MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (**"MD&A"**) in respect of the three and twelve month periods ended June 30, 2010 (the "**Reporting Periods**") as compared to the three and twelve month periods ended June 30, 2009 (the "**Comparable Prior Periods**") is dated October 20 , 2010.

The following discussion and analysis is management's assessment of the historical, financial and operating results of Manitok Exploration Inc. (the "**Corporation**" or "**Manitok**") and should be read in conjunction with the audited financial statements and related notes as at and for the years ended June 30, 2010 and 2009. All financial information (other than non-GAAP measures relating to terms used in the petroleum and natural gas industry) has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("**GAAP**") and all dollar amounts are expressed in Canadian dollars unless otherwise stated.

As at June 30, 2010 Manitok was a private entity engaged in the exploration for and the development, production and acquisition of, petroleum and natural gas reserves in Western Canada.

SELECTED ANNUAL INFORMATION

Year ended June 30, *($, except for production and share information)*	**2010**	2009	2008
Average daily production (boe at 6 mcf:1 bbl)	**203.1**	214.9	260.7
Petroleum and natural gas revenue	**2,821,722**	3,420,534	5,077,855
Total revenue, net royalties	**2,394,365**	2,868,224	4,097,301
Cash flow from operations	**(141,868)**	741,588	1,950,378
Per share – basic ($)	**(0.02)**	0.09	0.34
Per share – diluted ($)	**(0.02)**	0.09	0.33
Net earnings (loss)	**(1,781,001)**	(1,254,949)	103,287
Per share – basic ($)	**(0.19)**	(0.16)	0.02
Per share – diluted ($)	**(0.19)**	(0.16)	0.02
Capital expenditures	**2,759,657**	5,882,469	4,509,754
Total assets	**17,591,508**	16,559,077	14,594,525
Working capital deficiency (surplus)	**(202,985)**	(170,856)	1,324,202
Revolving credit facility	**1,040,105**	615,769	-
Total net debt	**837,120**	444,913	1,324,202
Shareholder's equity	**14,089,990**	13,297,172	9,114,541
Common shares outstanding			
End of period – basic	**10,649,567**	8,176,826	5,824,942
End of period – diluted	**11,619,567**	9,146,826	6,756,942
Weighted average shares for period – basic	**9,264,080**	7,950,158	5,747,755
Weighted average shares for period – diluted	**9,264,080**	7,950,158	5,873,952

NON-GAAP MEASURES

This MD&A makes references to terms commonly used in the petroleum and natural gas industry, such as cash flow, cash flow from operations, cash flow netback, cash flow per share, operating netback and net earnings (loss) netback.

Cash flow or cash flow from operations appears as a separate line on the Corporation's Statements of Cash Flows above "changes in non-cash working capital" and is reconciled to net earnings (loss) and comprehensive earnings (loss). In the Corporation's disclosure, operating netback denotes petroleum and natural gas revenue less royalties, operating expenses and transportation and marketing expenses. Cash flow netback as used herein denotes net earnings plus non-cash items including future income taxes expense (less any recovery), depletion, depreciation and accretion expense, and non-cash stock-based compensation expense.

These terms are not defined by GAAP and consequently, they are referred to as non-GAAP measures. The reader should be cautioned that these measures may not be directly comparable to measures by other companies where similar terminology is used.

BOE CONVERSIONS

*The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("**boe**") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. Manitok uses the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. However, boe's do not represent an economic value equivalency at the wellhead and therefore may be a misleading measure if used in isolation*.

FORWARD LOOKING STATEMENTS

This MD&A contains certain forward-looking statements and forward-looking information (hereinafter collectively referred to as "forward-looking statements") within the meaning of applicable Canadian securities laws. These statements relate to future events or future performance and are based upon the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. All statements other than statements of historical fact are forward-looking statements. In some cases, words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "would", "potential", "proposed" and other similar words, or statements that certain events or conditions "may" or "will" occur, are intended to identify forward-looking statements.

Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions and known and unknown risks and uncertainties that the predictions, forecasts, projections and other forward-looking statements will not occur. Although the Corporation believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Corporation cannot guarantee future results, levels of activity, performance or achievements. Consequently, there is no representation by the Corporation that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Such forward-looking statements in this MD&A speak only as of the date of this MD&A.

In particular, this MD&A contains forward-looking statements pertaining to the following: (i) cash flow and capital expenditures, (ii) drilling, completion and production matters, (iii) results of operations, (iv) financial position, and (v) other risks and uncertainties described from time to time in the Corporation reports. With respect to such forward-looking statements the key assumptions on which the Corporation relies are; that future prices for crude oil and natural gas, future currency exchange rates, interest rates and future availability of debt and equity financing will be at levels and costs that allow the Corporation to manage, operate and finance its business and develop its properties and meet its future obligations; that the regulatory framework in respect of royalties, taxes and environmental matters applicable to the Corporation will not become so onerous as to preclude the Corporation from viably managing, operating and financing its business *and the development of its properties; and that the Corporation will continue to be able to identify, attract and employ qualified staff and obtain the outside expertise and other equipment it requires to manage, operate and finance its business and develop its properties.*

All such forward-looking statements necessarily involve risks associated with oil and gas exploration, production and marketing which may cause actual results to differ materially from those anticipated in the forward-looking statements. Some of those risks include; general economic conditions in Canada, the United States and globally; industry conditions, including fluctuations in the price of oil and natural gas; uncertainties in the estimates of reserves and in the projection of future rates of production and timing of development expenditures, changes in governmental regulation of the oil and gas industry; geological, technical, drilling and processing problems and other difficulties in producing reserves; unanticipated operating events which can damage facilities or reduce production or cause production to be shut in or delayed; failure to obtain regulatory approvals in a timely manner; adverse conditions in the debt and equity markets; and competition from others for scarce resources.

Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. The Corporation is not under any duty to update any of the forward-looking statements after the date of this MD&A to conform such statements to actual results or to changes in the Corporation's plans or expectations, except as otherwise required by applicable securities laws.

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

bbls	barrels
mbbls	thousands of barrels
bbls/d	barrels per day
NGLs	natural gas liquids

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
mmbtu	million British thermal units
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day

Other

boe	barrels of oil equivalent converting 6 mcf of natural gas to 1 barrel of oil
mboe	thousands of barrels of oil equivalent
boe/d	barrels of oil equivalent per day

OVERALL PERFORMANCE

Production

Production in the twelve month Reporting Period averaged 203.1 boe/d, which is a 5% decrease from the average of 214.9 boe/d in the Comparable Prior Period. The decrease in production was due mainly to normal production declines in the natural gas assets and the reduced drilling program as the Corporation focused its capital activity on undeveloped land acquisitions. The decline in natural gas production was partially offset by an increase in heavy oil production in the twelve month Reporting Period as it increased 24% from the Comparable Prior Period, due to improved operations of the Corporation's heavy oil assets.

For the twelve month Reporting Period, the Corporation's production consisted of approximately 61% natural gas and 39% crude oil and natural gas liquids. See "Results of Operations – Petroleum and Natural Gas Revenue".

Commodity Prices

Average realized heavy oil prices in the twelve month Reporting Period were $60.48 per barrel which is a 4% decrease from $63.10 per barrel the Corporation averaged in the Comparable Prior Period. Average realized natural gas prices in the twelve month Reporting Period were $4.14 per mcf which is a 30% decrease from $5.91 per mcf the Corporation averaged in the Comparable Prior Period. The prices received for Manitok's petroleum and natural gas sales are impacted by world events that dictate the level of supply and demand for crude oil and natural gas. Manitok currently does not have any commodity hedges in place and thus is subject to fluctuations in commodity prices.

Canadian Edmonton Par oil prices averaged $76.05 per barrel in the twelve month Reporting Period which remained relatively consistent with $75.70 per barrel in the Comparable Prior Period. The AECO daily natural gas spot price averaged $4.10 per mmbtu in the twelve month Reporting Period as compared to $5.72 per mmbtu in the Comparable Prior Period, which is a 28% decrease. The reduction in natural gas prices translated into reduced cash flow available for reinvestment in the 2010 fiscal period.

