

FORM 51-101F1
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION OF
YANGARRA RESOURCES LTD.

Statements in this document may contain forward-looking information. Estimates provided for 2010 and beyond are based on assumptions of future events and actual results could vary significantly from these estimates. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted as a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Corporation. The reader is cautioned not to place undue reliance on this forward-looking information.

PART 1 DATE OF STATEMENT

This Statement of Reserves Data and Other Oil and Gas Information of Yangarra Resources Ltd. (“Yangarra” or the “Company”) is dated April 20, 2010. The effective date of the information provided in this Statement is December 31, 2009 unless otherwise indicated. The information was prepared between December 31, 2009 and April 20, 2010.

All dollars are Canadian dollars unless otherwise specified.

PART 2 DISCLOSURE OF RESERVES DATA

In accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, AJM Petroleum Consultants (“AJM”) prepared a report (the “AJM Report”) dated April 20 2010, in which it evaluated as at December 31, 2009, Yangarra’s oil, natural gas liquids (“NGL”), and natural gas reserves.

The reserves definition and ownership classification used in this evaluation are the standards defined by COGEH reserve definitions and consistent with NI 51-101 and used by AJM Petroleum Consultants.

The tables below are a summary of the oil, NGL and natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the AJM Report based on forecast price and cost assumptions. The net present value of future net revenue attributable to the Company’s reserves is stated without provision for financing and general and administrative costs, but includes estimates of royalties, production costs, developments costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by AJM.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company’s reserves estimated by AJM represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates for the Company’s oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The AJM Report is based on certain factual data supplied by the Company and AJM’s opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company’s petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to AJM and accepted without any further investigation. AJM accepted this data as presented and neither title searches nor field inspections were performed.

Item 2.1 RESERVES DATA (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES BASED ON FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2009

Reserves Category	Light and Medium Oil		Natural Gas Solution		Natural Gas (Associated & Non-Associated)		Natural Gas Liquids	
	Gross (Mstb)	Net (Mstb)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mstb)	Net (Mstb)
Proved Developed Producing	12.6	10.1	3.6	2.7	1,957.3	1,756.3	23.7	14.8
Proved Developed Non-Producing	4.6	3.9	5.2	4.5	1,350.9	1,128.4	6.3	3.3
Proved Undeveloped	84.6	60.3	20.7	14.9	3,773.9	3,210.0	56.0	38.7
Total Proved	101.7	74.4	29.5	22.1	7,082.0	6,094.7	86.1	56.8
Probable	192.9	129.7	157.0	120.1	6,841.4	5,421.7	109.1	74.3
Total Proved Plus Probable	294.6	204.1	186.5	142.2	13,923.4	11,516.5	195.2	131.1

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2009

Reserves Category	Before Income Taxes				
	0.0% (M\$)	5.0% (M\$)	10.0% (M\$)	15.0% (M\$)	20.0% (M\$)
Proved Developed Producing	6,720.5	5,849.2	5,277.9	4,858.8	4,529.0
Proved Developed Non-Producing	4,716.6	3,872.6	3,229.9	2,729.7	2,333.1
Proved Undeveloped	12,626.3	9,796.5	7,684.2	6,078.5	4,837.4
Total Proved	24,063.3	19,518.3	16,192.0	13,667.0	11,699.5
Probable	39,808.9	28,726.3	21,705.2	16,963.1	13,601.7
Total Proved Plus Probable	63,872.2	48,244.5	37,897.2	30,630.0	25,301.2

Reserves Category	After Income Taxes				
	0.0% (M\$)	5.0% (M\$)	10.0% (M\$)	15.0% (M\$)	20.0% (M\$)
Proved Developed Producing	6,720.5	5,849.2	5,277.9	4,858.8	4,529.0
Proved Developed Non-Producing	4,716.6	3,872.6	3,229.9	2,729.7	2,333.1
Proved Undeveloped	12,626.3	9,796.5	7,684.2	6,078.5	4,837.4
Total Proved	24,063.3	19,518.3	16,192.0	13,667.0	11,699.5
Probable	31,908.3	23,062.0	17,468.2	13,687.5	11,002.9
Total Proved Plus Probable	55,971.6	42,580.2	33,660.2	27,354.5	22,702.4

Note

M\$ = Thousands of Dollars

Values may not add due to rounding

Taxpool: Yangarra Tax Pool Vintage: 2010: Canada.

