Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the December 31, 2010 audited consolidated financial statements of Yangarra Resources Ltd. (the "Yangarra" or "Company"), together with the accompanying notes.

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

The MD&A has been prepared using information that is current to ***April 19, 2011.***

The financial information presented herein has been prepared on the basis of Canadian generally accepted accounting principles ("GAAP"). Throughout this discussion, percentage changes are calculated using numbers rounded to the decimal to which they appear. All references to dollar amounts are in Canadian dollars.

The comparative results included herein for the three months and year ended December 31, 2010 are those of Yangarra only.

On December 31, 2009, the Company acquired all of the issued and outstanding shares of Athabaska Energy Ltd. ("Athabaska"), a non-arm's length private corporation, in exchange for 10,000,001 common shares of the Company. On May 1, 2010, the Company and Athabaska were amalgamated and continue to carry on business under the name Yangarra Resources Ltd. At this time, the Company consolidated its common shares on a five old for one new (5:1) basis. All common share, warrant and stock option figures disclosed herein are presented on a consolidated basis.

BOE Presentation – *Production information is commonly reported in units of barrel of oil equivalent ("boe"). For purposes of computing such units, natural gas is converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalent wellhead value for the individual products. Such disclosure of boe may be misleading, particularly if used in isolation. Readers should be aware that historical results are not necessarily indicative of future performance.*

Special Note Regarding Non-GAAP Measures *– This MD&A includes references to financial measures commonly used in the oil and gas industry. The terms "**net petroleum and natural gas revenue**" (petroleum and natural gas sales less royalties, production expenses and transportation costs) and "**funds flow from operations**" (net loss for the period adjusted for non-cash items in the statement of operations) are not GAAP measures and do not have standardized meanings prescribed by GAAP.*

Forward-looking Statements – *Certain information regarding the Company set forth in this report, including management's assessment of the Company's future plans and operations, contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks and uncertainties, many of which are beyond the Company's control, include the impact of general economic conditions and specific industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. The Company's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits the Company will derive from such events.*

Company Description and Outlook

Yangarra is a junior oil and gas company engaged in the exploration, development and production of natural gas and oil with operations in Western Canada, with a main focus on Central Alberta, where the Company has extensive infrastructure and land holdings.

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

During the year ended December 31, 2010 the Company completed the following significant milestones:

- Purchased a 15% gross sliding scale over-ride on 11 sections in the Willesden Green area.
- Completed equity raises in March, May, June and October for total proceeds of $23 million, with each equity raise priced at a premium to the previous financing.
- Secured a drilling rig for the balance of 2010, through to spring breakup 2011 and exercised an option to retain the drilling rig through spring breakup 2012.
- Completed an asset acquisition in the Willesden Green/Ferrier area of Alberta for $4.0 million.
  - The asset included 31 sections of land (12.3 net), 10 gross producing wells (4.25 net) and 9 gross standing wells (4.8 net) with 50 boe/d, 90% weighted to oil, of production.
- Entered into a credit facility agreement with Alberta Treasury Branches in November 2010 and increased the facility to $12,000,000 in December 2010.
  - Credit facility increased to $14.5 million in first quarter of 2011

Subsequent to the year ended December 31, 2010 the Company completed the following :

- Established a capital budget for 2011 of $50 million which includes the drilling of 31 gross (13.7 net wells)
- Significantly increased the Company's future drilling locations to 123 gross (70.2 net) locations in the Glauconite, Cardium and multiple other zones

The following is a list of the initial 30 day production rates ("IP 30") of the horizontal wells that were drilled during 2010:

Location	Horizontal Length	Fracturing	Working Interest (w.i.)	IP	Production
06-03-41-7W5 Glauconite (operated)	710 m	8 stages 200 tonne	100% w.i.	IP 30	602 boe/d
09-20-41-7W5 Cardium (non-operated)	699 m	5 stages 150 tonne	68.15% w.i. plus 15% override	IP 30	85 boe/d
07-20-41-7W5 Cardium (operated)	725 m	8 stages 200 tonne	68.15% w.i. plus 15% override	IP 30	324 boe/d
13-02-41-7W5 Glauconite (operated)	1106 m	12 stages 300 tonne	68.15% w.i. plus 15% override	IP 30	760 boe/d
14-36-37-8W5 Cardium (operated)	550 m	6 stages 300 tonne	100% w.i.	IP 30	50 boe/d (on restricted production)
1-20-41-7W5 Cardium (operated)	1,067 m	6 stages 300 tonne	68.15% w.i. plus 15% override	IP 30	285 boe/d

