Yangarra Resources Ltd.

Management's Discussion and Analysis

For three and six months ended June 30, 2018

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, 2017 audited consolidated financial statements and the June 30, 2018 unaudited consolidated financial statements, together with the accompanying notes.

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

The MD&A has been prepared using information that is current to August 8, 2018.

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 flow from (used in) operations", which is an additional IFRS measure. The Company uses funds flow generated from (used in) 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 or adjusted working capital (deficit)" 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 operations

Yangarra's determination of funds flow from operations and funds flow from operations per share may not be comparable to that reported by other companies. Management uses funds flow from operations to analyze operating performance and leverage, and considers funds flow from 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 operations is calculated using cash from operating activities before changes in non-cash working capital and decommissioning costs incurred. Yangarra presents funds flow from 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 operations to cash from operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Cash from operating activities	$ 16,288,319	$ 9,241,194	$ 31,277,247	$ 17,851,607
Changes in non-cash working capital	716,394	2,806,476	4,365,415	4,539,267
Funds flow from operations	$ 17,004,713	$ 12,047,670	$ 35,642,662	$ 22,390,874

Netbacks

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.

Net debt or adjusted working capital (deficit)

Net debt or adjusted 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 adjusted working capital (deficit).

Adjusted earnings before interest, taxes, depletion & depreciation, amortization

Adjusted earnings before interest, taxes, depletion & depreciation, amortization ("Adjusted EBITDA") which represents EBITDA, excluding changes in derivative financial instruments are used to assess efficiency, liquidity and the general financial strength of the Company.

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

Second Quarter 2018 Highlights

- Reached 10,000 boe/d of production at the end of the quarter.
- Average production of 7,570 boe/d (60% liquids) during the quarter an increase of 1% from the first quarter of 2018 and 33% increase from the same period in 2017.
- Oil and gas sales were $29.9 million, an increase of 53% from the same period in 2017.
- Funds flow from operations of $17.0 million ($0.20 per share - basic), an increase of 41% from the same period in 2017.
- Adjusted EBITDA (which excludes changes in derivative financial instruments) was $16.6 million ($0.20 per share - basic).
- Net income of $1.6 million ($0.02 per share - basic) or $2.6 million net income before tax.
- Operating costs were $7.72/boe (including $1.31/boe of transportation costs).
- Field netbacks were $31.82 per boe.
- Operating netbacks, which include the impact of commodity contracts, were $26.64 per boe.
- Operating margins were 61% and cash flow margins were 57%.
- G&A costs of $0.56/boe.
- Royalties were 9% of oil and gas revenue.
- Total capital expenditures were $26 million.
- Commissioned the 20 mmcf/d Ferrier West facility together with the Company's third oil treating facility.
- Net debt (which excludes current derivative financial instruments) was $115.1 million.
- Net Debt to annualized second quarter funds flow from operations was 1.69:1.
- Corporate LMR is 8.78, with decommissioning liabilities of $11.4 million (discounted).

<u>Operations Update</u>

Yangarra has now drilled a total of 42 bioturbated Cardium wells. IP 30 results for wells 21-30 had a 10% improvement from wells 11-20 and a 25% improvement from wells 1-10 (all wells adjusted for lateral length).

The Company resumed drilling operations in late May and drilled 5 gross/net wells in the second quarter consisting of 3 two-mile and 2 one-mile horizontal wells. The Q2 drilling program included various inter-frack spacings on pads ranging from 60-96 stages per mile which will be compared to the current standard 80 stages per mile to assist with determining optimal frack spacing.

As a result of continuously improving drilling and production results, Yangarra continues to update future drilling inventory. The Company's Cardium type curve is the weighted average of all future inventory in all areas of the Cardium portfolio. Current inventory is estimated at 913 gross (716 net) locations (1-mile wells). Based on current inventory, drilling with 2 rigs year-round other than breakup, Yangarra estimates it has 16 years (net) of future inventory. In 2018, the Company added 17 sections of Cardium land.

Financial Information

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Statements of Comprehensive Income				
Petroleum & natural gas sales	$ 29,922,471	$ 19,527,395	$ 59,672,187	$ 35,076,783
Net income (before tax)	$ 2,604,506	$ 7,893,731	$ 10,651,217	$ 15,235,464
Net income	$ 1,646,498	$ 5,611,218	$ 7,304,557	$ 10,827,763
Net income per share - basic	$ 0.02	$ 0.07	$ 0.09	$ 0.13
Net income per share - diluted	$ 0.02	$ 0.07	$ 0.08	$ 0.13
Statements of Cash Flow				
Funds flow from operations	$ 17,004,713	$ 12,047,670	$ 35,642,663	$ 22,390,874
Funds flow from operations per share - basic	$ 0.20	$ 0.15	$ 0.42	$ 0.28
Funds flow from operations per share - diluted	$ 0.19	$ 0.14	$ 0.41	$ 0.27
Cash from operating activities	$ 16,288,319	$ 9,241,194	$ 31,277,247	$ 17,851,606
Statements of Financial Position				
Property and equipment	$ 387,733,694	$ 299,963,241	$ 387,733,694	$ 299,963,241
Total assets	$ 430,520,160	$ 326,865,302	$ 430,520,160	$ 326,865,302
Working capital deficit	$ 18,600,280	$ 69,864,913	$ 18,600,280	$ 69,864,913
instruments)	$ 115,118,849	$ 72,674,034	$ 115,118,849	$ 72,674,034
Non-Current Liabilities, excluding bank debt	$ 51,546,663	$ 39,580,252	$ 51,546,663	$ 39,580,252
Shareholders equity	$ 224,991,440	$ 197,280,541	$ 224,991,440	$ 197,280,541
Weighted average number of shares - basic	85,019,808	80,555,880	83,958,696	80,264,589
Weighted average number of shares - diluted	87,782,665	84,065,109	86,406,125	83,388,671

