Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the audited consolidated financial statements of Yangarra Resources Ltd. (the "Company") for the year ended December 31, 2009, together with the accompanying notes. The MD&A has been prepared using information that is current to April 29, 2010.

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.

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 can derive such events.*

Company Description and Outlook

Yangarra Resources Ltd. ("Yangarra" or the "Company") was formed by the amalgamation on November 9, 2005, under the Business Corporations Act (Alberta), of Yangarra Resources Inc. and TriOil Ltd. The Company is involved in the production, exploration and development of resource properties in the Ferrier, Medicine Hat, Mega, Viking, Jaslan and Bigstone areas of Alberta and in Bayhurst, Saskatchewan.

In June 2009, the Company contacted its unsecured creditors to extend repayment terms or settle accounts payable in common shares at $0.06 per share. On August 28, 2009, the Company issued 4,680,873 common shares for the settlement of $280,847 of accounts payable.

On October 22, 2009, the Company held a meeting to present a formal proposal to restructure under the Bankruptcy and Insolvency Act (the "Proposal") to its creditors at which time all affected creditors had the opportunity to vote on the Proposal as presented by the Company. Of the votes cast, 85% supported the Proposal which represented approximately 96% of the corresponding monetary value. The Company received court approval of the Proposal on November 10, 2009 and received final approval from the TSX Venture Exchange on December 31, 2009 upon completion of all aspects of the formal Proposal.

The purpose of the Proposal was to restructure the financial affairs of the Company in order to continue business. Pursuant to the terms of the Proposal:

a) The Company continued to make payments to its senior lender in accordance with the terms of its present arrangements with that senior lender or any other arrangements that may be agreed upon by that senior lender and the Company. The senior lender has a first secured charge on the property, assets and undertakings of the Company.

b) A second secured creditor that was owed $4,950,000 including accrued interest and fees, but whose interest is subordinate to that of the senior lender, had its debts satisfied as follows:

- $450,000 of accrued interest and fees satisfied through the issuance of 9,000,000 common shares of the Company at a deemed price of $0.05 per share;
- $3,500,000 satisfied through the issuance of 23,333,333 common shares of the Company at a deemed price of $0.15 per share; and
- $1,000,000 satisfied through the issuance of preferred shares of the Company, such preferred shares having a 5% annual dividend payable in common shares of the Company, redeemable at any time by the Company and redeemable by the subordinated lender on June 30, 2011.

c) Ordinary unsecured creditors who were owed $2,018,065 had their debts settled as follows:

i) The first $558 of each such ordinary unsecured creditor's claim was paid in cash resulting in a total cash payment of $55,000; and

ii) The balance was satisfied via the issuance of common shares of the Company at a deemed price of $0.17 per share resulting in the issuance of 11,600,000 common shares.

d) The Company acquired all of the issued and outstanding shares of Athabaska Energy Ltd. on December 31, 2009 in exchange for 50,000,004 common shares of the Company.

e) The Company completed a private placement on December 31, 2009 for total proceeds of $500,000.

Pursuant to arrangements with the Company's senior lender and in conjunction with the formal terms of the Proposal, the Company was required to drill three specified wells. To fulfill the drilling requirement, the Company entered into a participation and farmout agreement (the "Farmout Agreement") with Athabaska Energy Ltd. ("Athabaska") in June 2009. A director and principal shareholder of the Company is also an officer, director and principal shareholder of Athabaska. The Farmout Agreement covered seven sections of Company land and included the drilling of three wells specified and required by the senior lender. Pursuant to the terms of the Farmout Agreement, Athabaska contributed 100% of the cost to drill, complete and tie-in each well to the Company's facilities in order to earn a 60% working interest in each well at payout as well as one section of the farmout lands for each well drilled.

As noted above, the Company acquired Athabaska on December 31, 2009 and therefore the results included herein for the three months and year ended December 31, 2009 are those of Yangarra only.

The three wells required by the senior lender were drilled in the third quarter with the first well wet and abandoned. The second well, in which Yangarra held a 16.4% working interest before payout, was tied into facilities in October. The third well was drilled in October and tied into facilities in November with Yangarra holding a 0% working interest before payout. A standing well in the Jaslan area was farmed out to Athabaska in which Athabaska would earn 50% working interest for completion and tie-in of the well and was put on production in December. As a result of the acquisition of Athabaska, the Company now holds a 100% working interest in the aforementioned wells, on a consolidated basis.