Summary Financial Information

	For the Years ended December 31		
	2010	2009	2008
Statement of Operations and Deficit			
Petroleum & natural gas sales	$ 6,534,377	$ 3,579,738	$ 8,642,336
Net (loss) income for the period	$ (4,047,125)	$ (7,268,020)	$ (1,825,080)
Net (loss) income per share - basic	$ (0.07)	$ (0.46)	$ (0.15)
Weighted average number of shares - basic	57,581,832	15,662,664	13,499,997
Statement of Cash Flows			
Funds flow from operations	$ 2,959,286	$ 106,856	$ 3,820,278
Balance Sheet			
Property and equipment	$ 61,475,178	$ 38,830,516	$ 41,922,138
Total assets	$ 65,945,647	$ 39,641,449	$ 44,081,309
Preferred shares	$ 1,000,000	$ 1,000,000	$ -

Business Environment

	For the Years ended December 31	
	2010	2009
West Texas Intermediate ("WTI") (US$/bbl)	$ 78.48	$ 61.80
AECO gas (Cdn$/GJ)	$ 4.08	$ 3.75
Foreign Exchange (Cdn$/US$)	$ 1.030	$ 1.142

Crude oil prices strengthened in 2010, with West Texas Intermediate ("WTI") reference price averaging US$78.48 per barrel compared to US$61.80 per barrel in 2009. Demand for crude oil is generally tied to global economic growth, but is also influenced by factors such as political instability, market uncertainty, weather conditions and government regulations. The WTI forward strip price for the remainder of 2011 is over US$100.

Oil prices in Canada are also affected by the Canada/US dollar exchange rate since the WTI reference price of oil is in US dollars. During 2010, the Canadian dollar strengthened against the US dollar, averaging Cdn$1.030 to US$1 compared with Cdn$1.142 to $US1 in 2009. The strengthening dollar partially offsets the increased WTI benchmark pricing experienced during 2010.

AECO natural gas prices for 2010 increased to $4.08 per GJ from $3.75 per GJ in 2009. Demand from the price sensitive power and industrial sectors and hot weather patterns in the Northeast part of the United States temporarily offset the strong incremental production from shale gas plays. Although natural gas prices have recovered compared to a weak 2009 price environment, strong US natural gas production is limiting the upside to natural gas price recovery.

Results of Operations

Net petroleum and natural production, pricing and revenue

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Daily production volumes				
Natural Gas (mcf/d)	2,564	1,362	2,151	1,583
Oil (bbl/d)	260	11	116	12
NGL's (bbl/d)	54	12	28	15
Royalty income (boe/d)	19	-	6	-
Combined (boe/d 6:1)	761	249	509	291
Product pricing				
Oil ($/bbl)	$ 80.54	$ 69.07	$ 74.70	$ 65.56
NGL ($/bbl)	$ 62.30	$ 50.37	$ 56.04	$ 38.03
Gas ($/mcf)	$ 3.93	$ 3.69	$ 3.92	$ 3.88
Combined ($/boe)	$ 40.94	$ 32.91	$ 35.55	$ 33.74
Revenue				
Petroleum & natural gas sales - Gross	$ 2,864,802	$ 754,728	$ 6,534,377	$ 3,579,738
Royalty income	$ 93,882	$ -	$ 123,106	$ -
Royalty expense	$ (128,984)	$ (87,683)	$ (165,309)	$ (195,223)
Royalty recovery		$ 114,092		$ 289,728
Petroleum & natural gas sales - Net	$ 2,829,700	$ 781,137	$ 6,492,174	$ 3,674,243

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Production by Area (boe/d)				
Willesden Green/Ferrier	546	72	244	73
Willesden Green/Ferrier - royalty income	19	-	6	-
Medicine Hat	87	90	93	102
Jaslan	98	80	153	109
Other	11	7	13	7
Total	761	249	509	291

The increased production in 2010 can be attributed to the drilling program in Central Alberta. The initial 100% owned Glauconite horizontal well in the area was drilled in May which resulted in additional flush oil production in May. This well along with a second horizontal Cardium well were placed on full production in early August. Four additional horizontal wells were drilled over the remainder of the year, three Cardium and one Glauconite. Two of these wells were put on production in the fourth quarter, while the last two were not on production until the first quarter of 2011. These wells have significantly higher rates than the Company's traditional gas wells in the Jaslan and Medicine Hat area and have resulted in significant production increases from 2009. The overall average price earned by the Company was higher when compared to 2009 due to increased oil and natural gas liquids production (29% compared to 5% in 2009).

For the year ended December 31, 2010, the Company's production was more heavily weighted to oil (24% oil, 5% NGL and 71% natural gas) than the 2009 comparative period (4% oil, 5% NGL and 91% gas), this caused the overall average 2010 price to be higher as the realized price for oil and liquids in the 2010 period improved.

Included in petroleum and natural gas revenue for the three and twelve months ended December 31, 2010 is nil and $31,131, respectively, of realized gains on the fulfilled portion of commodity contracts from January 1 to March 31, 2010. Including the realized gains, the average gas price earned by the Company for the twelve month 2010 period increased to $4.29 per mcf from $4.25 per mcf.

