YANGARRA RESOURCES LTD.

ANNUAL INFORMATION FORM

April 22, 2014

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ABBREVIATIONS

Abbreviations

Oil and Natural Gas Liquids		Natural Gas	
Bbl or bbl	Barrel	Mcf or mcf	thousand cubic feet
Bbls or bbls	Barrels	Mmcf	million cubic feet
Mbbl	thousand barrels	Mcf/d or mcf/d	thousand cubic feet per day
Mmbbl	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels	Mbtu/d	thousand British Thermal Units per day
Bbl/d or bbl/d	barrels per day	MMBTU or mmbtu	million British Thermal Units
BOPD or bopd	barrels of oil per day	Bcf or bcf	billion cubic feet
NGLs	natural gas liquids	GJ	Gigajoule

Other

BOE or boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d, boe/d or boepd	barrel of oil equivalent per day.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated and M or M$ means thousands of dollars.

FORWARD-LOOKING STATEMENTS

Certain information contained in this Annual Information Form constitutes forward-looking statements and forward-looking information within the meaning of applicable securities legislation. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intend", "forecast", "plans", "guidance" and similar expressions is intended to identify forward-looking statements or information.

More particularly and without limitation, this Annual Information Form and the documents incorporated by reference herein contain forward-looking statements and information relating to the following:

- the performance characteristics of the Corporation's oil, NGLs and natural gas properties;
- oil, NGLs and natural gas production levels;
- the size of the oil, NGLs and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future funds from operations;
- capital programs;
- debt levels;
- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are based on certain key expectations and assumptions made by the Corporation, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labour and services.

Although the Corporation believes that the expectations reflected in the forward-looking statements and information in this Annual Information Form and in the documents incorporated by reference herein are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources, changes in tax, royalty and environmental legislation and the risks under the heading "Risk Factors" in this Annual Information Form. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of factors and risks is not exhaustive.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are made as of the date hereof and, unless so required by applicable law, the Corporation undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise. The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are expressly qualified by this cautionary statement.

READER ADVISORY

On April 28, 2010 the Corporation consolidated its Common Shares on a five old Common Shares for one new Common Share (5:1) basis (the "**Consolidation**"). All references to number and value of Common Shares of the Corporation in this Information Circular are presented on a post-consolidation basis unless noted otherwise.

INCORPORATION AND ORGANIZATION

Yangarra Resources Ltd. (the "**Corporation**" or "**Yangarra**") was formed on May 1, 2010 as a result of an amalgamation under the *Business Corporations Act* (Alberta) ("**ABCA**") between Yangarra and its wholly owned subsidiary, Athabaska Energy Ltd. The Corporation's predecessor entity, also called Yangarra Resources Ltd., was formed on November 9, 2005 as a result of an amalgamation under the ABCA between TriOil Ltd. ("**TriOil**") and Yangarra Resources Inc. ("**Yangarra Predecessor**"). Effective on December 31, 2009, Yangarra Predecessor acquired all of the issued and outstanding shares of Athabaska Energy Ltd. (“Athabaska”) by issuing 50,000,004 common shares in the capital of Yangarra Predecessor at a deemed price of $0.05 per share (the "**Athabaska Acquisition**").

TriOil was incorporated under the ABCA under the name "1000863 Alberta Ltd." and changed its name to "TriOil Ltd." and amended its share capital to add first and second preferred shares on September 26, 2002. TriOil amended its articles to remove its "private company" restrictions on November 13, 2002. Effective on August 13, 2004, TriOil amalgamated with Entrada Energy Inc. and continued to operate under the name "TriOil Ltd.".

Yangarra Predecessor was incorporated under the ABCA under the name "324220 Alberta Ltd" and changed its name to "Ayrex Resources Ltd" on August 20, 1985. Yangarra Predecessor consolidated its share capital on a four for one basis on May 6, 2003, and changed its name to "Yangarra Resources Inc." on June 16, 2003. Yangarra Predecessor amended and registered its restated articles to include an unlimited number of common shares and preferred shares on April 30, 2004.

The Corporation's head office and registered office is located at Suite 1530, 715 - 5th Avenue S.W., Calgary, Alberta, T2P 2X6.

The Corporation has one wholly-owned subsidiary, "Yangarra Resources Corp." incorporated under the ABCA.

BUSINESS OF THE CORPORATION

General

Yangarra is a growth oriented, exploration focused oil and natural gas company. The Corporation is involved in the production, exploration and development of resource properties in the Central Alberta, Medicine Hat and Jaslan areas of Alberta. For the year ended December 31, 2013, Yangarra's oil and gas assets produced 2,206 boe/d of oil, natural gas and NGLs. As at the date hereof, Yangarra's oil and gas assets produce approximately 3,200 boe/d of oil, natural gas and NGLs. As at December 31, 2013, Yangarra owns approximately 91,193 gross (83,582 net) acres of undeveloped land. See "Statement of Reserves Data and Other Oil and Gas Information" in this Annual Information Form.

Three Year History

On March 8, 2011, the Company, closed a "bought deal" financing, completed by way of a short form prospectus, for the sale of 23,632,500 Common Shares at a price of $0.73 per share for gross proceeds of $17,251,725.

On March 8, 2011, the Corporation redeemed preferred shares for $1,000,000 cash plus outstanding dividends payable.

On June 23, 2011, the Corporation, closed a "bought deal" financing, completed by way of private placement, for the sale of 12,500,000 Common Shares on a flow through basis at a price of $0.80 per share for gross proceeds of $10,000,000.

On December 12, 2013, the Company, closed a "bought deal" financing, completed by way of a short form prospectus. 13,855,370 Common Shares were issued at a price of $0.54 per Common Share for gross proceeds of $7,481,900. An aggregate of 11,149,915 Common Shares of the Corporation were issued on a "flow-through" basis pursuant to the *Income Tax Act* (Canada) comprised of: (i) 7,755,000 Common Shares issued in respect of Canadian exploration expenses ("CEE Flow-Through Shares") at a price of $0.645 per CEE Flow-Through Share for gross proceeds of $5,001,975; and (ii) 3,394,915 Common Shares issued on a flow-through basis in respect of Canadian development expenses ("CDE Flow-Through Shares") at a price of $0.59 per CDE Flow-Through Share for gross proceeds of $2,003,000. The total aggregated gross proceeds were $14,486,875 and a total of 25,005,285 Common Shares were issued.

Significant Acquisitions

In March 2011, the Corporation purchased a 15% overriding royalty on natural gas and a 5-15% sliding scale overriding royalty on oil that covered approximately eleven sections of Cardium and Glauconitic perspective land in the Willesden Green area. No Business Acquisition Report was filed on SEDAR regarding the acquisition, as the acquisition was not a “significant acquisition” as such term is defined under Part 8 of the National Instrument 51-102 *Continuous Disclosure Obligations*.

DESCRIPTION OF THE BUSINESS

Strategy

Yangarra plans to grow over the next five years by drilling its extensive Cardium, Glauconitic, Rock Creek and Viking assets in Central Alberta. Longer term development includes the Second White Specs and Duvernay plays.

Yangarra's business plan is to focus on sustainable and profitable per share growth in both cash flow from operations and net asset value. To accomplish this, the Corporation will focus on enhancing its asset base through selective land acquisitions, exploratory drilling and development drilling.