With the decline in the price of commodities, the price of natural gas in particular, Yangarra reduced capital expenditures in 2009. In addition, the Company entered into commodity swaps to provide a $ 5.69 per GJ floor price for natural gas sales for the majority of its production. This floor enabled Yangarra to continue to generate positive funds flow from operations in 2009. In addition Yangarra entered into commodity swaps for 500 GJ per day for the 2010 calendar year at a strike price of $5.68 per GJ and an additional 1000 GJ per day for the January/February period of 2010 at a strike price of $5.52 per GJ.

The completion of the various steps under the Proposal resulted in a considerably stronger balance sheet for the Company. Debt service fees are forecast to be reduced by approximately 80% per annum, the farm out program in Jaslan with Athabaska resulted in three additional producing wells and the acquisition of Athabaska will further enhance Yangarra's financial position in 2010. In addition, opportunities presented in the Ferrier area for horizontal drilling of the Cardium and Glauconite zones and the $6.0 million financing completed in March 2010 have positioned the Company to grow its production base.

The audited consolidated financial statements were prepared on a going concern basis which contemplates the realization of assets and the payment of liabilities in the ordinary course of business. As at December 31, 2009, the Company had a working capital deficiency of $7,963,051 (2008 – $13,599,207) and an accumulated deficit of $19,483,606 (2008 – $12,215,586). At the same time, the Company continues to generate positive cash flow from operations. The Company's ability to continue as a going concern is dependent upon its ability to attain profitable operations and generate funds therefrom, negotiate favorable terms with its lenders and to continue to obtain capital financing from investors sufficient to meet current and future obligations.

Should the Company be unable to continue as a going concern, it may be unable to realize the carrying value of its assets and to meet its liabilities as they become due. There can be no assurance that the steps management is taking will be successful and any adjustments necessary to the financial statements if the Company ceases to be a going concern could be material.

Summary Financial Information

	For the years ended December 31		
	2009	2008	2007
Statement of Operations and Deficit			
Petroleum & natural gas sales	$ 3,579,738	$ 8,642,336	$ 7,899,634
Net (loss) income for the period	$ (7,321,149)	$ (1,825,080)	$ (1,271,113)
Net (loss) income per share - basic	$ (0.09)	$ (0.03)	$ (0.02)
Weighted average number of shares - basic	78,313,321	67,499,983	55,896,744
Statement of Cash Flows			
Funds flow from operations	$ 106,856	$ 3,820,278	$ 3,504,225
Balance Sheet			
Property and equipment	$ 38,830,516	$ 41,922,138	$ 40,371,767
Total assets	$ 39,641,449	$ 44,081,309	$ 42,009,723
Preferred shares (liability classification)	$ 1,000,000	$ -	$ -

Results of Operations

Net petroleum and natural gas revenue

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Net petroleum & natural gas revenue	$ (342,420)	$ 1,023,858	$ 1,251,962	$ 5,483,741
Per boe	$ (14.93)	$ 24.78	$ 11.80	$ 32.38
Net petroleum & natural gas revenue with royalty recovery	$ (228,328)		$ 1,541,690	
Per boe	$ (9.96)		$ 14.53	

The variances in net petroleum and natural gas revenue are explained by changes in the following components:

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Total boe (boe 6:1)	22,931	41,324	106,111	169,348
Daily sales volumes (boe 6:1)	249	449	291	463
Petroleum & natural gas sales	$ 754,728	$ 1,806,264	$ 3,579,738	$ 8,642,336
Per boe	$ 32.91	$ 43.71	$ 33.74	$ 51.03
Royalties	$ 87,683	$ 162,048	$ 195,223	$ 1,329,490
Per boe	$ 3.82	$ 3.92	$ 1.84	$ 7.85
As a % of sales	12%	9%	5%	15%
Royalty recovery	$ 114,092	$ -	$ 289,728	$ -
Production & transportation costs	$ 1,009,465	$ 620,358	$ 2,132,553	$ 1,829,105
Per boe	$ 44.02	$ 15.01	$ 20.10	$ 10.80

