Q3

Q3/2011
QUARTERLY
REPORT

MANITOK ENERGY INC.

Manitok Energy is a unique oil and gas company which is positioned to take advantage of a once in a generation opportunity in the foothills of the Western Canada Sedimentary Basin for the benefit of its shareholders.

Dear Fellow Shareholders,

Manitok is pleased to report its third quarter financial results for the three and nine month period ended September 30, 2011. Highlights in the third quarter include:

- A 160% increase in production for the three months ending September 30, 2011. Production averaged 414 boe/d as compared to average production of 160 boe/d in the three months ending September 30, 2010. The third quarter exit production rate was about 1,000 boe/d.
- Manitok completed the tie-in operation of its Stolberg discovery well which began producing in early September 2011 at about 4.0 Mmcf/d (3.0 Mmcf/d net) and has climbed to the current rate of about 5.0 Mmcf/d (3.75 Mmcf/d net). It has cumulatively produced about 0.3 Bcf (0.225 Bcf net) to date.
- A 61% increase in net undeveloped land as at September 30, 2011 as compared to September 30, 2010. Manitok's undeveloped net land position as at September 30, 2011 was 120,568 acres versus 74,870 acres as at September 30, 2010.
- Manitok's capital expenditures for the three month period ended September 30, 2011 were approximately $8.0 million. Approximately $4.7 million related to the tie-in of the Stolberg discovery well, the drilling, completion and equipping of six heavy oil wells in Swimming, and about $2.8 million on undeveloped land acquisition costs in Manitok's core areas.
- As at September 30, 2011, Manitok had no outstanding debt and a working capital surplus of approximately $27.6 million. On August 22, 2011, Manitok amended its agreement to increase its demand revolving credit facility from $2.5 million to $5.0 million.
- Cash flow was $153,994 due mainly to the increase in natural gas and heavy oil production volumes and higher average heavy oil prices realized at the wellhead.

Activity in the Quarter

Corporate production increased in the quarter as it reflected the initial production from 4 of the 6 heavy oil wells drilled during the quarter and the Stolberg well which were all put on production in September. At the end of September, Manitok's production was approximately 1,000 boe/d (about 38% oil and liquids) with the Stolberg well accounting for the majority of that production.

The Stolberg well began flowing at approximately 4.0 Mmcf/d (3.0 Mmcf/d net) and has increased to about 5.0 Mmcf/d (3.75 Mmcf/d net). To date the well has flowed approximately 0.3 Bcf (.225 Bcf net) with very little change in the flowing pressure. We originally expected 400 to 700 gross boe/d, with conventional decline assumptions, when we made the decision to drill this well. It is currently flowing at over 800 gross boe/d and has not begun to materially decline yet. It has exceeded our original expectations to this point. This operation exemplifies the opportunity that is the basis for the formation of our company. By targeting conventional reservoirs with a wide range of possible outcomes and ensuring that the economics of that project are robust at the lower end of that band of outcomes, we give ourselves a higher probability of achieving above average rates of return over the longer run. In other words, we de-risk our projects as much as we can on a technical basis and then assume conservative outcomes and costs. By taking this approach, we can absorb variances between actual versus expected costs or production rates and still achieve top tier rates of return.

Outlook

Subsequent to the end of the third quarter, Manitok closed a 1,300 boe/d (6% oil and liquids) acquisition on October 31, 2011. As a result, Manitok's production at November 1, 2011 was approximately 2,300 boe/d (21% oil and liquids). About 83% of our production is now in the Alberta foothills. We are currently evaluating the newly acquired assets for potential field optimization, recompletion opportunities and 2012 drilling locations.

Initial production rates of our newly drilled heavy oil wells are very encouraging. However, it will be several months before we can truly determine the level of success of the program. We are in the process of shooting additional seismic in the area before year end. Assuming that the current price of oil and the narrow differential between light and heavy oil continues, the Swimming area will contribute significant cash flow over the next several quarters. Manitok will continue to devote a modest portion of its annual budget to this area given that the project returns are high.

Drilling is underway in the Stolberg area. The first drill (Manitok's working interest is 68%) of an expected 6 well program began last week. The horizontal drill is targeting a sweet Cardium light oil reservoir. The 5 (3.78 net) remaining drills are expected to be comprised of 3 (1.92 net) horizontal sweet Cardium light oil drills and 2 (1.86 net) vertical sweet Mannville liquids rich natural gas drills. The entire program is anticipated to be complete by early in the fourth quarter of 2012. Manitok's net capital expenditures for the 6 well Stolberg program are expected to be about $22 million.

Manitok expects to exit 2011 between 2,300 and 2,500 boe/d (21% oil and liquids). Average production in the fourth quarter is anticipated to be about 1,700 to 1,800 boe/d (23% oil and liquids). When comparing the production rate today to our 2010 exit rate of 220 boe/d, there has been a 10 fold increase while our outstanding common shares, on a diluted basis, have only increased by 2.8 times since that period.

Guidance

Manitok's capital expenditures for the fourth quarter are expected to be about $52.5 to $55.0 million. About $6.0 to $7.0 million of the $22 million of Stolberg drilling program costs will be incurred before year end. Manitok will also incur about $2.6 to $2.8 million of seismic expenditures and $2.1 to $2.2 million of land leased in crown land sales in the fourth quarter. The remaining $42.5 to $43 million includes the cost of the acquisition and related expenses. Manitok's net debt at 2011 year end is expected to be about $5.0 to $5.5 million.

Manitok is anticipating about $38 to $42 million of capital expenditures in 2012. Of which about $3.8 to $4.0 million will be for land and seismic, the remainder will be for drilling, completions, re-completions, workovers, and equipping. The program will be financed with cash flow and the current $30 million credit facility. Assuming success with the 2012 capital expenditure program, Manitok would exit 2012 with production of about 3,800 to 4,000 boe/d (40% oil & liquids) and net debt of about $22 to $24 million.

Over the last several quarters, we have taken several big steps towards achieving our long term corporate vision. Manitok has significantly increased its production, reserves and inventory of opportunities. We have also significantly increased the number of quality professionals at our company in that same period. We believe that we now have the key drivers in place to achieve superior long term growth at Manitok.

On behalf of Manitok's officers and directors, I would like to thank our employees, shareholders, and all other stakeholders, for their continued dedication and support.

Massimo M. Geremia
President and Chief Executive Officer

OPERATIONAL AND FINANCIAL HIGHLIGHTS

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
OPERATING				
Average daily production				
Natural gas (mcf/d)	**1,449.3**	533.5	**905.8**	624.1
Heavy oil (bbls/d)	**170.8**	67.1	**160.5**	73.5
Light oil (bbls/d)	**–**	0.2	**–**	0.5
NGLs (bbls/d)	**1.6**	3.3	**1.6**	4.7
Total (boe/d)	**413.9**	159.5	**313.0**	182.7
Average realized sales price (CAD$)				
Natural gas ($/mcf)	**3.73**	3.75	**3.71**	4.33
Heavy oil ($/bbl)	**63.31**	56.75	**67.09**	57.32
Light oil ($/bbl)	**–**	70.64	**–**	72.44
NGLs ($/bbl)	**86.40**	27.34	**83.87**	32.29
Total ($/boe)	**39.52**	37.06	**45.54**	38.88
Undeveloped Land (end of period)				
Gross (acres)	**124,608**	77,430	**124,608**	77,430
Net (acres)	**120,568**	74,870	**120,568**	74,870
NETBACK ($ per boe)				
Petroleum and natural gas revenue	**39.52**	37.06	**45.54**	38.88
Royalty expenses	**(3.49)**	(4.48)	**(3.40)**	(5.94)
Operating expenses	**(12.16)**	(22.22)	**(16.89)**	(17.01)
Transportation and marketing expenses	**(2.03)**	(1.93)	**(2.20)**	(1.87)
Operating netback	**21.84**	8.43	**23.05**	14.06
Administrative expenses, net	**(20.01)**	(29.57)	**(21.66)**	(22.12)
Interest expenses	**–**	(0.05)	**–**	(0.12)
Interest and other income	**2.21**	1.01	**2.71**	0.30
Cash flow netback	**4.04**	(20.18)	**4.10**	(7.88)
Depletion and depreciation expenses	**(23.30)**	(18.28)	**(23.68)**	(55.96)
Accretion expenses	**(0.44)**	(0.67)	**(0.52)**	(0.67)
Stock-based compensation expenses	**(5.30)**	(4.79)	**(8.24)**	(0.08)
Gain (loss) on disposition of assets	**–**	106.50	**(0.08)**	31.32
Deferred income tax recovery (expense)	**4.10**	(15.87)	**(5.06)**	5.28
Net income (loss) netback	**(20.90)**	46.71	**(33.48)**	(27.99)
FINANCIAL				
Petroleum and natural gas revenue ($)	**1,504,882**	543,805	**3,891,487**	1,939,615
Cash flow ($)(1)	**153,994**	(296,144)	**350,070**	(393,311)
Per share – basic ($)	**0.00**	(0.02)	**0.01**	(0.03)
Per share – diluted ($)	**0.00**	(0.02)	**0.01**	(0.03)
Net income (loss) ($)	**(795,741)**	685,198	**(2,862,265)**	(1,396,427)
Per share – basic ($)	**(0.02)**	0.04	**(0.06)**	(0.11)
Per share – diluted ($)	**(0.02)**	0.04	**(0.06)**	(0.11)
Common shares outstanding				
End of period – basic	**51,665,531**	16,730,460	**51,665,531**	16,730,460
End of period – diluted	**54,893,031**	18,318,960	**54,893,031**	18,318,960
Weighted average for the period – basic	**51,665,531**	16,267,784	**44,886,113**	12,352,578
Weighted average for the period – diluted	**52,266,109**	16,314,887	**45,761,888**	12,365,659
Capital expenditures, net ($)	**8,049,424**	1,757,099	**19,144,898**	3,948,275
Working capital deficiency (surplus) ($)	**(27,635,269)**	(6,659,296)	**(27,635,269)**	(6,659,296)
Revolving credit facility ($)	**–**	–	**–**	–
Total net debt ($)	**–**	–	**–**	–

(1) Cash flow denoted with "( )", is negative cash flow throughout this report.

Manitok Energy Inc. ("**Manitok**" or the "**Corporation**") is a junior oil and gas exploration, development and production company based in Calgary, Alberta. The Corporation formed as a result of an amalgamation between Manitok Exploration Inc. ("**MEX**") and Desco Resources Inc. ("**Desco**") pursuant to the *Business Corporations Act* (Alberta) on July 8, 2010 (the "**Amalgamation**"). The common shares of the Corporation ("**Manitok Shares**") are listed on the TSX Venture Exchange ("**TSX-V**") under the trading symbol "**MEI**" and began trading on July 29, 2010. Additional information relating to the Corporation, including its Annual Information Form is available electronically under the Corporation's profile on the System for Electronic Document Analysis and Retrieval ("**SEDAR**") website at www.sedar.com.

The following Management's Discussion and Analysis ("**MD&A**") is dated November 23, 2011. The unaudited condensed financial statements with respect to the three and nine months ended September 30, 2011 (the "**Reporting Periods**") as compared to the three and nine months ended September 30, 2010 (the "**Comparable Prior Periods**") and this MD&A have been prepared by management and approved by the Corporation's Audit Committee and Board of Directors. This MD&A should be read in conjunction with the unaudited condensed financial statements of the Corporation and related notes for the Reporting Periods. All financial information is expressed in Canadian dollars, unless otherwise stated.

Adoption of International Financial Reporting Standards ("IFRS")

Manitok's unaudited condensed financial statements and the financial data included in this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("**IASB**") and interpretations of the International Financial Reporting Interpretations Committee that are expected to be effective as at December 31, 2011, the date of the Corporation's first annual reporting under IFRS. Previously, the Corporation prepared its interim and annual financial statements in accordance with Canadian Generally Accepted Accounting Principles ("**Canadian GAAP**"). The adoption of IFRS does not impact the underlying economics of Manitok's operations.

The IFRS accounting polices set forth in note 3 of the unaudited condensed financial statements have been applied in preparing the financial statements for the three and nine months ended September 30, 2011 and comparative information as at and for the three and nine months ended September 30, 2010, as at and for the six months ended December 31, 2010, as at and for the twelve months ended June 30, 2010, and an opening Statement of Financial Position at July 1, 2009. Note 21 to the unaudited condensed financial statements contains a detailed description of the Corporation's adoption of IFRS, including a reconciliation of the financial statements previously prepared under Canadian GAAP to those under IFRS. The most significant impacts of the adoption of IFRS, together with details of IFRS 1 *First-time Adoption of IFR*S exemptions taken, are described in the "Transition to International Financial Reporting Standards" section of this MD&A.

Comparative information in this MD&A has been restated to comply with IFRS requirements, unless otherwise indicated.

Advisories

Non-IFRS Measures

This MD&A and the Corporation's interim and annual reports uses terms such as "cash flow", "operating netback", "cash flow netback", "net income (loss) netback" and "cash flow per share", which do not have standardized meanings prescribed by IFRS and therefore may not be comparable to measures by other companies where similar terminology is used. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Corporation's liquidity.

Cash flow denotes cash flow from operating activities as it appears on the Corporation's unaudited Condensed Statements of Cash Flows before decommissioning expenditures and changes in non-cash operating working capital and is reconciled to net income (loss). Operating netback denotes petroleum and natural gas revenue less royalty expenses, operating expenses and transportation and marketing expenses. Cash flow netback denotes net income plus non-cash items including deferred income tax expense (recovery), depletion and depreciation expenses, accretion expenses, stock-based compensation expenses and loss (gain) on disposition of assets.

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", "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's 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 information 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

bbl	barrel
bbls	barrels
bbls/d	barrels per day
Mbbls	thousand barrels
NGLs	natural gas liquids
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent

Natural Gas

mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
Mmcf	million cubic feet
Mmcf/d	million cubic feet per day
Bcf	billion cubic feet
mmbtu	million British thermal units
GJ	Gigajoule

Other

AECO	benchmark natural gas price determined at the AECO "C" hub in southeast Alberta
WTI	West Texas Intermediate crude oil, a benchmark oil price determined at Cushing, Oklahoma
API	the measure of the density or gravity of liquid petroleum products

Overall Performance

Production

Manitok's production averaged 413.9 boe/d in the three month Reporting Period, which is a 160% increase from the average of 159.5 boe/d during the Comparable Prior Period. In the nine month Reporting Period, production averaged 313.0 boe/d, which is a 71% increase from the average of 182.7 boe/d in the Comparable Prior Period. The increase in the Reporting Periods as compared to the Comparable Prior Periods is due primarily to the improved production of the five heavy oil wells in the Swimming area of Alberta, which were brought into production in the fourth quarter of 2010, the addition of four new heavy oil wells late in the quarter and the Stolberg discovery well brought on production in early September 2011. The increase in production from the new wells was partially offset by normal production declines in the mature heavy oil and natural gas wells and the disposition of the Corporation's interest in a minor producing asset in the Garrington area of Alberta on August 4, 2010 for gross proceeds of $1.8 million ("**Asset Disposition**"), which represented approximately 10 boe/d in the Comparable Prior Periods.

Production consisted of approximately 58% natural gas and 42% crude oil and natural gas liquids in the three month Reporting Period. See "Results of Operations – Petroleum and Natural Gas Revenue".

Commodity Prices

Realized heavy oil sales prices at the wellhead averaged $63.31/bbl in the three month Reporting Period, which is a 12% increase from $56.75/bbl averaged in the Comparable Prior Period. Realized natural gas prices at the wellhead averaged $3.73/mcf in the three month Reporting Period as compared to $3.75/mcf 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 as a result is subject to fluctuations in commodity prices.

Canadian Lloydminster Hardisty oil prices averaged $61.98/bbl in the three month Reporting Period as compared to $58.41/bbl in the Comparable Prior Period. The AECO daily natural gas spot price averaged $3.63/mmbtu in the three month Reporting Period as compared to $3.55/mmbtu in the Comparable Prior Period. The increase in oil prices have translated into increased cash flow in the Reporting Periods.

Cash Flow and Income (Loss)

Cash flow is commonly used in the oil and gas industry to analyze operating performance. Cash flow as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculations of similar measures for other issuers. Cash flow as presented is not intended to represent cash flow from operating activities, net income or other measures of financial performance calculated in accordance with IFRS. All references to cash flow throughout this report are based on cash flow from operating activities as per the unaudited Condensed Statements of Cash Flows before changes in non-cash operating working capital and decommissioning obligations.

The following schedule sets out the reconciliation of cash provided by (used for) operating activities to cash flow:

	Three months ended September 30		**Nine months ended September 30**	
($)	**2011**	2010	**2011**	2010
Cash provided by (used for) operating activities	**192,914**	(106,437)	**83,367**	(82,569)
Decommissioning expenditures	**524**	–	**1,069**	–
Changes in non-cash operating working capital	**(39,444)**	(189,707)	**265,634**	(310,742)
Cash flow[1]	**153,994**	(296,144)	**350,070**	(393,311)
per share – basic	**0.00**	(0.02)	**0.01**	(0.03)
per share – diluted	**0.00**	(0.02)	**0.01**	(0.03)

(1) Cash flow denoted with a "( )", is negative cash flow throughout this MD&A.

Cash flow increased to $153,994 ($0.00 per share) and $350,070 ($0.01 per share) for the three and nine month Reporting Periods as compared to negative cash flow of ($296,144) ($0.02 per share) and ($393,311) ($0.03 per share) for the Comparable Prior Periods. The increase in cash flow for the Reporting Periods as compared to the Comparable Prior Periods was due mainly to the increase in natural gas and heavy oil production volumes and higher average heavy oil prices realized at the wellhead which was partially offset by increased general and administrative costs due to a significant increase in professional personnel levels in anticipation of the Corporation's future activity.

Manitok had a net loss of $795,741 ($0.02 per share) and $2,862,265 ($0.06 per share) for the three and nine month Reporting Periods as compared to net income of $685,198 ($0.04 per share) and a net loss of $1,396,427 ($0.11 per share) for the Comparable Prior Periods. The increase in net loss for the Reporting Periods as compared to the Comparable Prior Periods was mainly attributable to a $1.6 million gain in the Comparable Prior Periods on the Asset Disposition.

Capital Expenditures

Capital expenditures amounted to $8.0 million and $19.1 million during the three and nine month Reporting Periods as compared to $1.8 million and $3.9 million during the Comparable Prior Periods. The increase in capital expenditures for the Reporting Periods as compared to the Comparable Prior Periods was due mainly to the equipping and tie-in of a natural gas well in the Stolberg area of the Alberta foothills, the drilling, completion and equipping of six heavy oil wells in the Swimming area of Alberta and the acquisition of undeveloped land at Alberta crown land sales in Manitok's core areas. The Comparable Prior Period included the drilling of five heavy oil wells in the Swimming area of Alberta partially offset by the Asset Disposition.

Of the total capital spent, for the nine month Reporting Period, approximately 46% was directed to drilling, completion, and equipping costs, 46% to strategic undeveloped land acquisitions and the remainder was comprised primarily of geological and geophysical expenses and workovers on heavy oil wells.

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

On August 22, 2011, the Corporation amended its agreement with a major Canadian lender to increase its demand revolving credit facility from $2.5 million to $5.0 million.

MAJOR TRANSACTIONS SUBSEQUENT TO THE REPORTING PERIOD

On October 31, 2011, the Corporation closed an acquisition of oil and natural gas assets in the central Alberta foothills area ("**Asset Acquisition**"), with an effective date of July 1, 2011, for total cash consideration of approximately $41.7 million (before post-closing adjustments and acquisition-related expenses). The consideration paid by Manitok for the assets was financed by existing cash balances and bank debt. Concurrent with the closing of the acquisition, the Corporation's credit facility was increased from $5 million to $30 million.

Effective November 15, 2011, the Corporation entered into an underwriting agreement with a syndicate of underwriters led by RBC Capital Markets (the "**Underwriters**"), pursuant to which the Underwriters have agreed to purchase, on a "bought deal" basis 6,500,000 Manitok Shares and 3,635,000 Manitok Shares issued on a "flow-through" basis under the *Income Tax Act* (Canada) ("**Manitok Flow-through Shares**") at a price of $1.85 per Manitok Share and $2.20 per Manitok Flow-through Share for aggregate gross proceeds of approximately $20 million pursuant to a short form prospectus (the "**Offering**"). Under the Offering, Manitok has agreed to grant the Underwriters an option to purchase an additional 15% of the number of Manitok Shares issuable under the Offering to cover over-allotments, if any. The net proceeds from the issuance of Manitok Shares will be used to repay the outstanding indebtedness under its revolving credit facility which was incurred to fund the Asset Acquisition and the net proceeds from the issuance of Manitok Flow-through Shares will be used to incur qualifying expenditures on or before December 31, 2012. The Offering is scheduled to close on or about December 5, 2011 and is subject to certain conditions including, but not limited to, the receipt of all necessary approvals including the approval of the TSX-V. The preliminary prospectus was filed with the securities regulatory authorities in each of the provinces of Canada, other than Quebec, on November 21, 2011.