The Corporation expects to internally generate exploration and development opportunities possessing medium risk and multiple prospective productive zone potential with a prudent exposure to higher risk/reward prospects. The Corporation intends to maintain a balance between exploration, development and exploitation drilling, combined with selective acquisition opportunities that meet the Corporation's business parameters. To achieve sustainable and profitable growth, the Corporation will control the timing and costs of its projects wherever possible. Accordingly, the Corporation will seek to become the operator of its properties to the greatest extent possible. Further, to minimize competition within its geographic areas of interest, the Corporation will, after giving consideration to its risk profile, strive to maximize its working interest ownership in its properties. While the Corporation intends to have the skills and resources necessary to achieve its objectives, participation in exploration and development in the oil and natural gas industry has a number of inherent risks. See "Risk Factors".

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria:

(a) risk capital required to secure or evaluate the investment opportunity;

(b) the potential return on the project, if successful;

(c) the likelihood of success; and

(d) the risked return versus cost of capital.

In general, the Corporation will use a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable high levels of profitable production and financial growth.

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

(a) world market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;

(b) political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;

(c) increases or decreases in crude oil quality and market differentials;

(d) availability of takeaway pipeline capacity;

(e) the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by the Corporation for its crude oil and natural gas;

(f) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;

(g) global and domestic economic and weather conditions;

(h) price and availability of alternative fuels; and

(i) the effect of energy conservation measures and government regulations.

Revenue Sources

For the year ended December 31, 2013, 77% of the revenue from Yangarra's properties before royalties was derived from oil and NGLs and 23% was derived from natural gas. Production is sold to marketers at delivery points in or close to the producing field.

Need to Replace and Grow Reserves

The future oil and natural gas production of the Corporation and, therefore, future cash flows, are highly dependent upon ongoing success in exploring on the Corporation's current and future undeveloped land base, exploiting the current producing properties and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

The business of discovering, developing, or acquiring reserves is capital intensive. To the extent cash flows from the Corporation's operating activities are insufficient and external sources of capital become limited or unavailable, the ability for the Corporation to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation will actively compete for capital, skilled personnel, undeveloped land, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Personnel

As at December 31, 2013, Yangarra had 18 employees (12 head office & 6 field). As at the date hereof, Yangarra has 19 employees (13 head office & 6 field).

Bankruptcy and Reorganization

On October 7, 2009, the Corporation filed the Restructure Proposal with its creditors to restructure under Part III Division I of the *Bankruptcy and Insolvency Act* (Canada). See "Business of the Corporation – Relevant Three Year History" of this Annual Information Form.

On December 31, 2009, the Corporation completed the Athabaska Acquisition and on May 1, 2010, the Corporation amalgamated with its wholly-owned subsidiary, Athabaska under the name "Yangarra Resources Ltd.". See "Business of the Corporation – Relevant Three Year History" of this Annual Information Form.

STATEMENT OF RESERVES DATA AND OTHER GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 21, 2014. The effective date of the Statement is December 31, 2013. All currency values are in Canadian dollars (unless otherwise specified).

The tables below summarize the Corporation's crude oil, NGLs and natural gas reserves and the present value of future net cash flows associated with such reserves, as December 31, 2013, as evaluated and prepared by Deloitte LLP ("**Deloitte**") independent petroleum engineers of Calgary, Alberta in the report dated March 21, 2014, based on forecasted price assumptions (the "**2013 Reserves Report**"). The 2013 Reserves Report has been prepared in accordance with the standards in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in National Instrument 51-101 and the COGE Handbook. The tables summarize the data contained in the 2013 Reserves Report and, as a result, may contain slightly different numbers than the 2013 Reserves Report due to rounding. All future cash flows are stated prior to provision for indirect costs and after deduction of royalties, estimated future capital expenditures and well abandonment costs. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The Corporation's crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided. In the various reserves related tables included herein, columns may not add due to rounding.

The Corporation is required to pay royalties to the Crown or other royalty owners and receives royalties from various working interest parties for commodities produced. Crown royalty payments are subject to change and any changes may have an adverse impact on the profitability of a project.

Attached as Schedule "A" to this Annual Information Form is the report on reserves data of Deloitte and attached as Schedule "B" is the report of management and directors of the Corporation on the oil and gas reserves disclosure.

Petroleum and Natural Gas Reserves and Net Present Value

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2013

Reserves Category	**Light and Medium Oil (Mbbl)**			**Natural Gas Liquids (Mbbl)**			**Natural Gas (MMcf)**		
	W.I. Gross	Co.Share Gross	Net	W.I. Gross	Co.Share Gross	Net	W.I. Gross	Co.Share Gross	Net
Proved Developed Producing	988	993	820	711	754	539	12,095	13,209	11,130
Proved Developed Non-Producing	215	216	194	65	67	53	1,634	1,679	1,511
Proved Undeveloped	1,276	1,289	1,118	866	923	705	14,806	16,304	14,351
Total Proved	**2,479**	**2,498**	**2,132**	**1,642**	**1,744**	**1,297**	**28,535**	**31,192**	**26,992**
Probable	2,392	2,401	2,031	1,308	1,357	1,010	24,227	25,590	22,739
Total Proved Plus Probable	**4,871**	**4,899**	**4,163**	**2,950**	**3,101**	**2,307**	**52,762**	**56,782**	**49,731**

SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2013

	Before Income Taxes				
Reserves Category	0.0% (M$)	5.0% (M$)	10.0% (M$)	15.0% (M$)	20.0% (M$)
Proved Developed Producing	112,355	92,026	78,259	68,457	61,179
Proved Developed Non-Producing	19,832	16,499	14,239	12,624	11,417
Proved Undeveloped	105,640	75,062	54,859	40,832	30,689
Total Proved	**237,827**	**183,587**	**147,357**	**121,913**	**103,284**
Probable	257,412	156,838	103,791	72,861	53,308
Total Proved Plus Probable	**495,239**	**340,425**	**251,148**	**194,774**	**156,592**

	After Income Taxes				
Reserves Category	0.0% (M$)	5.0% (M$)	10.0% (M$)	15.0% (M$)	20.0% (M$)
Proved Developed Producing	112,355	92,026	78,259	68,457	61,179
Proved Developed Non-Producing	16,349	14,509	13,061	11,904	10,965
Proved Undeveloped	79,239	55,990	40,545	29,752	21,893
Total Proved	**207,943**	**162,524**	**131,864**	**110,113**	**94,037**
Probable	193,270	117,008	76,701	53,157	38,248
Total Proved Plus Probable	**401,213**	**279,532**	**208,566**	**163,270**	**132,285**

Future Development Costs

The following table sets forth elements of future net revenue attributed to Proved Reserves and Proved Plus Probable Reserves of the Corporation as of December 31, 2013, based on forecast price assumptions and calculated without discount.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2013

Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Investment Costs (M$)**	**Well Abandonment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**	**Future Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
Proved Developed Producing	209,779	41,177	48,074	225	7,948	112,355	-	112,355
Proved Developed Non-Producing	33,367	3,782	8,045	1,583	126	19,832	3,483	16,349
Proved Undeveloped	265,553	39,913	51,304	66,256	2,441	105,640	26,401	79,239
Total Proved	**508,699**	**84,872**	**107,423**	**68,064**	**10,514**	**237,827**	**29,884**	**207,943**
Probable	513,188	82,454	112,924	56,723	3,675	257,412	64,142	193,270
Proved Plus Probable	**1,021,887**	**167,326**	**220,347**	**124,786**	**14,189**	**495,239**	**94,026**	**401,213**

The following table sets forth the net present value of future net revenues by production group attributed to Prove and Proved plus Probable Reserves of the Corporation as of December 31, 2013, based on forecast price assumptions.