Included in petroleum and natural gas revenue for the three and twelve months ended December 31, 2009 is $232,261 and $920,429, respectively, of realized gains on the fulfilled portion of commodity contracts from April 1 to December 31, 2009. Including the realized gains, the average gas price earned by the Company for the three and twelve months ended December 31, 2009 was $5.06 per mcf and $5.37 per mcf, respectively.

Royalty Income

	Three months ended December 31 2010	Three months ended December 31 2009	Years ended December 31 2010	Years ended December 31 2009
Royalty income	$ 93,882	$ -	$ 123,106	$ -

The majority of the royalty income is a result of the 15% sliding scale royalty purchased in the Willesden Green area in March 2010.

Royalty Expense

	Three months ended December 31 2010	Three months ended December 31 2009	Years ended December 31 2010	Years ended December 31 2009
Royalty expense	$ 128,984	$ 87,683	$ 165,309	$ 195,223
Per boe	$ 1.84	$ 3.82	$ 0.90	$ 1.84
As a % of sales	5%	12%	3%	5%
Royalty recovery	$ -	$ 114,092	$ -	$ 289,728

During the three and twelve months ended December 31, 2010, the Company received $15,270 and $263,451, respectively, of capital cost allowance, custom processing and operating deductions which are included in royalty expense. The capital cost allowance, custom processing and operating deductions in the three month period ended September 30, 2010 was $124,018 which caused the increase in royalty in the fourth quarter of 2010. The crown royalty rate on the new horizontal wells in Willesden Green is 5% for the earlier of 2 years or 60,000 boe of production.

During 2009, the Company recognized a recovery in the amount of $289,728 related to freehold and gross overriding royalties calculated and paid in previous years.

Production and Transportation Costs

	Three months ended December 31 2010	Three months ended December 31 2009	Years ended December 31 2010	Years ended December 31 2009
Production costs	$ 738,831	$ 954,655	$ 1,820,683	$ 1,994,861
Per boe	$ 10.56	$ 41.63	$ 9.91	$ 18.80
Transportation costs	$ 72,990	$ 54,810	$ 237,893	$ 137,692
Per boe	$ 1.04	$ 2.39	$ 1.29	$ 1.30

	Three months ended December 31 2010	Three months ended December 31 2009	Years ended December 31 2010	Years ended December 31 2009
Operating costs for core areas				
Willesden Green/Ferrier	$ 8.91	$ 8.93	$ 9.25	$ 31.83
Medicine Hat	$ 21.88	$ 24.13	$ 23.49	$ 23.55
Jaslan	$ 8.31	$ 5.31	$ 12.81	$ 7.30

Production and transportation costs per boe have dropped in 2010 due to increased production in areas with facilities in place and where the majority of the costs are fixed. Operating and transportation costs per boe in the Willesden Green area are expected to continue to decline as more production is brought on stream and fixed costs are shared over higher volumes. Lower volumes in Medicine Hat will likely increase operating costs during 2011 in that area.

Operating Netback

$/boe	Three months ended December 31 2010	Three months ended December 31 2009	Years ended December 31 2010	Years ended December 31 2009
Revenues	$ 40.94	$ 32.91	$ 35.55	$ 33.74
Royalty income	1.34	-	0.67	-
Royalty expense	(1.84)	(3.82)	(0.90)	(1.84)
Production costs	(10.56)	(41.63)	(9.91)	(18.80)
Transportation costs	(1.04)	(2.39)	(1.29)	(1.30)
Netback	$ 28.83	$ (14.93)	$ 24.12	$ 11.80

Netbacks were stronger due to higher oil and liquid sales and therefore higher relative prices to natural gas. The higher oil and liquid sales were a result of the Company's focus on Glauconite and Cardium wells in Willesden Green versus the gas-weighted Medicine Hat and Jaslan areas in 2009. The Company has also lowered operating costs as economies of scale are being realized in the Willesden Green/Ferrier due to increasing volumes.

As the Company continues to focus drilling in Central Alberta it expects netbacks to continue to rise as a result of both the increased proportion of oil and liquids and the continued decrease in operation costs.

Depletion, depreciation and accretion

	Three months ended December 31 2010	Three months ended December 31 2009	Years ended December 31 2010	Years ended December 31 2009
Depletion and depreciation	$ 2,532,404	$ 816,289	$ 6,066,568	$ 8,064,412
Per boe	$ 36.19	$ 35.60	$ 33.01	$ 76.00
Accretion	$ 46,478	$ 37,077	$ 173,703	$ 146,621

Depletion and depreciation per boe decreased in 2010 compared to 2009 due to: (1) an increase in the Company's proved reserves from that stated in the December 31, 2009 external reserve report; (2) the reclassification of reserves from the probable to proved category in the current period as a result of drilling activity; and (3) the addition of proved reserves related to a gross overriding royalty acquired in March 2010.

