Management's Discussion and Analysis

The following discussion is management's analysis of Anterra Energy Inc.'s ("Anterra" or the "Company") operating and financial data for the three months and year ended December 31, 2010 and prior periods, as well as estimates of future operating and financial performance based on information currently available. It should be read in conjunction with the audited financial statements and notes for Anterra Energy Inc. for the year ended December 31, 2010. The Management Discussion and Analysis ("MD&A") was prepared as of April 28, 2011.

Overall Performance Summary

During 2010, there was an increase in oil production and a decrease in gas production compared to last year, despite having wells shut down for maintenance. There was a decline in gas prices but an increase in oil prices compared to the previous year, which resulted in an increase in revenue of 37% to $4,024,800 compared to the last year at $2,946,793. There was an increase in average prices and an increase in the oil and gas operating costs during the year; as a result, the oil and gas operating margin amounted to $138,597 compared to $693,563 in the last year.

While production in 2010 averaged 169 boe per day, some wells were shut-in due to weather conditions in winter. Furthermore, the average sale price per barrel for in 2010 increased to $65.28 from $62.42 in 2009. During 2010, the Company generated negative funds flow from operations (ono-GAAP measure – see Presentation) is expected to remain close to breakeven levels until the Company sees more production from new projects.

At December 31, 2010, the Company had drawn down $1,299,841 on its credit facility of $5,800,000, and had a net working capital deficit including the negative bank balance of $507,073. In the first half of 2010, the Company expended $3,900,000 on land positions in Alberta and Saskatchewan.

Operating Summary

Production during 2010 averaged 169 boe per day compared to 165 boe per day in 2009. The oil production increased during the year. However, gas sales at both Breton and Judy Creek declined during the year. During 2010, oil prices averaged $74.97 and have since recovered to a range from $70 to $80 per barrel, while gas prices dropped to $3.91 per mcf during the year. The average oil price and average gas price for the year were 8% higher and 2% lower respectively than the prices for 2009. High maintenance costs in 2010 related to well work overs and site remediation at Breton. These costs continued into the fourth quarter and, in addition, the Company incurred work over costs at Matziwin and Scots Lake. Overall, the unit oil and gas operating cost increased from $34.02/boe in 2009 to $39.07/boe in this year. The resulting oil and gas operating margin for 2010 was $138,597 compared to $693,563 in 2009. During the year, the midstream contribution increased to $1,026,474 in 2010 from $526,055 in 2009.

In the first quarter of 2010, the Company acquired five sections of land over the Cardium play in the Breton and Buck Lake area to bring the Company's total Cardium land position to seven sections. In addition, the Company completed the acquisition of twelve sections of land in Saskatchewan which are prospective for Bakken oil, to bring the Company's total Bakken land holding to 17 sections. In aggregate, the Company spent approximately $3.9 million on these acquisitions. The Company continues to hold in excess of 51,000 gross acres of land and 31,000 net acres of land in Alberta and Saskatchewan. The Company's primary focus for 2010 was on the development of non-conventional oil and gas opportunities in the Cardium play at Breton and Buck Lake area, and the Company spudded its first Cardium well in November 2010, which well has been on production since mid-February of 2011. A second Buck Lake Cardium well was drilled earlier this year, and is waiting on break-up for testing and completion. The timing of up to four additional Cardium wells will depend on the availability of further funding. Anterra plans a 3-D seismic program over the Bakken lands in Saskatchewan in 2011. The drilling of the first well is now scheduled for 2011, depending on the outcome of the seismic program. The Company also intends to pursue acquisitions in Alberta and Saskatchewan when and as opportunities arise. Anterra also offers fee based third party midstream processing services and, during the year throughput and revenues were higher by 31% compared to 2009. The processing cost is 9% lower than the cost in 2009.