- The reduction in production for the 2009 periods as compared to the 2008 periods can be attributed to lower production from Medicine Hat, Ferrier and Viking South wells due to natural declines and the loss of two Bow Island wells in Medicine Hat due to premature watering out. Production from the Athabaska farmout wells is not included in the Company's 2009 results as the acquisition of Athabaska did not take place until December 31, 2009.
- The average price earned by the Company decreased in 2009 due to industry-wide price declines for all commodities as follows:

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Oil ($/bbl)	$ 69.07	$ 66.68	$ 62.56	$ 102.92
NGL ($/bbl)	$ 50.37	$ 51.90	$ 38.03	$ 73.47
Gas ($/mcf)	$ 3.69	$ 7.06	$ 3.88	$ 7.92

- Included in petroleum and natural gas revenue for the three months and year 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 2009 periods increases to $5.06 per mcf and $5.37 per mcf, respectively.
- Included in petroleum and natural gas revenue for the three months and year ended December 31, 2008 is a $138,840 realized gain and a $211,008 realized loss, respectively, on the fulfilled portion of commodity contracts. Including the realized gains/losses, the average gas price earned by the Company for the 2008 periods changes to $7.67 per mcf and $7.69 per mcf, respectively.
- The decrease in royalties in 2009 on both a boe and percentage basis relates to lower production and pricing, gas cost allowance adjustments from prior periods in combination with the realized gains from the commodity contracts, on which royalties are not paid. The majority of the Company's properties are at lower royalty rates in 2009 due to lower production levels. Royalties increased in the fourth quarter of 2009 due to a shift in production rates in the Ferrier area resulting in higher royalty rates for wells with production increases.
- During the first quarter of 2009, the Company recognized a recovery in the amount of $175,636 and an additional $114,092 in the fourth quarter related freehold and gross overriding royalties calculated and paid in previous years.
- Production and transportation costs per boe for the 2009 periods are higher than those for 2008 due to higher fixed costs per boe attributed to lower 2009 production levels, additional maintenance expenditures in the Medicine Hat area and adjustments from joint venture partners related to prior years in the Ferrier area, including a $235,000 13-month adjustment related to 2006 – 2008. Excluding prior year operating cost adjustments, production and transportation costs per boe for the three months and year ended December 31, 2009 are reduced to $19.96 and $20.02, respectively.

Depletion, depreciation and accretion

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Depletion and depreciation	$ 816,289	$ 1,466,950	$ 8,064,412	$ 4,797,322
Per boe	$ 35.60	$ 35.50	$ 76.00	$ 28.33
Accretion	$ 37,077	$ 31,745	$ 146,621	$ -

A ceiling test impairment in the amount of $4,300,000 was recognized in the third quarter of 2009, resulting in an increase in depletion per boe for the year. The December 31, 2009 ceiling test determined that there was no additional impairment.

Accretion expense increased in 2009 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		Year ended December 31	
	2009	2008	2009	2008
General and administrative expenses				
Restructuring fees	$ 139,291	$ -	$ 179,101	$ -
Other	193,965	68,412	718,983	813,314
	$ 333,256	$ 68,412	$ 898,084	$ 813,314
Interest and financing fees	$ 493,200	$ 474,948	$ 1,295,660	$ 1,404,947
Stock-based compensation	$ 206,091	$ (7,712)	$ 206,091	$ 579,609

Included in general and administrative expenses for the fourth quarter and annual 2009 periods is $139,291 and $179,101 of legal and monitor fees related to Company's restructuring. Management has continued to monitor general and administrative expenses to keep costs down.

During the fourth quarter of 2008, management undertook an extensive review of charges for 2008 consulting services and capitalized fees for work performed on specific exploration and development projects resulting in lower than average general and administrative expenses for the quarter.

Interest and financing fees for the three months ended December 31, 2009 includes:

- $1,854 of Part XII.6 interest on the unspent portion of flow-through expenditures incurred by December 31, 2009 under the look-back rule and other minor amounts;
- $91,142 on the revolving operating demand loan for which the average amount drawn during the period was $8,000,000 at an effective interest rate of 4.52% compared to $101,282 in the 2008 period on an average loan balance of $8,361,995 at an effective interest rate of 4.82%;
- $150,000 of fees on the revolving operating demand loan for which the Company issued 1,000,000 common shares pursuant to the Proposal; and
- $250,204 of interest and financing fees on the credit facility based on the effective interest method compared to $373,444 for the 2008 period.