The 2009 depletion rates include the effect of a ceiling test impairment in the amount of $4,300,000. The continued lower commodity prices combined with a decline in some of the Company's probable reserves resulted in the Company's net book value of its assets at September 30, 2009 being greater than the value as determined by the ceiling test.

Accretion expense increased in 2010 due to an increase in the undiscounted cash flows associated with the retirement of the Company's assets resulting from the increase in the number of properties and changes to certain reserve life and cost estimates.

Other expenses

	Three months ended December 31 2010	Three months ended December 31 2009	Years ended December 31 2010	Years ended December 31 2009
General and administrative expenses	$ 380,831	$ 333,256	$ 1,161,575	$ 898,084
Interest and financing fees	$ 94,780	$ 493,200	$ 265,251	$ 1,295,660
Dividends on preferred shares	$ 12,603	$ -	$ 50,000	$ -
Stock-based compensation	$ 961,984	$ 206,091	$ 1,746,939	$ 206,091

General and administrative expenses were higher in the 2010 periods due to an increase in professional fees related to the yearend audit, salaries/consulting fees related to new employees/consultants commensurate with the increase in the Company's exploration and development activities and legal fees related to a dispute with a joint venture partner.

Interest and financing fees for the three and twelve months ended December 31, 2010 is for interest on the revolving operating demand loan for which the average amount drawn in 2010 was $6,200,000 at an effective interest rate of 4.0%.

Interest and financing fees for the three and twelve months ended December 31, 2009 were significantly higher on a comparative basis as they included:

- $91,142 and $394,644, respectively, on the revolving operating demand loan for which the average amount drawn during the 2009 period was $8,175,000 at an effective interest rate of 4.8% plus other fees; and

- $250,205 and $732,534, respectively, of interest and financing fees on the subordinated credit facility (settled in December 2009) based on the effective interest method.

Dividends on preferred shares for the three and twelve months ended December 31, 2010 are at a rate of 5% payable semi-annually in cash or common shares of the Company on $1,000,000 of preferred shares issued in December 2009 in conjunction with the settlement of the subordinated credit facility.

During the year ended December 31, 2010, the Company granted a total of 4,570,000 stock options which vested immediately. The total fair value of the options was estimated at $2,817,600 of which $1,746,939 was recognized as stock-based compensation expense ("SBC") and $1,070,661 was capitalized to property and equipment. The Company did not grant any options in the 2009 comparative period.

Commodity price risk contracts

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Commodity contract settlement	$ (32,766)	$ -	$ 40,734	$ -
Change in fair value of commodity contracts	(6,270)	6,983	113,361	(113,361)
	$ (39,036)	$ 6,983	$ 154,095	$ (113,361)

As at January 1, 2010, the Company was committed to the following commodity price risk contracts for the sale of natural gas:

- 1,000 GJ per day from January 1 to January 31, 2010 at a fixed price of $5.51 per GJ;
- 1,000 GJ per day from February 1 to February 28, 2010 at a fixed price of $5.53 per GJ; and
- 500 GJ per day from January 1 to December 31, 2010 at a fixed price of $5.68 per GJ.

In addition the Company sold calls which provided a ceiling for the price it received for natural gas as follows:

- 500 GJ per day from January 1 to December 31, 2010 at the ceiling price of $6.25 per GJ;
- 500 GJ per day from March 1 to December 31, 2010 at the ceiling price of $6.50 per GJ; and
- 500 GJ per day from March 1 to December 31, 2010 at the ceiling price of $6.70 per GJ.

In March 2010, the Company settled all outstanding commodity price risk contracts for proceeds of $73,500 and reported an unrealized gain of $113,361 related to the reversal of the mark-to-market liability recognized at December 31, 2009.

In September 2010, the Company was committed to a commodity price risk "basis" contract for the sale of 1,000 MMBTU of natural gas per day from November 1, 2010 to March 31, 2011, the terms of which were related to the difference in price between AECO and NYMEX fixed at $0.45 per MMBTU. The Company terminated the contract in November 2010 at a cost of $32,766.

Included in petroleum and natural gas revenue for the year ended December 31, 2010 are $172,345 of realized gains (December 31, 2009 – $920,429) on the fulfilled portion of commodity contracts.

Future income tax reduction

During the year ended December 31, 2010, the Company recognized a $464,897 future tax benefit in share capital for share issue costs incurred in the period and a $356,887 future tax liability in property and equipment and SBC capitalized in the period. During the three and twelve months ended December 31, 2010, the Company recorded a reduction of future income taxes of $255,152 and $1,825,498.

During the three and twelve months ended December 31, 2009, the Company recorded a reduction of future income taxes of $255,152 and $1,825,498 respectively, related to the reversal of temporary differences between the carrying value and tax basis of the Company's property and equipment. Of this temporary timing difference, $1,000,000 related to the effect of the $4.3 million ceiling test impairment that was recorded during the third quarter 2009.