NET PRESENT VALUES OF FUTURE NET REVENUE
BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2013

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Net Reserves Unit Value Before Income Taxes (Discounted at 10%/Year) ($/bbl)
Proved	Light and Medium Oil (including solution gas and by-products)	114,342.5	$ 22.44
	Associated and Non-Associated Gas (including by-products)	33,015.2	$ 11.65
	TOTAL	**147,357.7**	$ 18.58
Proved Plus Probable	Light and Medium Oil (including solution gas and by-products)	196,245.4	$ 20.20
	Associated and Non-Associated Gas (including by-products)	54,902.9	$10.89
	TOTAL	**251,148.3**	$ 17.02

Definitions

"**W.I. Gross**" reserves are the Corporation's working interest (operating or non-operating) share before deducting royalty obligations and without including any royalty interests of the Corporation.
"**Co. Share Gross**" reserves are the Corporation's working interest (operating or non-operating) share and before deducting royalty obligations but including any royalty interests of the Corporation.
"**Net**" reserves are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations plus any royalty interests of the Corporation.
"**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according with the level of certainty associated with the estimates and may be sub-classified based on development and production status.
"**Production**" is the cumulative quantity of petroleum that has been recovered at a given date.
"**Proved Reserves**" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves is the targeted level of certainty.
"**Probable Reserves**" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probably reserves is the targeted level of certainty.
"**Developed Reserves**" are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.
"**Developed Producing Reserves**" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
"**Developed Non-Producing Reserves**" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
"**Undeveloped Reserves**" are those Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable) to which they are assigned.

Pricing Assumptions

Forecast Prices Used in Estimates

The forecast price and market forecasts prepared by Deloitte are based on information available from numerous government agencies, industry publication, oil refineries, natural gas marketers, and industry trends. The prices are Deloitte's best estimate of how the future will look, based on the many uncertainties that exist in both the domestic Canadian and international petroleum industries. Deloitte considers the current monthly trends, the actual and trends for the year to date, and the prior year actual in determining the forecast. The crude oil and natural gas forecasts are based on yearly variable factors weighted to higher percent in current data and reflecting a higher percent to the prior year historical. These forecasts are Deloitte's interpretation of current available information and while they are considered reasonable, changing market conditions or additional information may require alteration from the indicated effective date.

Inflation forecasts and exchange rates, an integral part of the forecast, have also been considered.

	Price Inflation Rate	Cost Inflation Rate	Cdn to US Exchange Rate
2013	1.1%	1.6%	$0.971
2014	0.0%	0.0%	$0.940
2015	2.0%	2.0%	$0.940
2016	2.0%	2.0%	$0.940
2017	2.0%	2.0%	$0.940
2018 beyond	2.0%	2.0%	$0.940

Oil, NGL, and natural gas base case prices, utilized by Deloitte in the Deloitte Reserve Report were as follows:

Price Forecast Used in Estimates

	Oil			Natural Gas		Natural Gas Liquids		
Year	WTI Cushing (Oklahoma)	Edmonton City Gate 40° API	Bow River 25° API Hardisty	Alberta Reference – Gas Prices	Alberta AECO – Gas Prices	Pentanes + Condensate Edmonton	Butanes Edmonton	Propane Edmonton
	($US/bbl)	($Cdn/bbl)	($Cnd/bbl)	($Cdn/mcf)	($Cdn/mcf)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)
Historical								
2006	$66.06	$73.34	$52.04	$6.56	$6.54	$78.19	$58.16	$44.11
2007	$72.38	$77.09	$53.86	$6.20	$6.44	$81.67	$59.40	$49.77
2008	$99.58	$102.83	$83.97	$7.88	$8.15	$109.80	$83.56	$56.94
2009	$61.78	$66.21	$59.90	$3.84	$3.96	$69.59	$56.29	$34.56
2010	$79.42	$77.79	$68.16	$3.76	$4.00	$84.68	$69.02	$45.60
2011	$94.99	$95.77	$78.60	$3.46	$3.65	$104.70	$83.62	$53.34
2012	$94.00	$87.76	$75.47	$2.25	$2.40	$98.74	$75.21	$33.71
2013	$97.83	$93.21	$76.23	$2.89	$3.20	$104.86	$76.64	$34.59
Forecast								
2014	$95.00	$95.75	$80.00	$3.45	$3.70	$105.35	$76.60	$33.50
2015	$91.80	$92.30	$76.30	$3.70	$3.95	$101.55	$73.85	$32.30
2016	$91.55	$95.20	$77.35	$3.85	$4.10	$104.70	$76.15	$52.35
2017	$91.25	$94.80	$76.80	$4.05	$4.30	$105.15	$75.85	$52.15
2018	$92.00	$95.60	$75.65	$4.30	$4.55	$107.25	$76.50	$52.60
2019	$93.85	$97.50	$76.50	$4.60	$4.85	$109.40	$78.00	$53.65

Notes:

- All prices are in Canadian dollars except WTI and NYMEX which are in U.S. dollars.
- Edmonton City Gate prices based on light sweet crude posted at major Canadian refineries (40 Deg. API <0.5% Sulphur).
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point.
- 1 Mcf is equivalent to 1 mmbtu.
- Alberta gas prices, except AECO, include an average cost of service to the plant gate.
- Real dollars listed include future growth in prices with no escalation considered.

Weighted average historical prices realized by Yangarra for the year ended December 31, 2013 before transportation were $3.53/Mcf for natural gas, $54.32/Bbl for NGLs and $92.08/Bbl for oil.

Reconciliations of Changes in Reserves

The following table sets out a reconciliation of the changes in the Corporation's reserves as at December 31, 2013 against such reserves at December 31, 2012 based on forecast prices and cost assumptions:

	Light and Medium Oil			**Natural Gas Liquids**			**Associated & Non-Associated Gas**		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(MMcf)	(MMcf)	(MMcf)
Opening Balance	**1,960.3**	**1,462.3**	**3,422.6**	**1,103.1**	**789.6**	**1,892.7**	**20,906.6**	**16,839.5**	**37,746.1**
Production	-191.9	0.0	-191.9	-124.0	0.0	-124.0	-2,187.6	0.0	-2,187.6
Technical Revisions	-552.9	-221.4	-774.3	212.2	48.9	261.1	3,294.3	517.3	3,811.6
Extensions & Improved Recovery	794.5	985.6	1,780.1	423.2	458.0	881.2	6,235.7	6,657.8	12,893.5
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	493.8	176.2	670.0	123.6	43.6	167.2	1,923.3	760.6	2,683.9
Dispositions	-24.4	-9.9	-34.3	-94.1	-32.8	-126.9	-1,562.4	-546.1	-2,108.5
Economic Factors	0.0	-0.7	-0.7	-1.5	0.6	-0.9	-74.8	-2.0	-76.8
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	**2,479.4**	**2,392.1**	**4,871.5**	**1,642.5**	**1,307.9**	**2.950.4**	**28,535.1**	**24,227.1**	**52,762.2**

Timing of Initial Undeveloped Reserves Assignment

The following table sets forth the gross volumes of proved undeveloped reserves, by each product type, attributed to the Corporation's assets for the years ended December 2013, 2012, and 2011, based on forecast prices and costs.