OUTLOOK

The Corporation's capital spending program in the fourth quarter is anticipated to be approximately $52.5 to $55 million, which includes approximately $42.5 to $43 million with respect to the Asset Acquisition and related expenses, $6.5 to $7 million allocated to drilling in the Stolberg area of Alberta and $4 to $5 million used to acquire land and seismic in order to continue to build a quality drilling inventory to fuel Manitok's growth over the next several years.

The Corporation anticipates average production in the fourth quarter of 2011 to be about 1,700 to 1,800 boe/d, with approximately 23% being oil and liquids. The 2011 exit production rate is anticipated to be approximately 2,300 to 2,500 boe/d, with about 21% being oil and liquids. These expectations have been revised upward primarily due to the Asset Acquisition in the fourth quarter of 2011.

Manitok's anticipated capital expenditures and estimated production results are based upon various assumptions as to equipment availability, well production rates, well drainage areas, success rates, timing and costs of future well drilling, the availability of capital, future costs and availability of labour and services.

LIQUIDITY

Working Capital

The Corporation's working capital surplus (current assets less current liabilities), which excludes any current portion of an amount drawn on the revolving credit facility, increased to $27.6 million at the end of the Reporting Period as compared to a $19.8 million working capital surplus at December 31, 2010. The increase in the working capital surplus at September 30, 2011 was due primarily to closing an equity issuance on April 14, 2011, which was partially offset by capital expenditures incurred in the Reporting Period.

At September 30, 2011, the major components of Manitok's current assets were: cash and cash equivalents (80%), a 10% deposit of $4.25 million related to the Asset Acquisition (14%) and revenue (2%) to be received from its marketers in respect of September 2011 production, which was subsequently received in October 2011. Current liabilities mainly consisted of trade payables (83%).

Manitok has invested excess cash in an interest bearing bank account and term deposits with its lender. The Corporation manages its working capital using its cash flow, excess funds from its equity issuances 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 during the first three quarters of 2011.

Bank Debt

The amount drawn under the Corporation's revolving credit facility was $NIL with an aggregate borrowing limit of $5 million as at September 30, 2011 and $2.5 million as at December 31, 2010. On August 22, 2011 Manitok amended its revolving credit facility with its lender which increased the borrowing base from $2.5 million to $5 million. Concurrent with the Asset Acquisition the borrowing base was increased from $5 million to $30 million. 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 (current assets plus any undrawn portion of the credit facility divided by current liabilities excluding any current portion of an amount drawn on the credit facility) of less than 1:1. Manitok was compliant with the covenant under its revolving credit facility throughout the Reporting Periods and the Comparable Prior Periods.

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 September 30, 2011:

	< 1 Year	1-2 Years	3-5 Years	Thereafter
Accounts payable and accrued liabilities	3,506,217	–	–	–
Drawn revolving credit facility	–	–	–	–
Office lease[1]	302,640	302,640	504,400	–
Total estimated contractual obligations[2]	**3,808,857**	**302,640**	**504,400**	**–**

(1) The Corporation is committed under an operating lease relating to its office premises, which began on May 1, 2010 and expires 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. The recovery of rental costs from the subleases is not reflected in the table.

(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 MEX ("**MEX Shares**") were the only class of shares issued and outstanding and immediately prior to the Amalgamation, there were 18,807,267 MEX Shares issued and outstanding, stock options to purchase 702,500 MEX Shares and performance warrants to purchase 267,500 MEX Shares. Subsequent to the Amalgamation, the Manitok Shares are the only class of shares issued and outstanding and the stock options to purchase 702,500 MEX Shares and the performance warrants to purchase 267,500 MEX Shares were terminated and cancelled. Manitok Shares began trading on the TSX-V on July 29, 2010 under the symbol MEI. The following table summarizes the Manitok Shares issued and outstanding:

	common shares
MEX balance at July 1, 2009	**8,176,826**
Issue of MEX Shares on December 31, 2009[1]	1,235,741
Issue of MEX Shares on February 12, 2010[2]	1,237,000
MEX balance at June 30, 2010	**10,649,567**
Issue of MEX Shares on July 8, 2010[3]	8,157,700
MEX balance at July 8, 2010 (prior to the Amalgamation)	**18,807,267**
Issue of Manitok Shares on the Amalgamation[4]	2,625,000
Conversion of MEX shareholders on the Amalgamation[5]	(4,701,807)
Issue of Manitok Shares on December 22, 2010[6]	16,650,059
Redemption of Manitok Shares on December 23, 2010[7]	(119,268)
Issue of Manitok Shares on December 30, 2010[8]	435,530
Manitok balance at December 31, 2010	**33,696,781**
Issue of Manitok Shares on April 14, 2011 [9]	17,968,750
Manitok balance at September 30, 2011	**51,665,531**

(1) On December 31, 2009, MEX completed a private placement of 176,956 MEX Shares (equivalent to 132,717 Manitok Shares) issued at a price of $1.15 per MEX Share (equivalent to $1.53 per Manitok Share) and 1,058,785 MEX Shares on a "flow-through" basis under the *Income Tax Act* (Canada) ("**MEX Flow-through Shares**") (equivalent to 794,089 Manitok Flow-through Shares) issued at a price of $1.30 per MEX Flow-through Share (equivalent to $1.73 per Manitok Flow-through Share) for total net proceeds of $1.5 million. The proceeds of the equity issue were used primarily to pay the outstanding balance on the revolving credit facility.

(2) On February 12, 2010, MEX completed a private placement of 1,237,000 MEX Shares (equivalent to 927,750 Manitok Shares) issued at a price of $1.15 per MEX Share (equivalent to $1.53 per Manitok Share) for total net proceeds of $1.3 million. The proceeds of the equity issue were used primarily to fund a portion of the Corporation's capital expenditures.

(3) On July 8, 2010, MEX completed a private placement of 4,311,700 MEX Shares (equivalent to 3,233,775 Manitok Shares) issued at a price of $1.15 per MEX Share (equivalent to $1.53 per Manitok Share) and 3,846,000 MEX Flow-through Shares (equivalent to 2,884,500 Manitok Flow-through Shares) issued at a price of $1.30 per MEX Flow-through Share (equivalent to $1.73 per Manitok Flow-through Share) for total net proceeds of $9.1 million. Proceeds of the equity issue were used to pay the outstanding balance on the revolving credit facility and fund the Corporation's drilling program in late 2010.

(4) On the Amalgamation each Desco shareholder received 0.375 of a Manitok Share 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 each MEX shareholder received 0.75 of a Manitok Share for every one MEX Share held. As of the Amalgamation date, MEX had 18,807,267 MEX Shares issued and outstanding.

(6) On December 22, 2010, Manitok completed the first tranche of a private placement of 10,031,500 Manitok Shares issued at a price of $1.00 per Manitok Share and 6,618,559 Manitok Flow-through Shares issued at a price of $1.15 per Manitok Flow-through Share for net proceeds of $16.3 million. Proceeds of the private placement were used to fund the Corporation's drilling program in 2011.

(7) On December 23, 2010, Manitok purchased for cancellation 119,268 Manitok Shares at a price of $1.00 per Manitok Share pursuant to an arrangement with a previous employee of the Corporation.

(8) On December 30, 2010, Manitok completed the second and final tranche of a private placement of 325,400 Manitok Shares issued at a price of $1.00 per Manitok Share and 110,130 Manitok Flow-through Shares issued at a price of $1.15 per Manitok Flow-through Share for net proceeds of $0.4 million.

(9) On April 14, 2011, Manitok completed an equity issuance pursuant to a short form prospectus offering whereby Manitok issued an aggregate of 17,968,750 Manitok Shares issued at a price of $1.60 per Manitok Share for net proceeds of approximately $26.7 million.

As at November 23, 2011 there were 51,665,531 Manitok Shares outstanding and 3,845,000 stock options to purchase an equivalent number of Manitok Shares.

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 September 30, 2011				Three months ended September 30, 2010			
	Total Revenue ($)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($)	Average Daily Production	%	Average ($/unit)
Natural gas (mcf)	**497,555**	**1,449.3**	**58**	**3.73**	183,938	533.5	56	3.75
Heavy oil (bbls)	**994,877**	**170.8**	**41**	**63.31**	350,088	67.1	42	56.75
Light oil (bbls)	**–**	**–**	**–**	**–**	1,556	0.2	–	70.64
Natural gas liquids (bbls)	**12,450**	**1.6**	**1**	**86.40**	8,223	3.3	2	27.34
Total P&NG revenue (boe)	**1,504,882**	**413.9**	**100**	**39.52**	543,805	159.5	100	37.06

	Nine months ended September 30, 2011				Nine months ended September 30, 2010			
	Total Revenue ($)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($)	Average Daily Production	%	Average ($/unit)
Natural gas (mcf)	**916,370**	**905.8**	**48**	**3.71**	737,633	624.1	57	4.33
Heavy oil (bbls)	**2,939,334**	**160.5**	**51**	**67.09**	1,150,143	73.5	40	57.32
Light oil (bbls)	**–**	**–**	**–**	**–**	10,713	0.5	–	72.44
Natural gas liquids (bbls)	**35,783**	**1.6**	**1**	**83.87**	41,126	4.7	3	32.29
Total P&NG revenue (boe)	**3,891,487**	**313.0**	**100**	**45.54**	1,939,615	182.7	100	38.88

The increase in petroleum and natural gas revenue in the Reporting Periods as compared to the Comparable Prior Periods was attributable to the increased natural gas and heavy oil production volumes and higher average oil prices realized at the wellhead which was partially offset by lower average natural gas prices realized at the wellhead during the Reporting Periods.

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 September 30			**Nine months ended September 30**		
	2011	2010	Change	**2011**	2010	Change
Heavy oil – 12° API at Hardisty ($/bbl)	**61.98**	58.41	6.1%	**66.18**	62.30	6.2%
Edmonton par ($/bbl)	**92.27**	74.76	23.4%	**94.79**	76.84	23.4%
AECO – natural gas ($/mmbtu)(1)	**3.63**	3.55	2.3%	**3.77**	4.13	(8.9%)

(1) $1.00/mmbtu = $1.00/mcf based on a standard heat value mcf.

The price the Corporation receives for its P&NG production depends on a number of factors, including AECO Canadian dollar spot market prices for natural gas, Canadian dollar Edmonton Par oil prices, U.S. dollar oil prices, the U.S. and Canadian dollar exchange rate, and transportation and product quality differentials. Manitok had no financial derivatives, such as fixed commodity price contracts or other hedge type contracts during the Reporting Periods and the Comparable Prior Periods, but regularly monitors the market to determine if they are required. The Corporation has no current intention to enter into any such contracts at this time.

Royalty Expenses

Royalties are paid to the Alberta Government and other land and mineral rights owners. The following table illustrates the Corporation's royalty expenses for the Reporting Periods and the Comparable Prior Periods:

	Three months ended September 30			Nine months ended September 30		
	2011	2010	Change	**2011**	2010	Change
Oil & natural gas royalties ($)	**132,750**	65,760	101.9%	**290,791**	296,231	(1.8%)
Oil & natural gas royalties ($/boe)	**3.49**	4.48	(22.1%)	**3.40**	5.94	(42.8%)
Effective royalty rate (%)[1]	**8.8%**	12.1%	(27.3%)	**7.5%**	15.3%	(51.0%)

(1) The effective royalty rate is calculated by dividing the total aggregate royalties into petroleum and natural gas revenue for the period.

The overall effective royalty rate in the three and nine month Reporting Periods was 8.8% and 7.5% as compared to 12.1% and 15.3% in the Comparable Prior Periods. The decrease in the effective royalty rates in the Reporting Periods as compared to the Comparable Prior Periods is largely due to production royalty incentives for the new natural gas and heavy oils wells brought on production in the Reporting Periods, that are subject to a 5% royalty rate in the first year of production to a maximum of 50,000 bbls of oil or 500 Mmcf of natural gas per well, and lower royalty rates applied to mature wells due to a reduction in production volumes.

Royalty and Drilling Incentives

There have been no significant changes to Alberta's royalty framework since December 31, 2010. Refer to the 2010 annual MD&A for discussion on royalty and drilling incentives proposed by the Alberta Government in 2009 and 2010.

Manitok has realized under the Drilling Royalty Credit ("**DRC**") incentive program approximately $222,800 in drilling credits between April 1, 2009 and March 31, 2011. Manitok was entitled to a DRC of $200 per meter drilled, up to a maximum of 50% of the aggregate Crown royalties paid by the Corporation, for new conventional oil and gas wells spud after April 1, 2009 and rig released before April 1, 2011.

Operating Expenses

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

	Three months ended September 30, 2011		Three months ended September 30, 2010		Change	
	$	$/boe	$	$/boe	$	$/boe
Field operating expenses	**462,884**	**12.16**	326,003	22.22	42.0%	(45.3%)
Expensed workovers	**–**	**–**	–	–	–	–
Total operating expenses	**462,884**	**12.16**	326,003	22.22	42.0%	(45.3%)

	Nine months ended September 30, 2011		Nine months ended September 30, 2010		Change	
	$	$/boe	$	$/boe	$	$/boe
Field operating expenses	**1,413,535**	**16.55**	848,702	17.01	66.6%	(2.8%)
Expensed workovers	**29,469**	**0.34**	–	–	–	–
Total operating expenses	**1,443,004**	**16.89**	848,702	17.01	70.0%	(0.7%)

Total operating costs per boe decreased by $10.06 in the three month Reporting Period as compared to the Comparable Prior Period and remained relatively consistent in the nine month Reporting Period as compared to the Comparable Prior Period. In general, the decrease in the three month Reporting Period was due to fixed costs applied over higher production volumes. Also the Comparable Prior Period included above normal fixed operating charges in the Coleman and Hairy Hill areas of Alberta being applied over fewer production volumes due to well downtime and increased processing and operator costs in the Coleman area due to a plant turnaround. The remainder of the decrease was due to property taxes recorded in the Comparable Prior Period, with the comparable amount recorded in the second quarter of 2011.

While the nine month Reporting Period was consistent with the Comparable Prior Period an expected increase due mainly to the higher proportion of heavy oil production relative to total corporate production in the Reporting Periods, as heavy oil operating costs are significantly higher on a per boe basis than natural gas operating costs was offset by certain fixed costs applied over higher production volumes.

Operations have significantly improved at the Corporation's heavy oil property in the Swimming area of Alberta, and Manitok will continue to monitor operating costs at all of its properties in an effort to reduce costs where possible.

Transportation and Marketing Expenses

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

	Three months ended September 30			Nine months ended September 30		
	2011	2010	Change	**2011**	2010	Change
Transportation & marketing expenses ($)	**77,382**	28,299	173.4%	**187,697**	93,474	100.8%
Transportation & marketing expenses ($/boe)	**2.03**	1.93	5.2%	**2.20**	1.87	17.6%

These costs consist primarily of transportation costs and per boe have increased 5.2% and 17.6% in the three and nine month Reporting Periods as compared to the Comparable Prior Periods. The increase in the Reporting Periods was due to the higher trucking costs for heavy oil transportation and a higher proportion of heavy oil production relative to total corporate production in the nine month Reporting Period, as heavy oil transportation costs are significantly higher on a per boe basis than natural gas transportation costs.

Administrative Expenses

The components of administrative expenses for the Reporting Periods and the Comparable Prior Periods are as follows:

	Three months ended September 30, 2011		Three months ended September 30, 2010		Change
	($)	%	($)	%	
Cash:					
Salaries and benefits (1)	**487,020**	**52**	305,766	59	59.3%
Other (2)	**444,474**	**48**	211,304	41	110.3%
	931,494	**100**	517,070	100	80.1%
Capitalized overhead(3)	**(169,619)**	**(18)**	(83,192)	(16)	103.9%
General & administrative expenses, net	**761,875**	**82**	433,878	84	75.6%
General & administrative expenses, net per boe	**20.01**		29.57		(32.3%)
Non-cash:					
Stock-based compensation	**322,192**	**100**	88,540	100	263.9%
Capitalized stock-based compensation(3)	**(120,192)**	**(37)**	(18,242)	(21)	558.9%
Stock-based compensation, net	**202,000**	**63**	70,298	79	187.3%
Stock-based compensation, net per boe	**5.30**		4.79		10.6%
Total administrative expenses, net	**963,875**	**77**	504,176	83	91.2%
Total administrative expenses, net per boe	**25.31**		34.36		(26.3%)

	Nine months ended September 30, 2011		Nine months ended September 30, 2010		Change
	($)	%	($)	%	
Cash:					
Salaries and benefits (1)	**1,259,665**	**56**	802,437	65	57.0%
Other (2)	**1,009,201**	**44**	438,946	35	129.9%
	2,268,866	**100**	1,241,383	100	82.8%
Capitalized overhead(3)	**(417,498)**	**(18)**	(137,883)	(11)	202.8%
General & administrative expenses, net	**1,851,368**	**82**	1,103,500	89	67.8%
General & administrative expenses, net per boe	**21.66**		22.12		(2.1%)
Non-cash:					
Stock-based compensation	**999,351**	**100**	22,312	100	–
Capitalized stock-based compensation(3)	**(295,206)**	**(30)**	(18,242)	(82)	–
Stock-based compensation, net	**704,145**	**70**	4,070	18	–
Stock-based compensation, net per boe	**8.24**		0.08		–
Total administrative expenses, net	**2,555,513**	**78**	1,107,570	88	130.7%
Total administrative expenses, net per boe	**29.90**		22.20		34.7%

(1) Includes salaries and benefits paid to all officers, employees and consultants of the Corporation.
(2) The Reporting Period includes acquisition-related costs with respect to the Asset Acquisition.
(3) Represents a portion of salaries and benefits and stock-based compensation that are directly attributable to the exploration and development activities of the Corporation.

General and administrative (cash)

Net General and Administrative ("**G&A**") expenses increased on an aggregate basis in the Reporting Periods as compared to the Comparable Prior Periods due primarily to the costs incurred in anticipation of the Corporation's future growth objectives. The costs included increased professional personnel levels, additional software requirements to accommodate an increase in capital spending and additional legal, accounting and regulatory fees as a result of becoming a reporting issuer. This increase was offset by higher capitalized overhead which is attributable to the increase in development and exploration activities.

In accordance with IFRS 3 *Business Combinations*, the majority of acquisition-related costs an acquirer incurs to effect a business combination are expensed in the period the costs are incurred and the services are received. Management considers the Asset Acquisition to be a business combination pursuant to IFRS 3 and as such, has recorded approximately $77,000 in acquisition-related costs for legal and other professional advisory fees during the Reporting Periods as compared to $NIL in the Comparable Prior Periods.

Stock-based compensation (non-cash)

The increase in the Reporting Periods was mainly due to the granting of a significant number of stock options subsequent to the Comparable Prior Periods. A summary of the Corporation's outstanding stock options at September 30, 2011 is set out in note 14 of the unaudited condensed financial statements. The stock-based compensation expense in the Comparable Prior Periods was also reduced due to the termination and cancellation of MEX's unexercised and unvested stock options pursuant to the Amalgamation.

Each stock option entitles the holder to purchase one Manitok Share upon payment of the exercise price.

Depletion and Depreciation Expenses

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

	Three months ended September 30, 2011		Three months ended September 30, 2010		Change	
	($)	$/boe	($)	$/boe	($)	$/boe
Depletion and depreciation	**887,401**	**23.30**	268,279	18.28	230.8%	27.5%
Impairment	–	–	–	–	–	–
Total D&D	**887,401**	**23.30**	268,279	18.28	230.8%	27.5%

	Nine months ended September 30, 2011		Nine months ended September 30, 2010		Change	
	($)	$/boe	($)	$/boe	($)	$/boe
Depletion and depreciation	**2,023,593**	**23.68**	903,937	18.12	123.9%	30.7%
Impairment	–	–	1,887,732	37.84	–	–
Total D&D	**2,023,593**	**23.68**	2,791,669	55.96	(27.5%)	(57.7%)

Depletion and depreciation expense is a function of the estimated proved plus probable reserve additions, the finding and development costs attributable to those reserves, the associated future development capital required to recover those reserves and production in the period. Depletion and depreciation expenses increased mainly due to an increase in average natural gas and heavy oil production volumes in the three and nine month Reporting Periods.

D&D also included a $1,887,732 impairment charge on June 30, 2010, as a result of decreased forward natural gas prices which impacted the fair value less costs to sell derived from the Corporation's reserves. Approximately $1.1 million of the impairment charge related to the Asset Disposition which resulted in a $1.6 million gain on sale of assets.

