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 first quarter financial results for the three months ended March 31, 2013. Operational and financial highlights in the first quarter include:

- An increase in the average production by 62% from 2,209 boe/d to 3,586 boe/d for the three months ended March 31, 2013 relative to the average production for the comparable period in 2012. Based on field estimates, current production is approximately 4,300 boe/d (52% crude oil and NGLs).
- Increased the oil and NGLs weighting from 24% of total production in the first quarter of 2012 to 50% of total production in the first quarter of 2013.
- Funds from operations for the three months ended March 31, 2013 increased by 299% from $2.0 million ($0.03 per share) to $7.9 million ($0.11 per share) as compared to the three months ended March 31, 2012.
- Operating netback increased by 98% from $14.44 per boe to $28.64 per boe for the first quarter of 2013 as compared to the first quarter of 2012 due to the increase of light oil volumes in the total production mix.
- Achieved strong quarterly per share growth as production and funds from operations per weighted average diluted share increased 39% and 245%, respectively.
- Total operating costs were $9.14 per boe net of recoveries and $9.87 per boe prior to recoveries, which is 6% and 10% lower, respectively, on a boe basis, than the comparable period last year. Transportation and marketing costs were $2.79 per boe, up from $1.42 per boe in the comparable period last year due mainly to the increased proportion of oil production.
- Manitok's capital expenditures for the three month period ended March 31, 2013 were $11.3 million, which is up 17% from $9.7 million in the comparable quarter in 2012.
- Drilled 3 gross (1.7 net) Cardium light oil wells in the first quarter of 2013 in the Stolberg area of Alberta.
- As at March 31, 2013, Manitok had net debt of approximately $13.5 million and unused credit facilities of $82.9 million.
- A 12% increase in undeveloped land to 200,271 net acres as at March 31, 2013 as compared to 178,938 net acres as at December 31, 2012.
- Reduced net loss from $2.5 million ($0.04/share) for the three months ended March 31, 2012 to $0.1 million ($0.00/share) in the three months ended March 31, 2013. The net loss in the first quarter of 2013 included an unrealized loss on financial instruments of $3.0 million due to higher crude oil forward price curves, compared to an unrealized loss on financial instruments of $0.5 million in the first quarter of 2012.

Activity in the Quarter

Corporate production and funds from operations increased significantly in the quarter compared to the same period one year ago. The increases were mainly due to the continued success of the Stolberg drilling program. In the quarter, Manitok's average production volumes were constrained in the Stolberg area as the Corporation transitioned wells in the southern end of the Stolberg trend from temporary to permanent facilities. Manitok's first quarter monthly sales volume averages were 2,977 boe/d (44% crude oil and NGLs), 3,709 boe/d (47% crude oil and NGLs) and 4,087 boe/d (56% crude oil and NGLs) for January, February and March, respectively. Based on field estimates, current production is approximately 4,300 boe/d (52% crude oil). Current field estimates do not include any contribution from the last three wells (1.3 net) drilled in the Stolberg area, which are either awaiting further completion operations or facilities construction and tie-in. Two (0.7 net) of these wells are not likely to add to Manitok's production levels until late in the third quarter due to being on a planned four well pad requiring at least two more months of drilling before facilities can be constructed.

With each successful new well and with increased production history from the existing wells, Manitok continues to prove up the reserves within the Stolberg trend. The twelfth well of the program was successful at testing the structure to a new depth and the results from the production tests of the thirteenth and fourteenth wells continue to prove the deliverability of the reservoir. More detailed information regarding Manitok's recent drilling success can be found in its press releases which are on the Manitok website at www.manitokenergy.com. Manitok believes that there are an additional 20 gross drilling locations remaining at Stolberg.

Manitok continues to improve upon its operating costs. Total operating costs were $9.14 per boe, net of recoveries and $11.93 per boe when including transportation and marketing costs. With the transition from temporary facilities to permanent facilities in the first quarter, there will be some savings from reduced fixed costs associated with the temporary equipment configuration, assuming that all other variables remain the same. Manitok will continue to work diligently at ways to optimize production and minimize our operating costs as we scale up our operations in the area.

Future tie-ins of new drills near the facilities at either end of the field will benefit from the work completed to date. Both the tenth and eleventh wells of the Stolberg drilling program were tied-in at the south end of the field during the first quarter in a relatively short time frame. Manitok believes that the next 6 to 8 wells of the drilling program, including the thirteenth and fourteenth wells, should also be tied-in with the same efficiency due to the proximity to existing facilities.

Subsequent to the end of the first quarter, Manitok utilized a second drilling rig to begin drilling operations in the Cabin Creek area which is a short distance north of the town of Hinton, Alberta. Manitok is drilling a horizontal oil well into the Cardium formation with its partner, Petrus Resources Ltd. Through a farm-in agreement with a third party that has a 100% working interest in 6 contiguous sections (3,840 acres), the well will earn both Manitok and its partner a 50% working interest in that 6 section block subject to a 9% non-convertible overriding royalty. The farm-in agreement also provides Manitok and its partner with a rolling option to drill additional wells on approximately 18 sections (11,520 acres), contiguous to the initial 6 section parcel of the farm-in, subject to a 12.5% non-convertible overriding royalty. Given that the farmor's working interest is only 50% on the option lands, Manitok's net earned interest on each option well will be dependent on the participation of its partner and other joint interest owners that are not a party to the farm-in agreement. Manitok anticipates that it should have the test results from the first well in June 2013.