<u>Proved Undeveloped Reserves</u>

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
2011	535	8,965	236
2012	1,306	12,370	671
2013	1,289	16,304	923

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in for production or wells not yet drilled at year end that are adjacent to producing wells. In addition, such reserves may relate to planned infill drilling locations. Plans are included in the Deloitte report to develop these reserves. The future timing of these undeveloped reserves reflects an orderly operational development of the reserves considering infrastructure limitations and corporate portfolio management.

<u>Probable Undeveloped Reserves</u>

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
2011	669	10,591	265
2012	2,486	22,665	1,270
2013	2,401	25,590	1,357

Significant Factors or Uncertainties Affecting Reserves Data

Probable undeveloped reserves are generally adjacent to proven undeveloped reserves, lands contiguous to production or indicated by analogy to be productive. In general, once proved and/or probable undeveloped reserves are identified, Yangarra schedules them into development plans within two years.

A number of factors that could result in delayed or cancelled development are: changing economic conditions (due to pricing, operating and capital expenditure fluctuations); changing technical conditions (for example production anomalies such as water breakthrough or accelerated depletion); multi-zone developments (for example, a prospective formation completion may be delayed until the initial completion is no longer economic); a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and surface access issues.

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and cost changes. The Corporation's estimates are based on current production forecast, prices and economic conditions.

As additional data and circumstances change, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either downward or upward as warranted. As new geological, production and economic data is incorporated into the process of estimated reserves the accuracy of the reserve estimate improves.

The Corporation's reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Corporation's control.

The Corporation's oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company which have been disclosed in financial statements and management's discussion and analysis as filed on SEDAR (www.sedar.com) and this Annual Information Form.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($M)
2014	41,230.2	73,085.4
2015	25,521.6	45,976.5
2016	370.4	421.5
2017	31.5	3,064.9
2018	636.7	1,363.8
Thereafter	237.1	874.2
Total for all years undiscounted	68,063.8	124,786.2

Yangarra expects that such funding of its share of future development on capital expenditure programs will be primarily obtained from internally generated cash flow and equity financings and debt facilities.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest or a royalty interest as at December 31, 2013, which are producing or which the Corporation considers to be capable of production. All wells set forth in the table are located in Alberta.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Medicine Hat, Alberta				
Producing	-	-	37	37.0
Shut-in	-	-	44	44.0
Central Alberta				
Producing	45	21.2	24	13.5
Shut-in	-	-	5	4.5
Jaslan, Alberta				
Producing	-	-	-	-
Shut-in	-	-	11	11.0

Notes:

(1) Shut-in wells means wells which are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons.

(2) Gross wells are defined as the total number of wells in which the Corporation has an interest.

(3) Net wells are defined as the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

Property Overview

The following is a description of the major oil and natural gas properties, and facilities in which the Corporation had an interest as of December 31, 2013. Production volumes represent the working interest share of the Corporation before the deduction of royalties. Reserve amounts are stated, before deduction of royalties, at December 31, 2013 based on escalating cost and price assumptions, as set forth in the 2013 Reserves Report.

Central Alberta Area

Yangarra holds working interests ranging from 10.78125% to 100% in multiple sections in this area with high potential Glauconitic (45 gross (24.0 net) sections), Cardium (27 gross (15.5 net) sections), Viking, Second White Specs (45 gross (29.0 net) sections), Rock Creek and Ellerslie zones. Not included in the preceding numbers, Yangarra entered into a farm-in with an industry major in 2013 covering 47 gross (27 net) sections of Cardium rights. The field is located 60 miles north west of Red Deer, near the town of Rocky Mountain House, Alberta. Yangarra has a 50% ownership in a compressor station in the Willesden Green area of Central Alberta capable of 10 Mmcf/d constructed in early 2004. Yangarra constructed another compressor facility in the Ferrier area of Central Alberta early in 2013, this compressor station is capable of 11 Mmcf/d. Both facilities process third party volumes providing the Corporation with incremental profit. Yangarra has a 100% interest in a field office with accommodation, a shop and storage. There is an overriding sliding scale royalty (5-15%) covering approximately 11 sections in this area that was purchased by the Corporation in 2010. As of December 31, 2013 69 gross wells (34.7 net wells) are producing.

Medicine Hat Area

Yangarra holds a 100% working interest in a total of 75 sections of land located 25 miles southwest of the city of Medicine Hat, Alberta. A total of 81 wells have been drilled, re-entered, or acquired on the property and currently 37 wells are on production. A 100% owned compressor station, capable of 2 million cubic feet per day situated at 5-25-9-6W4 was built at the end of 2003. Production is from the Sunburst, Bow Island, Second White Specks, Medicine Hat, and Milk River Formations. Wells that have been assigned reserves and are capable of producing that have not been tied in, will be tied in as development of the field reaches these outlying wells or gas prices increase.

Jaslan Area

The Jaslan property is located 100 miles north east of Edmonton and consists of 17.25 sections (100% working interest). A compressor station capable of 3.0 million cubic feet per day (100% working interest) and gathering system were completed in November 2006. Currently all wells in the Jaslan area are shut-in due to low natural gas prices. During 2011, Yangarra purchased their partners interest in the Jaslan area to increase its working interest to 100%.

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land holdings as of December 31, 2013.

Location	Gross (hectares)	Net (hectares)
Alberta	36,481	33,495

At December 31, 2013, there was no material commitments associated with the Corporation's undeveloped land holdings. The Corporation has no rights to explore, develop, and exploit undeveloped land holdings that will expire within one year.

Significant Factors to Properties with No Attributed Reserves

The Corporation expects to develop the unrecognized natural gas assets in Jaslan and Medicine Hat as natural gas prices improve.

Forward Contracts

As at December 31, 2013, the Corporation 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 Corporation 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

Exploration and Development

In 2014, the Corporation intends to undertake a portfolio of exploration and development projects to capture and advance projects that provide opportunities utilizing multi-well pads and horizontal drilling with multi-stage fracturing technology. The Corporation's 2014 capital program is anticipated to be equivalent to operating cash flows and the existing bank facilities.

Additional Information Concerning Abandonment and Reclamation Costs

The 2013 Reserves Report includes well abandonment costs ranging at rates of $33,000-$105,000 per well, depending on the formation and depth of the well. The abandonment costs are based on area averages taken from the Energy Resource Conservation Board ("**ERCB**") Directive 011 called the "Alberta Regional Well Abandonment Cost Tables". The 2013 Reserves Report does not address well site reclamation for existing wells, pipeline right-of-ways, and facility abandonment/salvage costs including potential environmental concerns.

Yangarra has 161 gross wells for which it expects to incur abandonment and restoration costs. These costs included well abandonment and surface lease reclamation. The estimated total abandonment and reclamation costs, forecast net of estimated salvage value, under the proved reserves category is $10,514,300 (undiscounted), and $4,130,000 (discounted at 10%). The total proved plus probable abandonment and reclamation costs are $14,189,400 (undiscounted), and $3,655,900 (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Corporation in respect of proved and proved plus probable reserves as disclosed above. Estimated abandonment costs are included in the 2013 Reserves Report as a deduction in arriving at future net revenue.