Interest and financing fees for the year ended December 31, 2009 includes:

- $13,482 of Part XII.6 interest on the unspent portion of flow-through expenditures incurred by December 31, 2009 under the look-back rule and other minor amounts;
- $394,644 on the revolving operating demand loan for which the average amount drawn during the year was $7,975,000 at an effective interest rate of 4.95% compared to $447,416 in the 2008 period on an average loan balance of $8,274,727 at an effective interest rate of 5.39%;
- $155,000 of fees on the revolving operating demand loan (2008 - $17,500); and
- $732,534 of interest and financing fees on the credit facility based on the effective interest method compared to $940,790 for the 2008 period.

In December 2009, the Company granted 12,350,000 stock options which vested immediately. The fair value of the options was estimated at $420,700 of which $214,609 was attributed to stock options granted to field personnel and capitalized to property and equipment and the remaining $206,091 was recognized as stock-based compensation expense ("SBC").

Total SBC recorded in the three months and year ended December 31, 2008 periods, was a net recovery of $5,757 and expense of $827,930, respectively. Of the total, $1,955 and $248,321, respectively, was attributed to stock options granted to field personnel and capitalized to property and equipment. The remaining SBC for the three months and year ended December 31, 2008 was a $7,712 recovery and a $579,609 expense, respectively, as reported in the consolidated statements of operations. The net recovery of SBC in the fourth quarter is due to the reversal of previously recorded SBC related to unvested options forfeited in the period. Options were granted in the first and second quarters of 2008. These options vested immediately resulting in all of the estimated fair value being recognized as SBC on the grant date.

Commodity price risk contracts

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Commodity contract settlement	$ -	$ (226,800)	$ -	$ (226,800)
Change in fair value of commodity contracts	(6,983)	76,940	113,361	-
	$ (6,983)	$ (149,860)	$ 113,361	$ (226,800)

During 2009, the Company fulfilled a commodity price risk contract for the sale of 1,500 GJ per day of natural gas from April 1 to December 31, 2009 at a fixed price of $5.69 per GJ.

During 2008, the Company fulfilled the following commodity price risk contracts for the sale of natural gas:

- 500 GJ per day from April 1 to December 31, 2008 at a ceiling price of $8.46 per GJ and a floor price of $7.25 per GJ;
- 500 GJ per day from April 1 to December 31, 2008 at a ceiling price of $8.31 per GJ and a floor price of $7.75 per GJ;
- 500 GJ per day from April 1 to August 31, 2008 at a ceiling price of $8.25 per GJ and a floor price of $7.00 per GJ; and
- 500 GJ per day from April 1 to August 31, 2008 at a ceiling price of $8.15 per GJ and a floor price of $7.50 per GJ.

In December 2008, the Company settled a commodity price risk contract for the total notional quantity of 182,500 GJ of natural gas over the period January 1 to December 31, 2009 at a fixed price of $7.79 per GJ for proceeds of $226,800 based on the fair value of the contract on the settlement date. The proceeds are reported as other income for the year ended December 31, 2008.

As at December 31, 2009, the Company is 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 provide a ceiling for the price it receives 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.

The mark-to-market value represents what the Company would have to pay (liability) or receive (asset) if the contracts were terminated on the measurement date. The mark-to-market value of the unfulfilled portion of the above contracts at December 31, 2009 is a liability of $113,361 based on the remaining contractual terms from January 1, 2010 to December 31, 2010.

Included in petroleum and natural gas revenue for the year ended December 31, 2009 is $920,429 of realized gains (2008 – $211,800 of realized losses) on the fulfilled portion of the commodity contracts.

In March 2010, the Company settled all contracts outstanding at December 31, 2009 for proceeds of $73,500 based on the fair value of the contracts on the settlement date.