Cash Flow and Earnings

Cash flow from operations decreased to negative $141,868 ($0.02 per share) for the twelve month Reporting Period as compared to positive cash flow of $741,588 ($0.09 per share) for the Comparable Prior Period. Manitok had a net loss of $1,781,001 ($0.19 per share) for the twelve month Reporting Period as compared to a net loss of $1,254,949 ($0.16 per share) for the Comparable Prior Period. The decrease in cash flow and increase in net loss for the twelve month period was due mainly to a 30% decrease in average realized natural gas prices, a 15% decrease in average natural gas production volumes and 37% increase in net general and administrative costs as the Corporation increased personnel levels in anticipation of its future activity and becoming a reporting issuer, offset by a 24% increase in average heavy oil production volumes in the Reporting Period as compared to the Comparable Prior Period.

Capital Expenditures and Total Debt

Total capital expenditures for the twelve month Reporting Period were $2,759,657 as compared to $5,882,469 in the Comparable Prior Period. The decrease in capital expenditures is the direct result of the Corporation's response to the drop in commodity prices in the latter part of 2009 and into the Reporting Periods.

Of the total capital spent for the twelve month Reporting Period, approximately 80% was directed to undeveloped land acquisitions at Alberta crown land sales, which will provide future growth for the Corporation.

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

- On December 31, 2009, the Corporation completed a private placement of 176,956 common shares issued at a price of $1.15 per share and 1,058,785 flow-through common shares issued at a price of $1.30 per share for total net proceeds of $1,494,625. The proceeds of the equity issue were used primarily to pay the outstanding balance on the revolving credit facility.
- On February 12, 2010, the Corporation completed a private placement of 1,237,000 common shares issued at a price of $1.15 per share for total net proceeds of $1,342,640. The proceeds of the equity issue were used primarily to acquire undeveloped land.
- On February 22, 2010, the Corporation amended its agreement with a major Canadian lender which decreased its demand revolving operating loan facility from $3,100,000 to $2,500,000. The decrease was due to the effect of the decline in commodity prices on the Corporation's reserve report.
- On July 8, 2010, immediately prior to the amalgamation, the Corporation completed a private placement of 4,311,700 common shares issued at a price of $1.15 per share and 3,846,000 flow-through common shares issued at a price of $1.30 per share for total net proceeds of $9,294,090. Proceeds of the equity issue were used to repay the outstanding bank debt and will be used to fund the Corporation's drilling program in late 2010 and early 2011.
- On July 8, 2010, Manitok amalgamated with a reporting issuer by the name of Desco Resources Inc. (**"Desco"**) pursuant to the Alberta Business Corporations Act to form a new company under the name "**Manitok Energy Inc**." Pursuant to the amalgamation, each Desco shareholder received 0.375 of a Manitok Energy Inc. share for every one Desco share and each Manitok shareholder received 0.75 of a Manitok Energy Inc. share for every one Manitok share. Manitok Energy Inc. is listed on the TSX Venture Exchange (the "**Exchange**") under the trading symbol MEI and began trading on July 29, 2010. For more information, the Joint Management Information Circular can be accessed on SEDAR at www.sedar.com.
- On July 8, 2010, pursuant to the amalgamation, 702,500 of the Corporation's unexercised stock options and 267,500 of the Corporation's unexercised performance warrants have been terminated and cancelled for nominal consideration. On August 16, 2010 Manitok Energy Inc. granted 1,588,500 stock options at a price of $1.10 per share which vest over a three year period and expire on August 16, 2015.
- On August 4, 2010, the Corporation disposed of an oil & gas asset in the Garrington area of Southern Alberta for approximately $1.8 million, with an effective date of June 1, 2010. The proceeds will be used to fund the Corporation's capital program.

LIQUIDITY AND BANK DEBT

Working Capital

The Corporation's working capital surplus (current assets less current liabilities), which excludes the current portion of the amount drawn on the revolving credit facility, increased to $202,985 at June 30, 2010 as compared to a $170,856 at June 30, 2009.

Manitok manages its working capital using its cash flow from operations and advances under its revolving credit facility. The Corporation did not have any liquidity issues with respect to the operation of its petroleum and natural gas business in the Reporting Period.

Bank Debt

The Corporation's revolving credit facility was $1,040,105 as at June 30, 2010, with an aggregate limit of $2,500,000 as compared to $615,769 as at June 30, 2009, when the aggregate limit was $3,100,000. The level of bank debt at June 30, 2010 was due mainly to professional fees incurred by the Corporation related to both the amalgamation and issuance of shares completed on July 8, 2010.

On February 22, 2010, the Corporation renewed the revolving credit facility with an authorized limit of $2,500,000. The Corporation's credit facilities are subject to the lender's redetermination of the borrowing base limit which is directly impacted by the value of the oil and natural gas reserves.

The Corporation is not permitted, without the prior written consent of the lender, to have a working capital ratio, which includes the undrawn portion of the facility and excludes any amount drawn on the facility, to fall below 1:1. Manitok was compliant with the covenant under its revolving credit facility throughout the Reporting Period.

Contractual Obligations

The Corporation enters into contractual obligations in the course of conducting its day-to-day business. The following table identifies Manitok's estimated contractual obligations at June 30, 2010:

	< 1 Year	1-2 Years	3-5 Years	Thereafter
Accounts payable and accrued liabilities	779,114	-	-	-
Revolving credit facility	1,040,105	-	-	-
Office lease(1)	151,320	605,280	731,380	-
Total estimated contractual obligations(2)	**1,970,539**	**605,280**	**731,380**	**-**

(1) The Corporation is committed under an operating lease relating to its office premises, beginning May 1, 2010 and expiring on June 30, 2015. Manitok does not presently use all of the leased premises and has sublet 5 offices to arms' length parties to recover a portion of the rental costs.

(2) Contractual commitments that are routine in nature and form part of the normal course of operations for Manitok are not included in the above table.

Outstanding Share Data

The Class "A" common shares of Manitok are the only class of shares outstanding and at July 8, 2010 immediately prior to the amalgamation, there were 18,807,267 common shares outstanding, stock options to purchase 702,500 common shares and performance warrants to purchase 267,500 common shares. Subsequent to the amalgamation, the common shares of Manitok Energy Inc. are the only class of shares outstanding and at October 20, 2010 there were 16,730,460 common shares outstanding and stock options to purchase 1,588,500 common shares. Manitok Energy Inc.'s common shares began trading on the TSX Venture Exchange on July 29, 2010 under the symbol "MEI". The following table summarizes the common shares issued and outstanding:

	Common Shares
Balance at June 30, 2009	**8,176,826**
Issue of common shares on December 31, 2009(1)	1,235,741
Issue of common shares on February 12, 2010 (2)	1,237,000
Balance at June 30, 2010	**10,649,567**
Issue of common shares on July 8, 2010 (3)	8,157,700
Manitok Exploration Inc. at July 8, 2010 prior to amalgamation	**18,807,267**
Issue of common shares on July 8, 2010 related to amalgamation(4)	2,625,000
Conversion of Manitok shareholders on amalgamation(5)	(4,701,807)
Manitok Energy Inc. at October 20, 2010	**16,730,460**

(1) On December 31, 2009, the Corporation completed a private placement of 176,956 common shares issued at a price of $1.15 per share and 1,058,785 flow-through common shares issued at a price of $1.30 per share for total net proceeds of $1,494,625. The proceeds of the equity issue were used to pay the outstanding balance on the revolving credit facility.

(2) On February 12, 2010, the Corporation completed a private placement of 1,237,000 common shares issued at a price of $1.15 per share for total net proceeds of $1,343,338. The proceeds of the equity issue were used primarily to acquire undeveloped land.

(3) On July 8, 2010, the Corporation completed a private placement of 4,311,700 common shares issued at a price of $1.15 per share and 3,846,000 flow-through common shares issued at a price of $1.30 per share for total net proceeds of approximately $9.3 million. Proceeds of the equity issue were used to repay the outstanding bank debt and will be used to fund the Corporation's drilling program in late 2010 and early 2011.

(4) On the amalgamation with Desco each Desco shareholder received 0.375 of a share of the new amalgamated corporation for every one Desco share held. As of the amalgamation date, Desco had 7,000,000 common shares issued and outstanding.

(5) On the amalgamation with Desco each Manitok shareholder received 0.75 of a share of the new amalgamated corporation for every one Manitok share held. As of the amalgamation date, Manitok had 18,807,267 common shares issued and outstanding.