Business Environment

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Realized Pricing (Including realized commodity contracts)				
Oil ($/bbl)	$ 71.34	$ 63.69	$ 69.89	$ 63.97
NGL ($/bbl)	$ 31.71	$ 29.14	$ 35.56	$ 29.51
Gas ($/mcf)	$ 1.16	$ 3.00	$ 1.69	$ 3.08
Realized Pricing (Excluding commodity contracts)				
Oil ($/bbl)	$ 80.03	$ 62.63	$ 75.95	$ 63.39
NGL ($/bbl)	$ 40.38	$ 27.85	$ 42.51	$ 28.89
Gas ($/mcf)	$ 1.16	$ 2.89	$ 1.69	$ 2.97
Oil Price Benchmarks				
West Texas Intermediate ("WTI") (US$/bbl)	$ 67.88	$ 48.29	$ 65.37	$ 50.10
Edmonton Par (C$/bbl)	$ 80.54	$ 61.92	$ 76.25	$ 62.95
Edmonton Par to WTI differential (US$/bbl)	$ (5.46)	$ (2.20)	$ (5.67)	$ (2.89)
Natural Gas Price Benchmarks				
AECO gas (Cdn$/mcf)	$ 1.03	$ 2.78	$ 1.44	$ 2.79
Foreign Exchange				
U.S./Canadian Dollar Exchange	$ 0.78	$ 0.74	$ 0.78	$ 0.75

Crude oil prices increased by 41% for the three months ended June 30, 2018, with the West Texas Intermediate ("WTI") reference price averaging US$67.88/bbl compared with US$48.29/bbl in the same period in 2017. For the six months ended June 30, 2018 WTI prices were up 30% averaging US$65.37/bbl. 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 widened in the three months ended June 30, 2018 when compared to the same period in 2017, moving from a US$2.20/bbl differential in 2017 to US$5.46/bbl in 2018. In the six months ended June 30, 2018 Edmonton par differentials widened from US$2.89/bbl to US$5.67/bbl.

In the three months ended June 30, 2018 the US/CDN foreign exchange rate was 0.78 compared to 0.74 for the same period in 2017 and was 0.78 for the six months ended June 30, 2018 compared to 0.75 for the same period in 2017. 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 therefore is the closest proxy to realized pricing.

When compared to the three and six months ended June 30, 2017, realized pricing on oil increased by 28% and 20%, respectively, excluding commodity contracts, and increased by 12% and increased by 9%, respectively when the effects of commodity contracts are included. The increase in oil pricing is a direct result of increased WTI pricing.

When compared to the three and six months ended June 30, 2017, liquids pricing increased by 9%, and 20%, respectively, excluding commodity contracts, and increased by 45% and 47%, respectively, when the effects of commodity contracts are included.

During the six months ended June 30, 2018, Yangarra had contracted 500 bbl/d in costless collars with a floor of C$62.50 WTI/bbl and an average ceiling of C$76.00 WTI/bbl. 2,400 bbl/day of oil production was hedged utilizing WTI fixed price contracts at an average price of C$74.28 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 decreased for the three and six months ended June 30, 2018 by 63% to $1.03/mcf and by 48% to $1.44/mcf.

When compared to the three and six months ended June 30, 2017, realized pricing on natural gas decreased by 60% and 43%, respectively.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Daily production volumes				
Natural gas (mcf/d)	18,336	15,586	18,436	13,315
Oil (bbl/d)	3,162	2,281	3,252	2,060
NGL's (bbl/d)	1,353	826	1,214	818
Combined (boe/d 6:1)	7,570	5,705	7,539	5,097
Revenue				
Petroleum & natural gas sales - Gross	$ 29,922,471	$ 19,527,395	$ 59,672,187	$ 35,076,783
Realized gain (loss) on commodity contract settlement	(3,569,273)	477,734	(5,091,298)	563,652
Total sales	26,353,198	20,005,129	54,580,889	35,640,435
Royalty expense	(2,684,294)	(1,487,371)	(5,485,515)	(2,718,546)
Total Revenue - Net of royalties	$ 23,668,904	$ 18,517,758	$ 49,095,374	$ 32,921,889

Total sales in Q2 2018 increased by 53% in 2018 to $26.4 million from $20.0 million in the same period 2017. The increase is attributable to:

- a 15% increase in average product prices
- a 33% increase in production (on a boe basis)
- $3.6 million loss from commodity contract settlement in 2018 compared to a $0.5 million in gain 2017.