Investment

The Company held a minority equity position in a public company which was sold in May 2009 for cash proceeds of $33,669. The reported amount of (gain) loss on investment was comprised of the following:

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Realized loss	$ –	$ –	$ 231,638	$ –
Reversal of previously recognized unrealized net losses	–	–	(254,839)	–
Unrealized loss on mark-to-market	–	13,958	–	115,152
	$ –	$ 13,958	$ (23,201)	$ 115,152

Future income tax reduction

During the three months and year ended December 31, 2009, the Company recorded a reduction of future income taxes of $255,152 and $1,825,498, respectively, (2008 – $299,792) related to the reversal of temporary differences between the carrying value and tax basis of the Company's property and equipment. On a year-to-date basis for 2009, $1,000,000 of the reduction relates to the effect of the $4.3 million ceiling test impairment that was recorded during the third quarter.

Liquidity and Capital Resources

During 2009, the Company generated $106,856 of funds flow from operations compared to $3,820,278 in the 2008 comparative period. The reduction in funds flow from operations is primarily due to the effect of lower production and commodity prices on net petroleum and natural gas revenue, production cost adjustments for prior years received from joint venture partners and restructuring costs.

The Company's senior secured bank debt is subject to a Forbearance Agreement dated June 16, 2009 and a Loan Extension Agreement dated October 27, 2009 (collectively the "Loan Agreements") between the senior lender and the Company. During the period May 1 to October 26, 2009, the interest rate on the revolving operating demand loan was increased to bank prime plus 4.0% (previously prime plus 0.5%) per annum calculated daily and payable monthly. Commencing October 27, 2009, the interest rate was reduced to bank prime plus 1.0%.

The maximum amount available under the revolving operating demand loan is $8,300,000 (2008 – $9,000,000) with monthly reductions based on the Company's excess cash flow (as defined in the Loan Agreements) commencing January 31, 2010. The annual renewal date of the bank debt is set for May 31, 2010. As at December 31, 2009, the $8,195,069 (2008 – $8,853,990) reported amount of bank debt was comprised of $7,800,000 (2008 – $8,150,000) drawn on the revolving operating demand loan and $395,069 (2008 – $703,990) of bank overdraft.

The Company is subject to a financial covenant with respect to working capital, which the Company was in compliance with at December 31, 2009.

As at December 31, 2009, the Company had a working capital deficit of $7,963,051 compared to $13,599,207 at December 31, 2008. The improvement in the Company's working capital position is primarily due to the settlement of the $4,500,000 credit facility and $2,243,912 of accounts payable through the issuance of 39,614,114 common shares and 1,000,000 preferred shares. The Company generated $106,856 of funds flow from operating activities, raised $500,000 in December 2009 through a private placement of flow-through shares and had other net cash inflows of $7,205. Cash expenditures on property and equipment were $1,614,961.

Capital Spending

Capital spending is summarized as follows:

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Land and lease rentals	$ 102,562	$ 137,485	$ 237,407	$ 843,539
Drilling and completion	262,256	585,577	854,518	3,086,664
Geological and geophysical	42,801	163,109	74,615	213,951
Equipment	251,496	860,307	448,421	1,626,417
	659,115	1,746,478	1,614,961	5,770,571
Dispositions	-	(28,776)	-	(78,776)
	$ 659,115	$ 1,717,702	$ 1,614,961	$ 5,691,795

Asset Retirement Obligation

As at December 31, 2009, the undiscounted fair value of the asset retirement obligation associated with the Company's existing properties was estimated to be $4,263,142 for which $2,181,727 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 10.3 years.

Related Party Transactions

During the years ended December 31, 2009 and 2008, 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:

	2009	*2008*
Administration and consulting fees	$ 159,174	$ 137,858
Production and capital expenditures	$ 119,865	$ 249,493

During the year ended December 31, 2009, the Company was charged $7,902 (2008 – $24,104) by a law firm in which a former director of the Company is a partner.

In June 2009, the Company entered into a participation and Farmout Agreement with Athabaska and in December 2009, the Company acquired all of the issued and outstanding shares of Athabaska as discussed under the Company Description and Outlook section. The Farmout Agreement and acquisition are related party transactions as a director and principal shareholder of the Company is also an officer, director and principal shareholder of Athabaska.