Impairment Test

The Corporation performed an impairment review of its exploration and evaluation assets and petroleum and natural gas properties and equipment to assess for recoverability. The Corporation's assets did not have any indicators of impairment at September 30, 2011, but it did recognize an impairment charge of $342,479 at December 31, 2010 and $1,887,732 at June 30, 2010.

Finance Expenses

The components of the Corporation's finance expenses for the Reporting Periods and Comparable Prior Periods are as follows:

	Three months ended September 30, 2011		Three months ended September 30, 2010		Change	
	($)	$/boe	($)	$/boe	($)	$/boe
Cash:						
Interest on revolving credit facility	**–**	**–**	768	0.05	–	–
Non-cash:						
Accretion on decommissioning obligations	**16,640**	**0.44**	9,770	0.67	70.3%	(34.3%)
Total finance expenses	**16,640**	**0.44**	10,538	0.72	57.9%	(38.9%)

	Nine months ended September 30, 2011		Nine months ended September 30, 2010		Change	
	($)	$/boe	($)	$/boe	($)	$/boe
Cash:						
Interest on revolving credit facility	**27**	**–**	5,925	0.12	–	–
Non-cash:						
Accretion on decommissioning obligations	**44,830**	**0.52**	33,550	0.67	33.6%	(22.4%)
Total finance expenses	**44,857**	**0.52**	39,475	0.79	13.6%	(34.2%)

These costs consist primarily of the accretion on the decommissioning obligations and have remained consistent in the Reporting Periods as compared to the Comparable Prior Periods.

Gain on Sale of Assets

The Asset Disposition resulted in a gain of approximately $1.6 million ($1.2 million, net of tax) or $31.32 per boe during the nine months ended September 30, 2010.

Interest Income

Manitok recorded interest income of $84,003 ($2.21 per boe) and $231,470 ($2.71 per boe) for the three and nine month Reporting Periods, as compared to $14,759 ($1.01 per boe) and $14,906 ($0.30 per boe) for the Comparable Prior Periods. The interest income in the Reporting Periods represents excess cash in an interest bearing bank account and term deposits purchased with its lender. The Corporation's average interest rate was 1.04% and 1.05% for the three and nine month Reporting Periods.

Taxes

Manitok recorded a deferred income tax recovery of $156,306 ($4.10 per boe) and an expense of $432,562 ($5.06 per boe) for the three and nine month Reporting Periods, as compared to an expense of $232,879 ($15.87 per boe) and a recovery of $263,605 ($5.28 per boe) for the Comparable Prior Periods. The recoveries attributed to the net losses in the Reporting Periods and the Comparable Prior Periods were offset by a $0.9 million charge in the nine month Reporting Period and a $0.2 million charge in the nine month Comparable Prior Period related to a flow-through share renunciation to shareholders.

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

Exploration and Evaluation Assets

The following table sets forth a summary of the Corporation's exploration and evaluation ("**E&E**") assets incurred during the Reporting Periods and the Comparable Prior Periods:

Three months ended September 30 ($)	**2011**	2010
Undeveloped land	**2,627,898**	1,570,410
Seismic	**338,111**	38,645
Drilling, completions, equipment and facilities	**215,147**	48,367
Total E&E expenditures	**3,181,156**	1,657,422
Other[2]	**142,332**	3,300
Total E&E assets	**3,323,488**	1,660,722

Nine months ended September 30 ($)	**2011**	2010
Undeveloped land	**7,488,968**	3,255,086
Seismic	**681,863**	299,084
Drilling, completions, equipment and facilities[1]	**4,430,229**	80,715
Total E&E expenditures	**12,601,060**	3,634,885
Other[2]	**242,807**	3,300
Total E&E assets	**12,843,867**	3,638,185

(1) Represents costs attributable to the discovery well drilled in the Stolberg area of Alberta.
(2) Represents non-cash items such as capitalized stock-based compensation and the change in decommissioning assets.

During the Reporting Period the Stolberg discovery well was determined to be commercially viable and associated E&E costs of approximately $6.9 million were transferred to developing and producing assets.

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 September 30 ($)	**2011**	2010
Land	**2,825,401**	1,654,297
Seismic	**378,951**	108,817
Workovers and recompletions	**3,528**	11,645
Drilling and completions	**2,716,398**	1,605,693
Well equipment and facilities	**1,925,331**	89,767
Capitalized overhead[1]	**169,619**	83,192
Total finding and development costs (F&D)	**8,019,228**	3,553,411
Acquisitions (dispositions), net	**–**	(1,802,802)
Total finding, development and acquisition costs (FD&A)	**8,019,228**	1,750,609
Administrative assets	**30,196**	6,490
Total capital expenditures[2]	**8,049,424**	1,757,099

Nine months ended September 30 ($)	**2011**	2010
Land	**8,715,573**	3,341,814
Seismic	**811,645**	365,625
Workovers and recompletions	**327,821**	108,371
Drilling and completions	**6,321,817**	1,663,022
Well equipment and facilities	**2,482,464**	99,603
Capitalized overhead[1]	**417,498**	137,817
Total finding and development costs (F&D)	**19,076,818**	5,716,252
Acquisitions (dispositions), net	**7,205**	(1,802,802)
Total finding, development and acquisition costs (FD&A)	**19,084,023**	3,913,450
Administrative assets	**60,875**	34,825
Total capital expenditures[2]	**19,144,898**	3,948,275

(1) Represents a portion of salaries and benefits that are directly attributable to the exploration and development activities of the Corporation that have been capitalized.
(2) Excludes non-cash items such as capitalized stock-based compensation and decommissioning assets.

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 September 30 ($)	**2011**	2010
Cash flow	**153,994**	(296,144)
Changes in non-cash operating working capital	**39,444**	189,707
Decommissioning expenditures	**(524)**	–
Increase (decrease) in revolving credit facility	**–**	(1,040,105)
Proceeds from share issuances	**–**	9,958,255
Share issue costs	**–**	(795,311)
Cash received from the Amalgamation	**–**	434,571
Cost of the Amalgamation	**–**	(47,855)
Changes in non-cash investing working capital	**(2,188,131)**	1,833,079
Total capital resources	**(1,995,217)**	10,236,197
Exploration and evaluation asset expenditures	**(3,181,156)**	(1,657,422)
Petroleum and natural gas properties and equipment expenditures	**(4,868,268)**	(1,902,479)
Property acquisitions and dispositions	**–**	1,802,802
Net increase (decrease) in cash and cash equivalents	**(10,044,641)**	8,479,098

Nine months ended September 30 ($)	**2011**	2010
Cash flow	**350,070**	(393,311)
Changes in non-cash operating working capital	**(265,634)**	310,742
Decommissioning expenditures	**(1,069)**	–
Proceeds from share issuances	**28,750,000**	11,380,805
Share issue costs	**(2,098,864)**	(973,583)
Cash received from the Amalgamation	**–**	434,571
Cost of the Amalgamation	**–**	(277,441)
Changes in non-cash investing working capital	**(4,307,226)**	1,721,326
Total capital resources	**22,427,277**	12,203,109
Exploration and evaluation asset expenditures	**(12,601,060)**	(3,634,885)
Petroleum and natural gas properties and equipment expenditures	**(6,536,633)**	(2,116,192)
Property acquisitions and dispositions	**(7,205)**	1,802,802
Net increase (decrease) in cash and cash equivalents	**3,282,379**	8,254,834

SUMMARY OF QUARTERLY INFORMATION

Quarters ended	**September 30, 2011**	June 30, 2011	March 31, 2011	December 31, 2010
OPERATING				
Average daily production				
Natural gas (mcf/d)	**1,449.3**	615.7	643.7	604.0
Heavy oil (bbls/d)	**170.8**	195.3	114.7	97.5
Light oil (bbls/d)	**–**	–	–	–
NGLs (bbls/d)	**1.6**	2.3	0.8	0.2
Total (boe/d)	**413.9**	300.3	222.8	198.4
Average realized sales price (CAD$)				
Natural gas ($/mcf)	**3.73**	3.70	3.65	3.64
Heavy oil ($/bbls)	**63.31**	74.61	59.88	62.04
Light oil ($/bbls)	**–**	–	–	–
NGLs ($/bbls)	**86.40**	86.23	71.73	64.19
Total ($/boe)	**39.52**	56.80	41.63	41.63
OPERATING NETBACK ($ per boe)				
Petroleum and natural gas revenue	**39.52**	56.80	41.63	41.63
Royalty expenses	**(3.49)**	(3.62)	(2.95)	(3.70)
Operating expenses	**(12.16)**	(22.74)	(17.89)	(19.29)
Transportation and marketing expenses	**(2.03)**	(2.79)	(1.70)	(1.65)
Operating netback	**21.84**	27.65	19.09	16.99
FINANCIAL				
Petroleum and natural gas revenue ($)	**1,504,882**	1,551,839	834,766	759,731
Royalty expenses ($)	**(132,750)**	(98,878)	(59,163)	(67,581)
Interest and other revenue ($)	**84,003**	103,792	43,675	20,840
Total revenues, net ($)	**1,456,135**	1,556,753	819,278	712,990
Net income (loss) ($)(1)	**(795,741)**	(469,680)	(1,596,844)	(1,277,154)
Per share – basic ($)(1)	**(0.02)**	(0.01)	(0.05)	(0.07)
Per share – diluted ($)(1)	**(0.02)**	(0.01)	(0.05)	(0.07)
Cash flow ($)(1)	**153,994**	291,412	(95,336)	(178,981)
Per share – basic ($)(1)	**0.00**	0.01	(0.00)	(0.01)
Per share – diluted ($)(1)	**0.00**	0.01	(0.00)	(0.01)
Capital expenditures, net ($)(1)	**8,049,424**	6,352,187	4,743,287	3,280,774
Book value of total assets ($)(1)	**70,462,012**	68,311,678	45,838,822	44,726,978
Working capital deficiency (surplus) ($)	**(27,635,269)**	(35,531,223)	(14,766,860)	(19,780,030)
Revolving credit facility ($)	**–**	–	–	–
Total net debt ($)	**–**	–	–	–
Shareholders' equity ($)(1)	**62,703,143**	63,176,692	36,113,675	37,390,205
Common shares outstanding				
End of period – basic	**51,665,531**	51,665,531	33,696,781	33,696,781
End of period – diluted	**54,893,031**	54,601,031	36,612,281	35,335,281
Weighted average for the period – basic	**51,665,531**	48,901,108	33,696,781	18,538,049
Weighted average for the period – diluted	**52,266,109**	49,845,473	34,732,503	18,603,545

(1) Manitok's IFRS transition date was July 1, 2009 and therefore all comparative information was restated to comply with IFRS requirements.

SUMMARY OF QUARTERLY INFORMATION

Quarters ended	September 30, 2010	June 30, 2010	March 31, 2010	December 31, 2009
OPERATING				
Average daily production				
Natural gas (mcf/d)	533.5	610.3	730.6	789.8
Heavy oil (bbls/d)	67.1	79.9	73.7	66.8
Light oil (bbls/d)	0.2	0.7	0.6	1.3
NGLs (bbls/d)	3.3	5.6	5.1	4.4
Total (boe/d)	159.5	188.0	201.2	204.1
Average realized sales price (CAD$)				
Natural gas ($/mcf)	3.75	3.95	5.08	4.78
Heavy oil ($/bbls)	56.75	51.50	64.22	69.68
Light oil ($/bbls)	70.64	69.97	76.01	74.48
NGLs ($/bbls)	27.34	34.21	33.38	27.92
Total ($/boe)	37.06	36.01	43.07	42.37
OPERATING NETBACK ($ per boe)				
Petroleum and natural gas revenue	37.06	36.01	43.07	42.37
Royalty expenses	(4.48)	(4.72)	(8.27)	(6.08)
Operating expenses	(22.22)	(13.73)	(15.89)	(16.13)
Transportation and marketing expenses	(1.93)	(1.72)	(1.97)	(1.52)
Operating netback	8.43	15.84	16.94	18.64
FINANCIAL				
Petroleum and natural gas revenue ($)	543,805	615,877	779,933	795,693
Royalty expenses ($)	(65,760)	(80,746)	(149,725)	(114,205)
Interest and other revenue ($)	14,759	(392)	539	203
Total revenues, net ($)	492,804	534,739	630,747	681,691
Net income (loss) ($)(1)	685,198	(1,577,698)	(503,928)	(253,451)
Per share – basic and diluted ($)(1)(2)	0.04	(0.15)	(0.05)	(0.03)
Per share – basic and diluted ($)(1)(3)	0.04	(0.20)	(0.07)	(0.04)
Cash flow ($)(1)	(296,144)	(15,378)	(81,790)	52,495
Per share – basic and diluted ($)(1)(2)	(0.02)	(0.00)	(0.01)	0.01
Per share – basic and diluted ($)(1)(3)	(0.02)	(0.00)	(0.01)	0.01
Capital expenditures, net ($)(1)	1,757,099	456,073	1,735,103	502,849
Book value of total assets ($)(1)	27,421,204	16,126,262	17,319,385	16,436,942
Working capital deficiency (surplus) ($)	(6,659,296)	(202,985)	(301,237)	(436,530)
Revolving credit facility ($)	–	1,040,105	338,261	–
Total net debt ($)	–	837,120	37,024	–
Shareholders' equity ($)(1)	25,522,284	12,824,435	14,493,300	13,608,800
Common shares outstanding(2)				
End of period – basic	16,730,460	10,649,567	10,649,567	9,412,567
End of period – diluted	18,318,960	11,619,567	11,619,567	10,382,567
Weighted average for the period – basic	16,267,784	10,649,567	10,072,300	8,190,258
Weighted average for the period – diluted	16,314,887	10,649,567	10,072,300	8,190,258
Common shares outstanding(3)				
End of period – basic	16,730,460	7,987,175	7,987,175	7,059,425
End of period – diluted	18,318,960	8,714,675	8,714,675	7,786,925
Weighted average for the period – basic	16,267,784	7,987,175	7,554,225	6,142,694
Weighted average for the period – diluted	16,314,887	7,987,175	7,554,225	6,142,694

(1) Manitok's IFRS transition date was July 1, 2009 and therefore all comparative information was restated to comply with IFRS requirements.

(2) All per share and share balances prior to the September 30, 2010 period have not been adjusted to reflect the 75% conversion factor of shares, pursuant to the Amalgamation.

(3) All per share and share balances prior to the September 30, 2010 period have been adjusted to reflect the 75% conversion factor of shares, pursuant to the Amalgamation.

Discussion of Quarterly Results

Manitok's average production in the quarter ended September 30, 2011 was 413.9 boe/d, which is a 38% increase from 300.3 boe/d in the quarter ended June 30, 2011 and a 160% increase from 159.5 boe/d in the quarter ended September 30, 2010. The quarter over quarter production increases are a direct result of improved operations at the Corporation's heavy oil property in the Swimming area of Alberta, the five heavy oil wells that were drilled in 2010 are now producing with less downtime and four new heavy oil wells were put on production during September 2011. There was also the addition of the new natural gas well in the Stolberg area of Alberta, which was put into production in early September 2011.

Manitok spent $8.0 million on capital expenditures for the current quarter as compared to $6.4 million for the quarter ended June 30, 2011 and $1.8 million during the quarter ended September 30, 2010. Capital spent in the third quarter of 2011 was primarily directed towards the equipping and tie-in of the natural gas well in the Stolberg area of Alberta and the drilling, completion and equipping of six heavy oil wells in the Swimming area of Alberta, while capital expenditures in the second quarter of 2011 were directed primarily towards strategic undeveloped land acquisitions in Manitok's core areas. Further details of the Corporation's capital expenditures for the Reporting Periods are set forth in the table entitled "Capital Expenditures" in this MD&A.

Cash flow generated by the Corporation in the quarter ended September 30, 2011 was $153,994, as compared to $291,412 in the quarter ended June 30, 2011 and negative ($296,144) in the quarter ended September 30, 2010. The positive cash flow in the second and third quarter of 2011 was due mainly to the increase in natural gas and heavy oil production volumes and higher average heavy oil prices realized at the wellhead which was partially offset by increased general and administrative costs due to a significant increase in professional personnel levels in anticipation of the Corporation's future activity.

Manitok has reported a net loss of $0.8 million in the third quarter of 2011 as compared to a net loss of $0.5 million in the second quarter of 2011 and net income of $0.7 million in the third quarter of 2010. The net loss in the second and third quarter of 2011 is due mainly to the non-cash items such as depletion and depreciation and stock-based compensation, while the net income in the third quarter of 2010 was due to a $1.6 million gain on the Asset Disposition.

The Corporation's average realized heavy oil prices decreased about 15% in the current quarter as it averaged $63.31/bbl as compared to $74.61/bbl in the quarter ended June 30, 2011 and increased about 12% in the current quarter as compared to $56.75/bbl in the quarter ended September 30, 2010. The average realized natural gas prices remained relatively consistent as it averaged $3.73/mcf in the third quarter of 2011 as compared to $3.70/mcf in the second quarter of 2011 and $3.75/mcf in the third quarter of 2010.

MERGERS AND ACQUISITIONS

Within its focus area, the Corporation is always reviewing potential property acquisitions and corporate mergers and acquisitions for the purposes of determining whether any such potential transaction is of interest to the Corporation and the terms on which such a potential transaction would be available. As a result, Manitok may from time to time be involved in discussions or negotiations with other parties or their agents in respect of potential property acquisitions and corporate merger and acquisition opportunities, but the Corporation is not committed to any such potential transaction and cannot be reasonably confident that it can complete any such potential transaction until appropriate legal documentation has been executed by the relevant parties.

TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

First-time Adoption of IFRS

In 2010, Manitok changed its fiscal year end from June 30 to December 31, which created a short six month transitional year ended December 31, 2010. As such, in accordance with National Instrument 52-107 and part 2.9 of Companion Policy 52-107CP, *Acceptable Accounting Principles and Auditing Standards*, the IFRS adoption date of January 1, 2011 required the restatement, for comparative purposes, of amounts reported by Manitok for the periods ended from September 30, 2009 to December 31, 2010, and an opening Statement of Financial Position as at July 1, 2009. Manitok's unaudited condensed financial statements as at and for the three and nine months ended September 30, 2011 and comparative financial statements as at and for the three and nine months ended

September 30, 2010, as at and for the six months ended December 31, 2010, as at and for the twelve months ended June 30, 2010 and an opening Statement of Financial Position as at July 1, 2009 (the "**transition date**") have been prepared in accordance with IFRS as issued by the IASB. Previously, the Corporation prepared its annual and interim financial statements in accordance with Canadian GAAP applicable to publicly accountable enterprises. Since the unaudited condensed financial statements for the three and nine months ended September 30, 2011 represent the Corporation's presentation of its results and financial position under IFRS, they have been prepared in accordance with International Accounting Standard ("**IAS**") 34, *Interim Financial Reporting* and IFRS 1, *First-time Adoption of IFRS*.

IFRS 1 requires the consistent and retrospective application of IFRS accounting policies for comparative information as at July 1, 2009 and subsequent comparative periods. To assist with the transition, the provisions of IFRS 1 allow for certain mandatory and optional exemptions for first-time adopters to alleviate the retrospective application of IFRS. Manitok has elected to apply the following relevant exemptions:

- IFRS 1, *First-time Adoption of IFRS*, whereby petroleum and natural gas properties and equipment balances as determined under the Corporation's previous accounting framework (Canadian GAAP) is allocated to the IFRS categories of exploration and evaluation assets and developing and producing properties. Under the exemption, for assets in the development and production phases, the amount was allocated to the underlying IFRS transitional assets on a pro-rata basis using proved plus probable reserve values as of the IFRS transition date;
- IFRS 2, *Share-based Payments*, whereby stock options that vested prior to July 1, 2009 are not required to be retrospectively restated. Therefore, IFRS 2 requirements apply only to those options that were unvested at the date of transition; and
- IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*, whereby the Corporation has elected to measure decommissioning obligations as at the transition date in accordance with IAS 37 and recognize directly in retained earnings (deficit) the difference between that amount and the carrying amount of those liabilities at the date of transition determined under Canadian GAAP.

Hindsight was not used to create or revise estimates and accordingly the estimates previously made by the Corporation under Canadian GAAP are consistent with their application under IFRS. A summary of the IFRS 1 mandatory and optional exemptions are also described in note 21 to the unaudited condensed financial statements.

Significant IFRS Accounting Policies

The IFRS accounting policies are set forth in note 3 of the unaudited condensed financial statements for the three and nine months ended September 30, 2011. A detailed explanation of how the transition from Canadian GAAP to IFRS has affected the Corporation's financial position, financial performance, and cash flow, including the reconciliations required by IFRS 1, is presented in note 21 to the unaudited condensed financial statements.