Unit Value calculation based on Net BOE reserves

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2009**

Reserves Category	Revenue * (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development 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	17,263.0	2,217.5	5,860.3	0.0	2,464.7	6,720.5	0.0	6,720.5
Proved Developed Non-Producing	10,855.9	1,782.7	3,480.4	876.2	0.0	4,716.6	0.0	4,716.6
Proved Undeveloped	39,943.1	6,931.9	9,170.6	10,194.4	1,019.9	12,626.3	0.0	12,626.3
Total Proved	68,062.0	10,932.2	18,511.3	11,070.6	3,484.6	24,063.3	0.0	24,063.3
Total Probable	84,579.0	19,067.3	18,511.7	6,635.2	555.8	39,808.9	7,900.6	31,908.3
Proved Plus Probable	152,640.9	29,999.5	37,023.0	17,705.8	4,040.4	63,872.2	7,900.6	55,971.6

Taxpool: Yangarra Tax Pool Vintage: 2010: Canada.

** Revenue includes product revenue and other income from facilities, wells and corporate if specified.*

**NET PRESENT VALUES OF FUTURE NET REVENUE
BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2009**

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)	2,111.6	\$31.00
	Associated and Non-Associated Gas (including by-products)	14,080.3	\$13.00
	TOTAL	16,192.0	\$14.07
Proved Plus Probable	Light and Medium Oil (including solution gas and by-products)	6,706.1	\$30.50
	Associated and Non-Associated Gas (including by-products)	31,191.1	\$15.15
	TOTAL	37,897.2	\$16.63

Notes to Reserves Tables:

- (1) Columns may not add due to rounding.
- (2) M\$ = Thousands of Dollars
- (3) The Company has no non-conventional gas or oil activities.

"**Gross Reserves**" are the Company's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interest of the Company.

"**Net Reserves**" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalties interests in reserves.

"**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.

PART 3 PRICING ASSUMPTIONS

Item 3.1 Forecast Prices Used in Estimates

The forecast price and market forecasts are based on yearly variable factors weighted to higher percent in current data and reflecting a higher percent to the prior year historical. AJM's forecast 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.

AJM's forecast used the following exchange rates:

	Price Inflation Rate	Cost Inflation Rate	Cdn to US Exchange Rate
2003	2.8%	2.8%	\$0.710
2004	1.8%	1.8%	\$0.770
2005	2.2%	2.2%	\$0.823
2006	2.0%	2.0%	\$0.882
2007	2.1%	2.1%	\$0.921
2008	2.4%	2.4%	\$0.951
2009	0.4%	0.4%	\$0.874
2010	0.0%	0.0%	\$0.950
2011	2.0%	2.0%	\$0.950
2012	2.0%	2.0%	\$0.950
2013	2.0%	2.0%	\$0.950
2014 beyond	2.0%	2.0%	\$0.950

Oil, NGLs, and natural gas base case prices, utilized by AJM in the AJM Report were as follows:

**Summary of Pricing Assumptions
Price Forecast Used in Estimates**

Year	Oil			Natural Gas			Natural Gas Liquids		
	WTI Cushing (Oklahoma) (\$US/bbl)	Edmonton City Gate 40° API (\$Cdn/bbl)	Bow River 25° API Hardisty (\$Cnd/bbl)	Alberta AECO – Gas Prices (\$Cdn/mcf)	Alberta Direct Plant Gate Sales (\$Cdn/mcf)	Alberta System Plant Gate Sales (\$Cdn/Mcf)	Pentanes + Condensate Edmonton (\$Cdn/bbl)	Butanes Edmonton (\$Cdn/bbl)	Propane Edmonton (\$Cdn/bbl)
Historical									
2003	\$31.01	\$43.51	\$32.96	\$6.70	\$6.53	\$6.11	\$45.18	\$36.03	\$32.31
2004	\$41.45	\$52.96	\$38.01	\$6.57	\$6.40	\$6.32	\$55.49	\$44.07	\$35.20
2005	\$56.61	\$69.33	\$45.68	\$8.78	\$8.61	\$8.56	\$74.67	\$51.91	\$43.23
2006	\$66.06	\$73.34	\$52.04	\$6.54	\$6.35	\$6.63	\$78.19	\$58.16	\$44.11
2007	\$72.38	\$77.09	\$53.86	\$6.44	\$6.22	\$6.31	\$81.67	\$59.40	\$49.77
2008	\$99.58	\$102.83	\$83.97	\$8.18	\$7.94	\$8.13	\$109.80	\$83.56	\$56.94
2009	\$61.60	\$66.00	\$59.72	\$3.94	\$3.72	\$3.92	\$68.99	\$55.69	\$33.13
Forecast									
2010	\$75.00	\$77.55	\$60.55	\$5.80	\$5.60	\$5.50	\$81.45	\$62.05	\$42.65
2011	\$81.60	\$84.45	\$66.45	\$6.70	\$6.50	\$6.40	\$88.65	\$67.55	\$46.45
2012	\$85.85	\$88.90	\$69.90	\$7.05	\$6.85	\$6.75	\$93.35	\$71.10	\$48.90
2013	\$90.20	\$93.45	\$73.45	\$7.45	\$7.25	\$7.15	\$98.15	\$74.75	\$51.40
2014	\$97.40	\$101.05	\$79.05	\$7.55	\$7.35	\$7.25	\$106.10	\$80.85	\$55.60
2015	\$104.90	\$108.85	\$86.85	\$7.75	\$7.55	\$7.55	\$114.30	\$87.10	\$59.85

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.
- System gas prices includes TCGSL, Progas, Pan Alberta and Alliance
- 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.
- The Alberta Royalty Tax Credit (ARTC) was eliminated effective January 1, 2007.

Weighted average historical prices realized by Yangarra for the year ended December 31, 2009 before transportation were \$5.37/Mcf for natural gas, \$38.03/Bbl for NGLs and \$62.56/Bbl for oil. Yangarra had a minimal amount of oil production in 2009 which is included with natural gas liquids production in its financial statements.

PART 4 RECONCILIATIONS OF CHANGES IN RESERVES
Item 4.1 Reconciliations of Changes in Reserves

The following table sets out a reconciliation of the changes in the Company's reserves as at December 31, 2009 against such reserves at December 31, 2008 based on forecast prices and cost assumptions:

	Light and Medium Oil			Natural Gas Liquids			Associated & Non-Associated Gas		
	Gross Proved (Mstb)	Gross Probable (Mstb)	Gross Proved Plus Probable (Mstb)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
Opening Balance	36.8	51.3	88.2	59.3	27.1	86.5	7,263.1	6,633.9	13,897.0
Drilling and Improved Recovery	28.0	10.0	38.0	47.5	89.6	137.0	1,181.4	1,724.3	2,905.7
Technical Revisions	41.8	127.3	169.2	-16.9	-8.6	-25.5	-227.7	-907.3	-1,134.9
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-1.4	4.3	2.7	2.2	1.0	3.1	-818.3	-124.7	-943.1
Production	-3.5	0.0	-3.5	-5.9	0.0	-5.9	-614.8	0.0	-614.8
Closing Balance	101.7	192.9	294.6	86.1	109.1	195.2	7,111.5	6,998.4	14,109.9

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

The following table sets forth the gross volumes of probable undeveloped reserves, each by product type, attributed to Yangarra's assets for the years ended December 2009, 2008, and 2007 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped reserves

Year	Light and Medium Oil (Mbbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbbl)
Prior thereto	-	-	-
2003	-	5,469.0	128.3
2004	-	3,728.0	42.8
2005	-	4,802.0	59.4
2006	-	3,349.0	65.0
2007	12.0	4,310.0	40.9
2008	25.2	3,738.7	31.9
2009	84.6	3,773.9	56.0

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 AJM Report to develop these reserves. Yangarra plans to develop the proved undeveloped reserves within the next two years.

Probable undeveloped reserves

Year	Light and Medium Oil (Mbbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbbl)
Prior thereto	-	-	-
2003	-	5,197.0	53.2
2004	77.5	4,191.0	97.3
2005	28.0	5,772.0	78.0
2006	18.6	7,139.0	132.2
2007	44.0	5,321.1	42.9
2008	51.3	6,550.6	27.1
2009	192.9	6,841.4	109.1

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 (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.