Summary of selected financial data

	Three Months December 31, 2010 (unaudited)	Three Months December 31, 2009 (unaudited)	Twelve Months December 31, 2010	Twelve Months December 31, 2009
Oil and Gas Production				
Revenue	1,198,607	773,596	3,908,326	2,942,566
Royalties	(160,909)	(57,630)	(358,826)	(159,460)
Gross overriding royalties	-	4,228	-	4,228
Net revenue	1,037,698	720,194	3,549,500	2,787,334
Operating costs	1,557,519	632,891	3,410,903	2,093,771
Oil and gas operating margin (non-GAAP)	(519,821)	87,303	138,597	693,563
Midstream Processing				
Revenue	551,558	368,919	1,772,757	1,348,406
Operating costs	194,268	269,996	746,283	822,351
Midstream operating margin (non-GAAP)	357,290	98,923	1,026,474	526,055
Intersegment revenue and cost	(3,110)	(20,595)	(5,237)	(80,877)
Total Net Revenue	**1,589,256**	**1,068,518**	**5,322,257**	**4,054,864**
Total Operating Costs	1,751,787	882,292	4,157,186	2,835,246
Total Operating Margin (non-GAAP)	**(162,531)**	**186,226**	**1,165,071**	**1,219,618**
Expenses				
General and administration	930,721	360,280	2,775,342	1,597,847
Stock compensation	-	-	315,254	84,373
Creditor settlements	-	(12,832)	-	(345,762)
Interest	23,828	70,789	79,262	335,575
Depletion, depreciation, accretion	593,294	766,387	2,308,625	2,482,713
Total Expenses	**1,547,843**	**1,184,624**	**5,478,483**	**4,154,746**
Net Loss Before Tax	**(1,710,374)**	**(998,398)**	**(4,313,412)**	**(2,935,128)**
Provision For Taxes	(91,934)	(295,628)	(760,869)	**(850,120)**
Net Loss	**(1,618,440)**	(702,770)	**(3,552,543)**	(2,085,008)
Earnings (loss) per Class A share				
Basic	(0.001)	(0.011)	(0.015)	(0.044)
Fully Diluted	(0.001)	(0.011)	(0.015)	(0.044)
Weighted Average Number of Class A Shares In Thousands	244,488	66,411	239,017	46,912
Cash flow from Operating Activities				
Net loss	(1,618,440)	(702,770)	(3,552,543)	(2,085,008)
Less: non-cash operating	448,437	470,759	1,810,122	1,696,643
Funds Flow From Operations (non-GAAP)	**(1,169,968)**	**(232,011)**	**(1,742,421)**	**(388,365)**
Funds Flow Per Class A Share (non-GAAP)	(0.005)	(0.004)	(0.007)	(0.008)

Presentation

Funds flow from operations is not a recognized measure under Canadian generally accepted accounting principles (GAAP). However, management believes that funds flow from operations is a useful measure of financial performance as an indication of cash generated from operations of the Company during a period to fund its capital expenditures without regard to changes in non-cash working capital during the period and, further, it is a commonly accepted measure in the industry which is useful for knowledgeable investors for comparison purposes. For the purposes of funds flow from operations calculations, funds flow is defined as “Funds flow from operations” before changes in non-cash operating working capital. Anterra’s determination of funds flow from operations may not be comparable to that reported by other companies.
Operating margin is not a recognized measure under GAAP; however management believes it is a useful measure of financial performance for assessing the operations of the Company. Operating margin is defined as revenue less operating costs, both of which are GAAP measures.

In this MD&A, the calculation of barrels of oil equivalent (boe) is calculated at a conversion rate of 6,000 cubic feet (mcf) of natural gas for one barrel (bbl) of oil based on an energy equivalency conversion method. Boe’s may be misleading particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Annual Financial Information

	Year Ended December 31	
	2010	2009
Revenues	$ 5,681,083	$ 4,214,324
Net Loss	(3,552,543)	(2,085,008)
Per Class A Share- Basic	(0.015)	(0.044)
Per Class A Share- Fully Diluted	(0.015)	(0.044)
Total Assets	30,486,966	26,338,400