RESULTS OF OPERATIONS

Petroleum and Natural Gas Revenue

The following table details Manitok's petroleum and natural gas revenue ("**P&NG**"), production and average realized sales prices by category for the Reporting Periods and the Comparable Prior Periods:

	Three months ended June 30, 2010				Three months ended June 30, 2009			
	Total Revenue ($)	Average Daily Production	%	Average ($/unit)	Total Revenue ($)	Average Daily Production	%	Average ($/unit)
Natural gas (mcf)	219,335	610.3	54	3.95	278,666	862.6	71	3.55
Heavy oil (bbls)	374,219	79.9	43	51.50	239,181	49.0	24	53.59
Light oil (bbls)	4,756	0.7	-	69.97	10,999	1.9	1	63.91
Natural gas liquids (bbls)	17,567	5.6	3	34.21	13,338	7.1	4	20.56
Total P&NG revenue (boe)	**615,877**	**188.0**	**100**	**36.01**	**542,184**	**201.8**	**100**	**29.52**

	Twelve months ended June 30, 2010				Twelve months ended June 30, 2009			
	Total Revenue ($)	Average Daily Production	%	Average ($/unit)	Total Revenue ($)	Average Daily Production	%	Average ($/unit)
Natural gas (mcf)	1,117,241	739.1	61	4.14	1,884,320	874.1	68	5.91
Heavy oil (bbls)	1,615,964	73.2	36	60.48	1,359,252	59.0	27	63.10
Light oil (bbls)	28,616	1.1	-	71.83	99,207	3.6	2	76.21
Natural gas liquids (bbls)	59,901	5.6	3	29.28	77,755	6.6	3	32.15
Total P&NG revenue (boe)	**2,821,722**	**203.1**	**100**	**38.07**	**3,420,534**	**214.9**	**100**	**43.61**

The 14% increase in petroleum and natural gas revenue in the three month Reporting Period as compared to the Comparable Prior Period was primarily attributable to a 63% increase in the average production volume of heavy oil and a 22% increase in the average realized total price during the Reporting Period, offset by a 29% reduction in average production volumes of natural gas. The 18% decrease in petroleum and natural gas revenue in the twelve month Reporting Period as compared to the Comparable Prior Period was due mainly to a 15% decrease in the average production volume of natural gas and a 30% decrease in the average realized natural gas prices during the Reporting Period, offset somewhat by a 24% increase in average production volumes of heavy oil.

Commodity Prices

Manitok's heavy oil pricing is based on Lloydminster Blend at Hardisty less a quality adjustment, blending costs, terminal charges and loss allowance. The Corporation sells virtually all of its natural gas production for prices based on the AECO daily spot price. The following table details the average reference price for the Reporting Periods and the Comparable Prior Periods:

	Three months ended June 30, 2010	Three months ended June 30, 2009	Change	**Twelve months ended June 30, 2010**	Twelve months ended June 30, 2009	Change
Heavy oil - 12° API at Hardisty ($/bbl)	59.70	58.07	2.8%	63.41	59.02	7.4%
AECO – natural gas ($/mmbtu)	3.90	3.46	12.7%	4.10	5.72	(28.3%)
Edmonton par ($/bbl)	75.44	66.19	14.0%	76.05	75.70	0.5%

The price the Corporation receives for its commodity production depends on a number of factors, including AECO Canadian dollar spot market prices for natural gas, Canadian dollar Lloydminster Hardisty oil prices, U.S. dollar oil prices, the U.S. and Canadian dollar exchange rate, and transportation and product quality differentials. Manitok currently has no financial derivatives such as fixed commodity price contracts or other hedge type contracts, but it regularly considers managing the risks associated with fluctuating spot market prices for natural gas and U.S. dollar oil prices and the U.S./Canadian dollar exchange rate. The Corporation has no current intention to enter into any such contracts at this time.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. The following table illustrates the Corporation's royalty expense for the Reporting Periods and the Comparable Prior Periods:

	Three months ended June 30, 2010	Three months ended June 30, 2009	Change	**Twelve months ended June 30, 2010**	Twelve months ended June 30, 2009	Change
Oil & natural gas royalties ($)	80,745	55,027	46.7%	427,912	620,074	(31.0%)
Oil & natural gas royalties ($/boe)	4.72	3.00	57.3%	5.77	7.91	(27.1%)
Royalties as a percentage of sales	13.1%	10.1%	29.7%	15.2%	18.1%	(16.0%)

The overall effective royalty rate in the three and twelve month Reporting Periods was 13.1% and 15.2% as compared to 10.1% and 18.1% in the Comparable Prior Periods, respectively. The increase in the effective royalty rate in the three month Reporting Period as compared to the Comparable Prior Period is largely due to the higher average commodity prices in the Reporting Period and the effect these higher prices have on the sliding scale royalty calculation. The decrease in the effective royalty rate in the twelve month Reporting Period as compared to the Comparable Prior Period is largely due to the lower average commodity prices in the Reporting Period and the effect these lower prices have on the sliding scale royalty calculation.

New Royalty and Drilling Incentives

On July 9, 2009, the Government of Alberta approved an incentive royalty rate of 5% for the first year of production from each new conventional oil or natural gas well brought on production after April 1, 2009 and before March 31, 2011 up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas per well.

On September 15, 2009, the Government of Alberta approved a drilling royalty credit incentive for new conventional oil and natural gas wells spud on or after April 1, 2009 and rig released before April 1, 2011. The Corporation will be entitled to a drilling royalty credit of $200 per metre drilled, up to a maximum of 50% of the aggregate Crown royalties paid by the Corporation during the incentive period.

On March 11, 2010, the Alberta Government announced certain changes to the existing royalty framework based on the recommendations from the Investment Competiveness Review. As a result of the competitiveness review, the existing Alberta Royalty Framework ("**ARF**") will be adjusted to better reflect current industry conditions. The adjusted ARF will be effective for the January 2011 production month. Some of the highlights include:

- The current 5% front-end royalty rate on natural gas and conventional oil will become a permanent feature of the royalty system with the current time and volume limits as described above;
- The $200 per meter drilling royalty credit program will continue to remain in place as legislated until March 31, 2011. Credits not used prior to January 1, 2011 and credits established by drilling on or after that date until March 31, 2011 will be offset from net royalties calculated using adjusted ARF rates;
- The maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%. For conventional oil, the maximum royalty will be reduced from 50% to 40%;
- Continuation of the transitional royalty framework for oil and gas introduced in November, 2008 until December 31, 2013. Effective January 1, 2011, the government will not allow any new wells to select the transitional royalty rates, but will allow an operator of wells for which transitional royalty rates have already been elected, an option to switch to the new rates effective January 1, 2011.

On May 27, 2010 the Alberta government finalized the new royalty curves for oil and natural gas wells. A number of new incentive programs were also introduced for unconventional resource exploration and the use of high-cost technologies. Some of the highlights include:

- Wells defined as a "horizontal gas well" will receive a lower upfront maximum royalty rate of 5% to account for the high cost of horizontal drilling. This new horizontal gas well royalty rate will apply for 18 producing months up to a maximum of 500 million cubic feet of gas equivalent production per well, and is retroactive for wells that were spud on or after May 1, 2010;
- Wells defined as a "horizontal oil well" will receive a lower upfront maximum royalty rate of 5% at the start of production to facilitate the recovery of investment costs prior to imposing a higher royalty rate. This new horizontal oil well royalty rate will apply to all products, with varying volume and production month limits set according to the depth of the well, and is retroactive for wells that were spud on or after May 1, 2010; and
- The Natural Gas Deep Drilling Program ("**NGDDP**") will become an ongoing feature of Alberta's royalty regime. Vertical depth requirements under this program were adjusted from 2,500 meters to 2,000 meters and will be applied retroactively for wells that were spud on or after May 1, 2010. Wells that have producing intervals that exceed 2,000 meters of true vertical depth are eligible for a royalty credit adjustment. The royalty credit ranges from $625 per metre to $3,750 per meter drilled and depends on the type of well drilled and the depth ranges specified under the program.

Manitok is currently assessing the impact of the new royalty curves and the new incentive programs, anticipating these changes to have a positive effect on Manitok's reserve values.

The royalty incentive programs will create a lower cost structure for Manitok and projects will have better economics under the new royalty framework as compared to the prior framework. The Corporation has not benefited from the drilling royalty credit incentive at this time due to its reduced capital spending program, but will maximize the incentives available with future drilling activities.

Operating Expense

The following table compares operating expenses for the Reporting Periods and the Comparable Prior Periods:

	Three months ended June 30, 2010	Three months ended June 30, 2009	Change	**Twelve months ended June 30, 2010**	Twelve months ended June 30, 2009	Change
Operating expenses ($)	234,887	207,000	13.5%	1,053,512	1,024,127	2.9%
Operating expenses ($/boe)	13.73	11.27	21.8%	14.21	13.06	8.8%

The $2.46 per boe increase in total operating costs during the three month Reporting Period as compared to the Comparable Prior Period was due primarily to charges received from joint venture partners in the Reporting Periods, but relating to prior periods ($0.97 per boe) and a significant increase in fees paid to the Energy Resources Conservation Board of Alberta ($1.40 per boe).