Forecast Prices and Costs – Proved (M$)

Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Discounted at 10%)
2014	504.1	480.7
2015	869.7	753.8
2016	854.8	673.5
2017	441.8	316.5
2018	326.6	212.7
Thereafter	7,517.3	2,079.9
Total	10,514.3	4,715.1

Forecast Prices and Costs – Proved Plus Probable (M$)

Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Discounted at 10%)
2014	68.1	65.0
2015	840.7	728.7
2016	758.9	598.0
2017	521.5	373.6
2018	728.3	474.3
Thereafter	11,271.9	2,120.5
Total	14,189.4	4,360.1

Tax Horizon

Yangarra was not required to pay income tax in 2013 and based on current tax pools, projected cash flow, and projected exploration costs, the Corporation does not expect to be taxable in 2014.

Costs Incurred

In 2013, exploration and development capital expenditures were $44.5 million. The breakdown for the Corporation's capital expenditures during 2013 is presented below:

	($000's)
Drilling and Completions	$ 35,705
Equipment & Facilities	7,595
Geological and Geophysical	757
Land Lease	184
Total	$ 44,561

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Yangarra participated during the year ended December 31, 2013.

Exploration Wells	Gross	Net	**Development Wells**	Gross	Net
Light and Medium Oil	-	-	Light and Medium Oil	14	9.6
Natural Gas	-	-	Natural Gas	1	1.0
Service	-	-	Service	-	-
Dry		-	Dry	-	-
Total	-	-	Total	15	10.6

Production Estimates

The following table sets out the volume of Yangarra's production estimated for the first year reflected in the estimates of future gross revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Total Proved Reserves			**Total Proved + Probable Reserves**		
	Light and medium oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Light and medium oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)
Medicine Hat	-	490.8	-	-	558.9	-
Central Alberta	447.2	8,831.9	558.8	592.9	10,304.9	665.9
Jaslan/Viking South	-	501.4	-	-	599.9	-

* Table includes fields that account for more than 20% of the estimated production reflected in the estimate of future net reserves.

Production History

The following tables set forth the Corporation's average daily production volume before deductions of royalties payable to others, and crude oil, NGLs and natural gas prices. Also shown are royalties, production and transportation costs, and average netbacks for the period January – December 2013.

Average Daily Production

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil (bbl/d)	501.8	491.5	546.6	682.7
Natural gas (mcf/d)	5,090.1	5,914.6	6,982.9	8,303.4
Natural gas liquids (bbl/d)	290.9	339.1	450.3	604.9
Royalty Income (bbl/d)	168.2	188.3	76.9	92.3
Total (BOE/d)	1,809.1	2,002.6	2,237.7	2,763.9

Average Prices Received per Unit – (Before Deduction of Royalties)

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil ($/bbl)	83.90	93.86	102.99	84.98
Natural gas ($/mcf)	3.09	3.64	2.57	3.67
Natural gas liquids ($/bbl)	48.30	50.08	60.77	51.45
BOE ($ / BOE)	44.95	48.95	44.89	45.37

Royalties Paid per Unit

Three months ended	March 31	June 30	Sept 30	Dec 31
Total royalties per BOE ($/BOE)	1.60	1.52	3.41	2.19

Production and Transportation Costs

Three months ended	March 31	June 30	Sept 30	Dec 31
Total costs per BOE ($/BOE)	9.00	7.13	6.92	7.48

Netbacks Received

Three months ended	March 31	June 30	Sept 30	Dec 31
Total netbacks per $/BOE	34.34	40.30	34.56	35.70

Production Volume by Field

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2013:

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Royalty Income (Bbls/d)	BOE (BOE/d)
Medicine Hat	-	300.4	0.9		50.9
Central Alberta	556.1	6,237.8	421.4	130.5	2,147.7
Jaslan	-	44.5	-	-	7.4

Uncertainty of Reserves Estimates

The reserve and recovery information contained in the 2013 Reserves Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the independent estimates of Deloitte.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the Corporation's assets have been independently evaluated effective December 31, 2013 by Deloitte. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success in the evaluations.

DIRECTORS AND OFFICERS OF THE CORPORATION

The name, province and country of residence and principal occupation for the last five years of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Office	Principal Occupation	Director Since	Common Shares Held
James G. Evaskevich[2][3] Alberta, Canada	President, Chief Executive Officer, and Director	President and Chief Executive Officer of the Corporation since December 2001.	December 19, 2001	6,699,060 (4.53%)[4]
James Glessing Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Corporation since December 1, 2010. Prior thereto CFO & VP Finance 2007-2010.	N/A	900,000 (0.61%)[5]
Randall Faminow Alberta, Canada	Vice President, Land	VP Land of the Corporation since October 18, 2011. Prior thereto VP, Land for Spry Energy Ltd (2007-2011.	N/A	418,500 (0.28%)
Lorne Simpson Alberta, Canada	Vice President, Operations	VP Operations of the Corporation since April 11, 2013. Prior thereto Manager of Drilling and Completions for the Corporation (2012-2013), Supervisor, Drilling Operations with PetroBakken Energy Ltd. (2010-2012), Manager Drilling and Completions with Open Range (2009-2010).	N/A	1,278,500 (0.86%)
Gordon A. Bowerman[1][2][3] Alberta, Canada	Director	President of Cove Resources Ltd., a private oil and gas company based in Calgary, since 1987.	December 19, 2001	11,078,972 (7.49%)[6]
Robert D. Weir[1][2][3] Alberta, Canada	Director	President of Weir Resource Management Ltd., a private company based in Calgary, since 1981.	November 11, 2003	939,455 (0.64%)[7]
Frederick (Ted) L. Morton[1][2][3] Alberta, Canada	Director	Professor at the University of Calgary (1981 – present) and MLA, Foothills Rockyview (2004 – 2012).	February 24, 2014	Nil
Neil M. Mackenzie [1][2][3] Alberta, Canada	Director	Vice President of Blackstone Drilling Fluids Ltd. (2010 – present), Vice President New Park Resources (1976 – 2010) and President Challenger Energy Corp. (2004 – 2007).	February 24, 2014	200,000 (0.14%)

Notes:

(1) Member of the Audit Committee of the Board of Directors.

(2) Member of the Corporate Governance and Nominating Committee.

(3) Member of the Compensation Committee.

(4) Includes 2,811,213 Common Shares held by Grassy Island Ranch Ltd., a private company controlled by Mr. Evaskevich.

(5) Includes 213,400 Common Shares held by Mr. Glessing's spouse.

(6) Includes 807,163 Common Shares held by Mr. Bowerman's spouse, over which Mr. Bowerman has control and direction over and 1,679,070 Common Shares held by Cove Resources Ltd., a private company controlled by Mr. Bowerman.

(7) Includes 89,166 Common Shares held by Weir Resources Management Ltd. and 3,800 Common Shares held by Wild Bull Resources, both private companies controlled by Mr. Weir.

Orders

To the knowledge of management of the Corporation, other than as disclosed herein, no director or executive officer as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Corporation), that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Neil M. MacKenzie was a director of BakBone Software Incorporated ("**BakBone**"). In October 2004, BakBone announced that, in conjunction with a change of accountants, it would not be in a position to file its quarterly report on Form #10-Q for the September 30, 2004 period and consequently, on December 4, 2004, each of the Alberta, British Columbia and Ontario Securities Commissions issued cease trade orders against BakBone to the effect that all trading in the securities of BakBone cease until it filed its financial statements in accordance with Canadian securities legislation. The outstanding financial statements have since been filed and the cease trade orders have been lifted.

