100 bbl/d from January 1 to December 31, 2015 at a fixed price of $90.10 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

2016 Contracts:

- Sold Swaption on 200 bbl/d @ $95.00 WTI/USD for January – December 2016

As at December 31, 2013, the Company was committed to the following commodity price risk contracts on the AECO basis:

- 1,000 GJ/d at $3.11/GJ for Jan – Dec 2014
- 1,000 GJ/d at $3.05/GJ for Jan – Dec 2014
- 1,000 GJ/d at $3.54/GJ for Jan – Dec 2014
- 1,000 GJ/d at $3.54/GJ for Jan – Dec 2014

The fair value on the contracts was in a loss position of $4,530,496 as at December 31, 2013 (2012 – a gain position of $2,398,111).

The following table summarizes the sensitivity of the fair value of the Company's commodity price contracts as at December 31, 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:

Sensitivities	Impact on Income Before Tax	
	Increase 10%	Decrease 10%
Crude oil	(7,532,432)	7,532,432
Natural Gas	(540,200)	540,200

Liquidity and Capital Resources

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

		2013		2012
Working capital (deficit) - beginning of period [1]	$	(36,301,842)	$	(34,028,162)
Funds flow from operating activities		25,648,666		14,588,405
Purchase of property and equipment & E&E Assets		(47,485,106)		(24,448,531)
Sale of property and equipment		-		4,650,000
Issuance of shares		13,593,273		2,552,333
Issuance of Subordinated Debt		7,786,632		-
Other Debt		(35,866)		384,113
Working capital (deficit) - December 31, 2013 [1]	$	(36,794,243)	$	(36,301,842)
Credit facility limit	$	45,000,000	$	42,000,000
Subordinated Debt Outstanding	$	(7,786,632)	$	-
Subordinated debt facility limit	$	20,000,000	$	-

(1) Excludes non-cash change in fair value of commodity contracts and flow through share obligations

As at December 31, 2013, the $32,112,455 (December 31, 2012 – $32,138,763) reported amount of bank debt with Alberta Treasury Branches ("ATB") was comprised of $9,850,000 (December 31, 2012 – $21,950,000) drawn on the revolving operating demand loan, $19,963,177 (December 31, 2012 – $9,992,093) of guaranteed notes and $2,299,280 (December 31, 2012 – $196,658) 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 obligations), which the Company was in compliance with at December 31, 2013. The facility is secured by a general security agreement.

As at December 31, 2013, the maximum amount available under the revolving operating demand loan was $45,000,000 (December 31, 2012 – $42,000,000) at an interest rate of bank prime plus 1.5% per annum on the operating demand load, payable monthly, and a credit spread of 2.5% on the guaranteed notes. The next scheduled review is May 31, 2014. During the year, the weighted average effective interest rate for the bank debt was approximately 4.9% (2012 – 4.5 %).

During the year ended December 31, 2013 the Company entered into a subordinated term loan facility of up to $20,000,000 with Alberta Treasury Branches ("ATB"). The subordinated term loan has a two year committed term (subject to an extension for an additional year upon mutual consent) is available in three tranches ($7,800,000 on or before December 31, 2013, $6,420,000 on or before May 31, 2014 and $5,780,000 on or before July 31, 2014) at 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 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 balance sheet and EBITDA is defined as earnings plus interest expense and other financing costs, depletion and depreciation and income taxes). In addition the Company is required to comply with a PV10 proved developed producing to debt ratio of not less than 0.92 : 1 on specified dates and a PV10 total proved to debt ratio of not less than 1.5 : 1 on specified dates. The Company was in compliance with all covenants at December 31, 2013.

In the fourth quarter the Company took down $7,800,000 of the subordinated term loan, leaving $12,200,000 undrawn. This facility is secured with a pledge of a general demand debenture and a general security agreement.

Yangarra's net debt to trailing year cash flow ratio as at December 31, 2013 was 1.7 : 1 and the annualized fourth quarter cash flow ratio as at December 31, 2013 was 1.4:1. All ratios include the subordinated debt but exclude the fair value of commodity contracts and the flow through share obligations.