Total sales in the six months ended June 30, 2018 increased by 70% to $54.6 million from $35.6 million in the same period 2017. The increase is attributable to:

- A 15% increase in average product prices; and
- a 48% increase in production (on a boe basis)
- $5.1 million loss from commodity contract settlement in 2018 compared to a $0.6 million gain in 2017.

The increased production in 2018 can be attributed to the 2017/2018 drilling program, 16 wells were drilled in 2017 and 15 additional wells were drilled in 2018.

Company Netbacks ($/boe)

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Sales price	$ 43.43	$ 37.61	$ 43.73	$ 38.02
Royalty expense	(3.90)	(2.86)	(4.02)	(2.95)
Production costs	(6.40)	(8.26)	(6.40)	(7.70)
Transportation costs	(1.31)	(0.73)	(1.48)	(0.82)
Field operating netback	**31.82**	**25.76**	**31.83**	**26.55**
Realized gain (loss) on commodity contract settlement	(5.18)	0.92	(3.73)	0.61
Operating netback	**26.64**	**26.68**	**28.10**	**27.16**
G&A	(0.56)	(0.92)	(0.56)	(0.74)
Finance expenses	(1.39)	(1.95)	(1.34)	(1.79)
Funds flow netback	**24.69**	**23.81**	**26.19**	**24.63**
Depletion and depreciation	(10.00)	(10.68)	(10.04)	(10.75)
Accretion	(0.08)	(0.09)	(0.07)	(0.10)
Stock-based compensation	(1.95)	(0.71)	(1.59)	(0.76)
Unrealized gain (loss) on financial instruments	(8.87)	2.88	(6.69)	3.50
Deferred income tax	(1.39)	(4.40)	(2.45)	(4.78)
Net Income netback	**$ 2.39**	**$ 10.81**	**$ 5.35**	**$ 11.74**

The overall average price earned by the Company was higher when compared to the three months ended June 30, 2017 as natural gas prices decreased by 61%, oil prices increased by 12% and liquid prices increased by 9%. The average sales price increased by 15% for the three months ended June 30, 2018 when compared to 2017.
Operating netbacks were flat for the three months ended June 30, 2018 and increased by 4% for the six months ended June 30, 2018 when compared to the same periods in 2017 with higher realized pricing.

Field netbacks increased by 24% for the three months ended March 31, 2018 and increased by 20% for the six months ended June 30, 2018 due to realized losses from hedges in 2018.

Royalty Expense

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Royalty expense	$ 2,684,294	$ 1,487,371	$ 5,485,515	$ 2,718,546
Per boe	$ 3.90	$ 2.86	$ 4.02	$ 2.95
As a % of sales (including commodity contracts)	10%	7%	10%	8%
As a % of sales (excluding commodity contracts)	9%	8%	9%	8%

Royalties increased to $2.7 million for the three months ended March 31, 2018 or 9% as a percentage of sales (excluding commodity contact settlements). For the six months ended June 30, 2018 royalties increased to $5.5 million or 9% as a percentage of sales. The increase is a result of pricing increases during 2018 and additional royalties being paid to partners on a variety of new farm-in deals.

Alberta implemented a Modernized Royalty Framework effective January 1, 2017. The new framework uses a revenue minus cost royalty structure across all hydrocarbons. A Company will pay a flat royalty rate of 5% on a well's early production until the well's revenue exceeds the Drilling and Completion Cost Allowance ("C*"). C* is based on average industry drilling and completion costs.

Production and Transportation Costs

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Production costs	$ 4,409,906	$ 4,287,197	$ 8,735,099	$ 7,107,936
Per boe	$ 6.40	$ 8.26	$ 6.40	$ 7.70
Transportation costs	$ 905,625	$ 377,071	$ 2,018,405	$ 755,166
Per boe	$ 1.31	$ 0.73	$ 1.48	$ 0.82
Combined ($/boe)	$ 7.72	$ 8.98	$ 7.88	$ 8.52

Production and transportation costs decreased by 14% on a per boe basis when compared to the three months ended June 30, 2017 and decreased by 8% on a per boe basis when compared to the six months ended June 30, 2018, due to increased production combined with improved efficiency in the field.

Yangarra now has eight Company owned trucks and four maintenance trucks which reduce the reliance on third-party trucking, maintenance crews and pressure pumping. Yangarra has 51.0 mmcf/d of compression capacity in 4 plants and 3 oil treating facilities capable of handling 12,500 bbl/d in Central Alberta.

Depletion and depreciation

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Depletion and depreciation	$ 6,892,614	$ 5,545,571	$ 13,693,380	$ 9,922,313
Per boe	$ 10.00	$ 10.68	$ 10.04	$ 10.75
Asset impairment	$ -	$ -	$ -	$ -

Depletion and depreciation increased in the three and six months ended June 30, 2018 due to increases in production. On a per boe basis, depletion decreased when compared 2017 due to lower finding and development costs in 2018.