In December 2009, the Company completed a private placement of 10,000,000 units on a flow-through basis at $0.05 per unit for total proceeds of $500,000. Officers and directors subscribed for 100% of the units.

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, 2008	**75,561,912**	**-**	**-**	**6,267,025**
Salary compensation	1,764,000	-	-	-
Settlement of accounts payable	16,280,781	-	-	-
Subordinated lender credit facility	23,333,333	1,000,000	-	-
Subordinated lender interest and fees	9,000,000	-	-	-
Senior lender fees	1,000,000	-	-	-
Acquisition of Athabaska	50,000,004	-	-	-
Unit private placement	10,000,000	-	10,000,000	-
Granted to directors, officer and consultants	-	-	-	12,350,000
Expired	-	-	-	(511,750)
Forfeited	-	-	-	(394,000)
Balance - December 31, 2009	**186,940,030**	**1,000,000**	**10,000,000**	**17,711,275**
Unit private placement	80,000,000	-	40,000,000	-
Balance - Date of MD&A	**266,940,030**	**1,000,000**	**50,000,000**	**17,711,275**

Subsequent Events

In March 2010, the Company completed a private placement of 80,000,000 Units at $0.075 per Unit for gross proceeds of $6,000,000. Each Unit is comprised of one common share of the Company and one half of one common share purchase warrant, with each full warrant exercisable anytime up to March 15, 2012, at a price of $0.10 per share, subject to certain earlier termination provisions. Management and directors subscribed for 13,356,669 Units for gross proceeds of $1,001,750 or 16% of the financing. Finder's fees of $364,480 were paid in conjunction with the financing. The common shares and warrants issued and the common shares issuable on the exercise of the warrants are all subject to hold periods expiring on July 17, 2010.

In March 2010, the Company acquired a 15% overriding royalty on natural gas and a 5-15% sliding scale overriding royalty on oil that covers approximately eleven sections of Cardium and Glauconite lands in the Willesden Green area.

In March 2010, the Company settled all commodity price risk contacts.

In March 2010, the Company held a special meeting of the shareholders which voted in the affirmative on a resolution to consolidate the common shares of the Company on a five old for one new (5:1) basis. The Company received TSX-V Exchange approval for the consolidation on April 28, 2010 and a new symbol has been given to the Company. Effective April 30, 2010 the Company's stock will trade under the new symbol "YGR" and will trade on a consolidated basis. As a result of the consolidation the Company will have 53,668,006 shares outstanding.

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 to the Court of Queen's Bench of Alberta, to 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 Defense 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

The Company has until December 31, 2011 to incur $500,000 of qualifying flow-through expenditures related to the private placement of Units completed in December 2009.

As at December 31, 2009, the Company is 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.
- 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.

All commodity price risk contracts were settled in the Company's favor in March 2010 for proceeds of $73,500. There are no commodity price risk contract commitments as of the date of this MD&A.

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

2010	$ 178,655
2011	141,236
2012	141,236
2013	83,833

Financial Instruments

The Company's financial instruments include accounts receivable, investment, accounts payable and accrued liabilities, bank debt, credit facility, preferred shares and commodity price risk contracts. 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 fair value of the commodity price risk contracts is considered to be Level 2 as it is estimated by discounting the difference in the contract price and forward prices using the remaining volumes in the contract.

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 the Company's financial statements.

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

a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. A substantial portion of the Company's accounts receivable are with natural gas and liquids marketers and 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, 2009, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of $658,080 (2008 – $1,710,780). As at December 31, 2009, the Company's receivables consisted of $304,930 from joint venture partners and other trade receivables and $353,150 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 $304,930 of revenue accruals and receivables from petroleum and natural gas marketers was received in January and February 2010.

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. As at December 31, 2009, the largest amount owing from one partner is $73,259.

The Company did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended December 31, 2009. 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, 2009, the Company considers its receivables to be aged as follows:

Not past due	$	415,968
Past due by less than 90 days		28,725
Past due by more than 90 days		213,387
	$	658,080

b) Liquidity risk

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

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Company has a 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, both of which have expected maturities of less than one year resulting in their current classification on the balance sheet.

c) Market risk

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

i) Interest rate risk
Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate. For the year ended December 31, 2009, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been $79,750 (2008 – $77,530) 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, 2009 and 2008.