Item 5.2 Significant Factors or Uncertainties

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

The Company's oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company and have been disclosed in financial statements and management's discussion and analysis as filed on SEDAR (www.sedar.com). Please refer to these documents for a discussion of these matters.

Item 5.3 Future Development Costs

The following table sets forth development costs deducted in the estimation of the Company'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)
2010	3,455.6	7,742.5
2011	6,574.5	8,033.1
2012	1,040.4	1,654.2
2013	-	275.9
Thereafter	-	-
Total for all years undiscounted	11,070.6	17,705.8

Yangarra expects that such funding of its share of future development on capital expenditure programs will be primarily obtained from a combination of cash flow from operations, sale of non-core properties and potential future equity offerings.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

The following table sets forth Yangarra's principal oil and natural gas properties as at December 31, 2009. The Company's proved plus probable reserves information is at December 31, 2009.

	Oil		Natural Gas	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Medicine Hat, Alberta				
Producing	-	-	30.0	30.0
Non-producing	-	-	51.0	51.0
Ferrier, Alberta				
Producing	1.0	0.31875	8.0	2.737
Non-producing	-	-	12.0	7.336
Jaslan, Alberta				
Producing	-	-	8.0	6.125
Non-producing	-	-	1.0	0.750
Viking South, Alberta				
Producing	-	-	3	0.75
Non-producing	-	-	-	-

MEDICINE HAT

Yangarra holds 100% working interest in a total of 84 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. A 100% owned compressor station, capable of 4.0 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. Plans for Medicine Hat area includes further development of the Bow Island U Pool and the shallow gas well horizons. Wells assigned reserves that are drilled and capable of producing and have been but not tied in, will be tied in as development of the field reaches these outlying wells.

FERRIER

Yangarra holds interests ranging from 24.375 to 100% working interest position in 26 sections in this multi-zone area. 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 the compressor station capable of 10 Mmcfd constructed in early 2004, which also processes third party volumes providing the Company incremental profit. To year end, a total of 24 wells, (3 oil, 17 gas, 4 abandoned) have been drilled, re-entered, or acquired in this area.

JASLAN

The Jaslan/Grasslands property is located 100 miles north east of Edmonton and consists of 12 sections (100% working interest) in the north block (Grasslands), and 5.25 sections (37.5% working interest) in the south block (Jaslan). A compressor station capable of 3.0 million cubic feet per day (45% working interest) and gathering system was completed in November 2006. In the Grasslands sections, three 100% working interest wells were tied in to the Jaslan compressor gas gathering system in 2009. To year end, five wells had been drilled in the north block, and a total of five wells have been drilled or re-entered in the south block.

VIKING SOUTH

Yangarra holds a 25% working interest in three wells in the Viking area, located 12 miles northwest of Wainwright, Alberta.

Item 6.2 Properties With No Attributed Reserves

<u>Location</u>	<u>Undeveloped Hectares</u>	
	<u>Gross</u>	<u>Net</u>
Alberta	22,656	19,052.08

An independent Seaton Jordon Evaluation of these properties had an estimated a value of \$ 2,430,577 as of December 31, 2009.

There are no work commitments on the undeveloped land holdings in which Yangarra has an interest in.

The Company expects that rights to explore, develop, and exploit 10,271 net hectares of undeveloped land holdings will expire within one year, but intends to drill or submit applications to continue selected portions of the above acreage. In addition, land holdings of ~6.8 sections in Saskatchewan expired within the first 3 months on the 2010 year, and the Company has subsequently abandoned the wells on those associated mineral rights.

Item 6.3 Forward Contracts

At December 31, 2009 the Company was committed to a commodity price risk contract for the sales of natural gas: 1,000 GJ/d for January, 2010 at a fixed price of \$5.51 per GJ, 1,000 GJ/d for February, 2010 at a fixed price of \$.5.53 per GJ, and 500 GJ/d from January to December 2010 at a fixed price of \$5.68 per GJ. In March 2010, the Company unwound all outstanding commodity contracts for which it received \$73,500 in cash and has no outstanding commodity contracts in place at date of this report.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

AJM has included well abandonment costs at a rate of \$20,000 per 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”. AJM’s report does not address wellsite reclamation for existing wells, pipeline right-of-ways, and facility abandonment/salvage costs including potential environmental concerns. Abandonment costs for new locations for the Company are included at the entity level at a cost of \$40,000 per well and include reclamation costs, also taken from the ERCB Directive 011.