The $1.15 per boe increase in total operating costs during the twelve month Reporting Period as compared to the Comparable Prior Period was due mainly to charges received from joint venture partners in the Reporting Periods, but relating to prior periods ($2.08 per boe), an increase in gas gathering and processing fees ($0.85 per boe) offset by a decrease in the costs of fuel and power resulting from improved operations of the Corporation's heavy oil assets ($1.88 per boe).

Transportation and Marketing Expense

The following table illustrates the Corporation's transportation and marketing expense for the Reporting Periods and the Comparable Prior Periods:

	Three months ended June 30, 2010	Three months ended June 30, 2009	Change	**Twelve months ended June 30, 2010**	Twelve months ended June 30, 2009	Change
Transportation & marketing expenses ($)	29,501	24,258	21.6%	131,175	126,034	4.1%
Transportation & marketing expenses ($/boe)	1.72	1.32	30.3%	1.77	1.61	9.9%

These costs consist primarily of transportation costs and have increased in the Reporting Periods as compared to the Comparable Prior Periods mainly due to the increase in average production volumes of heavy oil, partially offset by the decrease in average natural gas production volumes.

General and Administrative Expense

The components of general and administrative costs ("**G&A**") for the Reporting Periods and the Comparable Prior Periods are as follows:

	Three months ended June 30, 2010		Three months ended June 30, 2009		Change
	($)	%	($)	%	
Salaries, benefits and consultants	253,376	83	133,389	55	90.0%
Other	50,830	17	109,941	45	(53.8%)
G & A expense, gross	304,206	100	243,330	100	25.0%
Overhead recoveries	64	-	(1,574)	(1)	-
Capitalized overhead	-	-	-	-	-
G & A expense, net	**304,270**	**100**	**241,756**	**99**	**25.9%**
G & A expense, net per boe	**17.79**		**13.16**		**35.2%**

	Twelve months ended June 30, 2010		Twelve months ended June 30, 2009		Change
	($)	%	($)	%	
Salaries, benefits and consultants	795,331	60	559,052	53	42.3%
Other	539,395	40	501,744	47	7.5%
G & A expense, gross	1,334,726	100	1,060,796	100	25.8%
Overhead recoveries	(426)	-	(84,871)	(8)	-
Capitalized overhead	-	-	-	-	-
G & A expense, net	**1,334,300**	**100**	**975,925**	**92**	**36.7%**
G & A expense, net per boe	**18.00**		**12.44**		**44.7%**

The net G&A expenses have increased in the Reporting Periods as compared to the Comparable Prior Periods largely due to increased personnel levels in anticipation of the Corporation's future activity and initiating the process to become a public entity. The increase in the twelve month Reporting Period as compared to the Comparable Prior Period was also due to the lower overhead recoveries which are attributable to the decreased drilling and completion expenditures.

Interest Expense

Interest expense for the three and twelve month Reporting Periods was $5,148 ($0.30 per boe) and $17,246 ($0.23 per boe) as compared to $550 ($0.03 per boe) and $550 ($0.01 per boe) for the Comparable Prior Periods. The overall effective interest rate applicable to the prime-based loans in the was 3.9% and 3.7% in the three and twelve Reporting Periods as compared to 3.6% and 3.6% in the Comparable Prior Periods.

The Corporation's average bank debt was approximately $406,000 and $471,000 in the three and twelve Reporting Periods as compared to $47,000 and $16,000 in the Comparable Prior Periods, calculated as a simple average of the daily amounts.

Deferred Financing Fees

During the 2010 fiscal period the Corporation incurred $327,947 in fees related to the amalgamation with a reporting issuer and the issuance of common shares which was completed on July 8, 2010. These costs will be charged to share capital in the next fiscal quarter.

Depletion, Depreciation and Accretion Expenses

The components of depletion, depreciation and accretion ("**DD&A**") expenses for the Reporting Periods and the Comparable Prior Periods are as follows:

	Three months ended June 30, 2010		Three months ended June 30, 2009		Change	
	($)	$/boe	($)	$/boe	Amount	per boe
Depletion & depreciation	459,781	26.88	516,742	28.13	(11.0%)	(4.4%)
Accretion for asset retirement obligations	14,800	0.87	19,200	1.05	(22.9%)	(17.1%)
Total DD&A	**474,581**	**27.75**	**535,942**	**29.18**	(11.4%)	(4.9%)

	Twelve months ended June 30, 2010		Twelve months ended June 30, 2009		Change	
	($)	$/boe	($)	$/boe	Amount	per boe
Depletion & depreciation	2,092,940	28.24	2,209,917	28.17	(5.3%)	0.2%
Accretion for asset retirement obligations	75,000	1.01	73,230	0.93	2.4%	8.6%
Total DD&A	**2,167,940**	**29.25**	**2,283,147**	**29.11**	(5.0%)	0.5%

Depletion and depreciation expense is a function of the estimated proved reserve additions, the associated future development capital required to recover those proved reserves, and the cost of petroleum and natural gas properties in the full cost pool attributable to those proved reserves. At June 30, 2010, the Corporation excluded from its full cost pool $3,354,945 (June 30, 2009 – $997,804) of costs for undeveloped land acquired by Manitok.

Petroleum and Natural Gas Properties Impairment Test

The Corporation follows the full cost method of accounting which requires periodic review of capitalized costs to ensure that they do not exceed the recoverable value of the petroleum and natural gas properties and the fair value of the Corporation's assets.

Manitok performed an impairment review at June 30, 2010 and 2009 on its petroleum and natural gas assets and based on this review, the Corporation determined there was no impairment of its petroleum and natural gas assets. The assumptions used in the impairment test are discussed in this MD&A in the "Critical Accounting Estimates" section.

Stock-Based Compensation Expense

Manitok accounts for its stock-based compensation programs, including performance warrants and stock options, using the fair value method. Under this method, the Corporation records stock-based compensation expense related to the stock-based compensation programs in the income statement over the vesting period.

The Corporation recorded a non-cash stock-based compensation expense of negative $22,802 ($1.33 per boe) for the three month Reporting Period and $55,529 ($0.75 per boe) for the twelve month Reporting Period as compared to $32,487 ($1.77 per boe) and $118,390 ($1.51 per boe) for the Comparable Prior Periods. The reduction in the Reporting Period is due mainly to forfeitures of stock options, which had not vested.

Taxes

Manitok recorded a future income tax recovery of $134,684 ($7.87 per boe) for the three month Reporting Period and $584,336 ($7.88 per boe) for the twelve month Reporting Period, as compared to a recovery of $138,120 ($7.52 per boe) and $405,000 ($5.16 per boe) for the Comparable Prior Periods. These recoveries were attributed to the net losses recorded during the Reporting Periods and Comparable Prior Periods. Manitok incurred $10,323 and $17,205 Part XII.6 taxes in the three and twelve month Reporting Periods as compared to nil and $13,839 in the Comparable Prior Periods.

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

Capital expenditures amounted to $432,385 and $2,759,657 during the three and twelve month Reporting Periods as compared to $328,313 and $5,882,469 during the Comparable Prior Periods. The 32% increase in capital expenditures for the three month Reporting Period as compared to the Comparable Prior Period was due mainly to an increase in undeveloped land and seismic data acquisitions, offset somewhat by the reduction in the Corporation's drilling program. The 53% decrease in capital expenditures for the twelve month Reporting Period as compared to the Comparable Prior Period was the result of a decrease of $5.3 million in the Corporations drilling, completion, recompletion, workover and seismic program in the Reporting Period, as a direct result of the Corporation's response to the drop in commodity prices in the latter part of 2008 and into the Reporting Periods, offset by an increase of $2.2 million in undeveloped land acquisitions.