Quarterly Financial Information

	4th Quarter 2010	3rd Quarter 2010	2nd Quarter 2010	1st Quarter 2010
Net Revenue	**$ 1,589,256**	**$ 1,313,178**	**$ 1,174,644**	**$ 1,245,179**
Oil and gas operating margin	(519,821)	355,479	200,484	102,455
Processing operating margin	357,290	248,264	214,563	206,358
Net Loss	**(2,379,309)**	**(838,781)**	**(543,379)**	**(551,943)**
Loss per share				
Basic	(0.010)	(0.003)	(0.002)	(0.003)
Fully Diluted	(0.010)	(0.003)	(0.002)	(0.003)
Weighted Average Number of Shares In Thousands	244,488	244,488	244,488	219,488
Funds Flow From Operations	**(1,169,968)**	**(175,446)**	**(165,159)**	**(231,848)**
Funds Flow Per Share	(0.005)	(0.001)	(0.001)	(0.001)
Cash flow from operating activities	(1,504,344)	(129,435)	(602,237)	(1,565,077)

	4th Quarter 2009	3rd Quarter 2009	2nd Quarter 2009	1st Quarter 2009
Net Revenue	**$ 1,068,518**	**$ 1,027,786**	**$ 1,038,393**	**$ 920,167**
Oil and gas operating margin	87,303	186,595	305,344	114,321
Processing operating margin	98,923	166,190	131,628	129,314
Net Loss	**(702,770)**	**(396,293)**	**(439,964)**	**(545,981)**
Loss per share				
Basic	(0.011)	(0.009)	(0.012)	(0.014)
Fully Diluted	(0.011)	(0.009)	(0.012)	(0.014)
Weighted Average Number of Shares In Thousands	66,411	44,760	38,001	38,001
Funds Flow From Operations	**(232,011)**	**(38,211)**	**25,315**	**(143,458)**
Funds Flow Per Share	(0.004)	(0.001)	0.001	(0.004)
Cash flow from operating activities	(99,719)	(15,052)	183,420	53,039

Oil & Gas Production

Production during 2010 averaged 169 boe per day compared to 165 boe per day in 2009. In addition, during the year, gas sales declined at both Breton and Judy Creek. The Company's primary focus for 2010 was on the development of non-conventional oil and gas opportunities in the Cardium play in the Breton and Buck Lake areas, and the first Cardium well commenced drilling in November 2010. The timing of up to four additional wells will depend on the availability of funding.

Oil & Gas Production

	Three Months December 31, 2010	Three Months December 31, 2009	Twelve Months December 31, 2010	Twelve Months December 31, 2009
Oil (bbl/d)	164	107	136	116
Natural Gas (mcf/d)	22	284	59	320
NGLs (bbl/d)	4	3	8	3
Total (boe/d)	171	157	169	172

Oil & Gas Revenue and Realized Prices

The continuing uncertainty of the global economy has resulted in commodity price volatility. At current commodity price levels of approximately $80.00 for oil and $3.50 for gas, revenues in 2011 are expected to remain constant with 2010 levels. During 2010, oil prices recovered to a range from $70 to $80, while gas prices decreased below $4.00 during the quarter. The average oil price and average gas price for the year were 4% higher than and 2% lower than the prices for 2009 respectively. Assuming prices hold at current levels, the Company expects to generate breakeven funds flow from existing operational levels, assuming no unforeseen increase to operating expenses. Incremental production from new development activity should lead to positive funds flow from operations as the year progresses.