The adoption of IFRS does not impact the underlying economics of Manitok's operations. The most significant impacts of adoption are from the application of new accounting policies that reset the Corporation's opening financial position at July 1, 2009, and changes in the accounting for petroleum and natural gas properties and equipment, decommissioning obligations, stock-based compensation and deferred income taxes. Manitok also adopted certain presentation policies that differ from Canadian GAAP. The following discusses the significant accounting policy and presentation differences under IFRS:

Depletion and depreciation expenses

Under Canadian GAAP, the Corporation used total proved reserves in determining D&D. Under IFRS, the carrying amount of petroleum and natural gas properties and equipment is depleted over the useful life of the assets. Manitok has determined that depleting on a total proved plus probable reserve basis better approximates the useful life of the Corporation's assets. D&D was calculated at the country cost center level using the unit of production method on the full cost pool of assets under Canadian GAAP. Under IFRS, the net carrying value of developed and producing assets is depleted using the unit of production method at the area level. As a result of this accounting policy difference, D&D expenses decreased during the six months ended December 31, 2010 by $306,420 (three months ended September 30, 2010 – $127,956, nine months ended September 30, 2010 – $487,989 and twelve months ended June 30, 2010 – $778,632) from the amounts previously reported under Canadian GAAP.

Gain on disposition of assets

Under Canadian GAAP, proceeds from the disposition of assets were deducted from the full cost pool without the recognition of a gain or loss unless the disposition resulted in a change in the full cost depletion rate of 20 percent or more. Under IFRS, gains or losses on disposition of assets are measured as the difference between the proceeds and carrying value of the assets divested. As a result of this accounting policy difference, Manitok recorded a gain on disposition of assets of $1.6 million as a result of the Asset Disposition and a gain of $0.3 million, as a result of the sale of a non-producing asset as part of a swap arrangement in December 2010.

Impairment testing

Under Canadian GAAP, the recoverable amount of Manitok's petroleum and natural gas assets under the first step of the impairment test is determined using undiscounted future cash flow from proved reserves. Under IFRS, the recoverable amount is calculated using discounted future cash flow from proved plus probable reserves. In addition, impairment testing under Canadian GAAP is performed at the country cost centre level, while under IFRS the Corporation's assets are grouped into cash-generating units based on their ability to generate largely independent cash flows. As a result of decreased forward natural gas prices which impacted the fair value less costs to sell derived from the Corporation's reserves, Manitok recognized a $0.4 million impairment charge on its July 1, 2009 transition date to IFRS, a $1.9 million impairment charge for the twelve months ended June 30, 2010 and a $0.3 million impairment charge for the six months ended December 31, 2010.

Approximately $1.5 million of the total impairment charges related to an asset in the Garrington area of Alberta creating a recoverable amount of $0.2 million. The Asset Disposition resulted in a $1.6 million gain on sale of assets during the six months ended December 31, 2010.

Decommissioning obligations

Under Canadian GAAP, Manitok used a credit-adjusted discount rate of 8% in estimating the decommissioning obligations (formerly known as asset retirement obligations under Canadian GAAP). Under IFRS, the Corporation's policy is to estimate the decommissioning obligations using a risk-free discount rate on transition to IFRS. The effect of using a risk-free discount rate resulted in an increase of $0.4 million to the decommissioning obligation with a corresponding increase to the Corporation's retained earnings (deficit) at July 1, 2009. Accretion of decommissioning obligations has decreased by approximately $6,000 per quarter since the IFRS transition date.

Stock-based compensation expenses

Under Canadian GAAP the fair value of stock options was calculated using a Black-Scholes option-pricing model for each option grant and the resulting expense was recognized on a straight-line basis over the three year vesting period at a rate of one-third on each anniversary date of the stock option grant. Forfeitures of stock options were recognized as they occurred. Subsequent to June 30, 2010, the Corporation calculated stock-based compensation expense on a basis consistent with IFRS, which was allowable under Canadian GAAP.

Under IFRS, each vesting tranche of an option grant with different vesting dates was considered a separate grant for the calculation of fair value. This resulted in accelerated expense recognition that attributed higher stock-based compensation expense in the early years of an option grant and less expense in later years. Manitok also applied an estimated forfeiture rate at the initial grant date. When determining the fair value of each vesting tranche under IFRS, Manitok applied an estimated weighted average option life which reflects management's expectations. Under Canadian GAAP the option life was equal to the expiry period of five years.

The above accounting policy differences resulted in an increase of $16,809 to contributed surplus with a corresponding increase to the Corporation's retained earnings (deficit) at July 1, 2009. Stock-based compensation expense remained consistent during the six months ended December 31, 2010 (three months ended September 30, 2010 – $NIL, nine months ended September 30, 2010 – decreased $75,743 and twelve months ended June 30, 2010 – decreased $36,646) from the amounts previously recorded under Canadian GAAP.

Administrative expenses

Under Canadian GAAP, "capitalized overhead" related to the estimated time spent on operated capital projects which are not 100% owned by the Corporation, by engineering, land, accounting and operations based on an industry standard overhead charge per Authorization for Expenditure. Stock-based compensation expense was not capitalized under Canadian GAAP. Under IFRS, capitalized overhead represents a portion of salaries and benefits that are directly attributable to the exploration and development activities of the Corporation. In addition, under IFRS, Manitok has capitalized a portion of stock-based compensation expense directly attributable to the exploration and development of its assets.

These accounting policy differences resulted in a decrease to net general and administrative expenses (cash) by $158,701 during the six months ended December 31, 2010 (three months ended September 30, 2010 – $83,192, nine months ended September 30, 2010 – $137,883 and twelve months ended June 30, 2010 – $54,691) from amounts previously reported under Canadian GAAP. In addition, non-cash stock-based compensation expense decreased by $60,437 during the six months ended December 31, 2010 (three months ended September 30, 2010 – $18,242, nine months ended September 30, 2010 – $18,242 and twelve months ended June 30, 2010 – $NIL) from amounts previously reported under Canadian GAAP.

Share capital

Under Canadian GAAP, the proceeds from the issuance of flow-through shares are recognized as shareholders' equity. The tax basis of assets related to expenditures incurred to satisfy flow-through share obligations is reduced when the renunciation of the related tax pools occurs, which then increases the deferred income tax liability and reduces share capital.

Under IFRS, the amount recorded to share capital from the issuance of flow-through shares reflects the fair market value of "regular" common shares. The difference between the total value of a flow-through share issuance and the fair market value of a regular common share issuance (premium) is initially accrued as a deferred obligation when the flow-through shares are issued. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. Accordingly, on renunciation with Canada Revenue Agency, a deferred tax liability is recorded equal to the estimated amount of deferred income taxes payable by the Corporation as a result of the renunciations, the deferred obligation on the issuance of flow-through shares is reduced and the difference is recognized in deferred income tax expense. There is no impact to share capital on renunciation of flow-through shares.

The above accounting policy difference resulted in an increase to share capital of $717,309 at the transition date with a corresponding increase to retained earnings (deficit). The Corporation reflected an increase in share capital of $203,456 as at March 31, 2010 related to a flow-though share issuance in December 2009 and a decrease in share capital of $336,253 as at December 31, 2010 related to a flow-though share issuance in July 2010 and December 2010. As at December 31, 2010 the Corporation had a deferred obligation of $1.0 million with respect to the issuance of flow-through shares in December 2010.

Deferred income taxes

Each of the adjustments discussed above result in a change in deferred income tax assets and liabilities based on Manitok's effective tax rate. The Corporation recorded a decrease in deferred tax liabilities of $190,591 at July 1, 2009 and an increase in deferred tax liabilities of $74,604 at December 31, 2010 (September 30, 2010 – increase of $886, June 30, 2010 – decrease of $488,201) from amounts previously reported under Canadian GAAP. Additional deferred income tax expense of $1,235,855 for the six months ended December 31, 2010 (three months ended September 30, 2010 – $489,087, nine months ended September 30, 2010 – $282,509 and twelve months ended June 30, 2010 – reduction of $94,153) was recorded under IFRS.

Reclassifications

Under Canadian GAAP, interest expense and accretion were disclosed as separate line items in income or loss. Under IFRS, these amounts were unchanged, but reported as finance expenses. Interest paid is disclosed separately as an operating item in the Condensed Statements of Cash Flows.

Under Canadian GAAP, G&A expenses (cash) and non-cash stock-based compensation expenses were disclosed as separate line items in income or loss. Under IFRS, these items were grouped and reported as administrative expenses.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the unaudited interim condensed financial statements requires management to make judgments, estimates and assumptions that affect the application of IFRS accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The following are the critical judgments and estimations that management has made in the process of applying the Corporation's IFRS accounting policies and that have the most significant effect on the amounts recognized in these financial statements:

Reserves

Estimation of reported recoverable quantities of proved and probable reserves include judgmental assumptions regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and its anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Corporation's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Manitok's petroleum and natural interests are independently evaluated by reserve engineers at least annually.

The Corporation's petroleum and natural gas reserves represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if producibility is supported by either production or conclusive formation tests. Manitok's oil and gas reserves are determined pursuant to National Instrument 51-101, *Standard of Disclosures for Oil and Gas Activities*.

Decommissioning obligations

The Corporation estimates future remediation costs of production facilities, well sites and gathering systems at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Stock-based compensation

All share-based awards issued by the Corporation are fair valued using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

Impairment of assets

The impairment testing of petroleum and natural gas properties and equipment is based on estimates of proved plus probable reserves, production rates, forecasted petroleum and natural gas prices, future costs and other relevant assumptions. Manitok's assets are aggregated into cash-generating units, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Corporation's assets in future periods.

Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in income or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods.

CONDENSED STATEMENTS OF FINANCIAL POSITION

(UNAUDITED)

(expressed in Canadian dollars)

As at	**September 30, 2011**	December 31, 2010	June 30, 2010	July 1, 2009
		(note 21)	(note 21)	(note 21)
ASSETS				
Current assets:				
Cash and cash equivalents	**25,013,123**	21,730,744	70,648	70,765
Accounts receivable (note 17)	**1,140,347**	1,254,489	575,820	287,595
Deposits and prepaid expenses	**4,988,016**	374,154	335,631	291,562
	31,141,486	23,359,387	982,099	649,922
Non-current assets:				
Deferred financing fees (note 4)	**–**	–	327,947	–
Exploration and evaluation assets (note 5)	**12,415,056**	6,487,757	2,987,434	500,863
Petroleum and natural gas properties and equipment (note 6)	**26,905,470**	14,879,834	11,828,782	15,037,620
	39,320,526	21,367,591	15,144,163	15,538,483
	70,462,012	44,726,978	16,126,262	16,188,405
LIABILITIES				
Current liabilities:				
Accounts payable and accrued liabilities	**3,506,217**	3,579,357	779,114	479,066
Revolving credit facility (note 8)	**–**	–	1,040,105	615,769
	3,506,217	3,579,357	1,819,219	1,094,835
Non-current liabilities:				
Flow-through share premium (note 10o and 10r)	**–**	1,009,304	–	–
Decommissioning obligations (note 9)	**2,205,246**	1,617,855	1,079,290	1,363,845
Deferred income taxes	**2,047,406**	1,130,257	403,318	966,289
	4,252,652	3,757,416	1,482,608	2,330,134
	7,758,869	7,336,773	3,301,827	3,424,969
SHAREHOLDERS' EQUITY				
Share capital (note 10)	**69,906,150**	42,730,298	17,875,605	15,153,859
Contributed surplus	**1,796,937**	797,586	494,553	475,670
Retained earnings (deficit)	**(8,999,944)**	(6,137,679)	(5,545,723)	(2,866,093)
	62,703,143	37,390,205	12,824,435	12,763,436
Commitments (note 18)				
Subsequent events (note 20)				
	70,462,012	44,726,978	16,126,262	16,188,405

The accompanying notes are an integral part of these condensed financial statements

APPROVED BY THE BOARD

Bruno P. Geremia CA
Director

Massimo M. Geremia
Director

CONDENSED STATEMENTS OF NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

(expressed in Canadian dollars, except for share information)

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
		(note 21)		(note 21)
REVENUE				
Petroleum and natural gas	**1,504,882**	543,805	**3,891,487**	1,939,615
Royalty expenses	**(132,750)**	(65,760)	**(290,791)**	(296,231)
Interest and other	**84,003**	14,759	**231,470**	14,906
	1,456,135	492,804	**3,832,166**	1,658,290
EXPENSES				
Operating (note 11)	**462,884**	326,003	**1,443,004**	848,702
Transportation and marketing	**77,382**	28,299	**187,697**	93,474
Administrative, net (note 12)	**963,875**	504,176	**2,555,513**	1,107,570
Depletion and depreciation (note 6)	**887,401**	268,279	**2,023,593**	2,791,669
Finance (note 13)	**16,640**	10,538	**44,857**	39,475
Loss (gain) on disposition of assets	**–**	(1,562,568)	**7,205**	(1,562,568)
	2,408,182	(425,273)	**6,261,869**	3,318,322
INCOME (LOSS) BEFORE INCOME TAXES	**(952,047)**	918,077	**(2,429,703)**	(1,660,032)
Deferred income tax expense (recovery)	**(156,306)**	232,879	**432,562**	(263,605)
TOTAL NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**(795,741)**	685,198	**(2,862,265)**	(1,396,427)
Net income (loss) per common share (note 15)				
basic	**(0.02)**	0.04	**(0.06)**	(0.11)
diluted	**(0.02)**	0.04	**(0.06)**	(0.11)
Weighted average common shares (note 15)				
basic	**51,665,531**	16,267,784	**44,886,113**	12,352,578
diluted	**51,665,531**	16,314,887	**44,886,113**	12,352,578

The accompanying notes are an integral part of these condensed financial statements

CONDENSED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(UNAUDITED)

(expressed in Canadian dollars, except for share information)

	Number of Common Shares	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Total
Balance, July 1, 2009	8,176,826	15,153,859	475,670	(2,866,093)	12,763,436
Net income (loss) for the period	–	–	–	(598,005)	(598,005)
Share issuances (notes 10c and 10d)	1,235,741	1,421,103	–	–	1,421,103
Share issue costs (notes 10f)	–	(62,845)	–	–	(62,845)
Stock-based compensation	–	–	85,111	–	85,111
Balance, December 31, 2009	9,412,567	16,512,117	560,781	(3,464,098)	13,608,800
Balance, January 1, 2010	9,412,567	16,512,117	560,781	(3,464,098)	13,608,800
Net income (loss) for the period	–	–	–	(1,396,427)	(1,396,427)
Share issuances (notes 10e, 10h and 10i)	9,394,700	10,803,905	–	–	10,803,905
Share issue costs (notes 10g and 10j)	–	(729,316)	–	–	(729,316)
Issuance on an amalgamation (note 10k an 10l)	2,625,000	213,010	–	–	213,010
Conversion on an amalgamation (note 10m)	(4,701,807)	–	–	–	–
Stock-based compensation (note 14)	–	–	22,312	–	22,312
Balance, September 30, 2010	16,730,460	26,799,716	583,093	(4,860,525)	22,522,284
Balance, January 1, 2011	33,696,781	42,730,298	797,586	(6,137,679)	37,390,205
Net income (loss) for the period	–	–	–	(2,862,265)	(2,862,265)
Share issuances (notes 10t)	17,968,750	28,750,000	–	–	28,750,000
Share issue costs (notes 10u)	–	(1,574,148)	–	–	(1,574,148)
Stock-based compensation (note 14)	–	–	999,351	–	999,351
Balance, September 30, 2011	**51,665,531**	**69,906,150**	**1,796,937**	**(8,999,944)**	**62,703,143**

The accompanying notes are an integral part of these condensed financial statements

CONDENSED STATEMENTS OF CASH FLOWS

(UNAUDITED)

(expressed in Canadian dollars)

	Three months ended September 30		Nine months ended September 30	
Cash provided by (used in):	**2011**	2010	**2011**	2010
		(note 21)		(note 21)
OPERATING ACTIVITIES:				
Net income (loss)	**(795,741)**	685,198	**(2,862,265)**	(1,396,427)
Adjustments for items not affecting operating cash:				
Deferred income tax expense (recovery)	**(156,306)**	232,879	**432,562**	(263,605)
Depletion and depreciation expenses	**887,401**	268,279	**2,023,593**	2,791,669
Stock-based compensation expenses (note 12)	**202,000**	70,298	**704,145**	4,070
Finance expenses (note 13)	**16,640**	10,538	**44,857**	39,475
Loss (gain) on disposition of assets	–	(1,562,568)	**7,205**	(1,562,568)
Interest paid (note 13)	–	(768)	**(27)**	(5,925)
Decommissioning expenditures (note 9)	**(524)**	–	**(1,069)**	–
Changes in non-cash operating working capital (note 19)	**39,444**	189,707	**(265,634)**	310,742
	192,914	(106,437)	**83,367**	(82,569)
FINANCING ACTIVITIES:				
Increase (decrease) in revolving credit facility	–	(1,040,105)	–	–
Proceeds from share issuances	–	9,958,255	**28,750,000**	11,380,805
Share issue costs	–	(795,311)	**(2,098,864)**	(973,583)
Cash received from amalgamation	–	434,571	–	434,571
Cost of amalgamation	–	(47,855)	–	(277,441)
	–	8,509,555	**26,651,136**	10,564,352
INVESTING ACTIVITIES:				
Disposition of petroleum and natural gas properties and equipment	–	1,802,802	**(7,205)**	1,802,802
Exploration and evaluation asset expenditures	**(3,181,156)**	(1,657,422)	**(12,601,060)**	(3,634,885)
Petroleum and natural gas properties and equipment expenditures	**(4,868,268)**	(1,902,479)	**(6,536,633)**	(2,116,192)
Changes in non-cash investing working capital (note 19)	**(2,188,131)**	1,833,079	**(4,307,226)**	1,721,326
	(10,237,555)	75,980	**(23,452,124)**	(2,226,949)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(10,044,641)**	8,479,098	**3,282,379**	8,254,834
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	**35,057,764**	70,648	**21,730,744**	294,912
CASH AND CASH EQUIVALENTS, END OF PERIOD	**25,013,123**	8,549,746	**25,013,123**	8,549,746
Cash interest paid	–	768	**27**	5,925
Cash taxes paid	–	–	–	–

The accompanying notes are an integral part of these condensed financial statements

01 REPORTING ENTITY AND NATURE OF OPERATIONS

Manitok Energy Inc. ("**Manitok**" or the "**Corporation**") is domiciled and incorporated in Canada. Manitok was formed as a result of an amalgamation between Manitok Exploration Inc. ("**MEX**") and Desco Resources Inc. ("**Desco**") pursuant to the *Business Corporations Ac*t (Alberta) on July 8, 2010 (the "**Amalgamation**"). MEX was a private entity, incorporated under the *Business Corporations Act* (Alberta) on April 20, 2005 and Desco was a reporting issuer, incorporated under the *Business Corporations Act* (Alberta) on July 8, 2009 which commenced trading on the TSX Venture Exchange ("**TSX-V**") on November 5, 2009 under the symbol "**DSR.P**". Manitok is listed on the TSX-V under the symbol "**MEI**" which commenced trading on July 29, 2010.

The Corporation is engaged in the exploration for, and the development, production and acquisition of, petroleum and natural gas reserves in Western Canada. Currently, all of the Corporation's activities are in Alberta. Manitok's financial year end is December 31st and the Corporation's registered office is located at Suite 1400, 700 – 2nd Street S.W., Calgary, Alberta, T2P 4V5.

These condensed financial statements were approved and authorized for issuance by the Board of Directors on November 23, 2011.

02 BASIS OF PREPARATION

In conjunction with the Corporation's first annual audited financial statements to be issued under International Financial Reporting Standards ("**IFRS**") for the year ended December 31, 2011, these condensed financial statements present Manitok's financial results of operations and financial position under IFRS as at and for the three and nine months ended September 30, 2011, including 2010 comparative periods. As a result, they have been prepared in accordance with International Accounting Standard ("**IAS**") 34, *Interim Financial Reporting*, as issued by the International Accounting Standards Board ("**IASB**"). These condensed financial statements do not include all the necessary annual disclosures in accordance with IFRS. Previously, the Corporation prepared its interim and annual financial statements in accordance with Canadian Generally Accepted Accounting Principles ("**Canadian GAAP**").

The preparation of these condensed financial statements resulted in selected changes to the Corporation's accounting policies as compared to those disclosed in the Corporation's annual audited financial statements for the fiscal year ended December 31, 2010 issued under Canadian GAAP. A summary of the Corporation's significant accounting policies under IFRS is presented in note 3. Accordingly, the IFRS accounting policies have been retrospectively and consistently applied in preparing the financial statements for the 2010 comparative periods, except where specific exemptions permitted an alternative treatment upon transition to IFRS in accordance with IFRS 1, *First-time Adoption of IFRS*. Note 21 to these condensed financial statements contains a detailed description of the Corporation's adoption of IFRS, including a reconciliation of the financial statements previously prepared under Canadian GAAP to those under IFRS for the comparative periods.