Liquidity and Capital Resources

During the year ended December 31, 2010, the Company generated $2,959,286 of funds flow from operations compared to $106,856 in the 2009 comparative period. Funds flow from operations was higher for the 2010 period due primarily to the increase in petroleum and natural gas revenue and the reduction in interest and financing fees.

As at December 31, 2010, the maximum amount available under the revolving operating demand loan was $12,000,000 (December 31, 2009 – $8,300,000) at an interest rate of bank prime plus 1% per annum, payable monthly, and increased to bank prime plus 1.5% if the Company's net debt to trailing cash flow ratio is equal to or greater than 1 to 1.

As at December 31, 2010, the $5,559,208 (December 31, 2009 – $8,195,069) reported amount of bank debt was comprised of $4,600,000 (December 31, 2009 – $7,800,000) drawn on the revolving operating demand loan and $959,208 (December 31, 2009 – $395,069) of bank overdraft

The Company is compliant with all debt covenants as at December 31, 2010.

As at December 31, 2010, the Company had a working capital deficit of $11,472,461 compared to a deficit of $7,963,051 at December 31, 2009. The change in the Company's working capital position occurred primarily in the fourth quarter as the Company ramped up the drilling program utilizing the proceeds from the October equity financing and the increased credit facility. Production from the wells was not fully online until the first quarter of 2011.

The audited consolidated financial statements have been prepared on a going concern basis which contemplates the realization of assets and the payment of liabilities in the ordinary course of business. Subsequent to December 31, 2010 the Company completed a $17 million equity financing, with completion of the financing the Company's 2010 capital budget is fully funded. Any adverse changes to market conditions can be accommodated by revising the size and timing of the capital program throughout the year

Capital Spending

Capital spending is summarized as follows:

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Land and lease rentals	$ 3,827,343	$ 102,562	$ 5,449,298	$ 237,407
Drilling and completion	10,593,594	262,256	16,777,716	854,518
Geological and geophysical	190,640	42,801	505,583	74,615
Equipment	2,148,426	251,496	4,272,875	448,421
	$ 16,760,003	$ 659,115	$27,005,472	$ 1,614,961

2010 Drilling Activity:

	Three months ended December 30, 2010		Years ended December 31, 2010	
	Gross	Net	Gross	Net
Natural gas	–	–	–	–
Oil	3.0	2.36	6.0	4.0
	3.0	2.36	6.0	4.0

Asset Retirement Obligation

As at December 31, 2010, the undiscounted fair value of the asset retirement obligation associated with the Company's existing properties was estimated to be $4,815,382 for which $2,620,549 has been recorded using a discount rate of 7% - 10%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 10 years.

Off Balance Sheet Arrangements

There were no off balance sheet arrangements, other than the office, field equipment and truck lease commitments which are accounted for as operating leases.

Related Party Transactions

During the three and twelve months ended December 31, 2010 and 2009, the Company was charged or invoiced the following amounts by certain of its officers and directors and by companies controlled by certain of the Company's officers and directors:

	Three months ended December 31		*Years ended December 31*	
	2010	*2009*	*2010*	*2009*
Administration and consulting fees	$ 35,055	$ 121,348	$ 168,270	$ 159,174
Production and capital expenditures	$ 87,698	$ 28,571	$ 614,055	$ 119,865

These transactions were in the normal course of operations and were measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Share Capital

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

	Common Shares	Preferred Shares	Warrants	Stock Options
Balance - December 31, 2009	**37,388,006**	**1,000,000**	**2,000,000**	**3,542,255**
Private placement March 2010	16,000,000	-	8,000,000	-
Private placement May 2010 (Flow-through)	3,745,454	-	-	-
Private placement June 2010 (Flow-through)	1,650,000	-	-	-
Private placement June 2010	1,650,000	-	-	-
Special Warrant Financing October 2010 (Flow-through)	8,666,667	-	-	-
Special Warrant Financing October 2010	10,000,000	-	-	-
Grant of Options	-	-	-	4,570,000
Exercise of Options	70,000	-	-	(70,000)
Expiry of Options	-	-	-	(223,455)
Forfeiture of Options	-	-	-	(35,000)
Exercise of Warrants	548,000	-	(548,000)	-
Balance - December 31, 2010	**79,718,127**	**1,000,000**	**9,452,000**	**7,783,800**
Financing March 2011	23,632,500	-	-	-
Grant of Options	-	-	-	2,620,000
Exercise of Options	260,000	-	-	(260,000)
Expiry of Options	-	-	-	(15,000)
Exercise of Warrants	184,000	-	(184,000)	-
Redemption of Preferred Shares	-	(1,000,000)	-	-
Balance - Date of MD&A	**103,794,627**	**-**	**9,268,000**	**10,128,800**

Subsequent Events

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 of the Company at a price of $0.73 per share for gross proceeds of $17,251,725.