Bankruptcies

Other than as disclosed below, no director or executive officer of the Corporation is, as of the date hereof, or has been, within 10 years before the date hereof, a director or executive officer of any company that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal to under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

On October 7, 2009 the Corporation filed a proposal with its creditors to restructure under Part III Division I of the *Bankruptcy and Insolvency Act* (Canada), including a plan to merge with Athabaska Energy Ltd. See "Interest of Informed Persons in Materials Transactions" below. At the time of the Restructure Proposal, the directors and officers of Yangarra consisted of James Evaskevich, Gordon Bowerman and Robert Weir.

No director or executive officer of the Corporation has, within 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold its assets.

Penalties and Sanctions

To the knowledge of management of the Corporation, no director or executive officer or shareholder holding a sufficient number of common shares to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority, or has been subject to any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject to in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial or director positions with other oil and natural gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation.

AUDIT COMMITTEE

The purpose of the Corporation's audit committee is to provide assistance to the Board of Directors (the "**Board**") in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. It is the objective of the audit committee to maintain a free and open means of communications among the Board, the independent auditors and the senior management of the Corporation.

The full text of the audit committee's charter is attached hereto as Schedule "C" and forms part of this Annual Information Form.

Composition of the Audit Committee

The audit committee is comprised of Gordon Bowerman (Chair), Robert Weir, Frederick (Ted) Morton and Neil Mackenzie. Each of the members are independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**"). Each of the members is financially literate within the meaning of section 1.6 of NI 52-110.

Relevant Education and Experience

The following relevant education and experience of the members of the Audit Committee have been used in assessing their financial literacy:

Gordon Bowerman, B.A. – Mr. Bowerman has over 40 years experience in the oil and gas industry, including various experience in production, land, accounting, asset purchases and sales. Mr. Bowerman currently is the President of a private oil and gas company.

Robert Weir, P. Eng – Mr. Weir has over 30 years experience in the oil and gas industry, President of Weir Resource Management Ltd., a private company based in Calgary, since 1981.

Frederick (Ted) Morton B.A. PhD – Mr. Morton's various positions in the Alberta Government included Minister of Energy, Minister of Finance and Enterprise, and Minster of Sustainable Resources.

Neil Mackenzie –Mr. MacKenzie is or has been a director of various public companies, including Canyon Services Group Inc., and is currently a Vice President at Blackstone Drilling Fluids Ltd., an oil and gas drilling fluids company. Mr. MacKenzie held senior position in oil and gas companies from 1976-2010.

Pre-Approval Policies and Procedures

The audit committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Committee to nominate or compensate an external auditor (currently, KPMG LLP, Chartered Accountants) not adopted by the Board.

Reliance on Certain Exemptions

Since the effective date of NI 52-110, the Corporation has not relied on the exemptions contained in sections 2.4 or 8 of NI 52-110. Section 2.4 provides an exemption from the requirement that the audit committee must pre-approve all non-audit services to be provided by the auditor, where the total amount of fees related to the non-audit services are not expected to exceed 5% of the total fees payable to the auditor in the fiscal year in which the non-audit services were provided. Section 8 permits a company to apply to a securities regulatory authority for an exemption from the requirements of NI 52-110, in whole or in part.

The Corporation is also relying on the exemption set out in section 6.1 of NI 52-110 with respect to compliance with the requirements of Part 5 (Reporting Obligations) of NI 52-110.

External Auditor Service Fees (By Category)

Year Ended	Audit Fees	Audit Related Fees	Tax Fees	All Other Fees
December 31, 2013	$45,000	$30,000	$325	$42,500(1)
December 31, 2012	$39,000	$37,500	$875	$nil

Note:

(1) Represents involvement in a short-form prospectus dated December 6, 2013

DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares, without nominal or par value, and an unlimited number of First Preferred Shares (the "**First Preferred Shares**") and the Second Preferred Shares in the capital of the Corporation, both issuable in series (the "**Second Preferred Shares**", and together with the First Preferred Shares, the "**Preferred Shares**"). As of the date of this Annual Information Form, 147,942,008 Common Shares and nil Preferred Shares are issued and outstanding.

Common Shares

Holders of post-consolidation Common Shares are entitled to (a) one vote per post-consolidated Common Share at all meetings of shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board, as a class equally with the holders of the Preferred Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the post-consolidation Common Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the post-consolidation Common Shares in respect of return of capital on dissolution, share rateably, together with the holders of Preferred Shares and of shares of any other class of shares of the Corporation ranking equally with the post-consolidation Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

First Preferred Shares

Holders of First Preferred Shares shall: (a) not be entitled to receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) be entitled to receive dividends if, as and when declared by the Board on the First Preferred Shares as a class in preference to the holders of the Second Preferred Shares and post-consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends; and (c) be entitled to, in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive in preference to the holders of the Second Preferred Shares and post-Consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Series A First Preferred Shares

The Corporation previously had a series of First Preferred Shares outstanding ("**Series A First Preferred Shares**") Holders of Series A First Preferred Shares shall: (a) not be entitled to receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) be entitled to receive dividends: (i) on a semi-annual basis within 30 days of the first and second fiscal-year halves of the Corporation, which can be paid in the form of cash or post-consolidation Common Shares at the election of the Board, with the deemed price of such post-consolidation Common Shares to be the Market Price (as such term is defined in the Corporate Finance Manual of the TSX Venture Exchange) of such post-consolidation Common Shares at the time of settlement on the First Preferred Shares; (ii) as a class in preference to the holders of the Second Preferred Shares and post-consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends; and (iii) each Series A First Preferred Share shall be entitled to a cumulative dividend at the rate of 5% per annum on the stated amount of $1.00 per Series A Preferred Share (the "**Stated Amount**") of such Series A First Preferred Share; (c) be entitled to, in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive an amount equal to the Stated Amount per Series A First Preferred Share plus any declared but unpaid dividends prior to any payment or distribution to any other class of shares of the Corporation; and (d) have the option, exercisable not earlier than the date that is 18 months after the Series A Preferred Shares are issued, to force the Corporation to redeem or purchase all or any of the Series A First Preferred Shares held by such holder. In addition, the Corporation has the right to redeem the Series A First Preferred Shares at any time in cash at the price equal to the Stated Amount plus any declared but unpaid dividends.