These condensed financial statements have been prepared on a historical cost basis, except for certain financial and non-financial assets and liabilities, which have been measured at fair value as disclosed in note 3. The Corporation's condensed financial statements include the accounts of Manitok only as there are no subsidiary companies.

03 SIGNIFICANT ACCOUNTING POLICIES

a) Revenue recognition

Revenue from the sale of petroleum and natural gas is recognized when volumes are delivered and title passes to an external party at contractual delivery points and are recorded gross of transportation charges incurred by the Corporation. The costs associated with delivery and transportation, are recognized in the same period in which the related revenue is earned and recorded.

b) Joint controlled operations and assets

Certain activities of the Corporation are conducted jointly with others where the participants have a direct ownership interest in, and jointly control, the related assets. Accordingly, the accounts of Manitok reflect only its working interest share of revenues, expenses and capital expenditures.

c) Exploration and evaluation assets

Pre-exploration costs are recognized as an expense in the period incurred. Pre-exploration activities are expenditures incurred prior to obtaining the legal rights or licenses to explore a mineral resource.

Intangible exploration and evaluation expenditures are capitalized and may include costs of license acquisition, geological and geophysical evaluations, technical studies, exploration drilling and testing and other directly attributable costs. Tangible assets acquired which are consumed in developing an intangible exploration asset are recorded as part of the cost of the exploration asset. The costs are accumulated in cost centers by exploration area pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource in an exploration area is considered to be determinable when economical quantities of reserves are determined to exist. A review of each exploration project by area is carried out at each reporting date to ascertain whether reserves have been discovered. Upon determination of commercial reserves, associated exploration costs are transferred from exploration and evaluation assets to developing and producing petroleum and natural gas properties and equipment as reported on the Statements of Financial Position. Exploration and evaluation assets are reviewed for impairment prior to any such transfer. Assets classified as exploration and evaluation are not amortized.

d) Petroleum and natural gas properties and equipment

(i) Recognition and measurement

Petroleum and natural gas properties and equipment are measured at cost less accumulated depletion and depreciation and accumulated impairment losses, if any.

Petroleum and natural gas properties and equipment consists of the purchase price and costs directly attributable to bringing the asset to the location and condition necessary for its intended use. Petroleum and natural gas assets include developing and producing interests such as land acquisitions, geological and geophysical costs, development drilling and testing, facility and production equipment and associated turnarounds, other directly attributable costs and the initial estimate of the costs of dismantling and removing an asset and restoring the site on which it was located.

(ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as developing and producing petroleum and natural gas interests when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The cost of day-to-day servicing of an item of petroleum and natural gas properties and equipment is expensed in income or loss as incurred.

Petroleum and natural gas properties and equipment are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from the disposal of an asset, determined as the difference between the net disposal proceeds and the carrying amount of the asset, is recognized in income or loss.

(iii) Depletion and depreciation

The net carrying value of developing and producing petroleum and natural gas assets is depleted on a field or geotechnical area basis using the unit of production method. This depletion calculation includes actual production in the period and total estimated proved and probable reserves attributable to the assets being depleted, taking into account total capitalized costs plus estimated future development costs necessary to bring those reserves into production. Relative volumes of reserves and production (before royalties) are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. These estimates are reviewed by independent reserves evaluators at least annually.

Corporate assets, which include office furniture and equipment, software and computer equipment, are depreciated on a straight-line basis over the estimated useful lives of the assets, which are estimated to be four years. The Corporation records depreciation on its leasehold improvements on a straight-line basis over the term of the building lease of five years.

When significant parts of property and equipment, including petroleum and natural gas interests, have different useful lives, they are accounted for as separate items (major components). Depletion and depreciation methods and useful lives for petroleum and natural gas properties and equipment are reviewed at each reporting date.

e) Provisions

Provisions are recognized when the Corporation has a present obligation (legal or constructive), as a result of a past event, if it is probable that the Corporation will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. When a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows (where the effect of the time value of money is material).

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, a receivable is recognized as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

Provisions are not recognized for future operating losses.

f) Decommissioning obligations

The Corporation's activities give rise to dismantling, restoration and site disturbance remediation activities. Costs related to abandonment activities are estimated by management in consultation with the Corporation's engineers based on risk-adjusted current costs which take into consideration current technology in accordance with existing legislation and industry practices.

Decommissioning obligations are measured at the present value of the best estimate of expenditures required to settle the present obligations at the reporting date. When the fair value of the liability is initially measured, the estimated cost, discounted using a risk-free discount rate, is capitalized by increasing the carrying amount of the related petroleum and natural gas properties and equipment. The increase in the provision due to the passage of time ("**accretion**") is recognized as a finance expense whereas increases and decreases due to revisions in the estimated future cash flows are recorded as adjustments to the carrying amount of the related petroleum and natural gas properties and equipment. Actual costs incurred upon settlement of the liability are charged against the obligation to the extent that the obligation was previously established. The carrying amount capitalized in petroleum and natural gas properties and equipment is depleted in accordance with the Corporation's depletion and depreciation policy. The Corporation reviews the obligation at each reporting date and revisions to the estimated timing of cash flows, discount rates and estimated costs will result in an increase or decrease to the obligations. Any difference between the actual costs incurred upon settlement of the obligation and recorded liability is recognized as a gain or loss in income or loss.

g) Share-based payments

Equity-settled share-based awards granted by the Corporation include stock options granted to directors, officers, employees and key consultants. The fair value determined at the grant date of an award is expensed on a graded basis over the vesting period of each respective tranche of an award with a corresponding increase to contributed surplus. In calculating the expense of equity-settled share-based awards, the Corporation revises its estimate of the number of equity instruments expected to vest by applying an estimated forfeiture rate for each vesting tranche and subsequently revising this estimate throughout the vesting period, as necessary. Upon the exercise of share-based awards, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. In the event that vested share-based awards expire without being exercised, previously recognized compensation costs associated with such awards are not reversed. The expense related to share-based awards is included within administrative expenses in income or loss.

The fair value of equity-settled share-based awards is measured using the Black-Scholes option-pricing model taking into account the terms and conditions upon which the awards were granted. Measurement inputs as at the grant date include: share price, exercise price, expected volatility, weighted average expected life of the instruments, expected dividends and the risk-free interest rate (based on government bonds) applicable to the term of the award.

A portion of share-based compensation expense directly attributable to the exploration and development of the Corporation’s assets are capitalized.

h) Finance income and expenses

Finance expense comprises interest expense on borrowings, accretion of the discount on decommissioning obligations and impairment losses (if any) recognized on financial assets. Interest income is recognized as it is earned.

i) Borrowing costs

Borrowing costs incurred for the acquisition, construction or production of qualifying assets are capitalized during the period of time that is required to complete and prepare the asset for its intended use or sale. Assets are considered to be qualifying assets when this period of time is substantial. The capitalization rate, used to determine the amount of borrowing costs to be capitalized, is the weighted average interest rate applicable to the Corporation’s outstanding borrowings during the period. All other borrowing costs are charged to income or loss using the effective interest method.

j) Financial instruments

(i) Non-derivative financial instruments

Non-derivative financial instruments comprise cash and cash equivalents, accounts receivables, deposits, accounts payable and accrued liabilities and outstanding credit facilities. Non-derivative financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured based on their classification. The Corporation has made the following classifications:

- Cash and cash equivalents are classified as financial assets at fair value, showing separately (i) those designated as such upon initial recognition and (ii) those classified as held for trading in accordance IAS 39 *Financial Instruments: Recognition and Measurement*.
- Accounts receivables and deposits are classified as loans and receivables and are measured at amortized cost using the effective interest method. Typically, the fair value of these balances approximates their carrying value due to their short term to maturity.
- Accounts payable and accrued liabilities and outstanding credit facilities are classified as other liabilities and are measured at amortized cost using the effective interest method. Due to the short term nature of accounts payable and accrued liabilities, their carrying values approximate their fair values. The Corporation’s outstanding credit facilities bear interest at a floating rate and accordingly the fair market value approximates the carrying value before the carrying value is reduced for any remaining unamortized costs.

Financial instruments carried at fair value on the balance sheet are assessed using the following hierarchy based on the amount of observable inputs used to value the instrument.

- **Level 1** – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- **Level 2** – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- **Level 3** – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. The Corporation has categorized its financial instruments according to the hierarchy described above (see note 17).

(ii) Derivative financial instruments

Derivative financial instruments may be used by the Corporation to manage economic exposure to market risks relating to commodity prices, exchange rates and interest rates. Manitok's policy is not to utilize derivative financial instruments for speculative purposes. The Corporation does not designate its financial derivative contracts as hedges, and as such has not applied hedge accounting.

The Corporation accounts for any forward physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items, in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the Statements of Financial Position. Settlements of these physical sales contracts are recognized as petroleum and natural gas revenue.

(iii) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares are recognized as a reduction in share capital, net of any tax effects.

k) Impairment

(i) Impairment of financial assets

Financial assets are assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. Impairment losses are recognized in income or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(ii) Impairment of non-financial assets

The Corporation's petroleum and natural gas properties and equipment are grouped into Cash Generating Units ("**CGU**") for the purpose of assessing impairment. A CGU represents the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.

CGU's are reviewed at each reporting date for indicators of potential impairment. Such indicators may include changes in the Corporation's business plan, deterioration in commodity prices, significant downward revisions of estimated recoverable reserve volumes or increases in estimated future development expenditures. If such indicators exist, an impairment test is performed by comparing a CGU's carrying value to its recoverable amount, defined as the greater of a CGU's fair value less cost to sell and its current value in use. Any excess of carrying value over recoverable amount is recognized in income or loss as additional depletion and depreciation expense.

In assessing the value in use, the estimated future cash flows from proved and probable reserves are discounted to their present value using a discount rate that reflects current market assessment of the time value of money. In assessing fair value less cost to sell, the estimated future cash flows expected to be derived from production of proved and probable reserves are discounted to their present value. Fair value is determined as the amount that would be obtained from the disposition of the asset in an arm's length transaction between knowledgeable and willing parties. The petroleum and natural gas future prices used in the impairment test are based on period-end escalated commodity price forecasts estimated by the Corporation's independent reserves evaluators and are adjusted for petroleum and natural gas differentials, transportation and marketing costs specific to the Corporation.

Where circumstances change such that an impairment no longer exists or is less than the amount previously recognized, the carrying amount of the CGU is increased to the revised estimate of its recoverable amount as long as the revised estimate does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the CGU in prior periods. A reversal of an impairment loss is recognized immediately through income or loss.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability of a development area, or (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to CGU's.

l) Income taxes

The Corporation's income tax expense is comprised of current and deferred tax. Income tax expense is recognized through income or loss except to the extent that it relates to items recognized directly in equity, in which case the related income taxes are also recognized in equity.

Current tax is the expected tax payable on taxable income for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable income. Deferred tax liabilities are generally recognized for all taxable temporary differences. Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which those deductible temporary differences can be utilized. The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is expected to be settled or the asset realized, based on tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting period. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which Manitok expects, at the end of the reporting period, to recover or settle the carrying amount of its assets and liabilities.

m) Flow-through shares

The Corporation may issue flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. The difference between the value ascribed to flow-through shares issued and the value that would have been received for common shares at the date of issuance of the flow-through shares is initially recognized as a liability on the Statement of Financial Position. When the expenditures are renounced, the liability is drawn down, a deferred tax liability is recorded equal to the estimated amount of deferred income tax payable by the Corporation as a result of the renunciation and the difference is recognized as a deferred tax expense.

n) Critical accounting judgments and key sources of estimation uncertainty

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these condensed financial statements are outlined below.

Critical judgments in applying accounting policies:

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Corporation's accounting policies and that have the most significant effect on the amounts recognized in these condensed financial statements:

(i) Reserves

Estimation of reported recoverable quantities of proved and probable reserves include judgmental assumptions regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and its anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Corporation's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Manitok's petroleum and natural gas interests are independently evaluated by reserve engineers at least annually.

The Corporation's petroleum and natural gas reserves represent the estimated quantities of petroleum, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if producibility is supported by either production or conclusive formation tests. Manitok's petroleum and natural gas reserves are determined pursuant to National Instrument 51-101, *Standard of Disclosures for Oil and Gas Activities*.

(ii) Identification of cash-generating units

Manitok's assets are aggregated into cash-generating units, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Corporation's assets in future periods.

(iii) Share-based payments

All equity-settled, share-based awards issued by the Corporation are fair valued using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

Key sources of estimation uncertainty:

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

(i) Decommissioning obligations

The Corporation estimates future remediation costs of production facilities, well sites and gathering systems at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and discount rates to determine the present value of these cash flows.

(ii) Impairment of petroleum and natural gas assets

For the purposes of determining whether impairment of petroleum and natural gas assets has occurred, and the extent of any impairment or its reversal, the key assumptions the Corporation uses in estimating future cash flows are future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the recoverable amounts of assets, and impairment charges and reversals will affect income or loss.

(iii) Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in income or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods.

Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable income available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in income or loss in the period in which the change occurs.

o) Net income (loss) per share

Basic per share information is computed using the weighted average number of common shares outstanding during the period. Diluted per share information is calculated using the treasury stock method, which assumes that any proceeds from the exercise of “in-the-money” stock options would be used to purchase common shares at the average market price during the period. No adjustment to diluted net income (loss) per share is made if the result of these calculations is anti-dilutive.

p) Recent accounting standards and interpretations issued but not yet effective

On May 12, 2011, the IASB issued the following new and revised standards and interpretations effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted providing that IFRS 10, IFRS 11, IFRS 12, IAS 27 and IAS 28 are adopted together, except that IFRS 12 may be adopted earlier. Manitok is currently assessing the impact of adopting these pronouncements, however, it anticipates that these standards will not have a material impact on the Corporation’s financial statements.

IFRS 10 *Consolidated Financial Statements* builds on existing principles by identifying the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company. The standard provides additional guidance to assist in the determination of control where it is difficult to assess. IFRS 10 replaces those parts of IAS 27 *Consolidated and Separate Financial Statements* (revised 2011) that address when and how an entity should prepare consolidated financial statements and replaces SIC 12 *Consolidation – Special Purpose Entities* in its entirety. IAS 27 retains the current guidance for separate financial statements.

IFRS 11 *Joint Arrangements* provides for a more substance based reflection of joint arrangements by focusing on the rights and obligations of the arrangement, rather than its legal form (as is currently the case). The standard addresses inconsistencies in the reporting of joint arrangements by requiring a single method to account for interests in jointly controlled entities. IFRS 11 supersedes IAS 31 *Interests in Joint Ventures* and SIC 13 *Jointly Controlled Entities – Non-Monetary Contributions by Ventures*. IAS 28 *Investments in Associates and Joint Ventures* (revised 2011) has been amended to conform to changes based on the issuance of IFRS 10 and IFRS 11.

IFRS 12 *Disclosure of Interests in Other Entities* requires extensive disclosures relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. An entity is required to disclose information that help users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements. The effective date of IFRS 12 is January 1, 2013, but entities are permitted to incorporate any of the new disclosures in their financial statements before that date.

IFRS 13 *Fair Value Measurement* establishes a single framework for measuring fair values. This standard applies to all transactions and balances (whether financial or non-financial) for which IFRS requires or permits fair value measurements, with the exception of share-based payment transactions accounted for under IFRS *2 Share-based Payment* and leasing transactions within the scope of IAS 17 *Leases*. IFRS 13 defines fair value, provides guidance on its determination and introduces consistent requirements for disclosures on fair value measurements.

Other accounting standards and interpretations

IFRS 7 *Financial Instruments* includes amendments issued by the IASB on Disclosures – *Transfers of Financial Assets* that increase the disclosure requirements for transactions involving transfers of financial assets. These amendments are intended to provide greater transparency around risk exposures of transactions where a financial asset is transferred, but the transferor retains some level of continuing exposure in the asset. The amendments also require disclosure where transfers of financial assets are not evenly distributed throughout the period. These amendments are effective for annual periods beginning on or after July 1, 2011. The application of the standard did not have an impact on the Corporation's financial statements.

IFRS 9 *Financial Instruments* issued in November 2009 and amended in October 2010 introduces new requirements for the classification and measurement of financial assets and financial liabilities and for derecognition. IFRS 9 is expected to be published in three parts. The first part, Phase 1 – classification and measurement of financial instruments sets out the requirements for recognizing and measuring financial assets, financial liabilities and some contracts to buy or sell non-financial items. Phase 1 simplifies the measurement of financial assets by classifying all financial assets as those being recorded at amortized cost or being recorded at fair value. Phase 1 is effective for periods beginning on or after January 1, 2013, although earlier adoption is allowed. Except for certain additional disclosures, the adoption of this standard is not expected to have an impact on the Corporation's financial statements.

(expressed in Canadian dollars, unless otherwise stated)

04 DEFERRED FINANCING FEES

Fees incurred with respect to the issuance of common shares and the Amalgamation, before the transactions were completed had been deferred. The costs, which relate primarily to professional fees, were charged to share capital upon completion of the transactions.

At September 30, 2011, the balance of deferred financing fees was $NIL (December 31, 2010 – $NIL, June 30, 2010 – $327,947).

05 EXPLORATION AND EVALUATION ASSETS

The components of the Corporation's Exploration and Evaluation ("**E&E**") assets are as follows:

	Total
Balance, July 1, 2009	500,863
Additions	2,486,571
Balance, June 30, 2010	2,987,434
Additions	3,500,323
Balance, December 31, 2010	6,487,757
Additions	12,843,867
Transfer to petroleum and natural gas properties and equipment[(1)]	(6,916,568)
Balance, September 30, 2011	**12,415,056**

(1) Includes non-cash items such as capitalized stock-based compensation and decommissioning obligations.

E&E assets consist of the Corporation's exploration projects which are pending the determination of economic quantities of commercially producible reserves. Additions represent the Corporation's share of costs incurred on E&E assets during the period. Manitok capitalized cash and non-cash administrative costs directly attributable to E&E assets of $444,708 in the nine months ended September 30, 2011 (September 30, 2010 – $54,079).

During the period, the Corporation established technical feasibility and commercial viability of a discovery well in the Stolberg area of Alberta, as economical quantities of reserves were determined to exist and production commenced in the period. The Corporation determined no indicators of impairment to exist and transferred approximately $6.9 million of the Corporation's share of the related E&E expenditures to petroleum and natural gas properties and equipment.

In December 2010, the Corporation sold a non-producing E&E asset as part of an asset swap arrangement and recorded a gain on disposition of assets of $295,176.

At the end of each reporting period, the Corporation performs an impairment review of its E&E assets to ensure that the carrying values of those assets are recoverable. Any impairment of E&E assets and any eventual reversal are recognized as additional depletion and depreciation expense in the Statement of Income (Loss) and Comprehensive Income (Loss). The Corporation's E&E assets were not impaired during the periods ended September 30, 2011, December 31, 2010 and June 30, 2010.

(expressed in Canadian dollars, unless otherwise stated)

06 PETROLEUM AND NATURAL GAS PROPERTIES AND EQUIPMENT

The components of the Corporation's Petroleum and Natural Gas ("**P&NG**") Properties and Equipment are as follows:

	P&NG	Corporate	Total
Cost:			
As at, July 1, 2009	19,924,913	91,871	20,016,784
Additions	339,441	28,335	367,776
Asset dispositions	(40,000)	–	(40,000)
Change in decommissioning obligations	(334,574)	–	(334,574)
As at, June 30, 2010	19,889,780	120,206	20,009,986
Additions	3,707,140	42,772	3,749,912
Asset dispositions	(240,234)	–	(240,234)
Change in decommissioning obligations	520,115	–	520,115
As at, December 31, 2010	23,876,801	162,978	24,039,779
Additions	6,577,654	60,876	6,638,530
Transfer from E&E assets (note 5)	6,916,568	–	6,916,568
Change in decommissioning obligations	494,131	–	494,131
As at, September 30, 2011	**37,865,154**	**223,854**	**38,089,008**
Accumulated depletion and depreciation:			
As at, July 1, 2009	(4,939,673)	(39,491)	(4,979,164)
Depletion and depreciation expense	(1,290,920)	(23,388)	(1,314,308)
Impairment (note 7)	(1,887,732)	–	(1,887,732)
As at, June 30, 2010	(8,118,325)	(62,879)	(8,181,204)
Depletion and depreciation expense	(619,204)	(17,058)	(636,262)
Impairment (note 7)	(342,479)	–	(342,479)
As at, December 31, 2010	(9,080,008)	(79,937)	(9,159,945)
Depletion and depreciation expense	(1,991,141)	(32,452)	(2,023,593)
As at, September 30, 2011	**(11,071,149)**	**(112,389)**	**(11,183,538)**
Net book value:			
As at, July 1, 2009	14,985,240	52,380	15,037,620
As at, June 30, 2010	11,771,455	57,327	11,828,782
As at, December 31, 2010	14,796,793	83,041	14,879,834
As at, September 30, 2011	**26,794,005**	**111,465**	**26,905,470**

At September 30, 2011, estimated future development costs of $5.1 million (December 31, 2010 – $5.1 million, June 30, 2010 – $4.3 million) associated with the development of the Corporation's proved and probable reserves were added to the Corporation's net book value in the depletion and depreciation calculation. Manitok capitalized cash and non-cash administrative costs directly attributable to P&NG properties and equipment of $267,996 in the nine months ended September 30, 2011 (September 30, 2010 – $101,980)

In August 2010, the Corporation disposed of oil and gas assets in the Garrington area of Alberta for gross proceeds of $1.8 million. The Corporation recorded a gain of $1.6 million on the disposition during the fiscal year ended December 31, 2010.