On March 8, 2011, the Company granted options to purchase 2,570,000 common shares at a price of $0.74 per share, pursuant to its stock option plan. The options vested immediately and will expire March 8, 2016. Officers were granted options on 1,250,000 shares, directors were granted options on 200,000 shares, and the balance of the options were issued to employees and consultants.

Contingency

In December 2009, the Company terminated the Standstill Agreement that it had with an industry partner regarding a joint producing property and served that industry partner with a Statement of Claim issued from The Court of Queen's Bench of Alberta, by which the Company claims breach of the agreements between the parties, gross negligence and default of operator. The Company seeks judgment for specified and such further damages to be determined by the Court, as well as appointment as operator. The industry partner has filed a Statement of Defence and Counterclaim. The potential outcome of the lawsuit and claims are undetermined however they may be material. As the likely outcome of this litigation cannot be determined at this time, no provision has been made in the consolidated financial statements.

Commitments

As at December 31, 2010, the Company has until December 31, 2011 to incur $9,690,000 of qualifying flow-through expenditures related to the private placement of flow-through shares issued in May, June and October 2010, of which approximately $3,600,000 has been incurred.

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

2011	$	185,571
2012	$	185,571
2013	$	109,695

Financial instruments and financial risk management

The Company's financial instruments include cash, accounts receivable, accounts payable and accrued liabilities, bank debt, credit facility and preferred shares. The carrying values of accounts receivable, accounts payable and accrued liabilities, bank debt and credit facility approximate their fair values due to their relatively short periods to maturity.

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

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

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

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with the risk management policies as set out herein:

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. A substantial portion of the Company's accounts receivable are with natural gas and liquids marketers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas and liquids are subject to credit review to minimize the risk of non-payment. As at December 31, 2010, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of $3,752,477 (December 31, 2009 – $658,080). As at December 31, 2010, the Company's receivables consisted of $2,611,471 from joint venture partners and other trade receivables and $1,141,005 of revenue receivable from petroleum and natural gas marketers.

Receivables from petroleum and natural gas marketers are typically collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any significant collection issues with its petroleum and natural gas marketers. All of the revenue accruals and receivables from petroleum and natural gas marketers were received in January and February 2011.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company mitigates the risk from joint venture receivables by obtaining partner approval of capital expenditures prior to starting a project. However, the receivables are from participants in the petroleum and natural gas sector, and collection is dependent on typical industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. Further risk exists with joint venture partners as disagreements occasionally arise which increases the potential for non-collection. For properties that are operated by the Company, production can be withheld from joint venture partners who are in default of amounts owing. In addition, the Company often has offsetting amounts payable to joint venture partners from which it can net receivable balances.

The Company did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended December 31, 2010. The Company would only choose to write-off a receivable balance (as opposed to providing an allowance) after all reasonable avenues of collection had been exhausted.

As at December 31, 2010, the Company considers its receivables to be aged as follows:

Not past due	$	2,048,397
Past due by less than 90 days		1,117,588
Past due by more than 90 days		474,910
Related to contingency		111,582
	$	3,752,477

Liquidity risk

Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they are due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation.

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures.

To facilitate the capital expenditure program, the Company has a revolving reserve-based bank facility which is regularly reviewed by the lender. The Company monitors its total debt position monthly. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month. The Company anticipates it will have adequate liquidity to fund its financial liabilities through its future cash flows. The Company's financial liabilities are comprised of accounts payable and accrued liabilities, bank debt and the credit facility, which have expected maturities of less than one year resulting in their current classification on the balance sheet.

Market risk

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

i. Interest rate risk
Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate. For the year ended December 31, 2010, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been $62,000 (December 31, 2009 –$79,750) higher, respectively, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amounts. The Company had no interest rate swap or financial contracts in place at December 31, 2010.

ii. Currency risk
Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. All of the Company's petroleum and natural gas sales are denominated in Canadian dollars, however, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. The Company had no outstanding forward exchange rate contracts in place at December 31, 2010.

iii. Commodity price risk
Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand as well as the relationship between the Canadian and United States dollar, as outlined above. The Company's commodity price risk contracts are disclosed in note 11 of the audited financial statements.

Capital management

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute its capital expenditure program, which includes expenditures in oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include:

	December 31 2010	*December 31 2009*
Shareholders' equity	$ 47,382,168	$ 26,848,381

The Company monitors capital based on annual funds from operations and capital expenditure budgets, which are updated as necessary and are reviewed and periodically approved by the Company's Board of Directors.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions including the current economic conditions, the risk characteristics of the Company's petroleum and natural gas assets, the depth of its investment opportunities, current and forecasted net debt levels, current and forecasted commodity prices and other facts that influence commodity prices and funds from operations such as quality and basis differentials, royalties, operating costs and transportation costs.