Capital Expenditures

The following table sets forth a summary of the Corporation's capital expenditures incurred during the Reporting Periods and the Comparable Prior Periods:

Three months ended June 30, ($)	**2010**	2009
Land	157,285	5,355
Seismic	213,234	60,751
Workovers and recompletions	73,319	287,031
Drilling and completions	56,347	(31,254)
Well equipment and facilities	10,581	6,430
Total finding and development costs (F&D)	**510,766**	**328,313**
Acquisitions (dispositions), net	-	-
Total finding, development and acquisition costs (FD&A)	**510,766**	**328,313**
Administrative assets	(78,381)	-
Total capital expenditures	**432,385**	**328,313**

Twelve months ended June 30, ($)	**2010**	2009
Land	2,212,543	30,567
Seismic	266,653	701,266
Workovers and recompletions	183,968	1,950,835
Drilling and completions	103,119	2,803,602
Well equipment and facilities	5,039	376,850
Total finding and development costs (F&D)	**2,771,322**	**5,863,120**
Acquisitions (dispositions), net	(40,000)	-
Total finding, development and acquisition costs (FD&A)	**2,731,322**	**5,863,120**
Administrative assets	28,335	19,349
Total capital expenditures	**2,759,657**	**5,882,469**

Capital Resources

The following table sets forth a summary of the Corporation's capital resources for the Reporting Periods and the Comparable Prior Periods:

Three months ended June 30, ($)	**2010**	2009
Cash flow from operations	(39,066)	14,539
Changes in non-cash working capital from operations	206,705	(19,495)
Proceeds from share issuances, net	(699)	-
Increase (decrease) in revolving credit facility	701,844	615,769
Deferred financing fees paid	(327,947)	-
Changes in non-cash working capital from investing	(108,470)	(766,974)
Total capital resources	**432,367**	**(156,161)**
Expenditures on petroleum and natural gas assets	(432,385)	(328,313)
Property acquisitions and dispositions	-	-
Net Change in Cash	**(18)**	**(484,474)**

Twelve months ended June 30, ($)	**2010**	2009
Cash flow from operations	(141,868)	741,588
Changes in non-cash working capital from operations	269,163	33,816
Proceeds from share issuances, net	2,837,265	6,020,170
Increase (decrease) in revolving credit facility	424,336	615,769
Deferred financing fees paid	(327,947)	-
Changes in non-cash working capital from investing	(301,409)	(2,347,526)
Total capital resources	**2,759,540**	**5,063,817**
Expenditures on petroleum and natural gas assets	(2,799,657)	(5,882,469)
Property acquisitions and dispositions	40,000	-
Net Change in Cash	**(117)**	**(818,652)**

SUMMARY OF QUARTERLY INFORMATION

Quarters Ended	June 30, 2010	March 31, 2010	December 31, 2009	September 30, 2009
OPERATING				
Average daily production				
Natural gas (mcf/d)	610.3	730.6	789.8	824.0
Heavy oil (bbls/d)	79.9	73.7	66.8	72.5
Light oil (bbls/d)	0.7	0.6	1.3	1.7
NGLs (bbls/d)	5.6	5.1	4.4	7.3
Total (boe/d)	188.0	201.2	204.1	218.8
Average realized sales price (CAD$)				
Natural gas ($/mcf)	3.95	5.08	4.78	2.86
Heavy oil ($/bbls)	51.50	64.22	69.68	58.07
Light oil ($/bbls)	69.97	76.01	74.48	68.99
NGLs ($/bbls)	34.21	33.38	27.92	23.52
Total ($/boe)	36.01	43.07	42.37	31.31
OPERATING NETBACK ($ per boe)				
Petroleum and natural gas revenue	36.01	43.07	42.37	31.31
Royalties	(4.72)	(8.27)	(6.08)	(4.13)
Operating expense	(13.73)	(15.89)	(16.13)	(11.32)
Transportation and marketing expense	(1.72)	(1.97)	(1.52)	(1.86)
Operating netback	15.84	16.94	18.64	14.00
FINANCIAL				
Petroleum and natural gas revenue ($)	615,877	779,933	795,693	630,219
Royalties ($)	(80,745)	(149,725)	(114,205)	(83,236)
Interest and other revenue ($)	(392)	539	203	206
Total revenues, net ($)	534,740	630,747	681,691	547,189
Net earnings (loss) ($)	(356,161)	(546,038)	(411,841)	(466,962)
Per share - basic ($)	(0.03)	(0.05)	(0.05)	(0.06)
Per share - diluted ($)	(0.03)	(0.05)	(0.05)	(0.06)
Cash flow from operations ($)	(39,066)	(112,793)	52,495	(42,505)
Per share - basic ($)	(0.00)	(0.01)	0.01	(0.01)
Per share - diluted ($)	(0.00)	(0.01)	0.01	(0.01)
Capital expenditures, net ($)	432,385	1,704,100	502,849	120,323
Book value of total assets ($)	17,591,508	17,100,015	16,410,692	16,200,041
Working capital deficiency (surplus) ($)	(202,985)	(301,237)	(436,530)	(381,667)
Revolving credit facility ($)	1,040,105	338,261	-	989,408
Total net debt ($)	837,120	37,024	-	607,741
Shareholders’ equity ($)	14,089,990	14,469,651	13,981,458	12,845,404
Class “A” common shares outstanding				
End of period - basic	10,649,567	10,649,567	9,412,567	8,176,826
End of period - diluted	11,619,567	11,619,567	10,382,567	9,146,826
Weighted average for the period - basic	10,649,567	10,072,300	8,190,258	8,176,826
Weighted average for the period - diluted	10,649,567	10,072,300	8,190,258	8,201,978

SUMMARY OF QUARTERLY INFORMATION

Quarters Ended	June 30, 2009	March 31, 2009	December 31, 2008	September 30, 2008
OPERATING				
Average daily production				
Natural gas (mcf/d)	862.6	879.3	892.6	861.7
Heavy oil (bbls/d)	49.0	52.5	49.3	85.0
Light oil (bbls/d)	1.9	3.1	5.1	4.2
NGLs (bbls/d)	7.1	6.1	8.6	4.7
Total (boe/d)	201.8	208.3	211.7	237.5
Average realized sales price (CAD$)				
Natural gas ($/mcf)	3.55	5.00	6.97	8.04
Heavy oil ($/bbls)	53.59	36.96	41.41	96.89
Light oil ($/bbls)	63.91	51.78	61.37	117.57
NGLs ($/bbls)	20.56	25.42	33.03	56.62
Total ($/boe)	29.52	31.96	41.83	67.03
OPERATING NETBACK ($ per boe)				
Petroleum and natural gas revenue	29.52	31.96	41.83	67.03
Royalties	(3.00)	(4.51)	(8.23)	(14.65)
Operating expense	(11.27)	(13.46)	(14.17)	(13.22)
Transportation and marketing expense	(1.32)	(1.51)	(1.56)	(1.97)
Operating netback	13.93	12.48	17.87	37.19
FINANCIAL				
Petroleum and natural gas revenue ($)	542,184	599,274	814,688	1,464,389
Royalties ($)	(55,027)	(84,571)	(160,348)	(320,129)
Interest and other revenue ($)	945	9,650	36,461	20,708
Total revenues, net ($)	488,102	524,353	690,801	1,164,968
Net earnings (loss) ($)	(415,770)	(451,785)	(325,592)	(61,802)
Per share - basic ($)	(0.05)	(0.06)	(0.04)	(0.01)
Per share - diluted ($)	(0.05)	(0.06)	(0.04)	(0.01)
Cash flow from operations ($)	14,539	14,821	184,025	528,203
Per share - basic ($)	0.00	0.00	0.02	0.07
Per share - diluted ($)	0.00	0.00	0.02	0.07
Capital expenditures, net ($)	328,313	825,484	2,562,001	2,166,671
Book value of total assets ($)	16,559,077	17,505,864	19,331,639	18,786,688
Working capital deficiency (surplus) ($)	(170,856)	131,140	(679,524)	(2,447,121)
Revolving credit facility ($)	615,769	-	-	-
Total net debt ($)	444,913	131,140	-	-
Shareholders’ equity ($)	13,297,172	13,680,455	14,817,206	14,506,314
Class “A” common shares outstanding				
End of period - basic	8,176,826	8,176,826	8,176,826	7,899,678
End of period - diluted	9,146,826	9,294,326	9,294,326	8,831,678
Weighted average for the period - basic	8,176,826	8,176,826	7,908,474	7,545,895
Weighted average for the period - diluted	8,226,800	8,253,894	8,074,120	7,754,568

Discussion of Quarterly Results

Manitok's average quarterly production in the quarter ended June 30, 2010 was 188.0 boe/d, which is a 7% decrease from 201.2 boe/d in the quarter ended March 31, 2010 and a 7% decrease from 201.8 boe/d in the quarter ended June 30, 2009. The quarter over quarter production decreases are a direct result of normal production declines in the natural gas assets and reductions in the Corporation's drilling program, offset by increases in heavy oil production due to improved operations of the Corporation's heavy oil properties. Also in June 2010, the Corporation's two non-operated natural gas wells in the Coleman area, which represent about 180 mcf/d were shut-in for a gas plant turnaround.