Second Preferred Shares

Holders of Second Preferred Shares shall not be entitled to (a) receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board on the First Preferred Shares as a class in preference to the holders of the post-consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Second Preferred Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive in preference to the holders of the post-consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Second Preferred Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

DIVIDENDS

The Corporation has not declared or paid any dividends on the Common Shares. Any decision to pay dividends on such shares in the future will be made by its Board on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. It is not the current intention of the Corporation to pay any dividends on the post-consolidation Common Shares in the near future.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the TSX Venture Exchange since July 25, 2003 under the trading symbol "YAN" and changed as a result of the Consolidation on April 30, 2010 and began trading under the symbol "YGR". The following table sets out the price range for, and trading volume of, the post-consolidation Common Shares as reported by the TSX Venture Exchange for the periods indicated:

	Trading Price		Volume Traded
	High	**Low**	**# of shares**
January 2012	$0.64	$0.47	1,618,200
February 2012	$0.55	$0.43	2,967,500
March 2012	$0.55	$0.41	2,346,900
April 2012	$0.48	$0.34	5,211,700
May 2012	$0.41	$0.32	1,065,900
June 2012	$0.37	$0.23	4,026,800
July 2012	$0.35	$0.30	658,200
August 2012	$0.39	$0.30	715,000
September 2012	$0.37	$0.31	1,339,100
October 2012	$0.37	$0.31	1,748,000
November 2012	$0.42	$0.32	4,506,000
December 2012	$0.38	$0.29	1,323,600
January 2013	$0.35	$0.29	4,039,900
February 2013	$0.29	$0.26	4,647,000
March 2013	$0.30	$0.24	5,909,200
April 2013	$0.32	$0.27	3,652,500
May 2013	$0.35	$0.29	2,954,300
June 2013	$0.35	$0.29	3,863,200
July 2013	$0.37	$0.29	4,897,800
August 2013	$0.44	$0.35	1,291,800
September 2013	$0.46	$0.39	2,006,300
October 2013	$0.58	$0.41	9,773,500
November 2013	$0.65	$0.50	4,377,400
December 2013	$0.58	$0.52	2,352,700

ESCROWED SECURITIES

No securities of the Corporation are currently escrowed.

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the Government of Canada and various provincial governments, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Alberta.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices, however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to twenty years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that, any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Oil sands projects are also subject to Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1 % when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "Emerging Resource and Technologies Initiative"). Specifically:

- coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice if it decides to discontinue the program.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Various provinces, including Alberta, have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRO**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 30, 2014, the AER assumed the energy related functions and responsibilities of AESRO in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory Instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45 % of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force soon.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licences and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AS LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

The changes will be implemented over a three-year period, ending May 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the *United Nations Framework Convention* on Climate Change (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target in a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Comer: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008, The CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GOP by 2020. The accompanying regulations include the Specified Gas Emitters Regulation ("**SGER**"), which imposes GHG limits, and the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years, Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10%) of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the Carbon Capture and *Storage Statutes Amendment Act*, 2010. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

RISK FACTORS

The holding of securities in the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision relating to the Corporation's securities.

Volatility of Oil and Gas Prices and Markets

The Corporation's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of the Corporation including, but not limited, to the world economy and OPEC's ability to adjust supply to world demand, government regulation, political stability and the availability of alternative fuel sources. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources. In addition, the marketability of the production depends upon the availability and capacity of gathering systems and pipelines, the effect of federal and provincial regulation on such production and general economic conditions. All of these factors are beyond the control of the Corporation.

Decreases in oil and natural gas prices typically result in a reduction of the Corporation's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Corporation's reserves. Any substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in the Corporation's net production revenue, cash flows and profitability and have a material adverse effect on the Corporation's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation will in part be determined by the Corporation’s borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

From time to time the Corporation has and may in the future enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline, however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases.

Additional Funding Requirements

The Corporation’s cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experience unexpected and/or prolonged deterioration, the Corporation’s access to additional funding may be required.

Because of global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation’s revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation’s ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation’s ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production of the Corporation's properties.

Development of Additional Reserves

The Corporation's future success is dependent upon its ability to explore, develop or acquire additional oil and natural gas reserves that are economically recoverable at attractive acquisition prices. Except to the extent that the Corporation conducts successful activities or acquires properties containing proved reserves, or both, the proved reserves and production will generally decline as reserves are produced. If prevailing oil and natural gas prices were to increase significantly, the Corporation's costs to add reserves could be expected to increase. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of a dry hole or of a well that is not sufficiently productive to provide an economic return on the capital expended to drill the well.

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which the Corporation has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling may, where appropriate, be used by the Corporation to improve its ability to find, develop and produce oil and natural gas.

Title

Although satisfactory title reviews of the Corporation's properties are conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Corporation to a property.

Environmental Concerns

The operation of oil and natural gas wells involves a number of natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions resulting in liability to the Corporation and possibly liability to third parties. Companies operating in the oil and natural gas industry are subject to extensive environmental regulation which provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in fines or the issuance of clean-up orders. See "Information Concerning the Oil and Natural Gas Industry – Environmental Regulation". The Corporation will make reasonable provision for well abandonment and reclamation where appropriate; however, there can be no assurance that such provision will be sufficient to satisfy all such obligations. No sinking fund or reserve will be established for the purpose of site reclamation or abandonment costs.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which controls and regulations may be amended from time to time. See "Information Concerning the Oil and Natural Gas Industry". Governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

Reserves Estimates

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves consultants have used both constant and forecast price and cost estimates in calculating reserves quantities for the Corporation's reserves. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the applicable engineering reports. The reserves reports are based in part on the assumed success of activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in the applicable engineering reports will be reduced to the extent that such activities do not achieve the level of success assumed in the engineering reports.

Purchase of Reserves

Acquisitions of resource issuers and resource assets by the Corporation will be based on engineering and economic assessments made by management and reviewed by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other governmental levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. In particular, changes in the prices of and markets for oil and natural gas from those anticipated at the time of making such assessments will affect the value of the Corporation's securities. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than anticipated.

Depletion of Reserves

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on the Corporation's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited, and from time to time production declines can be severe under certain conditions.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired.

There can be no assurance that the Corporation will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

Foreign Exchange

Operating costs incurred by the Corporation are generally paid in Canadian dollars. World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Corporation's net production revenue. To the extent that the Corporation has engaged or will in the future engage in risk management activities related to commodity prices and foreign exchange rates, through entry into oil and natural gas price hedges and forward foreign exchange contracts or otherwise, the Corporation will be subject to unfavourable price changes and credit risks associated with the counter parties with which it contracts.

Potential Conflicts of Interest

Some of the directors of the Corporation are also directors of other oil and natural gas companies, which may from time to time be in competition with the Corporation for working interest partners, property acquisitions, or other limited resources. Where required by law, appropriate disclosure of such conflicts will be made by the applicable directors. In particular, the Corporation follows the provisions of the ABCA. These provisions state that in the event that a director has an interest in a contract or proposed contract or agreement, such director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise permitted by the ABCA.

Competition

The oil and natural gas industry is intensely competitive and the Corporation will compete for joint venture partners, capital, reserves acquisitions and skilled industry personnel with a substantial number of other companies which have greater resources. Many such companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a worldwide basis and as such have greater and more diverse resources upon which to draw. There is also competition between the oil industry and other industries with respect to the supply of energy and fuel to industrial, commercial and individual customers.

Operating Risks

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blowouts and encountering formations with abnormal pressure and oil spills, the occurrence of any of which could result in substantial losses to the Corporation. The Corporation will maintain insurance against some, but not all, of these risks, in amounts which meet or exceed standard industry practice. There can be no assurance that any insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

Continuing production from the Corporation's properties, and to some extent the marketing of production therefrom, are dependent upon the ability of the operator of such properties. To the extent that the operator of a property fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent or experiences cash flow problems.

Changes in Legislation

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry, will not be changed in a manner which will adversely affect the Corporation. There can be no assurance that tax authorities having jurisdiction will agree with how the Corporation calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of the Corporation.