	Three Months December 31, 2010	Three Months December 31, 2009	Twelve Months December 31, 2010	Twelve Months December 31, 2009
Oil				
Revenues	$1,175,372	$652,959	$3,711,033	$1,797,369
Prices $/bbl	$78.08	$66.59	$74.97	$56.72
Natural Gas				
Revenues	$43,682	$79,380	$251,921	$337,695
Prices $/mcf	$3.55	$3.04	$3.91	$3.86
NGL’s				
Revenues	$12,910	$12,079	$61,847	$33,906
Prices $/bbl	$38.71	$43.45	$43.84	$41.00
Total				
Revenues	$1,231,964	$744,418	$4,024,800	$2,168,970
Price $/bbl	$70.65	$51.57	$65.28	$46.06

Gross Overriding Royalty Income

Two farm-in gas wells drilled at Breton generate gross overriding royalties to the Company until payout. These wells have provided gross overriding royalties of $1,147 for the year ended December 31, 2010, (2009 – $4,228).

Oil & Gas Royalties Expense

Total royalties, including crown royalties, were $358,826 for the year of 2010 as compared to $159,460 for the year of 2009. This represented $5.82 per boe for the year of 2010 as compared to $2.65 per boe for the year of 2009. The Company’s royalty rate increase was due to increased production from higher royalty rate wells at Breton and Matziwin.

Oil & Gas Operating Costs

Total oil and gas operating costs for 2010 were $3,410,903 or $55.32 per boel, including $57,523 for inter-divisional processing charges. In comparison, operating costs were $2,093,771 for 2009 or $34.02 per boe, including $47,137 for inter-divisional processing charges. The high operating and maintenance costs in 2010 related to well workovers to bring production back on line and site remediation at Breton. These costs continued into the year. However, in October, the Company saw a considerable improvement as these projects were concluded. Overall, the unit oil and gas operating cost increased from $34.02 per boe in 2009 to $55.32 per boe in the year, it is expected to decline in the future with increases to production. The unit operating costs are budgeted to improve in 2011 with the addition of new production from the Company's Cardium horizontal wells. Inter-divisional charges were eliminated in 2010 for consolidation purposes.

Oil & Gas Operating Net Back

The operating net back for 2010 was $19.45 per boe compared to $11.46 per boe for 2009. These numbers reflect increased commodity prices. Maintenance costs were higher than usual in 2010 as the Company worked to bring production back on line, reversing the impact of the cost constraint activities in 2009. The Company incurs high unit operating costs due to the low productivity of most of its wells. Oil and Gas operating net back is a non-GAAP measure but it is derived entirely from GAAP measures and management believes it is commonly used in the industry and for comparison purposes by investors.

	Three Months December 31, 2010	Three Months December 31, 2009	Twelve Months December 31, 2010	Twelve Months December 31, 2009
Average realized price ($/boe)	$70.65	$51.57	$65.28	$48.91
Royalties ($/boe)	9.23	2.38	5.82	2.65
Operating expenses ($/boe)	30.35	36.26	40.01	34.80
Operating net back ($/boe)	$31.07	$12.93	19.45	11.46

Processing Revenue

Processing revenue for 2010 was $1,772,757 compared to $1,348,406 2009. There was some increase in volumes in the year. The Company continued to experience stronger third party volumes during 2010 compared to 2009 and this trend appears likely to continue through 2011.

Processing Operating Costs

Processing operating costs for 2010 were $746,283 (including $54,902 of inter-divisional charges) compared to $822,351 (including $33,222 of inter-divisional charges) for 2009. In 2010, the Company has been able to lower maintenance charges to a more consistent level after some significant maintenance and plant turnaround costs at the end of 2009. Inter-divisional charges were eliminated for consolidation purposes.

General and Administrative Expenses

General and administrative ("G&A") expenses for 2010 totaled $2,775,342, including the expense of $328,000 cash payment and $60,000 value of common shares to satisfy the obligations under the provisions of employment agreements. The comparable cost for the year ended December 31, 2009 was $1,597,847. During 2010, the Company has experienced a higher level of consulting fees and business development costs as the Company has ramped up its resources to prepare for future development plans, compared to 2009 when these costs had been reduced to respond to the downturn in economic conditions.

Interest Expense

Interest expense for 2010 was $79,262 compared to $335,575 in 2009. The reduction in cost, compared to 2009, is related to paying down the credit facility after the equity investment funds were received in January. The expense for the year includes accrued interest of $6,351on the debentures issued in settlement of the Company's payables.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense was $2,308,625 in 2010 compared to $2,249,032 in 2009.