Commodity prices have decreased significantly since the quarter ended September 30, 2008, when realized commodity prices were at an average of $96.89 per barrel for heavy oil and $8.04 per mcf for natural gas. For the quarter ended June 30, 2010, realized heavy oil prices averaged $51.50 per barrel, which is a 47% decrease and realized natural gas prices averaged $3.95 per mcf, which is a 51% decrease.

Manitok spent $432,385 on capital expenditures for the current quarter as compared to $1,704,100 for the quarter ended March 31, 2010 and $328,313 during the quarter ended June 30, 2009. The decrease in capital expenditures from March 31, 2010 was due mainly to acquisitions of undeveloped land in the prior quarter. The increase in capital expenditures from June 30, 2009 is due mainly to undeveloped land and seismic data acquisitions partially offset by a reduction in Manitok's drilling program, which was the Corporation's response to the drop in commodity prices in the latter part of 2008 and into the Reporting Period.

Cash flow from operations generated by the Corporation in the quarter ended June 30, 2010 was negative $39,066, as compared to negative $112,793 in the quarter ended March 31, 2010 and positive $14,821 in the quarter ended June 30, 2009. The decrease in cash flow is due mainly to a lower average commodity prices and production volumes and an increase in net general and administrative costs in the June 30, 2010 and March 31, 2010 quarters.

MERGERS AND ACQUISITIONS

The Corporation continues to review potential property acquisitions, joint venture opportunities and corporate mergers and acquisitions with the intention of completing such a transaction if acceptable terms can be negotiated. As a result, Manitok may at any time be involved in negotiations with other parties in respect of property acquisitions and dispositions, joint venture opportunities and corporate merger acquisition opportunities.

DISCLOSURE CONTROLS AND PROCEDURES

The Corporation has established and maintains disclosure controls and procedures that have been designed by, or under the supervision of, the Corporation's Chief Executive Officer and the Chief Financial Officer ("**Certifying Officers**") to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Corporation's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure. Such disclosure controls and procedures are referred to as the "**Disclosure Controls and Procedures**".

The Certifying Officers have evaluated, or caused to be evaluated under the supervision, the effectiveness of the Corporation's Disclosure Controls and Procedures as at June 30, 2010 and have concluded that such Disclosure Controls and Procedures were effective as at that date to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized, and reported within the time periods specified in the securities legislation and that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Corporation's management, including the Certifying Officers, as appropriate to allow timely decisions regarding required disclosure.

It should be noted that while the Certifying Officers believe that the Corporation's Disclosure Controls and Procedures are effective to provide a reasonable level of assurance, they do not expect that the Disclosure Controls and Procedures will provide an absolute level of assurance or prevent all errors and fraud. A control system, no matter how well conceived, maintained and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are achieved.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The Corporation has established and maintains internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP applicable to the Corporation and reasonable assurance that all assets are safeguarded and transactions are appropriately authorized and recorded to facilitate the preparation of relevant, reliable and timely information. It should be noted that a control system, no matter how well conceived, maintained and operated, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected to prevent all errors and fraud. There have been improvements and enhancements to the Corporation's internal controls over financial reporting during the three month Reporting Period and the Corporation will continue to make adjustments when deemed necessary.

CHANGE IN ACCOUNTING POLICIES

On July 1, 2009 the Corporation prospectively adopted the following Canadian Institute of Chartered Accountant ("**CICA**") Handbook Sections:

Section 3064 *Goodwill and Intangible Assets*, which defines the criteria for the recognition of intangible assets. The adoption of this Section did not have an impact on the Corporation's financial statements.

Section 3855 *Financial Instruments — Recognition and Measurement* and Section 3025 *Impaired Loans.* The Accounting Standards Board amended these Sections to converge with international standards (IAS 39 *Financial Instruments — Recognition and Measurement)* for impairment of debt instruments by changing the categories into which debt instruments are required or permitted to be classified. The amendments to these Sections did not have an impact on the Corporation's financial statements.

Section 3862 *Financial Instruments — Disclosures* which was amended in June 2009 to include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after December 31, 2009. The amendments are consistent with recent amendments to financial instrument disclosure standards in IFRS. The Corporation has included the applicable disclosures related to this Section in Note 8 of the Financial Statements.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, Canada's Accounting Standards Board ("**AcSB**") confirmed that International Financial Reporting Standards ("**IFRS**") will replace Canadian GAAP beginning January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Manitok for the twelve months ended June 30, 2010 and the six months ended December 31, 2010, including the opening balance sheet as at July 1, 2009.

IFRS uses a conceptual framework similar to Canadian GAAP; however, there could be significant differences in recognition, measurement and disclosures that will need to be addressed. Manitok expects to be fully compliant by January 1, 2011.

IFRS Transition Plan

Manitok's transition plan includes training and development throughout the organization, and three key phases:

- *Scoping and diagnostic phase*

  This phase involves performing a high level impact analysis to identify areas that may be affected by the transition to IFRS. The results of this analysis are priority ranked according to complexity and the amount of time required to assess the impact of changes in transitioning to IFRS.
- *Impact analysis and evaluation phase*

  During this phase, items identified in the diagnostic phase are addressed according to the priority levels assigned to them. This phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are further investigated to assess whether there may be a broader impact to Manitok's debt agreements, business processes or management reporting systems. The conclusion of the impact analysis and evaluation phase will require the Audit Committee of the Board of Directors to review and approve all accounting policy choices as proposed by management.
- *Implementation phase*

  This phase involves implementation of all changes approved in the impact analysis phase and will include changes to information systems, business processes, modification of agreements and training of all staff who are impacted by the conversion.

During 2010, Manitok made significant progress on its transition plan. The Corporation conducted preliminary analysis of accounting policy alternatives and preliminarily drafted several of its IFRS accounting policies. Broader business process and systems impacts have been considered for significant areas of impact, with internal control requirements taken into account.

Process and system changes will be implemented in late 2010 to ensure IFRS comparative data is captured. As management has not yet finalized its chosen IFRS accounting policies, it is unable to quantify the impact of these policies on the July 1, 2009 opening balance sheet. Management expects to make recommendations of the chosen accounting policies to the Audit Committee of the Board of Directors for their review and final approval in the fourth quarter of 2010. Communication of impacts to external stakeholders is expected to occur in the first quarter of 2011.

Manitok will continue to update its IFRS transition plan to reflect new and amended accounting standards issued by the International Accounting Standards Board ("**IASB**").

IFRS Accounting Policies and Significant Impact

Manitok has determined the areas that will be most significantly affected by the adoption of IFRS. The areas identified as being significant have the greatest potential impact to the Corporation's financial statements or the greatest risk in terms of complexity to implement. The most significant areas continue to include:

- Property, Plant and Equipment (**"PP&E"**), including;
  - Transition on date of adoption of IFRS
  - Pre-exploration costs
  - Exploration and Evaluation (**"E&E"**) costs
  - Depletion, depreciation and amortization (**"DD&A"**)
- Impairment testing
- Decommissioning liabilities (known as "asset retirement obligations" under GAAP)
- Stock-based compensation
- Income taxes

Each of these significant impact areas is discussed in more detail below.

Property, Plant & Equipment

PP&E will be one of the most significant areas impacted by the adoption of IFRS. Under Canadian GAAP, Manitok follows the CICA's guideline on full cost accounting, while IFRS has no equivalent guideline. In order to facilitate the transition to IFRS by full cost accounting companies, the IASB released additional exemptions for first-time adopters of IFRS in July 2009. Included in the amendments is an exemption which permits full cost accounting companies to allocate their existing PP&E net book value (full cost pool) using either reserve volumes or reserve values to the unit of account level upon transition to IFRS. Manitok expects to adopt this exemption on transition and is currently evaluating whether to allocate based on reserve volumes or values using either proved or proved plus probable reserves. Without this exemption, the Corporation would have been required to retrospectively determine the carrying amount of oil and gas assets at the date of transition, or use the fair value or revaluation amount as the new deemed cost under IFRS. By using the exemption, the net book value of Manitok's PP&E at the date of transition to IFRS will be the same as it was under Canadian GAAP, subject to any potential IFRS impairments that are recognized at the date of transition.

In moving to IFRS, Manitok will be required to adopt different accounting policies for pre-exploration activities, exploration and evaluation costs, DD&A and the accounting for gains and losses on property dispositions, significant components of PP&E and other material non-monetary transactions.