In order to maintain or adjust the capital structure, the Company considers its forecasted funds from operations while attempting to finance an acceptable capital expenditure program including acquisition opportunities, the current level of bank credit available from the Company's lender, the level of bank credit that may be attainable from its lender as a result of petroleum and natural gas reserve growth, the availability of other sources of debt with different characteristics than existing debt, the sale of assets, limiting the size of the capital expenditure program and the issue of new equity if available on favorable terms. At December 31, 2010, the Company's capital structure was not subject to external restrictions. The Company's bank facility is determined by the senior lender and based on the lender's borrowing base model and the Company's petroleum and natural gas reserves.

Selected Historical Financial Information

2010	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Petroleum and natural gas sales	$ 1,009,188	$ 839,054	$ 1,821,333	$ 2,864,802
Net petroleum and natural gas revenue	$ 646,831	$ 439,729	$ 1,299,935	$ 2,017,879
Net loss	$ (570,592)	$ (1,637,373)	$ (672,494)	$ (1,195,890)
Net loss per share	$ (0.00)	$ (0.03)	$ (0.01)	$ (0.02)
Funds flow from operations	$ 410,168	$ 59,390	$921,972	$1,567,756
Net capital expenditures	$ 3,799,846	$ 3,756,574	$ 2,689,049	$ 16,760,003
2009	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Petroleum and natural gas sales	$ 1,025,969	$ 909,592	$ 889,449	$ 754,728
Net petroleum and natural gas revenue	$ 629,971	$ 533,449	$ 430,962	$ (228,328)
Net loss	$ (405,050)	$ (757,791)	$ (4,308,038)	$ (1,797,141)
Net loss per share	$ (0.05)	$ (0.05)	$ (0.25)	$ (0.10)
Funds flow from (used in) operations	$ 432,673	$ 180,863	$ 133,901	$ (640,581)
Net capital expenditures	$ 298,013	$ 132,898	$ 524,935	$659,115

Business Risks and Uncertainties

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

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

The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses.

Disclosure Controls and Procedures

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

Critical Accounting Estimates

The Company's financial statements are prepared in accordance with Canadian generally accepted accounting principles. A comprehensive discussion of the Company's significant accounting policies is contained in Note 2 to the audited consolidated financial statements for the year ended December 31, 2010. The Company's significant accounting policies are subject to estimates and key judgments about future events, many of which are beyond management's control.

The Company believes the following are the most critical accounting estimates used in the determination of its financial results:

Petroleum and natural gas properties – depletion and ceiling test

The Company follows the full cost method of accounting by initially capitalizing all costs related to the acquisition, development and exploration of petroleum and natural gas reserves. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead directly related to exploration and development activities and lease and well equipment. Costs capitalized are depleted using the unit-of-production method based on gross proved petroleum and natural gas reserves as determined by independent qualified reserve evaluators. Production and reserves of petroleum and natural gas are converted to common units of measure based on their relative energy content where one barrel of oil is equivalent to six thousand cubic feet of natural gas. The depletion base excludes the cost of significant unproved properties until it is determined whether proved reserves are attributable to the properties or impairment has occurred.

The Company performs a ceiling test where the carrying amount of property and equipment is compared to the sum of the undiscounted cash flows expected to result from the future production of proved and probable reserves and the cost, less any impairment of unproved properties. Estimated cash flows are discounted at the Company's risk-free rate of interest using forecast prices and costs. The carrying amount of undeveloped properties and seismic excluded from the ceiling test are compared to independent evaluations of fair value. Any impairment is recorded as additional depletion expense.

Estimates are the basis for amounts recorded as depletion and the ceiling test. These estimates include proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

Asset retirement obligation

The Company recognizes the liability for the asset retirement obligation associated with the abandonment of petroleum and natural gas wells, related facilities, compressors and plants and the removal of equipment from leased acreage and returning such land to its original condition. The fair value the Company's asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the assets at the Company's credit-adjusted risk-free interest rate based on the expected timing of such cash outflows.

Future costs and their expected timing are estimates that are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

Income taxes

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These amounts are estimates and the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. A valuation allowance is recorded to the extent that there is uncertainty regarding utilization of future tax assets.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations, often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability and expense may differ from that estimated and recorded.

Stock-based compensation

Stock-based compensation expense is recorded in the statement of loss and deficit for all options granted based on the estimated fair value at the time of the grant and recognized as expense over the vesting period of the option. The fair value of options is estimated using the Black-Scholes pricing model based on estimates and assumptions for expected life of the options, expected volatility, risk-free interest rate and dividend yield. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

International Financial Reporting Standards ("IFRS")

The Canadian Accounting Standards Board (AcSB) published a new strategic plan that outlines the convergence of Canadian generally accepted accounting principles with IFRS over an expected five year transitional period. The changeover date for publicly-listed companies to use IFRS, replacing Canada's own generally accepted accounting principles is interim and annual financial statements for fiscal years beginning on or after January 1, 2011 with the restatement for comparative purposes of amounts reported by the Company for the year ended December 31, 2010.