Net Income and Loss

The net loss in 2010 was $3,552,543, including stock compensation expense of $315,254. It reflected a tax recovery of $760,869, and a loss before tax of $4,313,412. This compared to a net loss of $2,085,008, and loss before tax of $2,935,128, in 2009. The operating margin for 2010 was $1,165,071 compared to $1,219,618 in 2009.

During the year, the Company has increased production levels and realized a higher price for oil sales, which have increased the revenue by 35% compared to the last year. The increase in revenue and in operating costs were more than offset by the G&A expenses, including the expense of $328,000 cash payment and $60,000 value of common share issued to satisfy the obligations under the provisions of employment agreements. During this period, the processing contribution has increased quarter to quarter. A significant improvement in results is expected in 2011 with the new production from Buck Lake.

Capital Expenditures, Commitments and Contingencies

The Company spent $4,760,795 on capital expenditures during the year, as the Company consolidated its position and made preparations to drill its first well on the Cardium lands in the Breton/Buck Lake area. The Company had previously spent approximately $3.9 million on land acquisitions on Cardium lands at Breton / Buck Lake in Alberta, and on Bakken lands in Saskatchewan in the first quarter.

In prior years, the Company entered into employment agreements with certain senior management. In addition to defining the terms of employment, the agreements entitled the employees to payments ranging from 6 months to 18 months of compensation for termination without cause or in the event of a change of control. On January 15, 2010 completion of the final installment of the new investment transaction described in the section on Share Capital triggered a change of control. On July 13, 2010, as part of an arrangement to restructure executive management and retain the services of certain officers, the Company agreed to issue 600,000 Class A Shares, at a price of $0.10 per share, to two officers of the Company and agreed to pay certain employees $328,000 in aggregate compensation, in order to satisfy the obligations under the provisions of the employment agreements.

Liquidity, Capital Resources and Subsequent Events

Funds flow from operations for 2010 totaled a negative $1,742,421 compared to a negative $388,365 for 2009.

At December 31, 2010, there was $1,299,841 drawn down under the Company's revolving demand loan facility (see Bank Debt below) and the Company's net working capital deficit, including the cash position, was $507,073, compared to a working capital deficit of $5,062,056 at December 31, 2009. The working capital deficit at December 31, 2010 includes $1,238,076 in deposits under the Licensee Liability Rating ("LLR") requirement with the Energy Resources Conservation Board which has increased during 2010 as a result of the impact of the low production in the first quarter of 2010 as reflected in the deemed value of the Company's producing assets when compared to the deemed value of its reclamation liabilities.

During 2010, the Company expended $3.9 million on land positions in Alberta and Saskatchewan, and drilled one horizontal well in the Cardium in November. The first well has been on production since mid-February of 2011. A second Buck Lake Cardium well was drilled earlier this year, and is waiting on break-up for testing and completion.

On March 29, 2011, the bank increased the revolving demand loan facility from $5,800,000 to $8,500,000.

Bank Debt

At December 31, 2010, the Company had available a $5,800,000 revolving demand loan facility with a Canadian chartered bank. The revolving loan bears interest at prime plus 0.75%, an effective rate at year end of 3.75%, and the loans are secured by a general assignment of book debts and a $10,000,000 first floating charge debenture over all assets of the Company. As at December 31, 2010, the Company had drawn down $1,299,841 under the facility. The loans are shown as a current liability due to their demand nature despite the lender having not demanded repayment of the loan.

Under its credit facility agreement, the Company is required to maintain a working capital ratio, after adding the unused portion of the revolving demand loan and after excluding outstanding bank debt under the facility, of not less than 1:1. The Company was in compliance with this covenant at December 31, 2010.