Pre-exploration costs are costs incurred before the Corporation obtains the legal right to explore an area. Under Canadian GAAP, these costs are capitalized, while under IFRS, these costs must be expensed. At this time, Manitok does not anticipate that this accounting policy difference will have a significant impact on the IFRS financial statements.

During the exploration and evaluation phase, Manitok capitalizes costs incurred for these projects under Canadian GAAP. Under IFRS, the Corporation has the alternative to either continue capitalizing these costs until technical feasibility and commercial viability of the project is determined, or to expense these costs as incurred. Once technical feasibility and commercial viability of an E&E project is determined, the related costs are transferred to the Developed and Producing ("D&P") phase. If Manitok's policy choice is to continue capitalizing E&E project costs under IFRS, the Corporation has the alternative to either begin depleting the related costs when in the E&E phase or to deplete the costs once the project is in the D&P phase. At this time, the Corporation has not finalized its policy in this regard, and therefore the impact of this difference in accounting policy is not reasonably determinable.

Under Canadian GAAP, Manitok calculates its DD&A rate at the country cost centre level. Under IFRS, this rate will be calculated at a lower unit of account level. At this time, the Corporation has not finalized its policy in this regard, and therefore the impact of this difference in accounting policy is not reasonably determinable.

Full cost accounting under Canadian GAAP requires that gains or losses on divestitures of properties are only recognized when the disposal would affect the DD&A rate by 20 percent or more. Under IFRS, there is no such exemption, and therefore Manitok will be required to recognize all gains and losses on property divestitures. At this time, the impact of this difference in accounting policy is not reasonably determinable.

As a result of the additional exemption released by the IASB in July 2009, the Corporation anticipates that all changes to its PP&E accounting policies will be adopted prospectively.

Impairment Testing

For the first step of the impairment test under Canadian GAAP, future cash flows are not discounted. Under IFRS, the future cash flows are discounted. In addition, for PP&E, impairment testing is currently performed at the country cost centre level, while under IFRS, it will be performed at a lower level, referred to as a cash-generating unit. The impairment calculations will be performed using either total proved or proved plus probable reserves. Canadian GAAP prohibits reversal of impairment losses. Under IFRS if the conditions giving rise to impairment have reversed, impairment losses previously recorded would be partially or fully reversed to eliminate write-downs recorded. Manitok expects to adopt these changes in accounting policy prospectively. At this time, the impact of accounting policy differences related to impairment testing is not reasonably determinable.

Decommissioning Liabilities

Under Canadian GAAP, the Corporation recognizes a liability for the estimated fair value of the future retirement obligations associated with PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. Manitok estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in wells and facilities, including an estimate for the timing of the costs to be incurred in future periods. These cash outflows are discounted using a credit-adjusted rate. Changes in the net present value of the future retirement obligation are expensed through accretion as part of DD&A. Under IFRS, these liabilities are known as "decommissioning liabilities" and are included in the scope of IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*. Decommissioning liabilities are calculated at each reporting period by estimating the risk-adjusted future cash outflows, which are discounted using a risk-free rate. Changes in the net present value of the future retirement obligation are expensed through accretion as part of DD&A. Due to the change in the discount rate from a credit-adjusted rate to a risk-free rate, Manitok expects there will be an increase in the value of the decommissioning liability under IFRS as compared to Canadian GAAP. At this time, the impact of this difference in accounting policy is not reasonably determinable.

Stock-based Compensation

IFRS 2 *Share-Based Payments* requires the expense related to share-based payments to be recognized as the options vest. For options with different vesting periods, each vesting tranche must be treated as a separate option grant which accelerates the expense recognition, in comparison to Canadian GAAP which allows the expense to be recognized on a straight-line basis over the period the options vest. Manitok must also apply an estimated forfeiture rate at the initial grant date for each option tranche. The forfeiture rate is taken into account by adjusting the number of stock options expected to vest under each tranche and subsequently revising this estimate throughout the vesting period, as necessary. Manitok expects to adopt this change in accounting policy prospectively.

Manitok expects to record an increase to contributed surplus due to revaluing (under IFRS standards) the options not vested at July 1, 2009. Going forward under IFRS, Manitok anticipates stock-based compensation expense to be higher than under Canadian GAAP because the graded vesting requirements of IFRS result in accelerated expense recognition.

Income Tax

In transitioning to IFRS, the carrying amount of Manitok's deferred tax balances will be directly impacted by the tax effects resulting from changes required by the above IFRS accounting policy differences. Manitok is still determining the impact of the revised standard on its IFRS transition. Therefore, at this time the income tax impacts of the differences are not reasonably determinable.

Changes to IFRS Accounting Standards

Manitok's analysis of accounting policy differences specifically considers the current IFRS standards that are in effect. The Corporation will continue to monitor any new or amended accounting standards that are issued by the IASB.

Internal Controls over Financial Reporting

Manitok does not anticipate that the transition to IFRS will have a significant impact on its internal controls over financial reporting. The review of internal controls over financial reporting will be an ongoing process throughout 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

Disclosure Controls and Procedures

Manitok does not anticipate that the transition to IFRS will have a significant impact on its disclosure controls and procedures. Throughout the transition, Manitok will assess stakeholders' information requirements and will ensure that adequate and timely information is provided so that all stakeholders remain apprised.

Information Systems

Manitok has evaluated its information systems required to support IFRS reporting on adoption. Manitok anticipates system updates to be minimal, however, they are critical in order to allow for reporting of both Canadian GAAP and IFRS statements in 2010 as well as the updates required to track E&E and PP&E expenditures at a more granular level of detail for IFRS reporting in 2011 and thereafter. Manitok expects to complete most of the accounting system updates in November and December of 2010.

Impacts to our Business

Manitok does not expect that the adoption of IFRS in 2011 will have a significant impact or influence on its business activities, operations or strategies going forward.

CRITICAL ACCOUNTING ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of GAAP that may have a significant impact on the financial results of the Corporation. The following summarizes the accounting estimates that are critical to determining Manitok's financial results.

Estimates of P&NG Reserves, Depletion and Depreciation and Impairment Test

The Corporation, at least annually, engages a qualified independent reserves evaluator to provide an estimate of the Corporation's year-end reserve volumes and associated future net revenues. These estimates are herein referred to as the "**Reserve Estimates**". To facilitate this process, the Corporation provides relevant production, financial and technical data to the reserves evaluator. The Corporation considers the Reserve Estimates to be critical estimates for the reasons discussed below.

The Reserves Estimates relating to the volume of reserves are utilized in the calculation of depletion and depreciation expense in the financial statements. The reserve volumes together with the production volumes for the relevant period are utilized in calculating a depletion rate for the Corporation. This depletion rate is used in conjunction with other accounting information to determine the depletion and depreciation for that period.

The Reserve Estimates relating to future net revenues of reserves are utilized in an impairment test calculation to determine if the costs capitalized under the full cost method of accounting have been impaired and thus should be written down. This potential impairment is based on a determination of whether the carrying value of petroleum and natural gas properties exceeds the estimated undiscounted future net cash flows from the proved reserves attributable to such properties.

Should the Reserve Estimates relating to the volume of reserves be materially incorrect, it could have a material impact on the Corporation's recorded amount of depletion and depreciation expense. Should the Reserves Estimates relating to the future net revenues of reserves be materially incorrect it may have a material impact on the determination of whether or not the Corporation is required to write down its petroleum and natural gas assets as a result of the impairment test. The Reserve Estimates will from time to time change based on changes in the many factors underlying the Reserve Estimates, which include but are not limited to: production performance, commodity prices, amount and timing of projected capital expenditures, revised technical interpretations based on activity and new information and the impact of additional activities not contemplated in the preparation of the Reserve Estimates.

The Reserve Estimates are also relied upon by the Corporation's lender in determining the amounts available to the Corporation under its credit facilities. The lender relies on all components of the Reserve Estimates and the underlying assumptions, except for the price forecast. The lender in most instances utilizes its own price forecast. The availability of these credit facilities is important to the Corporation because it relies on this source of capital to fund its capital budget in excess of its internally generated funds. Should the Reserves Estimates change materially and negatively, it may have a material adverse affect on the amount of capital available to the Corporation under the credit facilities, which may impair the Corporation's ability to pursue its business plans.