General and administrative expenses ("G&A")

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Gross G&A expenses	$ 701,499	$ 606,425	$ 1,533,046	$ 1,234,122
G&A recoveries	(313,368)	(127,959)	(762,989)	(550,987)
Net G&A expenses	$ 388,131	$ 478,466	$ 770,057	$ 683,135
Per boe	$ 0.56	$ 0.92	$ 0.56	$ 0.74

G&A decreased by 19% on a net basis and increased by 16% on a gross basis when compared to three months ended June 30, 2017 due to increased costs reduced by higher recoveries. When compared to the six months ended June 30, 2017 G&A decreased by 24% on a net basis and increased by 24% on a gross basis due to higher recoveries from an increased drilling program.

On a boe basis, for the three and six months ended June 30, 2018 G&A decreased by 39% and 24% due to increased production in 2018 and higher recoveries.

Other expenses

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Finance				
Interest and Finance Expense	$ 938,058	$ 1,258,866	$ 1,874,660	$ 1,848,446
Realized loss on interest rate contract settlement	22,471	68,488	54,490	136,333
Change in fair value of interest rate contracts	(65,082)	(316,561)	(224,866)	(331,309)
Accretion of decommissioning liability	55,134	47,801	102,008	93,375
Accretion of debt issue costs	61,811	-	122,895	-
	$ 1,012,392	$ 1,058,594	$ 1,929,187	$ 1,746,845
Share-based compensation	$ 1,344,757	$ 369,869	$ 2,165,020	$ 701,012

Interest and financing fees for the three and six months ended June 30, 2018 include interest on the revolving operating demand loan (the average amount drawn in 2018 was $95 million), servicing charges on the demand loan and the change in fair value of the interest rate contracts.

The Company had the following interest rate contracts in place at June 30, 2018:

- Pay a floating rate to receive a 1.945% (plus a 2.50% credit spread) fixed rate on $10 million (June 2018-November 2023)
- Pay a floating rate to receive a 1.935% (plus a 2.50% credit spread) fixed rate on $10 million (May 2018-November 2023)

The fair value on the interest rate contracts was in a gain position of $480,859 as at June 30, 2018 (December 31, 2017 –$255,993).

During the six months ended June 30, 2018, the Company granted options to purchase 4,010,180 common shares, 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 $10,141,050 ($2.53 per option) using the Black-Scholes option pricing model.

Deferred Taxes

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Deferred income tax expense	$ 958,008	$ 2,282,513	$ 3,346,660	$ 4,407,701

Yangarra did not pay income taxes in 2017 and does not expect to pay income taxes in 2018 as it has sufficient tax pools to cover taxable income.

Commodity price risk contracts

	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Realized gain (loss) on commodity contract settlement	$ (3,569,273)	$ 477,734	$ (5,091,298)	$ 563,652
Change in fair value of commodity contracts	(6,110,973)	1,492,741	(9,133,010)	3,229,981
	$ (9,680,246)	$ 1,970,475	$ (14,224,308)	$ 3,793,633

As at June 30, 2018 the Company was committed to the following commodity price risk contracts in place:

Year	Volume	Term	Reference	Type	Strike Price
Oil					
2018	200 bbl/d	Jan to Dec	CDN$ WTI	Collar	CDN$ 62.50/bbl-75.90/bbl
2018	300 bbl/d	Jul to Dec	US$ WTI	Collar	US$ 55.00/bbl-64.40/bbl
2018	300 bbl/d	Jan to Dec	CDN$ WTI	Swap	CDN$ 71.60/bbl
2018	200 bbl/d	Jan to Dec	US$ WTI	Sold Call	US$ 70.00/bbl
2018	300 bbl/d	Mar to Dec	CDN$ WTI	Swap	CDN$ 78.20/bbl
2018	300 bbl/d	Apr to Dec	CDN$ WTI	Swap	CDN$ 80.15/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Sold Call	CDN$ 75.17/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Swap	CDN$ 75.40/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Swap	CDN$ 75.40/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Swap	CDN$ 76.00/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Swap	CDN $81.05/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Swap	CDN $89.85/bbl
2019	300 bbl/d	Jan to Jun	CDN$ WTI	Swap	CDN $84.75/bbl
2019	300 bbl/d	Jan to Jun	CDN$ WTI	Swap	CDN $85.45/bbl
2020	1,250 bbl/d	Jan to Dec	US$ WTI	Sold Call	USD$ 65.00/bbl
Propane					
2018	200 bbl/d	Jan to Dec	Conway - C3	Swap	USD $32.34
Natural Gas					
2018	200 bbl/d	Jul to Oct	CDN$ AECO	Swap	CDN $1.55/GJ

The fair value of the commodity contracts was in a loss position of $12,640,871 as at June 30, 2018 (December 31, 2017 – $3,507,861).