Yangarra intends to fund the 2014 budget with cash flow from operations and the remaining availability on the revolving operating demand loan and the subordinated term loan.

Capital Spending

Capital spending is summarized as follows:

	2013		2012	Year Ended	
Cash Additions	Q4	Q3	Q4	2013	2012
Land, acquistions and lease rentals	$ (261,263)	$ 307,274	$ 240,777	$ 184,606	$ 734,910
Drilling and completion	18,958,090	6,725,516	6,679,886	35,705,499	19,727,708
Geological and geophysical	170,565	417,101	337,060	756,870	1,002,064
Equipment	1,490,863	1,036,654	1,758,120	7,595,294	2,812,328
Other Asset Additions	100,771	80,681		318,233	171,521
	$ 20,459,026	$ 8,567,226	$ 9,015,843	$ 44,560,502	$ 24,448,531
Disposition of Property and Equipment	$ -	$ -	$ (4,650,000)	-	(4,650,000)
Net Capital Additions	$ 20,459,026	$ 8,567,226	$ 4,365,843	$ 44,560,502	$ 19,798,531
Exploration & evaluation assets additions	$ 2,461,506	$ -	$ -	$ 2,461,506	$ -

The Company drilled 15 gross (10.6 net) horizontal wells during 2013. The drilling resulted in increased production.

In 2013, the average drill cost per well was $1.9 million and the average completion cost per well was $1.3 million mainly as a result of drilling deeper wells with more complicated fracture programs.

Outlook

The $50 million 2014 capital budget is focused on the development of Yangarra's Cardium light oil play with 15.5 net wells planned for the year. The budget also includes a Duvernay strata-graphic ("Strat") vertical test well. The budget is expected to increase the Company's annual production to 3,200 boe/d with funds flow from operations estimated at $40 million. The Company expects year-end 2014 net debt of $55 million resulting in a debt to annual cash flow ratio of 1.4 to 1.0. The budget assumes an average price of US$95.00/bbl for WTI crude oil (CDN$85.00/bbl Edmonton par) and an average price of $3.00/GJ for AECO natural gas.

Decommissioning Liabilities

As at December 31, 2013, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $8,745,195 for which $5,497,222 has been recorded using a discount rate of 1.80% - 3.24%, 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, 2013 and 2012, the Company was charged or invoiced the following amounts by certain of its officers and directors through controlled companies:

	2013 Q4	2013 Q3	2012 Q4	Year Ended 2013	Year Ended 2012
Administration and consulting fees	$ 318,008	$ 88,500	$ 52,997	$ 540,043	$ 194,960
Production and capital expenditures	27,071	52,033	57,769	203,023	137,846
	$ 345,078	$ 140,533	$ 110,766	$ 743,065	$ 332,806

Included in accounts payable and accrued liabilities at December 31, 2013 is $7,727 (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 $328,545 (December 31, 2012 - $361,411) held in the name of an officer of the Company for a property that is used as a field office. The Company is the beneficial owner through a trust agreement of the property against which the mortgage is secured. All mortgage payments are made by the Company.

Share Capital

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

	Common Shares	Warrants	Stock Options
Balance - December 31, 2012	**121,711,723**	**1,420,000**	**11,840,000**
Equity Financing	25,005,285	-	-
Grant of options	-	-	2,540,000
Forfeiture of options	-	-	(2,965,000)
Exercise of options	400,000	-	(400,000)
Expiry of options	-	-	(380,000)
Balance - December 31 2013	**147,117,008**	**1,420,000**	**10,635,000**
Grant of Options	-	-	1,500,000
Exercise of options	825,000	-	(825,000)
Balance - Date of MD&A	**147,942,008**	**1,420,000**	**11,310,000**

Contingency

In December 2009, the Company terminated the Standstill Agreement that it had with an industry partner regarding a joint producing property and served that industry partner with a Statement of Claim issued from The Court of Queen's Bench of Alberta, by which the Company claims breach of the agreements between the parties, gross negligence and default of operator. The Company seeks judgment for specified and such further damages to be determined by the Court, as well as appointment as operator. The Company increased the statement of claim based on the information provided by the defendant. The potential outcome of the lawsuit and claims are undetermined, however, they could be material.