Asset Retirement Obligations

Manitok records a liability for the fair value of legal obligations associated with the retirement of long-lived assets in the period in which they are incurred, normally when the asset is purchased or developed. In the oil and gas industry, this retirement obligation is normally associated with abandonment and reclamation costs relating to wells and facilities. On recognition of the asset retirement obligation there is a corresponding increase in the carrying amount of the related asset (an increase to petroleum and natural gas properties and equipment) which is recorded as the asset retirement cost. The total future asset retirement obligation is an estimate at a point in time based on the Corporation's net ownership interest in all wells (producing, shut-in, suspended and others) and facilities, the estimated cost to abandon and reclaim these wells and facilities, and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligation is the Corporation's best estimate at any given point in time that is subject to measurement uncertainty and any change may potentially impact the liability materially.

Manitok attempts to mitigate this risk by reviewing all of its wells and facilities included in the calculation and by utilizing the expertise of its reserve engineer in order to provide the best estimates possible at the time.

Current Income Taxes

The Corporation is required to file a corporate income tax return annually and is required to pay any income tax liability in a timely manner. As a result of this requirement, Manitok must estimate at the end of each financial reporting period its potential current income tax liability for the particular fiscal year in question. In order to determine its income tax liability for the fiscal year, the Corporation must estimate revenue, royalties, other income, operating expenses, general and administrative expenses, interest expense, capital expenditures and other relevant items. The critical estimates in this process are production rates, commodity prices, capital expenditures and the tax category of these capital expenditures for the entire fiscal period. The risk of materially misstating the amount of current taxes payable is highest in respect of the first quarter and reduces for each quarter thereafter as more actual data is used and the estimated amounts apply to a shorter period.

To the extent that the estimate of current taxes payable varies materially from the actual amount of taxes payable, the Corporation may be required to pay an unexpected material amount of taxes which may adversely affect the Corporation's financial condition. The most critical part of this estimate is the estimate of the amount and tax category of capital expenditures that will be incurred during the relevant year as those expenditures form the basis of any new tax pools that Manitok can use as deductions in respect of that year. To the extent that a material amount of capital allocated to exploration drilling, which is 100% deductible in the fiscal year, is ultimately allocated to development drilling, which is only 30% deductible in the fiscal year, the Corporation's current taxes payable can change materially. There is a risk that wells that are drilled in an effort to encounter a new oil or natural gas accumulation can encounter an already discovered accumulation, thus changing the tax category from an exploration expenditure to a development expenditure. This risk is significant because many wells drilled by the Corporation are drilled in proximity to other wells and the tax category of the expenditures is not finally determined until drilling is completed. To mitigate this risk, the Corporation allocates its entire budget to tax categories based on discussions with its operations group and reviews the continuing validity of these categorizations at the end of each reporting period.

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

RISK FACTORS & RISK MANAGEMENT

Commodity Price Risk

Manitok's liquidity and cash flow are largely impacted by petroleum and natural gas commodity prices. Currently, Manitok has not hedged any of its oil and natural gas production at the date hereof and although it does monitor the hedge market, its strategy is to continue to sell its oil and natural gas production at the spot market rate. Management remains bullish about future commodity prices and believes Manitok is well positioned to take advantage of a rising oil and natural gas price environment. If there is a significant deterioration in the price it receives for oil and natural gas, Manitok will consider reducing its capital spending or access alternate sources of capital.

Foreign Currency Exchange Risk

The Corporation is exposed to foreign currency fluctuations because its Canadian revenues are strongly linked to United States dollar denominated benchmark prices.

Production Risk

Manitok believes it has a stable production base and that an adverse event affecting production at any single well would not cause a liquidity issue. Nonetheless, Manitok remains subject to the risk that production rates of its most significant wells may decrease in an unpredictable and uncontrollable manner, which could result in a material decrease in the Corporation's overall production and associated cash flows.

All of Manitok's production passes through third party infrastructure prior to it being ready for transfer at designated commodity sales points. There is a risk that should this infrastructure fail and cause a significant portion of Manitok's production to be shut-in and unable to be sold, this could have a material adverse effect on Manitok's available cash flow.

Reserve Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. The success of the Corporation's business is highly dependent on its ability to acquire and/or discover new reserves in a cost efficient manner. Substantially all of the Corporation's cash flow is derived from the sale of the petroleum and natural gas reserves it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. In order to mitigate this risk, the Corporation employs a competent and experienced team of petroleum and natural gas professionals and closely monitors the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

Health, Safety & Environmental Risk

Health, safety and environment risks influence the workforce, operating costs and the establishment of regulatory standards. Manitok provides staff with the training and resources need to complete work safely and effectively; incorporates hazard assessment and risk management as an integral part of everyday operations; monitors performance to ensure its operations comply with legal obligations and internal standards; and identifies and manages environmental liabilities associated with its existing asset base. Manitok carries insurance to cover a portion of property losses and liability to others resulting from unusual events.

Manitok is subject to the risk that the unexpected failure of its equipment used in drilling, completing or producing wells or in transporting production could result in releases of fluids substances that pollute or contaminate lands at or near its facilities which could result in significant liability to the Corporation for costs of clean up, remediation and reclamation of contaminated lands. Manitok's policy with regards to the environment is to conduct all operations with due regard for the potential impact on the environment. This policy is implemented by hiring skilled personnel and reminding staff involved with operations of their responsibilities in this regard and by retaining expert environment advice and assistance to deal with environmental releases and remediation and reclamation work where such expertise is needed.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on the Corporation. As an oil and natural gas producer, Manitok is subject to a broad range of regulatory requirements. Manitok does its best to remain knowledgeable regarding changes to the regulatory regime under which it operates.

All of Manitok's properties are currently located within the province of Alberta. There is a risk that although the Corporation believes it is making an economic investment at the time all of the upfront capital is invested in facilities or drilling, completing and equipping an oil or natural gas well, the Government may at any point in the economic life of that project, expropriate without compensation a portion of the expected profit under a new royalty/tax regulation or regime with no grandfathering provisions. Without grandfathering provisions this may cause that particular project to become uneconomic once the new royalties or taxes take effect. This type of possible future government action is unpredictable and cannot be forecast by the Corporation.

Counterparty Risk

Manitok assumes customer credit risk associated with oil and gas sales and joint venture participants. To mitigate this risk, the Corporation performs regular reviews of receivables to minimize default or non-payment and takes the majority of its production in kind. The Corporation also puts in place security arrangements with respect to amounts owed to it by others when reviews indicate it is appropriate to do so.

Access to Credit Markets

Due to the nature of the Corporation's business it is necessary from time to time for the Corporation to access other sources of capital beyond its internally generated cash flow in order to fund the development and acquisition of its long term asset base. As part of this strategy the Corporation obtains some of this necessary capital by incurring debt and therefore the Corporation is dependent to a certain extent on continued availability of the credit markets.

The continued availability of the credit markets for Manitok is primarily dependent on the state of the economies and the health of the banking industry in Canada and United States. There is risk that should these economies and banking industry see unexpected and/or prolonged deterioration, then Manitok's access to credit markets may contract or disappear all together. The Corporation tries to mitigate this risk by dealing with reputable lenders and tries to structure its lending agreements to give it the most flexibility possible should these situations arise. However, the situations that may give rise to credit markets tightening or disappearing are ultimately uncontrollable by Manitok.

Manitok is also dependent to a certain extent on continued access to equity capital markets. Continued access to capital is dependent on Manitok's ability to continue to perform at a level that meets market expectations.

Climate Change Risks

North American climate change policy is evolving at both regional and national levels and recent political and economic events may significantly affect the scope and timing of new climate change measures that are ultimately put in place. Although it is not the case today, the Corporation expects that some of its significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas ("**GHG**") emissions.

The Government of Alberta released its climate change strategy which sets a target to reduce GHG emissions in Alberta by 50% by 2050. Implementing carbon capture and storage technology across industrial sectors is a large component of the strategy, along with energy-efficiency measures, clean energy technologies, and expanding the use of renewable sources of energy. In July 2008, the Alberta government announced that it will commit to $2 billion in capital investments to fund the carbon capture and storage technology.

The Canadian government has expressed interest in pursuing the development of a North American cap and trade system for GHG emissions. In April 2007, the Government of Canada released the Regulatory Framework for Air Emissions ("**Framework**"). The Framework outlines short, medium and long-term objectives for managing both GHG emissions and air pollutants in Canada. It is uncertain how the Framework will fit within a North American cap and trade system and what the specific requirements for industrial emitters such as Manitok will be. Proposed regulations have not yet been released and therefore it is uncertain whether the impacts from such future regulations will be material to the Corporation.