Enforcement of Operating Agreements

Operations of the wells located on properties not operated by the Corporation are generally governed by operating agreements that typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation.

Substantial Capital Requirements

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, the Corporation may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly, including transactions involving the issuance of securities, which may be dilutive. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to the Corporation.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Insurance

The Corporation's involvement in the exploration for and development of oil and gas properties may result in the Corporation becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although the Corporation has obtained insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer, could have a material adverse effect on the Corporation's financial position, results of operations or prospects.

Reliance on Operators and Key Employees

To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Corporation will be largely dependent upon the performance of its management and key employees. The Corporation does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Corporation.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of oil and natural gas to the Corporation or to the operators, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

Permits and Licences

The operations of the Corporation may require licences and permits from various governmental authorities. There can be no assurance that the issuer will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of the Corporation's assets, however, if a claim arose and was successful, it could have an adverse effect on the Corporation and its operations.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and potential declines in production of oil and gas of the Corporation.

Income Taxes

The Corporation will file all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures, or otherwise, such reassessment may have a negative impact on current and future taxes payable and such impact may be material.

Borrowing

The Corporation's lenders have been provided with security over substantially all of the assets of the Corporation. If the Corporation becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell the Corporation's properties. The proceeds of any such sale would be applied to satisfy amounts owed to the Corporation's lenders and other creditors and only the remainder, if any, would be available to the Corporation.

Acquisition Risk

The Corporation may make future acquisitions or enter into financings or other transactions involving issuance of securities of the Corporation which may be dilutive.

Additionally, the oil and gas property acquisition business is highly competitive, and is populated with many companies, large and small, with the capital and expertise to evaluate, purchase, and exploit producing and non-producing opportunities. Even with capital and experience, the industry risks of drilling dry holes and cost overruns are significant. Environmental compliance is an increasingly complex and costly burden to entry for many new exploration areas, and often times, and even if permits are obtained, they are sufficiently restrictive that a property cannot be explored to its full potential. The Corporation may not be able to locate acquisition opportunities, or finance those that the Corporation can. The Corporation offer no assurance that its entry into this business activity will be successful.

Third Party Credit Risk

The Corporation is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

To the knowledge of the management of the Corporation, there are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated, other than: (a) the statement of claim filed by Yangarra on December 11, 2009 in the Court of Queen's Bench of Alberta against a certain industry partner in the amount of $508,862 for a breach of the agreements between the parties, gross negligence and default of operator (the "**Claim**"); (b) the statement of defence and counterclaim in the amount of $1,236,457 to the Claim filed by the aforementioned industry partner on December 22, 2009 (the "**Counterclaim**"); and (c) statement of defence to the Counterclaim filed by Yangarra on January 14, 2010. On April 1, 2011, the Corporation amended its statement of claim. The Company increased the statement of claim based on the information provided by the defendant and expects the matter to go to trial during 2014.

In the normal conduct of operations, there are other pending claims by and against the Corporation. 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 Corporation.

Regulatory Actions

To the knowledge of management of the Corporation, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set out below, none of the directors, executive officers of the Corporation, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10 percent of any class or series of outstanding voting securities of the Corporation, nor any associate or affiliate of the foregoing persons had any material interest, direct or indirect, in any transaction during the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

In March 2011 the Company, closed a "bought deal" financing, completed by way of a short form prospectus, for the sale of 23,632,500 Common Shares at a price of $0.73 per share for gross proceeds of $17,251,725. Management and directors subscribed for 753,500 shares for gross proceeds of $550,055 (3%) of the financing.

On December 12, 2013 the Company, closed a "bought deal" financing, completed by way of a short form prospectus. 13,855,370 Common Shares were issued at a price of $0.54 per Common Share for gross proceeds of $7,481,900. An aggregate of 11,149,915 Common Shares of the Corporation were issued on a "flow-through" basis pursuant to the *Income Tax Act* (Canada) comprised of: (i) 7,755,000 Common Shares issued in respect of Canadian exploration expenses ("CEE Flow-Through Shares") at a price of $0.645 per CEE Flow-Through Share for gross proceeds of $5,001,975; and (ii) 3,394,915 Common Shares issued on a flow-through basis in respect of Canadian development expenses ("CDE Flow-Through Shares") at a price of $0.59 per CDE Flow-Through Share for gross proceeds of $2,003,000. The total aggregated gross proceeds were $14,486,875 and a total of 25,005,285 Common Shares were issued. James Evaskevich, James Glessing, Randall Faminow, Lorne Simpson, Gordon Bowerman, Robert Weir and Alan Pettie subscribed for 1,457,000 shares for gross proceeds of $851,710 (6%) of the financing.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal office located in Calgary, Alberta.

MATERIAL CONTRACTS

The Corporation did not enter into any material contracts outside the ordinary course of business within the most recently completed financial year or prior thereto that are still in effect.

INTERESTS OF EXPERTS

Deloitte prepared the 2013 Reserves Report referred to in this Annual Information Form. As of the date hereof, the partners, employees and consultants of Deloitte who participated in or who were in a position to directly influence the preparation of the 2013 Reserves Report do not hold any of the securities of the Corporation.

KPMG LLP has confirmed that it is independent of the Corporation in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Corporation's information circular dated April 22, 2014. Additional financial information is also provided in the Corporation's consolidated financial statements and MD&A for the year ended December 31, 2013.

SCHEDULE "A"
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Yangarra Resources Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Management /Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Yangarra Resources Ltd. Reserve Estimation and Economic Evaluation	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue ($M, before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Deloitte LLP	December 31, 2013	Canada	**-**	**$251,148.30**	**-**	**$251,148.30**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 3P8

(signed) "Douglas S. Ashton"
Douglas S. Ashton, P. Eng.
Associate Partner

Execution date: March 21, 2014

SCHEDULE "B"
REPORT OF MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Management of Yangarra Resources Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation and, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed) "James Evaskevich"	*(signed) "James Glessing"*
James Evaskevich	James Glessing
President and CEO	CFO
(signed) "Robert Weir"	*(signed) "Gordon Bowerman"*
Robert Weir	Gordon Bowerman
Director	Director

March 21, 2014

SCHEDULE "C"

AUDIT COMMITTEE CHARTER

All of the Audit Committee members shall be independent and financially literate within the meaning of National Instrument 52-110 or its successor or replacement policy (the "**Instrument**") or as the case may be exempt from the requirements of sections 1.4 and 1.5 of the Instrument in accordance with the Instrument provisions.

Meaning of Financial Literacy — For the purposes of this Mandate, an individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

The Audit Committee shall meet at least four times per year, on a quarterly basis, to fulfill its mandate.

The Audit Committee shall recommend to the Board of Directors:

(a) the external auditor to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation; and

(b) the compensation of the external auditor.

The Audit Committee is directly responsible for overseeing the work of the external auditor engaged for the purposes of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditor regarding financial reporting.

The Audit Committee shall pre-approve all non-audit services to be provided to the Corporation or its subsidiaries' entities by the Corporation's external auditor.

The Audit Committee shall review the Corporation's financial statements, MD&A and annual and interim profit or loss press release before the Corporation publicly discloses this information.

The Audit Committee must satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the public disclosure referred to in the paragraph above, and must periodically assess the adequacy of those procedures.

The Audit Committee must establish procedures for:

(a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal controls, or auditory matters; and

(b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

The Audit Committee shall review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.