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, 2009 and 2008.

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 the Commitments section, above.

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:

	2009	*2008*
Working capital deficiency	$ (7,963,051)	$ (13,599,207)
Shareholders' equity	26,848,381	24,452,012
	$ 18,885,330	$ 10,852,805

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, 2009, the Company's capital structure is subject to external restrictions as a result of the Loan Agreements with the Company's senior lender. As a result, the Company's approach to capital management has changed to ensure compliance with the Loan Agreements. 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.

The Company has not paid or declared any dividends since the date of incorporation, nor are any contemplated in the foreseeable future.

Selected Historical Financial Information

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	$ (0.01)	$ (0.01)	$ (0.05)	$ (0.02)
Funds flow from operations	$ 432,673	$ 180,863	$ 133,901	$ (640,581)
Net capital expenditures	$ 298,013	$ 132,898	$ 524,935	$659,115

2008	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Petroleum and natural gas sales	$ 2,104,060	$ 2,661,004	$ 2,071,008	$ 1,806,264
Net petroleum and natural gas revenue	$ 1,427,515	$ 1,744,759	$ 1,287,609	$ 1,023,858
Net income (loss)	$ (1,045,274)	$ (1,076,877)	$ 871,862	$ (574,791)
Net income (loss) per share	$ (0.02)	$ (0.02)	$ 0.01	$ (0.01)
Funds flow from operations	$ 944,104	$ 1,214,745	$ 724,869	$ 936,560
Net capital expenditures	$ 1,017,265	$ 1,513,100	$ 1,443,728	$ 1,717,702

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. The Company's risk in regards to financial instruments is detailed in note 18 to the December 31, 2009 audited consolidated financial statements.

Disclosure Controls and Procedures

In connection with Exemption Orders issued in November 2007 by each of the securities commissions across Canada, the Company's certifying officers will file a Venture Issuer Basic Certificate with respect to the financial information contained in the unaudited interim financial statements and the audited annual financial statements and respective 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 Notes 2 and 3 to the audited consolidated financial statements for the year ended December 31, 2009. 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 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.

Changes in Accounting Policies

During 2009, the Company adopted the following new or revised Canadian accounting standards and abstracts. Prior periods have not been restated. The adoption of these policies had no impact on the Company's financial position or results of operations however the policies did result in new disclosures.

(a) *Section 3064 Goodwill and Intangible Assets* which replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets.

(b) *EIC-173 Credit Risk and the Fair Value of Financial Assets and Financial Liabilities* which clarifies that an entity must consider its own risk and the credit risk of the counterparty when measuring the fair value of derivative instruments.

(c) Amendments to *Section 3855 Financial Instruments — Recognition and Measurement*. The changes bring greater consistency between Canadian GAAP, IFRS and US GAAP regarding the timing of impairment recognition for debt instruments. The amendments allow more debt instruments to be classified as loans and receivables. In addition, the amendments require reversal of previously recognized impairment losses on available-for-sale financial assets in specified circumstances and require that loans and receivables that an entity intends to sell immediately or in the near term be classified as held for trading. The transitional provisions are complex and are accompanied by disclosure requirements to explain any reclassifications made on adopting the amendments.

(d) Amendments to *Section 3862 Financial Instruments — Disclosures*. The amendments require improved and consistent disclosures about fair value measurements of financial instruments and liquidity risk. The amendments apply to annual financial statements relating to fiscal years ending after September 30, 2009. In the first fiscal year of application, an entity need not provide comparative information for the disclosures required by the amendments. See note 18.

In addition, the Company is currently assessing the impact of the following new or amended standards tht are effective in future periods:

		Effective for Annual Periods Beginning on or After
Section 1506	Accounting Changes	July 1, 2009
Section 1582	Business Combinations	January 1, 2011
Section 1601	Consolidations	January 1, 2011
Section 1602	Non-controlling Interests	January 1, 2011
Section 1625	Comprehensive Revaluation of Assets and Liabilities	January 1, 2011

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 next steps for the Company are to complete 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) and conclude on any accounting and systems implications. Subsequent phases will propose detailed solutions for accounting policies and quantify the expected impact.