Share Capital

At December 31, 2010, there were 245,088,032 Class A Shares and nil Class B Shares outstanding. At December 31, 2010, there were 2,666,665 warrants outstanding. No additional warrants to purchase Shares have been issued since December 31, 2010. On July 13, 2010, the Company agreed to issue 600,000 Class A Shares, at a price of $0.10 per share, to two officers of the Company, in satisfaction of obligations under their employment agreements.

On July 13, 2010, the Company granted 18,500,000 stock options to directors, officers, employees, and consultants to purchase Class A Shares at an exercise price of $0.10. Of the total options granted, one fourth vested immediately, with the balance vesting equally on the first and third anniversary of the grant date. Included in these options were 750,000 options granted to consultants providing investor relations services to the Company.

The options have been fair valued and the value estimated at $315,254 included in the stock compensation expense. The value was estimated using the Black-Scholes option pricing model with a current share price of $0.08 on July 13, 2010; an exercise price of $0.10 per option; a risk free interest rate of 2.00%; expected volatility of 75%; and a five year average life.

Pursuant to an investment agreement with an international investor dated September 10, 2009, on January 15, 2010, the Company closed the final tranche of the investment, whereby the investor acquired 150,000,000 Class A Shares at a price of $0.08 per Class A Share for gross proceeds of $12,000,000. In conjunction with the closing, the Company paid finder's fees to two agents in an aggregate amount of $480,000 and issued an aggregate of 1,599,999 warrants, each warrant entitling the holder to purchase one Class A Share at a price of $0.15 per share exercisable for two years from the date of the closing. Following the closing of the final installment of this investment, the investor held 77.7% of the outstanding Class A Shares.

Pursuant to the rules of the TSX Venture Exchange, certain shares of the previous directors, officers and insiders of Resolve (which were exchanged for shares of the Company) were subject to escrow conditions, whereby the Class A Shares were released from escrow over a period of 36 months. Pursuant to these conditions, at December 31, 2009, 555,900 Class A shares remained in escrow; and at December 31, 2010, all Class A Shares had been released.

At April 26, 2011, there were 245,884,699 Class A Shares and nil Class B Shares outstanding. Since January 1, 2011, warrants to purchase 796,667 Class A Shares have been exercised at $0.15 per share. On March 29, 2011, the Company granted stock options to directors, officers and consultants to purchase an aggregate of 5,350,000 Class A Shares at $0.255 per share.

Related Party Transactions

Except as disclosed elsewhere the Company had the following related party transactions:

(a) In July 2009, the Company completed a private placement of Units, each Unit comprising one Class A Share and one flow-through Class A Share, for a total of 2,666,740 Class A Shares and 2,666,740 flow-through Class A Shares, at a price of $0.15 per Unit. Directors and officers of the Company subscribed for an aggregate of 1,000,040 Class A Shares and 1,000,040 flow-through Class A Shares.

(b) During the year, a legal firm, of which a director is a partner, charged the Company $21,257 (2009 - $32,341) for legal fees and services.

(c) At December 31, 2010, the Company has a receivable for $21,399 due from Alliance Success Holding Group Limited ("Alliance"), which owns 42% of the Company's shares at December 31, 2009, for services paid for by the Company on behalf of Alliance, relating to Alliance's investment in the Company.

All related party transactions in the normal course of operations have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and which is similar to those negotiated with third parties.

Changes in Accounting Policies

In February 2008, the Canadian Accounting Standards Board (AcSB) announced 2011 is the changeover date for publicly listed companies to adopt IFRS, in place of Canadian generally accepted accounting principles (GAAP). The date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011.

During 2009 the Company commenced the process of evaluating and planning the implementation of a comprehensive enterprise wide project to manage the transition to IFRS with reporting to both senior management and the Audit Committee. The project has focused on key impact areas including:

* Financial reporting,
* Systems and processes,
* Communication, and
* Training.