In September 2009, the Government of Alberta approved a drilling royalty incentive for new conventional oil and natural gas wells drilled on or after April 1, 2009, but before April 1, 2011. Included as a reduction of P&NG assets at September 30, 2011 is a recovery of $222,820 (December 31, 2010 – $103,896, June 30, 2010 – $NIL) related to the Alberta Drilling Royalty Credit Program.

07 IMPAIRMENT

As a result of decreasing natural gas prices and well performance in certain CGUs, Manitok recognized a $370,673 impairment charge on its July 1, 2009 transition date to IFRS, a $1,887,732 impairment charge for the twelve month period ended June 30, 2010 and a $342,479 impairment charge for the six month period ended December 31, 2010, which were recorded as additional depletion and depreciation expense. The impairments were based on the difference between the period end net book value of the assets and the recoverable amount. The recoverable amount was determined using fair value less costs to sell, based on discounted cash flows of proved plus probable reserves using forecast prices and costs and a discount rate of 10%.

Approximately $1.5 million of the total impairment charges of $2.6 million related to an asset in the Garrington area of Alberta creating a recoverable amount of $0.2 million. In August 2010, the Garrington property sold for gross proceeds $1.8 million creating a $1.6 million gain on the disposition of assets during the six month fiscal period ended December 31, 2010.

08 REVOLVING CREDIT FACILITY

On August 22, 2011, the Corporation amended its agreement with a major Canadian lender to increase its demand revolving credit facility from $2.5 million to $5.0 million. The revolving credit facility allows for loans in Canadian dollars which bear interest at the prime lending rate plus 1.0% or bankers' acceptance rates which are subject to stamping fees of 2.50%. Standby fees are charged on the undrawn facility at 0.35%.

The facility is subject to a review by the lender at any time in its sole discretion, and at least annually and any change in or redetermination of the borrowing base limit which results in a borrowing base shortfall must be eliminated by the Corporation. The next annual review date has been set for May 31, 2012, but may be set at an earlier or later date at the sole discretion of the lender. The revolving credit facility is secured by a general security agreement encompassing all of the Corporation's assets.

At September 30, 2011, the Corporation had drawn $NIL (December 31, 2010 – $NIL, June 30, 2010 - $1,040,105) on the credit facility.

09 DECOMMISSIONING OBLIGATIONS

The Corporation's decommissioning obligations result from net ownership interests in petroleum and natural gas properties and equipment including well sites and gathering systems. Manitok estimates the total undiscounted amount of cash flows required to settle its decommissioning obligations as at September 30, 2011 to be approximately $2.9 million (December 31, 2010 – $2.4 million, June 30, 2010 – $1.5 million) with the majority of costs expected to be incurred between 2020 and 2030. A risk-free discount rate of 2.77% (December 31, 2010 – 3.52%, June 30, 2010 – 3.65%) and an inflation rate of 2% (December 31, 2010 – 2%, June 30, 2010 – 2%) were used to calculate the fair value of the decommissioning obligation.

A reconciliation of the decommissioning obligations is provided below:

As at ($)	**September 30, 2011**	December 31, 2010	June 30, 2010
Opening Balance	**1,617,855**	1,079,290	1,363,845
Obligations incurred	**388,380**	601,320	–
Obligations acquired (disposed), net	–	(36,220)	(32,790)
Actual expenditures	**(1,069)**	(53,945)	–
Changes in estimates	**155,250**	8,960	(301,784)
Accretion expense	**44,830**	18,450	50,019
Ending Balance	**2,205,246**	**1,617,855**	**1,079,290**

(expressed in Canadian dollars, unless otherwise stated)

10 SHARE CAPITAL

(a) Authorized:

- Unlimited number of voting common shares
- Unlimited number of preferred shares issuable in series, with rights and privileges to be designated by the board of directors at the time of issuance

(b) Issued and outstanding:

	Number of common shares	Amount $
MEX balance, July 1, 2009	**8,176,826**	**15,153,859**
Issued, net of costs (note 10c)	176,956	191,289
Issued, net of costs (note 10d)	1,058,785	1,144,518
Issued, net of costs (note 10e)	1,237,000	1,342,640
Tax effect of share issue costs (note 10f)	–	22,450
Tax effect of share issue costs (note 10g)	–	20,849
MEX balance, June 30, 2010	**10,649,567**	**17,875,605**
Issued, net of costs (note 10h)	4,311,700	4,513,474
Issued, net of costs (note 10i)	3,846,000	3,974,209
Tax effect of share issue costs (note 10j)	–	223,418
MEX balance, July 8, 2010 (prior to the Amalgamation)	**18,807,267**	**26,586,706**
Issuance on the Amalgamation, net of costs (note 10k)	2,625,000	157,131
Tax effect of costs of the Amalgamation (note 10l)	–	55,879
Conversion of MEX shareholders on the Amalgamation (note 10m)	(4,701,807)	–
Manitok balance, September 30, 2010	**16,730,460**	**26,799,716**
Issued, net of costs (note 10n)	10,031,500	9,287,967
Issued, net of costs (note 10o)	6,618,559	6,054,408
Share redemption (note 10p)	(119,268)	(149,086)
Issued, net of costs (note 10q)	325,400	301,282
Issued, net of costs (note 10r)	110,130	100,742
Tax effect of share issue costs (note 10s)	–	335,269
Manitok balance, December 31, 2010	**33,696,781**	**42,730,298**
Issued net of costs (note 10t)	17,968,750	26,651,136
Tax effect of share issue costs (note 10u)	–	524,716
Manitok balance, September 30, 2011	**51,665,531**	**69,906,150**

(c) On December 31, 2009, MEX issued a private placement of 176,956 Class "A" common shares of MEX ("**MEX Shares**") (equivalent to 132,717 common shares of Manitok ("**Manitok Shares**")) at a price of $1.15 per MEX Share (equivalent to $1.53 per Manitok Share) for total net proceeds of $191,289.

(d) On December 31, 2009, MEX issued a private placement of 1,058,785 MEX Shares on a "flow-through" basis under the *Income Tax Act* (Canada) ("**MEX Flow-through Shares**") (equivalent to 794,089 Manitok Shares issued on a "flow-through" basis under the *Income Tax Act* (Canada) ("**Manitok Flow-through Shares**")) at a price of $1.30 per MEX Flow-through Share (equivalent to $1.73 per Manitok Flow-through Share) for total net proceeds of $1,303,336. As at December 31, 2010 the Corporation had incurred the entire $1,376,421 in renounced exploration expenditures. In accordance with IFRS, the amount recorded to share capital from the issuance of MEX Flow-through Shares reflects the fair market value of MEX Shares, which was $1.15 per MEX Share less share issue costs. The difference between the total value of the MEX Flow-through Shares and the fair market value of MEX Shares ("**Premium**") of $158,818 was initially accrued as a deferred obligation when the flow-through shares were issued, and reversed upon the renunciation of the expenditures to the subscribers.

(e) On February 12, 2010, MEX issued a private placement of 1,237,000 MEX Shares (equivalent to 927,750 Manitok Shares) at a price of $1.15 per MEX Share (equivalent to $1.53 per Manitok Share) for total net proceeds of $1,342,640.

(f) MEX recognized a future income tax benefit of $22,450 in respect of share issue costs of $85,295 incurred on the issuance of 176,956 MEX Shares and 1,058,785 MEX Flow-through Shares on December 31, 2009.

(g) MEX recognized a future income tax benefit of $20,849 in respect of share issue costs of $79,911 incurred on the issuance of 1,237,000 MEX shares on February 12, 2010.

(h) On July 8, 2010, immediately prior to the Amalgamation, MEX issued a private placement of 4,311,700 MEX Shares (equivalent to 3,233,775 Manitok Shares) at a price of $1.15 per MEX Share (equivalent to $1.53 per Manitok Share) for total net proceeds of $4,513,474.

(i) On July 8, 2010, immediately prior to the Amalgamation, MEX issued a private placement of 3,846,000 MEX Flow-through Shares (equivalent to 2,884,500 Manitok Flow-through Shares) at a price of $1.30 per MEX Flow-through Share (equivalent to $1.73 per Manitok Flow-through Share) for total net proceeds of $4,551,109. The Corporation has until December 31, 2011 to incur the $4,999,800 in exploration expenditures. In accordance with IFRS, the amount recorded to share capital from the issuance of MEX Flow-through Shares reflects the fair market value of MEX Shares, which was $1.15 per MEX Share less share issue costs. The Premium of $576,900 was initially accrued as a deferred obligation when the flow-through shares were issued, and reversed upon the renunciation of the expenditures to the subscribers.

(j) MEX recognized a future income tax benefit of $223,418 in respect of share issue costs of $893,673 incurred on the issuance of 4,311,700 MEX Shares and 3,846,000 MEX Flow-through Shares on July 8, 2010.

(k) On the Amalgamation each Desco shareholder received 0.375 of a Manitok Share for every one Desco share held on July 8, 2010. As of the Amalgamation date, Desco had 7,000,000 common shares issued and outstanding with $157,131 in total net identifiable assets distributed to Manitok, net of costs incurred with respect to the Amalgamation.

(l) Manitok recognized a future income tax benefit of $55,879 in respect of $298,022 in costs incurred with respect to the Amalgamation.

(m) On the Amalgamation each MEX shareholder received 0.75 of a Manitok Share for every one MEX share held on July 8, 2010. As of the Amalgamation date, MEX had 18,807,267 MEX Shares issued and outstanding.

(n) On December 22, 2010, Manitok issued the first tranche of a private placement of 10,031,500 Manitok Shares at a price of $1.00 per Manitok Share for total net proceeds of $9,287,967.

(o) On December 22, 2010, Manitok issued the first tranche of a private placement of 6,618,559 Manitok Flow-through Shares at a price of $1.15 per Manitok Flow-through Share for total net proceeds of $7,047,192. The Corporation has until December 31, 2011 to incur the $7,611,343 in exploration expenditures. In accordance with IFRS, the amount recorded to share capital from the issuance of Manitok Flow-through Shares reflects the fair market value Manitok Shares, which was $1.00 per Manitok Share less share issue costs. The Premium of $992,784 was initially accrued as a deferred obligation when the flow-through shares were issued, and reversed upon the renunciation of the expenditures to the subscribers.

(p) On December 23, 2010, Manitok purchased for cancellation 119,268 Manitok Shares at a price of $1.00 per Manitok Share pursuant to an arrangement with a previous employee of the Corporation. The excess of the book value of share capital over the purchase price of $29,817 has been charged to contributed surplus.

(q) On December 30, 2010, Manitok issued the second and final tranche of a private placement of 325,400 Manitok Shares at a price of $1.00 per Manitok Share for total net proceeds of $301,282 respectively.

(expressed in Canadian dollars, unless otherwise stated)

(r) On December 30, 2010, Manitok issued the second and final tranche of a private placement of 110,130 Manitok Flow-through Shares at a price of $1.15 per Manitok Flow-through Share for total net proceeds of $117,262. The Corporation has until December 31, 2011 to incur the $126,650 in exploration expenditures. In accordance with IFRS, the amount recorded to share capital from the issuance of Manitok Flow-through Shares reflects the fair market value of Manitok Shares, which was $1.00 per Manitok Share less share issue costs. The Premium of $16,520 was initially accrued as a deferred obligation when the flow-through shares were issued, and reversed upon the renunciation of expenditures to the subscribers.

(s) Manitok recognized a future income tax benefit of $335,269 in respect of share issue costs of $1,341,190 incurred with respect to the issuance of 10,031,500 Manitok Shares and 6,618,559 Manitok Flow-through Shares on December 22, 2010 and the issuance of 325,400 Manitok Shares and 110,130 Manitok Flow-through Shares on December 30, 2010.

(t) On April 14, 2011, Manitok closed an equity financing completed by way of a short form prospectus, for the issuance of 17,968,750 Manitok Shares at a price of $1.60 per Manitok Share for net proceeds of $26,651,136.

(u) Manitok recognized a future income tax benefit of $524,716 in respect of share issue costs of $2,098,864 incurred with respect to the issuance of 17,968,750 Manitok Shares on April 14, 2011.

11 OPERATING EXPENSES

The Corporation's operating expenses include all costs with respect to day-to-day well and facility operations. The components of operating expenses are as follows:

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
Field operating costs	**462,884**	326,003	**1,413,535**	848,702
Expensed workovers	**–**	–	**29,469**	–
Total operating expenses	**462,884**	326,003	**1,443,004**	848,702

12 ADMINISTRATIVE EXPENSES

The components of administrative expenses are as follows:

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
Cash:				
Salaries and benefits(1)	**487,020**	305,766	**1,259,665**	802,437
Other	**444,474**	211,304	**1,009,201**	438,946
	931,494	517,070	**2,268,866**	1,241,383
Capitalized overhead(2)	**(169,619)**	(83,192)	**(417,498)**	(137,883)
General and administrative, net	**761,875**	433,878	**1,851,368**	1,103,500
Non-cash:				
Stock-based compensation (note 14)	**322,192**	88,540	**999,351**	22,312
Capitalized stock-based compensation(2)	**(120,192)**	(18,242)	**(295,206)**	(18,242)
Stock-based compensation, net	**202,000**	70,298	**704,145**	4,070
Total administrative expenses, net	**963,875**	504,176	**2,555,513**	1,107,570

(1) Includes salaries and benefits paid to all officers, employees and consultants of the Corporation.

(2) Represents a portion of salaries and benefits and stock-based compensation that are directly attributable to the exploration and development activities of the Corporation that have been capitalized.

(expressed in Canadian dollars, unless otherwise stated)

13 FINANCE EXPENSES

The components of finance expenses are as follows:

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
Cash:				
Interest on revolving credit facility (note 8)	–	768	**27**	5,925
Non-cash:				
Accretion on decommissioning obligations (note 9)	**16,640**	9,770	**44,830**	33,550
Total finance expenses	**16,640**	10,538	**44,857**	39,475

14 STOCK-BASED COMPENSATION

Stock Options

The Corporation established an Incentive Stock Option Plan (the "**Plan**") on June 25, 2010 whereby directors, officers, employees and key consultants may be granted options to purchase Manitok Shares at a fixed price not less than the fair market value of the stock at the time of grant, subject to certain conditions. Stock options granted under this Plan vest over a three year period at the rate of one-third on each anniversary date of the stock option grant. All stock options granted are for a five year term. Each stock option entitles the holder to purchase one Manitok Share at the exercise price. The Corporation is authorized to issue stock options to a maximum of 10% of the issued and outstanding Manitok Shares pursuant to the Plan.

At September 30, 2011, the Corporation's Plan permitted the grant of options to a maximum of 5,166,553 Manitok Shares. At September 30, 2011, there remained available for issuance stock options in respect of 1,939,053 Manitok Shares.

A summary of the Corporation's outstanding stock options as at September 30, 2011 is presented below:

	Number	Weighted Average Exercise Price ($)
MEX balance, July 1, 2009	**702,500**	**2.09**
Granted	–	–
Cancelled or forfeited	–	–
MEX balance, June 30, 2010	**702,500**	**2.09**
Granted	1,638,500	1.10
Cancelled or forfeited[1]	(702,500)	(2.09)
Manitok balance, December 31, 2010	**1,638,500**	**1.10**
Granted	1,624,000	1.28
Cancelled or forfeited	(35,000)	1.10
Manitok balance, September 30, 2011	**3,227,500**	**1.19**

(1) Pursuant to the Amalgamation, 702,500 of MEX's unexercised stock options have been terminated and cancelled for nominal consideration on July 8, 2010.

(expressed in Canadian dollars, unless otherwise stated)

The range of exercise prices for stock options outstanding and exercisable under the plan at September 30, 2011 is as follows:

Exercise Prices		Awards Outstanding			Awards Exercisable		
Low	High	Quantity	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Quantity	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price
$1.10	$1.78	3,227,500	4.1	$1.19	517,833	3.9	$1.10
		3,227,500	**4.1**	**$1.19**	**517,833**	**3.9**	**$1.10**

Stock-Based Compensation Expense

In order to calculate the compensation expense, the fair value of the stock options are estimated using the Black-Scholes option-pricing model that takes into account, as of the grant date: exercise price, expected life, current share price, expected volatility, expected dividends, and risk-free interest rates.

During the three and nine months ended September 30, 2011, the Corporation recorded $202,000 and $704,145 (September 30, 2010 – $70,298 and $4,070) of stock-based compensation expense, net of $120,192 and $295,206 (September 30, 2010 – $18,242 and $18,242) in capitalized amounts directly attributable to the exploration and development activities of the Corporation. In determining the stock-based compensation expense, the Corporation applied a weighted average estimated forfeiture rate of 2.0% and 1.1% for vesting option tranches during the three and nine months ended September 30, 2011 (September 30, 2010 – 0.7% and 0.7%).

The fair value of each option granted in the period is estimated using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
Weighted average fair value of options granted	**$0.84**	$0.75	**$0.85**	$0.75
Risk-free interest rate	**1.28%**	2.10%	**2.12%**	2.10%
Expected life (years)	**3.9**	4.5	**4.3**	4.5
Expected volatility	**91.0%**	90.3%	**90.2%**	90.3%
Expected dividends	**0.0%**	0.0%	**0.0%**	0.0%

15 PER SHARE INFORMATION

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
Weighted average shares outstanding – basic	**51,665,531**	16,267,784	**44,886,113**	12,352,578
Weighted average shares outstanding – diluted	**51,665,531**	16,314,887	**44,886,113**	12,352,578

As the Corporation reported a loss for the three and nine month periods ended September 30, 2011 and the nine month period ended September 30, 2010, the basic and diluted weighted average shares outstanding are the same for these periods.

16 CAPITAL MANAGEMENT

The Corporation's general policy is to maintain a sufficient capital base in order to manage its business in the most effective manner with the goal of increasing the value of its assets and thus its underlying share value. The Corporation's objectives when managing capital are to maintain financial flexibility in order to preserve its ability to meet financial obligations; to maintain a capital structure that allows Manitok the ability to finance its growth strategy using internally-generated cash flow and its available debt capacity; and to optimize the use of its capital to provide an appropriate investment return to its shareholders.

(expressed in Canadian dollars, unless otherwise stated)

Manitok strives to properly exploit its current asset base and to acquire top quality assets. As such, the Corporation is not averse to maintaining a higher ratio of debt to total capital if management determines the assets it is acquiring or the projects it is drilling are of high quality. However, the Corporation manages its capital structure and makes adjustments considering changes in economic conditions and the risk characteristics of the assets. In order to maintain or adjust the capital structure, Manitok may issue new shares or debt, increase the credit facility limits, or adjust its capital spending to manage current and projected debt levels. Management expects to be able to continue to raise equity and obtain debt financing sufficient to meet both its short-term and long-term growth requirements in the current environment.

There were no changes in the Corporation's approach to capital management during the September 30, 2011 reporting period. The capital structure of the Corporation is as follows:

As at ($)	September 30, 2011	December 31, 2010	June 30, 2010
Total shareholders' equity(1)	**62,703,143**	37,390,205	12,824,435
Total shareholders' equity as a % of total capital	**100%**	100%	94%
Working capital deficiency (surplus)(2)	**(27,635,269)**	(19,780,030)	(202,985)
Revolving credit facility	**–**	–	1,040,105
Total net debt(2)	**–**	–	837,120
Total net debt as a % of total capital	**0%**	0%	6%
Total Capital	**62,703,143**	37,390,205	13,661,555

(1) Shareholders' equity is defined as share capital plus contributed surplus plus retained earnings (deficit).

(2) Working capital deficiency (surplus) is defined as current assets less current liabilities excluding the current portion of the amount drawn on the revolving credit facility. Working capital (surplus) is only included in total net debt if the Corporation is in a net debt position.

During the period ended September 30, 2011, the increase in total shareholders' equity was due mainly to the equity financing of 17,968,750 Manitok Shares at a price of $1.60 per Manitok Share for net proceeds of approximately $26.7 million.

The Corporation's lender requires quarterly compliance that the "working capital ratio" (current assets plus any undrawn portion of the facility divided by current liabilities excluding any current portion of an amount drawn on the credit facility) is not less than the required ratio of 1:1. Manitok was in compliance with the financial covenant as at September 30, 2011, December 31, 2010 and June 30, 2010.