Yangarra has 100 net 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 \$3,484.6 M (undiscounted), and \$1,685.58M (discounted at 10%). The total proved plus probable abandonment and reclamation costs are \$4,040.4 M (undiscounted), and \$1,569.48 M (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Company in respect of proved and proved plus probable reserves as disclosed above. Abandonment and reclamation estimated costs are included in the AJM 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%)
2010	0.0	0.0
2011	65.3	56.39
2012	197.7	155.20
2013	321.5	230.36
2014	396.2	258.04
Thereafter	2,503.9	985.59
Total	3,484.6	1,685.58

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

Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Discounted at 10%)
2010	0.0	0.0
2011	65.3	56.39
2012	190.4	149.49
2013	181.5	130.01
2014	244.6	159.34
Thereafter	3,358.6	1,074.25
Total	4,040.4	1,569.48

Item 6.5 Tax Horizon

Yangarra was not required to pay income tax in 2009. Based on current tax pools, projected cash flow, and projected exploration costs, the Company does not expect to be taxable in 2010.

Item 6.6 Costs Incurred

The following summarizes certain expenditures related to Yangarra's activities for the year ended December 31, 2009

	<u>Year Ended December 31, 2009</u>
Property acquisitions	
Proved	-
Unproved	237,407
Exploration Costs	929,133
Development Costs	448,421

Item 6.7 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, 2009.

Exploration Wells	<u>Gross</u>	<u>Net</u>	Development Wells	<u>Gross</u>	<u>Net</u>
Light and Medium Oil	-	-	Light and Medium Oil	-	-
Natural Gas	2.0	2.0	Natural Gas	1.0	1.0
Service	-	-	Service	-	-
Dry	1.0	1.0	Dry	-	-
Total	<u>3.0</u>	<u>3.0</u>	Total	<u>1.0</u>	<u>1.0</u>

Item 6.8 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 Probable Reserves		
	Light and medium oil (Bbls/d)	Natural Gas (MMcf/d)	Natural Gas Liquids (Bbls/d)	Light and medium oil (Bbls/d)	Natural Gas (MMcf/d)	Natural Gas Liquids (Bbls/d)
Medicine Hat	-	0.49	-	-	0.55	-
Ferrier	13.8	0.36	21.8	28.7	0.49	29.8
Jaslan	-	0.09	-	-	1.05	-

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

Item 6.9 Production History

Average Daily Production

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil (bbl/d)	12.4	11.8	12.6	10.5
Natural gas (mcf/d)	1,795.9	1,686.1	1,494.7	1,362.2
Natural gas liquids (bbl/d)	17.8	12.9	17.6	11.7
Total (BOE/d)	329.6	305.7	279.3	249.2

Prices Received, Royalties Paid, Production Costs and Net backs

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)	\$48.06	\$63.82	\$69.94	\$69.07
Natural gas (\$/mcf)	\$5.61	\$5.20	\$5.55	\$5.06
Natural gas liquids (\$/bbl)	\$40.73	\$36.55	\$28.24	\$50.37
BOE (\$ / BOE)	\$34.59	\$32.69	\$34.61	\$32.91

Royalties Paid per Unit

Three months ended	March 31	June 30	Sept 30	Dec 31
Total royalties per BOE (\$/BOE)	\$2.15	\$0.56	\$1.09	\$3.82

Production and Transportation Costs

Three months ended	March 31	June 30	Sept 30	Dec 31
Total costs per BOE (\$/BOE)	\$11.20	\$12.96	\$16.75	\$44.02

Netbacks Received

Three months ended	March 31	June 30	Sept 30	Dec 31
Total netbacks per \$/BOE	\$21.24	\$19.17	\$16.77	\$(14.93)

Production Volume by Field

The following table indicates the Company's average daily production from its important fields for the year ended December 31, 2009:

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
Medicine Hat	-	609	-	102
Ferrier	12	284	14	73
Jaslan	-	657	-	109