The Company has completed a high-level review and preliminary assessment of the differences between Canadian GAAP and IFRS and the potential effects of IFRS to accounting and reporting processes, information systems, business processes and external disclosures. This assessment has provided insight into what are anticipated to be the most significant areas of difference applicable to the Company. The next step is to perform an in-depth review of the significant areas of difference and select ongoing IFRS policies. Key areas addressed will also be reviewed to determine any information technology issues, the impact on internal controls over financial reporting and the impact on business activities including the effect, if any, on covenants and compensation arrangements.

The Company will also continue to monitor standards development as issued by the IASB and the AcSB as well as regulatory developments as issued by the Canadian Securities Administrators, which may affect the timing, nature or disclosure of its adoption of IFRS.

The following IFRS standards are considered most relevant to the Company's conversion process:

IFRS 1 - First-time Adoption of IFRS which generally requires that an entity apply all IFRS standards retrospectively, with specific mandatory exemptions, and a limited number of optional exemptions. A preliminary assessment of the available exemptions has been completed.

Elections made upon transition to IFRS can have a significant impact on the level of time and effort needed for the conversion to IFRS. The following optional exemptions appear to be the most applicable to the Company:

a) fair value as deemed cost - this exemption provides the Company with the option to elect specific fair values as the deemed cost of any qualifying item of property, plant and equipment;

b) deemed cost of full cost oil and gas assets - this exemption provides the Company with the option of measuring exploration and evaluation assets and assets in the D&P phases at the amount determined for the cost centre under Canadian GAAP; the cost of the D&P assets are allocated to the underlying assets on a pro rata basis using reserve volumes or reserve values as of the transition date;

c) business combinations - this exemption provides the Company with the option of not applying IFRS 3 Business Combinations to business combinations that took place before the date of transition;

d) share-based payments - this exemption provides the Company with the option of not applying IFRS 2 to equity-settled share-based payment transactions issued after November 7, 2002 and which have vested before the date of transition; and

e) decommissioning liabilities - if the exemption discussed under b) is utilized, the Company may then measure decommissioning, restoration and similar liabilities at the transition date in accordance with IAS 37 and recognize, directly in retained earnings, any difference between that amount and the Canadian GAAP carrying amount of the liabilities at the transition date.

In addition to these exemptions, IFRS 1 provides other exemptions that are available on transition to IFRS. These exemptions may become useful for the Company to consider in the future.

IFRS 2 – Share-based Payments requires the use of a forfeiture rate based on an estimate of the number of options expected to vest and requires that each tranche of options be treated as a separate arrangement as graded vesting is utilized.

IFRS 6 – Exploration and Evaluation of Mineral Resources ("E&E") requires that costs associated to the exploration for and evaluation of resources be recorded separately from the costs associated to the development of resources. Assets within this category are not depreciated and are tested for impairment when events suggest that the carrying amount may exceed the recoverable amount.

IAS 16 – Property, Plant and Equipment requires that assets be assigned to a cash generating unit and be depreciated over the useful life of each significant component. This requires a useful life assessment at a potentially lower level than under current Canadian GAAP and potential amendments to the accounting system to enable the tracking of costs at both a component and cash generating unit level.

IAS 36 – Impairment of Assets involves an impairment test at the cash generating unit level using either proven or proven and probable reserves whereby the recoverable amount, defined as the higher of the fair value less costs to sell or value in use, is compared to the carrying value of the assets. Impairments are likely to be triggered at an earlier date under IFRS as this test involves a one step approach utilizing discounted cashflows at a potentially lower asset group than currently required under Canadian GAAP.

IAS 37 - Provisions, Contingent Liabilities, and Contingent Assets will impact the calculation and presentation of the asset retirement obligation. This calculation will now include both legal and constructive obligations based on managements estimate and will be discounted based on the risk specific to the asset to be retired which is likely to be a lower discount rate.

There is also a potential Canadian GAAP – IFRS difference with respect to the treatment of flow-through shares which may impact the Company's financial statements with respect to future flow-through share issuances. As the International Accounting Standards Board is not expected to issue specific guidance on the accounting treatment of flow-through shares, the Company will be required to develop an appropriate accounting policy which may or may not be significantly different from current Canadian GAAP.

Based on the preliminary assessment of IFRS, the Company anticipates the conversion to IFRS will primarily impact the reported amount for property and equipment and asset retirement obligation. Financial statement disclosures will be greatly expanded.

The Company has received a formal diagnostic of Canadian GAAP and IFRS differences. The Company has commenced a more detailed analysis of each of the specific areas identified in the diagnostic (i.e. preparing position papers, drafting consolidated financial statements, identifying the impact on systems and processes, etc) to conclude on the accounting and systems implications. Subsequent phases will propose detailed solutions for accounting policies and quantify the expected impact. The Company plans to have a draft opening balance sheet and related IFRS disclosures completed in the first quarter of 2011.