17 FINANCIAL INSTRUMENTS & RISK MANAGEMENT

Manitok is exposed to credit risk, liquidity risk and market risk as part of its normal course of business. The Board of Directors has overall responsibility for the establishment and oversight of the Corporation's financial risk management framework and periodically reviews risk management activities and all outstanding positions, if any. Management identifies and analyzes the risks faced by the Corporation, monitors risks and market conditions and the Corporation's activities.

Credit Risk

Cash and cash equivalents consist of bank balances, but may also include short term investments. Counter-parties for the short term investments will be selected based on credit ratings and management will monitor all investments to ensure a stable return, and complex investment vehicles with higher risk will be avoided. The Corporation's exposure to cash credit risk at the balance sheet date is very low.

Credit risk is the risk of financial loss to the Corporation if a customer fails to meet its contractual obligations. A substantial portion of the Corporation's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks. The carrying amount of accounts receivable reflects management's assessment of the maximum credit risk associated with these customers.

(expressed in Canadian dollars, unless otherwise stated)

The following table illustrates the Corporation's maximum exposure for receivables:

As at ($)	September 30, 2011	December 31, 2010	June 30, 2010
Marketers	**805,032**	510,002	425,815
Joint venture partners	**31,593**	397,906	122,918
Other	**303,722**	346,581	27,087
Total Receivables	**1,140,347**	1,254,489	575,820

At September 30, 2011, approximately 70% of the Corporation's significant individual accounts receivable was due from two marketers (December 31, 2010 – 41% from two marketers, June 30, 2010 - 39% from two marketers). For the period ended September 30, 2011, the Corporation received the majority of its revenue from two marketers which accounted for approximately 99% of its revenue (December 31, 2010 – 99% from two marketers, June 30, 2010 – 98% from two marketers). Receivables from marketers are normally collected on the 25th day of the month following production. Manitok mitigates the credit risk associated with these balances by establishing relationships with credit worthy companies. The Corporation historically has not experienced any material collection issues with its marketers.

Manitok attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the commencement of the joint venture project. However, joint venture receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risks exist with joint venture partners as disagreements arise that increase the potential for non-collection. The Corporation's accounts receivables are aged as follows:

As at ($)	September 30, 2011	December 31, 2010	June 30, 2010
Current (less than 30 days)	**1,104,436**	1,148,610	445,422
30 to 60 days	–	36,871	5,766
61 to 90 days	–	5,766	3,771
Over 90 days	**35,911**	63,242	120,861
Total Receivables	**1,140,347**	1,254,489	575,820

At September 30, 2011, approximately 3% of Manitok's total accounts receivable are aged over 90 days and considered past due.

Should Manitok determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to income or loss. If the Corporation subsequently determines an account is uncollectible, the account is written off with a corresponding charge to allowance for doubtful accounts. At September 30, 2011, Manitok's allowance for doubtful accounts balance was $NIL (December 31, 2010 – $NIL, June 30, 2010 - $NIL).

Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities that are settled by cash as they become due. Manitok's approach to managing liquidity risk is to ensure, as much as possible, that it will have sufficient liquidity to meet its short-term and long-term financial obligations when due, under both normal and unusual conditions without incurring unacceptable losses or risking harm to the Corporation's reputation.

All of the Corporation's contractual financial liabilities at September 30, 2011 are to be settled in cash. Manitok utilizes prudent cash and debt management to mitigate the likelihood of encountering difficulties in meeting its financial obligations. The Corporation also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

Typically, the Corporation ensures that it has sufficient cash on demand to meet expected operational expenses, including the servicing of financial obligations. To achieve this objective, the Corporation prepares annual capital expenditure budgets, which are approved by the Board of Directors and are reviewed and updated as considered necessary. Petroleum and natural gas production is monitored regularly and used to provide monthly current cash flow estimates. Also, Manitok utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures.

To facilitate the capital expenditure program, the Corporation has a reserve-based revolving credit facility, as disclosed in note 8, which is reviewed at least annually by the lender. At September 30, 2011, $5,000,000 (December 31, 2010 – $2,500,000, June 30, 2010 – $1,459,895) in unused credit was available to fund future obligations.

The following table lists the contractual obligations of the Corporation's financial liabilities as at September 30, 2011:

$	< 1 Year	1-2 Years	2-5 Years	Thereafter
Accounts payable and accrued liabilities	3,506,217	–	–	–
Drawn revolving credit facility (1)	–	–	–	–
Total Financial Liabilities	**3,506,217**	**–**	**–**	**–**

(1) The revolving credit facility bears interest at a floating rate.

Market Risk

Market risk is the risk that changes in market conditions, such as commodity prices, exchange rates and interest rates, will affect the Corporation's net income or the value of its financial instruments, if any. The objective of market risk management is to manage and control exposures within acceptable limits, while maximizing returns. These risks are consistent with prior years. All risk management transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in market commodity prices. A significant change in commodity prices can materially impact the Corporation's borrowing base under its revolving credit facility and may reduce the Corporation's ability to raise capital. Commodity prices for crude oil and natural gas are not only impacted by demand in Canada and the United States ("**U.S.**"), but also by world economic events that dictate the levels of supply and demand.

From time to time, the Corporation may attempt to mitigate commodity price risk through the use of financial derivatives. Manitok did not have any price risk management contracts in place as at or during the periods ended September 30, 2011, December 31, 2010 and June 30, 2010. The Corporation actively monitors the market to determine whether commodity price risk contacts are warranted.

Foreign Currency Risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Crude oil and to a certain extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of the Corporation's expenses are denominated in Canadian dollars. The exchange rate effect cannot be quantified, but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by Manitok for its petroleum and natural gas sales.

When appropriate, Manitok may enter into agreements to fix the exchange rate of Canadian dollars to U.S. dollars to manage the risk. The Corporation did not have any forward exchange rate contracts in place as at or during the periods ended September 30, 2011, December 31, 2010 and June 30, 2010.

Interest Rate Risk

Interest rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in market interest rates. The Corporation's credit facilities are exposed to interest rate cash flow risk on a floating interest rate due to fluctuations in market interest rates. The remainder of Manitok's financial assets and liabilities are not exposed to interest rate risk.

A 1% change in the Canadian interest rates in the three and nine month periods ended September 30, 2011 and 2010 would have resulted in an insignificant change in net income, due to a limited amount of outstanding debt in the periods, assuming that all other variables remain constant. A sensitivity of 1% is considered reasonable given the current level of interest rates and market expectations for future movements. The Corporation considers this risk to be limited and thus did not have any interest rate swaps or financial contracts in place as at or during the periods ended September 30, 2011, December 31, 2010 and June 30, 2010.

(expressed in Canadian dollars, unless otherwise stated)

Fair Value of Financial Instruments

Manitok's financial instruments include cash and cash equivalents, accounts receivable, deposits, accounts payable and accrued liabilities and the outstanding credit facility on the balance sheet.

The carrying value and fair value of these financial instruments at September 30, 2011 is disclosed below by financial instrument category, as well as any related loss or interest expense for the period:

$	Carrying Value	Fair Value	Loss	Interest Expense
Assets Held for Trading				
Cash and cash equivalents(1)	25,013,123	25,013,123	–	–
Loans and Receivables				
Accounts receivable(2)	1,140,347	1,140,347	–	–
Deposits (2) (3)	4,750,113	4,750,113	–	–
Other Liabilities				
Accounts payable and accrued liabilities(2)	3,506,217	3,506,217	–	–
Revolving credit facility(4)	–	–	–	27

(1) Cash and cash equivalents are reported at fair value, based on a Level 1 designation as identified in note 3j.

(2) Accounts receivable, deposits and accounts payable and accrued liabilities are reported at amortized cost. Due to the short term nature of accounts receivable, deposits and accounts payable and accrued liabilities, their carrying values approximate their fair values.

(3) Includes a deposit of $4.25 million related to the acquisition as disclosed in note 20a.

(4) The Corporation's revolving credit facility bears interest at a floating rate and accordingly the fair market value approximates the carrying value.

18 COMMITMENTS

The Corporation is committed to incur exploration expenditures of $4,999,800 on or before December 31, 2011, related to the Manitok Flow-through Share issuance completed on July 8, 2010, as indicated in note 10i. Manitok will be subject to Part XII.6 tax based on the prescribed rate on the balance of exploration expenditures not yet incurred at the end of each month subsequent to January 31, 2011. As at September 30, 2011, the Corporation had satisfied its obligation.

The Corporation is committed to incur exploration expenditures of $7,737,993 on or before December 31, 2011, related to the Manitok Flow-through Share issuance completed on December 22, 2010 and December 30, 2010, as indicated in note 10o and 10r. Manitok will be subject to Part XII.6 tax based on the prescribed rate on the balance of exploration expenditures not yet incurred at the end of each month subsequent to January 31, 2011. As at September 30, 2011, the costs incurred for exploration expenditures were approximately $1.2 million leaving about $6.5 million to be spent on or before December 31, 2011.

On February 17, 2010, Manitok committed to an operating lease relating to its office premises beginning May 1, 2010 which expires on June 30, 2015. Under this commitment the Corporation will pay a monthly rate of approximately $25,220, excluding occupancy costs, until the lease expires. The Corporation is committed to the following aggregate minimum lease payments:

Year	$
2011	75,660
2012	302,640
2013	302,640
2014	302,640
2015	126,100

(expressed in Canadian dollars, unless otherwise stated)

19 SUPPLEMENTARY CASH FLOW INFORMATION

The following table details the components of non-cash working capital:

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
Provided by (used in):				
Accounts receivable	**333,736**	221,704	**114,141**	67,923
Deposits and prepaid expenses	**(4,712,566)**	(35,990)	**(4,613,862)**	(83,250)
Accounts payable and accrued liabilities	**2,230,143**	1,837,072	**(73,139)**	2,047,395
	(2,148,687)	2,022,786	**(4,572,860)**	2,032,068
Provided by (used in):				
Operating activities	**39,444**	189,707	**(265,634)**	310,742
Investing activities	**(2,188,131)**	1,833,079	**(4,307,226)**	1,721,326
	(2,148,687)	2,022,786	**(4,572,860)**	2,032,068

20 SUBSEQUENT EVENTS

(a) On October 31, 2011, the Corporation closed an acquisition of oil and natural gas assets in the central Alberta foothills area, with an effective date of July 1, 2011, for total cash consideration of approximately $41.7 million (before post-closing adjustments and acquisition-related expenses). The consideration paid by Manitok for the assets was financed by existing cash balances and bank debt. Concurrent with the closing of the acquisition, the Corporation's credit facility, as disclosed in note 8, was increased from $5 million to $30 million.

(b) Effective November 15, 2011, the Corporation entered into an underwriting agreement with a syndicate of underwriters led by RBC Capital Markets (the "**Underwriters**"), pursuant to which the Underwriters have agreed to purchase, on a "bought deal" basis 6,500,000 Manitok Shares and 3,635,000 Manitok Flow-through Shares at a price of $1.85 per Manitok Share and $2.20 per Manitok Flow-through Share for aggregate gross proceeds of approximately $20 million pursuant to a short form prospectus (the "**Offering**"). Under the Offering, Manitok has agreed to grant the Underwriters an option to purchase an additional 15% of the number of Manitok Shares issuable under the Offering to cover over-allotments, if any. The net proceeds from the issuance of Manitok Shares will be used to repay the outstanding indebtedness under its revolving credit facility and the net proceeds from the issuance of Manitok Flow-through Shares will be used to incur qualifying expenditures on or before December 31, 2012. The Offering is scheduled to close on or about December 5, 2011 and is subject to certain conditions including, but not limited to, the receipt of all necessary approvals including the approval of the TSX-V. The preliminary prospectus was filed with the securities regulatory authorities in each of the provinces of Canada, other than Quebec, on November 21, 2011.

21 TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

The adoption of IFRS requires the application of IFRS 1 – *First-time Adoption of IFRS*. IFRS 1 generally requires that an entity retrospectively apply all IFRS accounting policies effective at the end of its first reporting period, however IFRS 1 provides certain mandatory exceptions and permits limited optional exemptions. Certain IFRS 1 optional exemptions have been applied including:

- Deemed cost exemption for full cost oil and gas entities whereby exploration and evaluation assets were classified from the full cost pool at the amount that was recorded under previous Canadian GAAP and the remaining full cost pool was allocated to the developing and producing assets on a pro-rata basis using proved plus probable reserves values.
- Decommissioning obligation exemption that allows any changes in decommissioning obligations on transition to IFRS to be adjusted through opening retained earnings (deficit).
- Stock-based compensation exemption that allows a company to only evaluate share-based compensation awards that were unvested as of the date of transition and issued subsequent to November 7, 2002.
- Business combinations exemption that allows a company to not restate any business combinations that occurred prior to the date of transition.

In 2010, Manitok changed its fiscal year end from June 30 to December 31, which created a six month transitional year ended December 31, 2010. As such, in accordance with National Instrument 52-107 and part 2.9 of Companion Policy 52-107CP, *Acceptable Accounting Principles and Auditing Standards*, the IFRS adoption date of January 1, 2011 required the restatement, for comparative purposes, of amounts reported by Manitok for the periods ended from September 30, 2009 to December 31, 2010, and an opening Statement of Financial Position as at July 1, 2009.

IFRS 1 requires the presentation of comparative information as at the transition date and subsequent comparative periods as well as the consistent and retrospective application of IFRS accounting policies. The IFRS accounting polices set forth in note 3 have been applied in preparing the condensed financial statements as at and for the three and nine months ended September 30, 2011, and comparative financial statements as at and for the three and nine months ended September 30, 2010, as at and for the six month transitional year ended December 31, 2010, as at and for the twelve months ended June 30, 2010 and an opening Statement of Financial Position as at July 1, 2009 ("**transition date**"). In preparing the 2009 and 2010 comparative financial statements, the Corporation adjusted amounts previously reported in financial statements prepared in accordance with Canadian GAAP.

An explanation of how the transition from Canadian GAAP to IFRS has affected the Corporation's financial position and financial performance is illustrated in the following reconciliation tables and the notes following the tables. Certain amounts in these financial statement reconciliations have been reclassified, where applicable, to conform to IAS 1, *Presentation of Financial Statements*.

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Financial Position as at July 1, 2009 – date of transition to IFRS:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
ASSETS				
Current assets:				
Cash and cash equivalents	70,765	–		70,765
Accounts receivable	287,595	–		287,595
Deposits and prepaid expenses	291,562	–		291,562
	649,922	–		649,922
Non-current assets:				
Exploration and evaluation assets	–	500,863	A	500,863
Petroleum and natural gas properties and equipment	15,909,155	(871,535)	A	15,037,620
	15,909,155	(370,672)		15,538,483
	16,559,077	(370,672)		16,188,405
LIABILITIES				
Current liabilities:				
Accounts payables and accrued liabilities	479,066	–		479,066
Revolving credit facility	615,769	–		615,769
	1,094,835	–		1,094,835
Non-current liabilities:				
Decommissioning obligations	1,010,190	353,655	B	1,363,845
Deferred income taxes	1,156,880	(190,591)	B,H	966,289
	2,167,070	163,064		2,330,134
	3,261,905	163,064		3,424,969
SHAREHOLDERS' EQUITY				
Share capital	14,436,550	717,309	G	15,153,859
Contributed surplus	458,861	16,809	C	475,670
Retained earnings (deficit)	(1,598,239)	(1,267,854)		(2,866,093)
	13,297,172	(533,736)		12,763,436
	16,559,077	(370,672)		16,188,405

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Financial Position as at June 30, 2010:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
ASSETS				
Current assets:				
Cash and cash equivalents	70,648	–		70,648
Accounts receivable	575,820	–		575,820
Deposits and prepaid expenses	335,631	–		335,631
	982,099	–		982,099
Non-current assets:				
Deferred financing fees	327,947			327,947
Exploration and evaluation assets	–	2,987,434	A	2,987,434
Petroleum and natural gas properties and equipment	16,281,462	(4,452,680)	A,B,D,E,F	11,828,782
	16,609,409	(1,465,246)		15,144,163
	17,591,508	(1,465,246)		16,126,262
LIABILITIES				
Current liabilities:				
Accounts payables and accrued liabilities	779,114	–		779,114
Revolving credit facility	1,040,105	–		1,040,105
	1,819,219	–		1,819,219
Non-current liabilities:				
Decommissioning obligations	790,780	288,510	B	1,079,290
Deferred income taxes	891,519	(488,201)	H	403,318
	1,682,299	(199,691)		1,482,608
	3,501,518	(199,691)		3,301,827
SHAREHOLDERS' EQUITY				
Share capital	16,954,840	920,765	G	17,875,605
Contributed surplus	514,390	(19,837)	C	494,553
Retained earnings (deficit)	(3,379,240)	(2,166,483)		(5,545,723)
	14,089,990	(1,265,555)		12,824,435
	17,591,508	(1,465,246)		16,126,262

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Financial Position as at September 30, 2010:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
ASSETS				
Current assets:				
Cash and cash equivalents	8,549,746	–		8,549,746
Accounts receivable	359,449	–		359,449
Deposits and prepaid expenses	371,621	–		371,621
	9,280,816	–		9,280,816
Non-current assets:				
Exploration and evaluation assets	–	4,648,157	A	4,648,157
Petroleum and natural gas properties and equipment	17,715,495	(4,223,264)	A,B,D,E,F	13,492,231
	17,715,495	424,893		18,140,388
	26,996,311	424,893		27,421,204
LIABILITIES				
Current liabilities:				
Accounts payables and accrued liabilities	2,621,520	–		2,621,520
	2,621,520	–		2,621,520
Non-current liabilities:				
Flow-through share premium	–	576,900		576,900
Decommissioning obligations	959,080	384,520	B	1,343,600
Deferred income taxes	356,014	886	H	356,900
	1,315,094	962,306		2,277,400
	3,936,614	962,306		4,898,920
SHAREHOLDERS' EQUITY				
Share capital	26,455,850	343,866	G	26,799,716
Contributed surplus	602,930	(19,837)	C	583,093
Retained earnings (deficit)	(3,999,083)	(861,442)		(4,860,525)
	23,059,697	(537,413)		22,522,284
	26,996,311	424,893		27,421,204

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Financial Position as at December 31, 2010:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
ASSETS				
Current assets:				
Cash and cash equivalents	21,730,744	–		21,730,744
Accounts receivable	1,254,489	–		1,254,489
Deposits and prepaid expenses	374,154	–		374,154
	23,359,387	–		23,359,387
Non-current assets:				
Exploration and evaluation assets	–	6,487,757	A	6,487,757
Petroleum and natural gas properties and equipment	20,524,904	(5,645,070)	A,B,D,E,F	14,879,834
	20,524,904	842,687		21,367,591
	43,884,291	842,687		44,726,978
LIABILITIES				
Current liabilities:				
Accounts payables and accrued liabilities	3,579,357	–		3,579,357
	3,579,357	–		3,579,357
Non-current liabilities:				
Flow-through share premium	–	1,009,304	G	1,009,304
Decommissioning obligations	1,073,585	544,270	B	1,617,855
Deferred income taxes	1,055,653	74,604	H	1,130,257
	2,129,238	1,628,178		3,757,416
	5,708,595	1,628,178		7,336,773
SHAREHOLDERS' EQUITY				
Share capital	42,145,786	584,512	G	42,730,298
Contributed surplus	817,423	(19,837)	C	797,586
Retained earnings (deficit)	(4,787,513)	(1,350,166)		(6,137,679)
	38,175,696	(785,491)		37,390,205
	43,884,291	842,687		44,726,978

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Net Income (Loss) and Comprehensive Income (Loss) for the three and nine months ended September 30, 2010:

Three months ended September 30, 2010	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
REVENUE				
Petroleum and natural gas	543,805	–		543,805
Royalty expenses	(65,760)	–		(65,760)
Interest and other	14,759	–		14,759
	492,804	–		492,804
EXPENSES				
Operating	326,003	–		326,003
Transportation and marketing	28,299	–		28,299
Administrative, net	605,610	(101,434)	F	504,176
Depletion and depreciation	396,235	(127,956)	E	268,279
Finance	12,708	(2,170)	B	10,538
Loss (gain) on disposition of assets	–	(1,562,568)	D	(1,562,568)
	1,368,855	(1,794,128)		(425,273)
INCOME (LOSS) BEFORE INCOME TAXES	(876,051)	1,794,128		918,077
Deferred income tax expense (recovery)	(256,208)	489,087	H	232,879
TOTAL NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	(619,843)	1,305,041		685,198