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at March 31, 2018 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 in commodity prices is a reasonable measure ($6.50/bbl for oil). Fluctuations in commodity prices potentially could have resulted in unrealized gains (losses) impacting income before tax as follows:

	Impact on Income Before Tax	
	Increase 10%	Decrease 10%
Crude oil	$ (9,440,364)	$ 9,681,911

Liquidity and Capital Resources

The following table summarizes the change in working capital during the six months ended June 30, 2018 and the year ended December 31, 2017:

	2018	2017
Net Debt - beginning of period	$ (93,533,252)	$ (65,005,805)
Funds flow from operations	35,642,662	52,902,650
Additions to property and equipment	(57,322,323)	(83,472,094)
Decommissioning costs incurred	-	(95,433)
Additions to E&E Assets	(6,520,031)	-
Issuance of shares	6,758,792	2,179,593
Other	(144,697)	(42,163)
Net Debt - end of period	$ (115,118,849)	$ (93,533,252)
Credit facility limit	$ 150,000,000	$ 120,000,000

On April 6, 2018 the syndicated credit facility was increased to $150 million and the maturity date was extended to May 29, 2020.

As at June 30, 2018, the maximum amount available under the syndicated credit facility was $150 million (2017 – $100 million) comprised of a $140 million (2017 – $90 million) extendible revolving term credit facility and a $10 million (2017 – $10 million) operating facility. The amount available under these facilities is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions (the "Borrowing Base"). If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay any shortfall. The maturity date of the facility is May 29, 2020 (the "Maturity Date") and the next Borrowing Base review is scheduled for November 30, 2018. The Maturity Date may be extended for 364 day periods pursuant to delivery of a request for extension by the Company within certain time periods specified in the syndicated credit facility agreement.

As at June 30, 2018, the $105,540,972 (December 31, 2017 – $84,886,124) reported amount of bank debt was comprised of $1,079,550 (December 31, 2017 – nil) drawn on the operating facility, $104,685,647 (December 31, 2017 – $84,821,111) drawn on the extendible revolving term credit facility in bankers' acceptance and net of unamortized transaction costs of $224,225 (December 31, 2017 – $347,119).

The Company is subject to a single 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 obligation). The Company was in compliance with this covenant as at June 30, 2018 and December 31, 2017. The facility is secured by a general security agreement over all assets of the Company.

The total standby fees range, depending on the debt to EBITDA ratio, between 100 bps to 250 bps on bank prime borrowings and between 200 bps and 350 bps on bankers' acceptances. The undrawn portion of the credit facility is subject to a standby fee in the range of 50 bps to 87.5 bps. During the six months ended June 30, 2018, the weighted average effective interest rate for the bank debt was approximately 3.89% (2017 – 3.86%).

The Company intends to fund the 2018 budget with cash flow from operations and the availability on the revolving operating demand loan.

Capital Spending

Cash additions	2018 Q2	2017 Q2	Six months ended 2018	Six months ended 2017
Land, acquisitions and lease rentals	$ 92,348	$ 1,726,569	$ 149,490	$ 2,497,484
Drilling and completion	19,519,585	4,299,243	46,291,097	23,963,628
Geological and geophysical	199,680	284,010	338,771	427,802
Equipment	6,112,877	1,382,772	10,453,838	4,293,044
Other asset additions	85,687	208,438	89,126	215,336
	$ 26,010,177	$ 7,901,032	$ 57,322,322	$ 31,397,294
Exploration & evaluation assets	$ 1,471,820	$ -	$ 6,520,031	$ -

Capital spending is summarized as follows:

Total wells drilled in the half were 15 gross (13.2 net) consisting of 8 gross (7.7 net) two-mile wells and 7 gross (5.5 net) one-mile wells. The two wells drilling over year-end 2017 were completed in January 2018. The Ferrier West plant was constructed in the second quarter.

Outlook

The Board of Directors approved an increase in the capital budget from $90 million to $120 million for 2018. This budget will allow the Company to continue to utilize 2 drilling rigs which optimizes drilling operations and provides economies of scale.

As the additional spending will occur in the fourth quarter, the existing guidance of 9,000 - 10,000 boe/d average production for 2018 remains unchanged.

Yangarra estimates that 22 gross (19 net) wells will be put on production during the second half of 2018, including wells drilled in the first half of 2018 but expected to be completed in the second half of 2018.

Decommissioning Liabilities

As at June 30, 2018, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $13,733,438 for which $11,376,406 has been recorded using a discount rate of 2.02% - 2.23%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 10 years.

Off Balance Sheet Arrangements

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

Share Capital

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

	Common Shares	Stock Options
Balance - December 31, 2017	81,378,490	7,863,861
Grant of options	-	4,010,180
Forfeited options	-	(74,167)
Exercise of options	3,952,403	(3,952,403)
Balance - June 30, 2018	85,330,893	7,847,471

Contingency

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.