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

Commitments

The Company has until December 31, 2014 to incur $5 million of qualifying CEE flow-through expenditures related to CEE flow-through shares issued in December 2013. The Company has satisfied its full CDE commitment related to the CDE flow-through shares issued in December 2013 as at December 31, 2013.

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

2014	$	241,277
2015	$	241,277
2016	$	241,277

Financial Instruments and Financial Risk Management

The Company's financial instruments include accounts receivable, accounts payable and accrued liabilities, bank debt, subordinated debt, other long term liability, interest rate contracts 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 of commodity contracts and interest rate 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 December 31, 2013, the maximum credit exposure is the carrying amount of the accounts receivable of $8,846,547 (December 31, 2012 – $8,398,042).

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

Oil and natural gas marketers	$	2,685,431
Joint venture partners		4,230,898
Other		1,930,218
	$	8,846,547

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 January and February 2014.

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, 2013. The Company would only choose to write-off a receivable balance after all reasonable avenues of collection had been exhausted.

As at December 31, 2013, the Company considers its receivables to be aged as follows:

Not past due	$	5,129,602
Past due by less than 90 days		85,002
Past due by more than 90 days		3,631,943
	$	8,846,547

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 balance based on their maturity dates.

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 and subordinated 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, 2013, if interest rates had been 1% lower with all other variables held constant, income for the period would have been $308,150 (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 December 31, 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 and debt:

	December 31, 2013	*December 31, 2012*
Shareholders' equity	$ 95,583,587	$ 79,689,765
Bank debt	$ 32,112,455	$ 32,138,763
Subordinated debt	$ 7,786,632	$ -

The Company monitors capital based on annual funds flow 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 factors that influence commodity prices and funds flow 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 funds flow 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, 2013, the Company's capital structure was not subject to external restrictions. No changes have been made to the capital policy since 2012.

Selected Historical Financial Information

	2013 Q4($)	2013 Q3($)	2013 Q2($)	2013 Q1($)
Petroleum and natural gas sales	**11,087,956**	9,372,931	7,747,389	6,518,381
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	**0.01**	0.00	0.02	0.00
Net income (loss) per share – diluted	**0.01**	0.00	0.02	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	**0.06**	0.05	0.05	0.04
Funds flow from operations per share –diluted	**0.06**	0.05	0.05	0.04
Net capital expenditures	**22,920,532**	8,567,226	3,708,601	11,262,592

	2012 Q4($)	2012 Q3($)	2012 Q2($)	2012 Q1($)
Petroleum and natural gas sales	4,842,343	4,311,738	5,265,664	6,907,412
Net petroleum and natural gas revenue	5,055,666	4,311,406	5,627,535	7,299,772
Net loss	340,623	(2,073,174)	3,305,628	(1,790,789)
Net loss per share – basic	0.00	(0.02)	0.03	(0.02)
Net loss per share – diluted	0.00	(0.02)	0.03	(0.02)
Funds flow from operations	3,168,328	2,780,520	3,493,003	5,146,554
Funds flow from operations per share – basic	0.03	0.02	0.03	0.04
Funds flow from operations per share –diluted	0.03	0.02	0.03	0.04
Net capital expenditures	4,537,364	4,679,623	3,006,024	7,575,520

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.

Fourth Quarter Activities

Fourth quarter 2013 production of 2,764 boe/d an increase of 63% compared to the 1,700 boe/d in the comparable period in 2012. Petroleum and natural gas sales and funds flow from operations increased by 129% and 158%, respectively, when compared to 2012. The increase is due to the 63% increase in production and a 42% increase in operating netbacks. Production in the month of December 2013 averaged 3,000 boe/d.

Capital expenditures were $23 million in the fourth quarter of 2013 compared to $4.5 million in the same period in 2012. The increased capital is due to increased drilling activity, increased working interests due to the property swap that was closed in the quarter and land purchases.

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

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

Critical Accounting Estimates

The preparation of the 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.

Critical judgments in applying accounting policies

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.

Key sources of estimation uncertainty

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.