Nine months ended September 30, 2010	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
REVENUE				
Petroleum and natural gas	1,939,615	–		1,939,615
Royalty expenses	(296,231)	–		(296,231)
Interest and other	14,906	–		14,906
	1,658,290	–		1,658,290
EXPENSES				
Operating	848,702	–		848,702
Transportation and marketing	93,474	–		93,474
Administrative, net	1,339,438	(231,868)	C,F	1,107,570
Depletion and depreciation	1,391,926	1,399,743	A,E	2,791,669
Finance	52,905	(13,430)	B	39,475
Loss (gain) on disposition of assets	–	(1,562,568)	D	(1,562,568)
	3,726,445	(408,123)		3,318,322
INCOME (LOSS) BEFORE INCOME TAXES	(2,068,155)	408,123		(1,660,032)
Deferred income tax expense (recovery)	(546,114)	282,509	H	(263,605)
TOTAL NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	(1,522,041)	125,614		(1,396,427)

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Net Income (Loss) and Comprehensive Income (Loss) for the twelve month fiscal year ended June 30, 2010:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
REVENUE				
Petroleum and natural gas	2,821,722	–		2,821,722
Royalty expenses	(427,912)	–		(427,912)
Interest and other	555	–		555
	2,394,365	–		2,394,365
EXPENSES				
Operating	1,053,512	–		1,053,512
Transportation and marketing	131,175	–		131,175
Administrative, net	1,389,829	(91,337)	C,F	1,298,492
Depletion and depreciation	2,092,940	1,109,100	A,E	3,202,040
Finance	92,246	(24,981)	B	67,265
	4,759,702	992,782		5,752,484
INCOME (LOSS) BEFORE INCOME TAXES	(2,365,337)	(992,782)		(3,358,119)
Deferred income tax expense (recovery)	(584,336)	(94,153)	H	(678,489)
TOTAL NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	(1,781,001)	(898,629)		(2,679,630)

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Net Income (Loss) and Comprehensive Income (Loss) for the six month transitional year ended December 31, 2010:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
REVENUE				
Petroleum and natural gas	1,303,536	–		1,303,536
Royalty expenses	(133,341)	–		(133,341)
Interest and other	35,599	–		35,599
	1,205,794	–		1,205,794
EXPENSES				
Operating	678,036	–		678,036
Transportation and marketing	58,399	–		58,399
Administrative, net	1,375,630	(219,137)	F	1,156,493
Depletion and depreciation	942,683	36,059	A,E	978,742
Finance	30,569	(11,350)	B	19,219
Loss (gain) on disposition of assets	–	(1,857,745)	D	(1,857,745)
	3,085,317	(2,052,173)		1,033,144
INCOME (LOSS) BEFORE INCOME TAXES	(1,879,523)	2,052,173		172,650
Deferred income tax expense (recovery)	(471,250)	1,235,855	H	764,605
TOTAL NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	(1,408,273)	816,318		(591,955)

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Cash Flow for the nine months ended September 30, 2010:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
Cash provided by (used in):				
OPERATING ACTIVITIES				
Net income (loss)	(1,522,041)	125,614		(1,396,427)
Adjustments for items not affecting operating cash:				
Deferred income tax expense (recovery)	(546,114)	282,509	H	(263,605)
Depletion and depreciation expenses	1,391,926	1,399,743	A,E	2,791,669
Stock-based compensation expenses	98,055	(93,985)	C	4,070
Finance expenses	52,905	(13,430)	B	39,475
Loss (gain) on disposition of assets	–	(1,562,568)	D	(1,562,568)
Interest paid	(5,925)	-		(5,925)
Changes in non-cash operating working capital	310,742	-		310,742
	(220,452)	137,883		(82,569)
FINANCING ACTIVITIES:				
Proceeds from share issuances	11,380,805	–		11,380,805
Share issue costs	(973,583)	–		(973,583)
Cash received from amalgamation	434,571	–		434,571
Cost of amalgamation	(277,441)	–		(277,441)
	10,564,352	–		10,564,352
INVESTING ACTIVITIES:				
Disposition of petroleum and natural gas properties and equipment	1,802,802	–		1,802,802
Exploration and evaluation asset expenditures	–	(3,634,885)	A	(3,634,885)
Petroleum and natural gas properties and equipment expenditures	(5,613,194)	3,497,002	A,F	(2,116,192)
Changes in non-cash investing working capital	1,721,326	–		1,721,326
	(2,089,066)	(137,883)		(2,226,949)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	8,254,834	–		8,254,834
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	294,912	–		294,912
CASH AND CASH EQUIVALENTS, END OF PERIOD	8,549,746	–		8,549,746

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Cash Flow for the twelve month fiscal year ended June 30, 2010:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
Cash provided by (used in)				
OPERATING ACTIVITIES:				
Net income (loss)	(1,781,001)	(898,629)		(2,679,630)
Adjustments for items not affecting operating cash:				
Deferred income tax expense (recovery)	(584,336)	(94,153)	H	(678,489)
Depletion and depreciation expenses	2,092,940	1,109,100	A,E	3,202,040
Stock-based compensation expenses	55,529	(36,646)	C	18,883
Finance expenses	92,246	(24,981)	B	67,265
Interest paid	(17,246)	–		(17,246)
Changes in non-cash operating working capital	269,163	–		269,163
	127,295	54,691		181,986
FINANCING ACTIVITIES:				
Increase (decrease) in revolving credit facility	424,336	–		424,336
Proceeds from share issuances	2,998,232	–		2,998,232
Share issue costs	(259,328)	–		(259,328)
Cost of amalgamation	(229,586)	–		(229,586)
	2,933,654	–		2,933,654
INVESTING ACTIVITIES:				
Disposition of petroleum and natural gas properties and equipment	40,000	–		40,000
Exploration and evaluation asset expenditures	–	(2,486,571)	A	(2,486,571)
Petroleum and natural gas properties and equipment expenditures	(2,799,657)	2,431,880	A,F	(367,777)
Changes in non-cash investing working capital	(301,409)	–		(301,409)
	(3,061,066)	(54,691)		(3,115,757)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(117)	–		(117)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	70,765	–		70,765
CASH AND CASH EQUIVALENTS, END OF PERIOD	70,648	–		70,648

(expressed in Canadian dollars, unless otherwise stated)

Reconciliation of the Statement of Cash Flow for the six month transitional year ended December 31, 2010:

	Canadian GAAP	Effects of transition to IFRS	Notes	IFRS
Cash provided by (used in)				
OPERATING ACTIVITIES:				
Net income (loss)	(1,408,273)	816,318		(591,955)
Adjustments for items not affecting operating cash:				
Deferred income tax expense (recovery)	(471,250)	1,235,855	H	764,605
Depletion and depreciation expenses	942,683	36,059	A,E	978,742
Stock-based compensation expenses	273,216	(60,436)	F	212,780
Finance expenses	30,569	(11,350)	B	19,219
Loss (gain) on disposition of assets	–	(1,857,745)	D	(1,857,745)
Interest paid	(769)	–		(769)
Decommissioning expenditures	(53,945)	–		(53,945)
Changes in non-cash operating working capital	(205,465)	–		(205,465)
	(893,234)	158,701		(734,533)
FINANCING ACTIVITIES:				
Increase (decrease) in revolving credit facility	(1,040,105)	–		(1,040,105)
Proceeds from share issuances	28,053,147	–		28,053,147
Share issue costs	(2,136,052)	–		(2,136,052)
Cash received from amalgamation	434,571	–		434,571
Cost of amalgamation	(48,304)	–		(48,304)
Redemption of common shares	(119,268)	–		(119,268)
	25,143,989	–		25,143,989
INVESTING ACTIVITIES:				
Disposition of petroleum and natural gas properties and equipment	1,799,910	–		1,799,910
Exploration and evaluation asset expenditures	–	(3,500,323)	A	(3,500,323)
Petroleum and natural gas properties and equipment expenditures	(6,679,085)	3,341,622	A,F	(3,337,463)
Changes in non-cash investing working capital	2,288,516	–		2,288,516
	(2,590,659)	(158,701)		(2,749,360)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	21,660,096	–		21,660,096
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	70,648	–		70,648
CASH AND CASH EQUIVALENTS, END OF PERIOD	21,730,744	–		21,730,744

Notes to reconciliations:

The following discussion explains the significant differences between Manitok's Canadian GAAP accounting policies and those applied by the Corporation under IFRS. IFRS policies have been retrospectively and consistently applied except where specific IFRS 1 optional and mandatory exemptions permitted an alternative treatment upon transition to IFRS for first-time adopters. The note captions below correspond to the adjustments presented in the preceding reconciliations.

Hindsight was not used to create or revise estimates and accordingly the estimates previously made by the Corporation under Canadian GAAP are consistent with their application under IFRS.

(A) IFRS 1 deemed cost election for full cost oil and gas reporting entities

The Corporation has elected to use the IFRS 1 exemption, whereby the petroleum and natural gas properties and equipment balance, as determined under Canadian GAAP, is allocated to the IFRS categories of exploration and evaluation assets and developing and producing assets. Under the exemption, for assets in the development and production phases, the amounts were allocated on an area basis to the underlying IFRS transitional assets on a pro-rata basis using proved plus probable reserve values as of the IFRS transition date. Exploration and evaluation assets were recorded at the amounts previously recorded under Canadian GAAP.

Under IFRS, exploration and evaluation assets are those expenditures for an area where technical feasibility and commercial viability has not yet been determined. Developing and producing assets include those expenditures for areas where technical feasibility and commercial viability has been determined and are included in the general balance of petroleum and natural gas properties and equipment.

Exploration and evaluation assets at July 1, 2009 were deemed to be $500,863, representing the unproved properties balance under Canadian GAAP. This resulted in a reclassification of $500,863 from petroleum and natural gas properties and equipment to exploration and evaluation assets as at July 1, 2009. As at December 31, 2010, the Corporation's exploration and evaluation assets totalled $6,487,757 (September 30, 2010 - $4,648,157, June 30, 2010 – $2,987,434). These exploration activities are pending the determination of economic quantities of commercially producible reserves. As such, no costs have been reclassified from exploration and evaluation to petroleum and natural gas properties and equipment during the periods ended December 31, 2010, September 30, 2010 and June 30, 2010.

The Corporation performed an impairment test on its exploration and evaluation assets and petroleum and natural gas properties and equipment in accordance with the accounting policy stated in note 3. The recoverable amount of Manitok's assets were estimated based on the fair value less cost to sell approach using discounted cash flows from proved plus probable reserves, taking into consideration escalated prices and future development costs and a discount rate of 10%, as obtained from the Corporation's independent reserve report. As a result of decreased forward natural gas prices which impacted the fair value less costs to sell derived from the Corporation's reserves, Manitok recognized a $370,672 impairment charge on its July 1, 2009 transition date to IFRS, a $1,887,732 impairment charge for the twelve months ended June 30, 2010 and a $342,479 impairment charge for the six months ended December 31, 2010. This resulted in a reduction of P&NG assets with the offset recorded as additional depletion and depreciation expense.

(B) Decommissioning obligations

The Corporation has elected to measure decommissioning obligations (formerly known as asset retirement obligations under Canadian GAAP) on transition to IFRS in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets* and recognize directly in retained earnings (deficit) the difference between that amount and the carrying amount of those obligations determined under Canadian GAAP at the transition date. Under Canadian GAAP, accretion on decommissioning obligations was included in depletion and depreciation expense. Under IFRS, accretion expense is included in finance expense.

Under Canadian GAAP, decommissioning obligations were discounted at a credit-adjusted risk-free rate of 8%. Under IFRS, the estimated cash flow to abandon and remediate well sites, facilities and gathering systems has been risk-adjusted and therefore the provision as at December 31, 2010 was discounted at a risk-free rate of 3.52% (September 30, 2010 – 3.35%, June 30, 2010 – 3.65%) based on Government of Canada long-term bonds.

The application of IAS 37 resulted in a $353,655 increase to decommissioning obligations with a corresponding charge to the Corporation's retained earnings (deficit) at the date of transition. This resulted in a $93,082 decrease to deferred income tax liability with a corresponding decrease to the Corporation's retained earnings (deficit) at the date of transition. As a result of the change in the discount rate applied, accretion expense decreased during the six months ended December 31, 2010 by $11,350 (three months ended September 30, 2010 - $2,170, nine months ended September 30, 2010 - $13,430, and twelve months ended June 30, 2010 – $24,981) from the amounts previously recorded under Canadian GAAP.

(C) Share-based payments

The Corporation has elected to apply IFRS 2, *Share-based Payments* to equity instruments granted after November 7, 2002 that have not vested by the transition date. Under Canadian GAAP, stock-based compensation expense was disclosed as a separate line item in income or loss. Under IFRS, stock-based compensation expense is included in administrative expenses.

Under Canadian GAAP prior to June 30, 2010, the fair value of stock options was calculated using a Black-Scholes option-pricing model for each option grant and the resulting expense was recognized on a straight-line basis over the three year vesting period at a rate of one-third on each anniversary date of the stock option grant. Forfeitures of stock options were recognized as they occurred. Subsequent to June 30, 2010, the fair value of stock options was calculated on a basis consistent with IFRS.

Under IFRS, each vesting tranche of an option grant with different vesting dates was considered a separate grant for the calculation of fair value. This results in accelerated expense recognition which attributes higher stock-based compensation expense in the early years of an option grant and less expense in later years. Manitok also applied an estimated forfeiture rate at the initial grant date. The forfeiture rate is taken into account by adjusting the number of stock options expected to vest under each vesting tranche and subsequently revising this estimate throughout the vesting period, as necessary. When determining the fair value of each vesting tranche under IFRS, Manitok applied an estimated weighted average option life for each respective tranche which reflects management's expectations. Under Canadian GAAP prior to June 30, 2010, the option life was equal to the expiry period of five years.

The application of IFRS 2 resulted in a $16,809 increase to contributed surplus with a corresponding charge to the Corporation's retained earnings (deficit) at the date of transition. Stock-based compensation expense remained consistent during the six months ended December 31, 2010 (three months ended September 30, 2010 – $NIL, nine months ended September 30, 2010 – decreased $75,743, and twelve months ended June 30, 2010 – decreased $36,646) from the amounts previously recorded under Canadian GAAP. The Corporation applied a weighted average estimated forfeiture rate of 0.9% during the year ended December 31, 2010 (September 30, 2010 – 0.7%, June 30, 2010 – 0.0%).

(D) Gain (loss) on disposition of assets

Under Canadian GAAP, proceeds from the disposition of assets were applied in full against petroleum and natural gas properties and equipment, with no gain or loss recognized, unless such a disposition would change the rate of depletion and depreciation by 20 percent or more. Under IFRS, a gain or loss is recorded when petroleum and natural gas properties and equipment are sold. There was no impact of this policy on the transition date due to the IFRS 1 deemed cost exemption discussed above.

The above accounting policy difference resulted in a gain of $1,562,568, as a result of the disposition of a minor oil and gas asset in the Garrington area of Alberta in August 2010 and a gain of $295,177, as a result of the sale of a non-producing E&E asset as part of a swap arrangement in December 2010, with a corresponding increase to petroleum and natural gas properties and equipment during the six months ended December 31, 2010. No gain or loss was recorded on the disposition of these assets under Canadian GAAP.

(expressed in Canadian dollars, unless otherwise stated)

(E) Depletion and depreciation

Under Canadian GAAP, the Corporation depleted the full cost pool based on the unit of production method using proved reserves for each country cost centre. Under IAS 16, *Property, Plant & Equipment*, the Corporation has elected to deplete its development and production costs on an area basis using the unit of production method over proved plus probable reserves. Exploration and evaluation costs are not amortized under IFRS.

Depleting at an area level over proved plus probable reserves resulted in a decrease to depletion and depreciation of $306,420 for the six months ended December 31, 2010 (three months ended September 30, 2010 – $127,956, nine months ended September 30, 2010 – $487,989, and twelve months ended June 30, 2010 – $778,632) from amounts previously reported under Canadian GAAP.

(F) Administrative expenses

Administrative expenses include the total cash remuneration from salaries and benefits paid to officers, employees and consultants of the Corporation, other general business expenses and non-cash stock-based compensation, net of any capitalized portions thereof. The components of administrative expenses for the 2010 comparative periods under IFRS are as follows:

($)	Six months ended December 31,2010	Three months ended September 30, 2010	Nine months ended September 30, 2010	Twelve months ended June 30, 2010
Cash:				
Salaries and benefits	662,616	305,766	802,437	795,331
Other	439,799	211,304	438,946	538,969
	1,102,415	517,070	1,241,383	1,334,300
Capitalized overhead	(158,701)	(83,192)	(137,883)	(54,691)
General and administrative, net	943,714	433,878	1,103,500	1,279,609
Non-cash:				
Stock-based compensation	273,216	88,540	22,312	18,883
Capitalized stock-based compensation	(60,437)	(18,242)	(18,242)	–
Stock-based compensation, net	212,779	70,298	4,070	18,883
Total Administrative expenses, net	1,156,493	504,176	1,107,570	1,298,492

Under Canadian GAAP, “capitalized overhead” related to the estimated time spent on operated capital projects which are not 100% owed by the Corporation, by engineering, land, accounting and operations based on an industry standard overhead charge per Authorization for Expenditure. Stock-based compensation was not capitalized under Canadian GAAP. Under IFRS, capitalized overhead represents a portion of salaries and benefits that are directly attributable to the exploration and development activities of the Corporation. In addition, under IFRS, Manitok has capitalized a portion of stock-based compensation directly attributable to the exploration and development of its assets.

These accounting policy differences resulted in an decrease to net general and administrative expenses (cash) by $158,701 during the six months ended December 31, 2010 (three months ended September 30, 2010 – $83,192, nine months ended September 30, 2010 – $137,883, and twelve months ended June 30, 2010 – $54,691) from amounts previously reported under Canadian GAAP. In addition, non-cash stock-based compensation expense decreased by $60,437 during the six months ended December 31, 2010 (three months ended September 30, 2010 – $18,242, nine months ended September 30, 2010 – $18,242, and twelve months ended June 30, 2010 – $NIL) from amounts previously reported under Canadian GAAP.

(G) Share capital

Under Canadian GAAP, the proceeds from the issuance of flow-through shares are recognized as shareholders' equity. The tax basis of assets related to expenditures incurred to satisfy flow-through share obligations is reduced when the renunciation of the related tax pools occurs which then increases the deferred income tax liability and reduces share capital.

Under IFRS, the amount recorded to share capital from the issuance of flow-through shares reflects the fair market value of "regular" common shares. The difference between the total value of a flow-through share issuance and the fair market value of a regular common share issuance is initially accrued as a deferred obligation when the flow-through shares are issued. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. Accordingly, on renunciation with Canada Revenue Agency, a deferred tax liability is recorded equal to the estimated amount of deferred income taxes payable by the Corporation as a result of the renunciations, the deferred obligation on the issuance of flow-through shares is reduced and the difference is recognized in deferred income tax expense. There is no impact to share capital on renunciation of flow-through shares.

The above accounting policy difference resulted in an increase to share capital of $717,309 at the transition date with a corresponding charge to retained earnings (deficit). The Corporation reflected an increase in share capital of $203,456 as at March 31, 2010 related to a flow-though share issuance in December 2009 and a decrease in share capital of $336,253 as at December 31, 2010 related to a flow-though share issuance in July 2010 and December 2010. As at December 31, 2010 the Corporation had a deferred obligation of $1,009,304 with respect to the issuance of flow-through shares in December 2010.

(H) Income taxes

Each of the adjustments discussed above result in a change in deferred income tax assets and liabilities based on Manitok's effective tax rate. The Corporation recorded a decrease in deferred tax liabilities of $190,591 at July 1, 2009 and an increase in deferred tax liabilities of $74,604 at December 31, 2010 (September 30, 2010 – increase of $886, June 30, 2010 – decrease of $488,201) from amounts previously reported under Canadian GAAP. Additional deferred income tax expense of $1,235,855 for the six months ended December 31, 2010 (three months ended September 30, 2010 – $489,087, nine months ended September 30, 2010 – $282,509, and twelve months ended June 30, 2010 – recovery of $94,153) was recorded under IFRS.

CORPORATE INFORMATION

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Cameron G. Vouri, P. Eng. (1)
Calgary, Alberta

Massimo M. Geremia (1) (2)
Calgary, Alberta

(1) Reserve & Occupational Health & Safety Committee Member

(2) Audit Committee Member

(3) Compensation Committee Member

OFFICERS

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President and Chief Executive Officer

Tim de Freitas, M.Sc., Ph.D.
Vice President, Exploration and
Chief Operating Officer

Robert G. Dion, C.A.
Vice President, Finance and
Chief Financial Officer

Dorothy Else
Vice President, Land

Gregory E. Peterson, LL.B.
Corporate Secretary

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Calgary, Alberta

AUDITORS

Kenway Mack Slusarchuk Stewart LLP
Chartered Accountants
Calgary, Alberta

INDEPENDENT RESERVE EVALUATOR

Sproule Associates Limited
Calgary, Alberta

BANKER

Alberta Treasury Branch
Calgary, Alberta

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