Contractual Obligations and Commitments

As at June 30, 2018 the contractual maturities of the Company's obligations are as follows:

	Carrying Amount	Contractual Cash Flows	Less than 1 year	1-2 Years	2-5 Years
Accounts payable and accrued liabilities	39,269,067	39,269,067	39,269,067	-	-
Bank debt	105,540,972	105,765,197	-	105,765,197	-
Other long-term liabilities	147,996	147,996	44,965	46,856	56,175
Commodity contracts	12,702,392	12,702,392	9,172,018	3,530,374	-
	157,660,427	157,884,652	48,486,050	109,342,427	56,175

The Company has entered into lease agreements for office premises and Company vehicles with payments as follows:

2018	$ 307,036
2019	$ 580,904
2020	$ 546,491
2021	$ 333,807
Thereafter	$ 167,824

Financial Instruments and Financial Risk Management

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

a. Credit risk

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

Purchasers of the Company's natural gas and liquids are subject to credit review to minimize the risk of non-payment. As at June 30, 2018, the maximum credit exposure is the carrying amount of the accounts receivable of $25,492,207 (December 31, 2017 – $26,413,976). The maximum exposure to credit risk for accounts receivable as at June 30, 2018 and December 31, 2017 by type of customer was:

	June 30, 2018	December 31, 2017
Natural gas and liquids marketers	$ 12,017,051	$ 12,737,640
Partners on joint operations	10,212,998	11,159,533
Realized commodity contracts	–	67,093
Other	3,262,158	2,449,710
	$ 25,492,207	$ 26,413,976

Receivables from natural gas and liquids marketers are typically collected on the 25th day of the month following production. The Company has mitigated the credit risk associated with the natural gas and liquids marketer through a security arrangement with Computershare. The Company historically has not experienced any significant collection issues with its natural gas and liquids marketers. The majority of the revenue accruals and receivables from natural gas and liquids marketers were received in July 2018.

Receivables from partners on joint operations are typically collected within one to three months of the bill being issued to the partner. The Company mitigates the risk from receivables from partners on joint operations 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 partners on joint operations as disagreements occasionally arise which increases the potential for non-collection. For properties that are operated by the Company, production can be withheld from partners on joint operations who are in default of amounts owing. In addition, the Company often has offsetting amounts payable to partners on joint operations from which it can net receivable balances.

As at June 30, 2018 and December 31, 2017, the Company considers its receivables to be aged as follows:

	June 30, 2018	December 31, 2017
Under 30 days	$ 14,876,641	$ 17,449,229
30 to 60 days	1,710,649	2,003,025
60 to 90 days	356,745	168,871
Over 90 days	8,548,172	6,792,851
	$ 25,492,207	$ 26,413,976

89% of the over 90-day receivables are made up of two industry partners. The Company has performed an analysis of each partner's financial situation and have determined they have the ability to pay. Included in the over 90-day receivables are balances with a significant portion in dispute with two of the industry partners (see note 15). The Company did not provide for any doubtful accounts nor write-off any accounts receivable during the six months ended June 30, 2018.

Risk management assets and liabilities consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. During 2018 and 2017, the Company did not experience any collection issues with risk management contracts. The Company typically does not obtain or post collateral or security from its oil and natural gas marketers or financial institution counterparties. The carrying amounts of accounts receivable represent the maximum credit exposure.

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 and availability on bank facilities. The Company's financial liabilities are comprised of accounts payable and accrued liabilities, interest rate contracts, commodity contracts, other long-term liabilities and bank debt, which are classified as current or non-current on the consolidated statement of financial position based on their maturity dates.

The Company has been funding the 2018 budget with cash flow from operations and the $44 million available on credit facility (see note 5).

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 six months ended June 30, 2018, if interest rates (including the effect of the interest rate contract) had been 1% lower with all other variables held constant, income for the period would have been $ 456,942 (2017 - $345,694) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amount.

ii. Currency risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. All of the Company's petroleum and natural gas sales are denominated in Canadian dollars, however, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. The Company had no outstanding forward exchange rate contracts in place at June 30, 2018.

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 dollar and United States dollar, as outlined above

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:

	June 30, 2018	*December 31,2017*
Shareholders' equity	$ 224,991,440	$ 207,956,624
Bank debt	$ 105,540,972	$ 85,233,243

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 debt available from the Company's lender, the level of bank debt 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 required and if available on favorable terms. At June 30, 2018, the Company's capital structure was subject to the banking covenants disclosed in note 5. No changes were made to the capital policy in 2018.

Selected Quarterly Financial Information

	2018 Q2($)	2018 Q1($)	2017 Q4($)	2017 Q3($)
Petroleum & natural gas sales	29,922,471	29,749,716	25,172,383	17,663,925
Net income (loss)	1,646,498	5,658,059	4,681,958	3,975,606
Net income (loss) per share – basic	0.02	0.07	0.06	0.05
Net income (loss) per share – diluted	0.02	0.07	0.05	0.05
Funds flow from operations	17,004,713	18,637,949	17,563,628	12,948,149
Funds flow from operations per share – basic	0.20	0.22	0.22	0.16
Funds flow from operations per share –diluted	0.20	0.22	0.20	0.15
Net capital expenditures (including E&E)	27,481,997	36,360,357	31,164,275	20,910,525