The scoping and planning phase was completed in 2010. This phase included a high-level impact assessment to identify key areas that may be impacted by the transition to IFRS.
The Company is in the process of engaging an external advisor to assist with the completion of the documentation assessing the differences between GAAP and IFRS prepared as well as preparation of shell financial statements, including notes. We are currently engaged in the implementation of changes identified affecting financial reporting, internal controls and businesses, finalization and approval of accounting policy choices and IFRS 1 exemptions, and training of accounting and other staff, as necessary. The overall IFRS transition is expected to be completed on schedule and we will issue our first interim consolidated financial statements in accordance with IFRS as issued by the IASB beginning with the first quarter ending March 31, 2011 with comparative interim IFRS financial results for 2010.

Based on our current analysis, the significant accounting differences between our current accounting policies under Canadian GAAP and expected accounting policies under IFRS include the following:

* Under IFRS, depletion and depreciation of property and equipment ("PP&E") will be calculated at a "significant component level" as opposed to the current "entity level" under existing GAAP. The existing full cost pool under Canadian GAAP will be separated into components and depleted individually at the component level. Although depletion will continue to be calculated using the unit-of-production method, under IFRS, the Company has the option to calculate depletion using proven plus probable reserves.

* IFRS differentiates between Exploration and Evaluation ("E&E") assets and Development and Producing ("D&P") assets, whereas under Canadian GAAP they are both considered PP&E. Upon adoption to IFRS, Exploration and Evaluation ("E&E") costs will be separated from PP&E and shown as a separate line item on the balance sheet. E&E costs, to the extent that they are not impaired, are expected are transferred into PP&E when reserves have been assigned to these assets. If reserves have not been established and there are no further plans for development activity, then the E&E expenditures will be reviewed for impairment. Any impairment of E&E assets are charged to income.

* Under IFRS, impairment testing on oil and gas properties will be performed at a lower level than that under current Canadian GAAP. Under IFRS the impairment test compares the carrying value of the oil and gas assets to the greater of the fair value of the assets and the value-in-use of the assets, which is a discounted cash flow measure. Future impairment tests will be required when management determines that

indicators of impairment exist. Should impairment losses be recorded in accordance with IFRS, certain of those losses can be reversed in the future, if facts and circumstances change.

* Under IFRS, gains and losses on the disposal of oil and gas assets are recognized in net earnings. The amount of gain or loss is determined by comparing the proceeds from disposal with the corresponding carrying amount.

* Discount rates used in calculating asset retirement obligations ("ARO") has been subject to various interpretations and thus diversity in practice. As a result the IASB is currently reviewing the discount rate issue. Future changes to the standards and interpretations of the guidance could lead to a material change in this provision upon adoption of IFRS.

During 2010, the Company continued its planning for the implementation of IFRS. However, progress on adoption was delayed due to limitations on the Company's available resources. The IFRS requirements for financial statement presentation and disclosure are currently being reviewed in conjunction with the preparation of IFRS compliant financial statements and notes.

There are other differences between IFRS and Canadian GAAP that may be applicable to the Company, but we do not anticipate will have a significant impact. The IASB continues to amend and add to current IFRS with several projects underway. The Company's transition plan includes monitoring actual and anticipated changes to IFRS and related rules and regulations and assessing the impact of these changes on the Company and its financial statements, including expected dates of when such impacts are effective

Business Risks

Crude oil and natural gas exploration, development, production and processing involve a number of business risks, some of which are beyond the Company's control. These can be categorized as operational, financial and regulatory risks.

Operational risks include finding and developing reserves economically, marketing production and services, product deliverability uncertainties, changing government law and regulation, hiring and retaining skilled employees and contractors and conducting operations in a cost effective and safe manner. The Company continuously monitors and responds to changes in these factors and adheres to all regulations governing its operations. Insurance is also maintained at levels consistent with prudent industry practices to minimize risks, but the Company is not fully insured against all risks, nor are all such risks insurable.

Financial risks include commodity prices, interest rates and the Canadian/United States exchange rate, all of which have considerable impact on the estimates contained herein but are beyond the Company's control. The Company sells all of its production on the spot market and does not currently have a hedge program in place.