	2017 Q2($)	2017 Q1($)	2016 Q4($)	2016 Q3($)
Petroleum & natural gas sales	19,527,395	15,549,388	11,149,691	5,988,310
Net income (loss)	5,611,218	5,216,545	(339,197)	(470,783)
Net income (loss) per share – basic	0.07	0.07	(0.00)	(0.01)
Net income (loss) per share – diluted	0.07	0.06	(0.00)	(0.01)
Funds flow from operations	12,047,670	10,343,203	6,781,301	3,331,966
Funds flow from operations per share – basic	0.15	0.13	0.09	0.04
Funds flow from operations per share –diluted	0.14	0.12	0.09	0.04
Net capital expenditures	7,901,032	23,496,262	13,672,922	10,436,072

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 and declines tied to the timing of drilling activity. The Company has focused capital expenditures on drilling and completions. Production has grown steadily, with significant increases starting with the fourth quarter of 2016 due to a positive change in the productivity of new 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

As at June 30, 2018, an evaluation of the effectiveness of the Company's disclosure controls and procedures, as defined under the rules adopted by the Canadian securities regulatory authorities, was carried out under the supervision and with the participation of Management, including the President and Chief Executive Officer ("CEO"), and the Chief Financial Officer ("CFO"). Based on this evaluation, the CEO and CFO concluded that, as at June 30, 2018, the design and operation of the Company's disclosure controls and procedures were effective to provide reasonable assurance in meeting all regulatory filing requirements.

Internal control over financial reporting means a process designed by, or under the supervision of, an issuer's certifying officers, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's Generally Accepted Accounting Procedures ("GAAP") and includes those policies and procedures that:

(a) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;

(b) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and

(c) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial reports;

Management is responsible for establishing and maintaining adequate internal controls over financial reporting.

Management has conducted an evaluation of its internal controls over financial reporting, and determined that at June 30, 2018 the controls were effective to provide reasonable assurance regarding the reliability of financial reporting, and the preparation of financial statements for external reporting purposes. In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") issued an updated Internal Control-Integrated Framework ("2013 Framework") replacing the Internal Control - Integrated Framework (1992). The control framework Yangarra's officers used to design the Company's ICFR is the 2013 Framework.

During the period beginning on April 1, 2018 and ended on June 30, 2018, there were no material changes to the Company's internal controls over financial reporting, and the CEO and CFO have filed certifications with the Canadian securities regulators regarding the Company's 2018 public filing documents.

New Accounting Standards

<u>IFRS 15 Revenue from Contracts with Customers ("IFRS 15")</u>

Effective January 1, 2018, the Company adopted IFRS 15 on a modified retrospective basis. The standard supersedes IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations.

The Company principally generates revenue from the sale of commodities, which include crude oil and natural gas. Revenue associated with the sale of commodities is recognized when control is transferred from the Company to its customers. The Company's commodity sale contracts represent a series of distinct transactions. The Company considers its performance obligations to be satisfied and control to be transferred when all the following conditions are satisfied:

- The Company has transferred title and physical possession of the commodity to the buyer;
- The Company has transferred significant risks and rewards of ownership of the commodity to the buyer; and
- The Company has the present right to payment.

Revenue is measured based on the consideration specified in a contract with the customer. Payment terms for the Company's commodity sales contracts are on the 25th of the month following delivery. The Company does not have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a result, the Company does not adjust its revenue transactions for the time value of money. Revenue represents the Company's share of commodity sales net of royalty obligations to governments and other mineral interest owners.

The Company enters into contracts with customers that can have performance obligations that are unsatisfied (or partially unsatisfied) at the reporting date. The Company applies a practical expedient of IFRS 15 and does not disclose information about remaining performance obligations that have original expected durations of one year or less, or for performance obligations where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance completed to date.

Contract modifications with the Company's customers could change the scope of the contract, the price of the contract, or both. A contract modification exists when the parties to the contract approve the modification either in writing, orally, or based on the parties' customary business practices. Contract modifications are accounted for either as a separate contract when there is an additional product at a stand-alone selling price, or as part of the existing contract, through either a cumulative catch-up adjustment or prospectively over the remaining term of the contract, depending on the nature of the modification and whether the remaining products are distinct.

In its modified retrospective adoption of IFRS 15, the Company applied a practical expedient that allows the Company to avoid re-considering the accounting for any sales contracts that were completed prior to January 1, 2018 and were previously accounted for under its previous revenue accounting policy.

The adoption of IFRS 15 did not result in any adjustments to the amounts recognized in the Company's condensed consolidated interim financial statements for the year ended December 31, 2017. Additional disclosures regarding the Company's reported revenue from contracts with customers as required by IFRS 15 for the periods ended March 31, 2018 and 2017 are disclosed in Note 14 of the financial statements.

Yangarra has applied the practical expedient to recognize revenue in the amount to which the Company has the right to invoice. As such, no disclosure is included relating to the amount of transaction price allocated to remaining performance obligations and when these amounts are expected to be recognized as revenue.

<u>IFRS 9 Financial Instruments ("IFRS 9")</u>

Effective January 1, 2018, the Company retrospectively adopted IFRS 9, as well as consequential amendments to IFRS 7 Financial Instruments: Disclosures. The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 Financial Instruments: Recognition and Measurement. The adoption of IFRS 9 did not result in any adjustments to the amounts recognized in the Company's condensed consolidated interim financial statements for the year ended December 31, 2017.

Classification and Measurement of Financial Instruments

The Company measures its financial assets and financial liabilities at fair value on initial recognition, which is typically the transaction price unless a financial instrument contains a significant financing component. Subsequent measurement is dependent on the financial instrument's classification which in the case of financial assets, is determined by the context of the Company's business model and the contractual cash flow characteristics of the financial asset. Financial assets are classified into two categories: (1) measured at amortized cost and (2) fair value through profit and loss ("FVTPL"). Financial liabilities are subsequently measured at amortized cost, other than financial liabilities that are measured at FVTPL or designated as FVTPL where any change in fair value resulting from an entity's own credit risk is recorded as other comprehensive income ("OCI"). The Company does not employ hedge accounting for its risk management contracts currently in place.
Amortized Cost

The Company classifies its cash and cash equivalents, trade and other receivable, deposits, accounts payable and accrued liabilities and long-term debt as measured at amortized cost. The contractual cash flows received from the financial assets are solely payments of principal and interest and are held within a business model whose objective is to collect the contractual cash flows. These financial assets and financial liabilities are subsequently measured at amortized cost using the effective interest method. The carrying values of the Company's cash and cash equivalents, trade and other receivable, deposits, accounts payable and accrued liabilities approximate their fair values.

FVTPL

The Company classifies its risk management contracts as measured at FVTPL. Financial assets and liabilities classified as FVTPL are subsequently measured at fair value with changes in fair value charged immediately to the statements of income. The adoption of IFRS 9 has resulted in changes to the classification of some of the Company's financial assets but did not change the classification of the Company's financial liabilities. There is no difference in the measurement of these instruments under IFRS 9 due to the short-term and liquid nature of these financial assets. The following table summarizes the classification categories for the Company's financial assets and liabilities by financial statement line item under the superseded IAS 39 standard and the newly adopted IFRS 9.

	IAS 39	IFRS 9
Financial Assets		
Accounts receivable	Loans and receivables (Amortized cost)	Amortized cost
Risk management assets	Held-for-trading ("FVTPL")	FVTPL
Interest rate contracts	Held-for-trading ("FVTPL")	FVTPL
Financial Liabilities		
Accounts payable and accrued liabilities	Amortized cost	Amortized cost
Risk management assets	Held-for-trading ("FVTPL")	FVTPL
Interest rate contracts	Held-for-trading ("FVTPL")	FVTPL
Bank Debt	Amortized cost	Amortized cost

Impairment of Financial Assets

IFRS 9 also introduces a new model for the measurement of impairment of financial assets based on expected credit losses which replaces the incurred losses impairment model applied under IAS 39. Under this new model, the Company's accounts receivable are considered collectible within one year or less; therefore, these financial assets are not considered to have a significant financing component and a lifetime expected credit loss ("ECL") is measured at the date of initial recognition of the accounts receivable. ECL allowances have not been recognized for cash and cash equivalents and deposits due to the virtual certainty associated with their collectability.

The Company's trade and other receivables are subject to the expected credit loss model under IFRS 9. For the trade and other receivables, the Company applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which requires the use of the lifetime expected loss provision for all trade receivables. In estimating the lifetime expected loss provision, the Company considered historical industry default rates as well as credit ratings of major customers. There were no material adjustments to the carrying value of any of the Company's financial instruments following the adoption of IFRS 9. Additional disclosure related to the Company's financial assets required by IFRS 9 is included in Note 11 of the financial statements.

Standards Issued but not yet Effective

The Company has reviewed new and revised accounting pronouncements listed below that have been issued but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported income or net assets of the Company.

IFRS 16 Leases ("IFRS 16") IFRS 16 was issued in January 2016 and replaces IAS 17 Leases and related interpretations. The standard is required to be adopted either retrospectively or by recognizing the cumulative effect of initially applying IFRS 16 as an adjustment to opening equity at the date of initial application. IFRS 16 is effective for fiscal years beginning on or after January 1, 2019 with earlier adoption permitted if IFRS 15 Revenue from Contracts with Customers has also been adopted. Yangarra is currently evaluating the impact of the standard on the Company's condensed consolidated interim 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.

Critical judgments in applying accounting policies

Business combinations

Determination of the fair value of acquired assets and liabilities in a business combination requires management to make assumptions and estimates about future events. The fair value of crude oil and natural gas interests is estimated with reference to the discounted cash flows expected to be derived from crude oil and natural gas production. These assumptions and estimates generally require judgment and include estimates of reserves acquired, liabilities assumed, forecast commodity prices, expected production volumes, future development and operating costs, income taxes, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to the net assets acquired, goodwill or gain on business combination.

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.

Accounts Receivable

Significant estimates are included in accounts receivable in terms of collectability as a significant portion of the balance is in dispute, the outcome for which is uncertain and could result in a material adjustment to the financial statements.

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.