The Company relies on access to capital markets for new equity to supplement internally generated cash flow and debt to finance its growth plans. Periodically, these markets may not be receptive to offerings of new equity from treasury or debt, whether by way of private placement or public offerings. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors. Periodic fluctuations in energy prices may also affect lending policies of the Company's bankers, whether for existing loans or new borrowings. This in turn could limit growth prospects over the short run or may even require the Company to dedicate cash flow, dispose of properties or raise new equity to reduce bank borrowings under circumstances of declining energy prices or disappointing drilling results.

The Company is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

General adverse economic conditions globally, including recession in Canada and a worldwide economic slowdown, disruptions to the credit and financial markets in Canada and worldwide and local economic turmoil may adversely affect the value of the Company's business and value of its securities.

Regulatory risks include changes to Canadian federal and provincial laws, which are beyond the Company's control. The Government of Alberta has completed a comprehensive review of the province's oil and natural gas royalty structure.

Forward Looking Statements

This MD&A contains forward looking information related to the Company's planned drilling program, production, revenue, commodity prices, royalties, capital expenditures and commitments, operating costs, general and administrative expenses, funds flow from operations, financing plans, liquidity and capital resources and debt settlement. Forward-looking information is based on expectations and estimates as of the date of this document, and is information that is subject to known and unknown risks and other factors that may cause future actions, conditions or events to differ materially from the anticipated actions, conditions or events expressed or implied by such forward-looking information. Forward-looking information is information that does not relate strictly to historical or current facts, and can be identified by the use of the future tense or other forward-looking words such as "believe", "expect", "anticipate", "intend", "plan", "estimate", "should", "could" "may", "objective", "projection", "forecast", "continue", "strategy", "position" or the negative of those terms or other variations of them or comparable terminology.

Further examples of such forward-looking information in this document include but are not limited to the following, each of which is subject to significant risks and uncertainties and is based on a number of assumptions, which may prove to be incorrect including: the amounts recorded for depletion, depreciation and accretion, the provision for asset retirement obligations and the ceiling test, which are based on estimates of reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. Stock-based compensation expense is based upon estimates using the Black-Scholes option pricing model.

Risks include, but are not limited to, the availability and costs of financing, general economic conditions and risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the financial health of the Company's joint venture partners; health, safety and environmental risks; and the uncertainty of dealing with government and obtaining regulatory approvals).

At this time, the most significant risk relates to the uncertainty of future oil and gas prices and the current volatility in these markets. Revenues and funds flow from operations will be impacted positively or negatively depending on the ultimate variance to the Company's forecast assumptions. Furthermore, the outcome of commodity price changes are expected to impact the Company's capital spending plans and the ability of joint venture partners and other sources of capital funding to provide financing for the Company's projects.

Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, ability to attract and retain employees on a cost effective basis, commodity and marketing risk and seasonality. The Company is subject to significant drilling risk and uncertainties including the ability to find oil and gas reserves on an economic basis. The Company is also exposed to risks relating to the inability to obtain timely regulatory approvals, surface access, access to third party gathering and processing facilities, transportation and other third party related operational risks. Financial risks that Anterra is exposed to include, but are not limited to, access to debt or equity markets and fluctuations in commodity prices, interest rates and the Canadian/US dollar exchange rate.

It is anticipated that subsequent events and developments may cause a change to the assumptions made by the Company. The Company does not have an intention to update this forward-looking information, except as required by applicable securities laws. This forward-looking information represents the Company's views as of the date of this document and such information should not be relied upon as representing the Company's views as of any date subsequent to the date of this document. The Company has attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking information. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations. **There can be no assurance that forward-looking information will prove to be accurate, as actual results and**

future events could differ materially from those expected or estimated in such statements. Accordingly, readers should not place undue reliance on forward-looking information. These factors are not intended to represent a complete list of factors that could affect the Company.

Additional information relating to the Company is available on SEDAR at www.sedar.com and on the Company's website at www.anterraenergy.com.