During the quarter, Manitok entered into an arrangement with National Bank of Canada ("**NBC**") for a $70 million revolving operating demand loan facility and a $20 million acquisition and development demand loan facility for total credit facilities of $90 million. Manitok is pleased to enter into a new banking relationship with NBC and believes that there is a good fit between Manitok's business plan and the range of services provided by NBC going forward. The new credit facilities will significantly enhance Manitok's financial capacity to execute its $71 million capital expenditure program in 2013 without having to raise additional equity during the year. It provides Manitok the financial flexibility, assuming that the targets of the current 2013 capital expenditure program are met, to significantly increase its capital expenditure program later in the year, should it make sense to do so based on results of the capital program, commodity prices, and the opportunities available to Manitok at that time.

2013 Guidance

The 2013 guidance remains unchanged from the press release dated February 12, 2013. The press release can be found on the Manitok website at www.manitokenergy.com or under Manitok's SEDAR profile at www.sedar.com.

Subsequent to March 31, 2013, the Corporation entered into the following derivative commodity contracts:

Commodity	Volume	Term	Reference	Strike Price	Contract Traded
Oil	400 bbls/d	June 1, 2013 to December 31, 2013	CAD$ WTI	$99.40	Swap[1]
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$96.00	Swap[2]

(1) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 400 bbls/d of oil at CAD$99.40 for the 2014 calendar period.

(2) The counter-party to this contract holds a one-time option no later than December 31, 2014 to extend a swap on 500 bbls/d of oil at CAD$96.00 for the 2015 calendar period.

A full summary of Manitok's hedging contracts can be found in the management's discussion and analysis section of this report.

This quarter we continued to make significant progress towards achieving our long term corporate vision. Manitok has significantly increased its production, funds from operations and inventory of opportunities on an absolute and per share basis. At the same time, the company has strengthened its financial position through the increase of its credit facility and its hedging activities. I strongly believe that Manitok is in the best position it has ever been in to deliver growth to its shareholders with the people, opportunities and capital now in place.

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.

(signed) *"Massimo M. Geremia"*

Massimo M. Geremia
President and Chief Executive Officer

OPERATIONS AND FINANCIAL HIGHLIGHTS

Three months ended March 31,	2013	2012
OPERATING		
Average daily production		
Natural gas (mcf/d)	**10,810**	10,049
Light oil (bbls/d)	**1,701**	68
Heavy oil (bbls/d)	**-**	378
NGLs (bbls/d)	**83**	89
Total (boe/d)	**3,586**	2,209
Average realized sales price (CAD$)		
Natural gas ($/mcf)	**3.70**	2.36
Light oil ($/bbl)	**89.09**	85.23
Heavy oil ($/bbl)	**-**	76.29
NGLs ($/bbl)	**84.25**	84.16
Total ($/boe)	**55.39**	29.77
Undeveloped Land (end of period)		
Gross (acres)	**252,611**	203,047
Net (acres)	**200,271**	150,233
NETBACK AND COST		
($ per boe)		
Petroleum and natural gas sales	**55.39**	29.77
Realized gain on financial instruments	**0.86**	0.04
Royalty income	**0.44**	0.38
Royalty expenses	**(16.12)**	(4.62)
Operating expenses, net	**(9.14)**	(9.71)
Transportation and marketing expenses	**(2.79)**	(1.42)
Operating netback	**28.64**	14.44
General and administrative expenses, net	**(4.11)**	(4.52)
Interest and financing expenses	**(0.29)**	(0.12)
Interest and other income	**0.11**	-
Funds from operations netback(1)	**24.35**	9.80
FINANCIAL		
Petroleum and natural gas revenue ($000)	**18,021**	6,061
Funds from operations ($000)(1)	**7,861**	1,970
Per share – basic ($)(1)	**0.11**	0.03
Per share – diluted ($)(1)	**0.11**	0.03
Net loss ($000)	**(135)**	(2,459)
Per share – basic ($)	**-**	(0.04)
Per share – diluted ($)	**-**	(0.04)
Common shares outstanding		
End of period – basic	**70,357,180**	61,800,531
End of period – diluted	**76,759,280**	66,756,031
Weighted average for the period – basic	**70,348,151**	61,800,531
Weighted average for the period – diluted	**72,758,478**	62,856,623
Capital expenditures, net ($000)	**11,295**	9,677
Working capital deficiency ($000)(2)	**6,354**	4,073
Drawn on credit facilities ($000)	**7,130**	11,590
Total net debt ($000)	**13,484**	15,663

(1) Funds from operations, funds from operations per share and funds from operations netback are non-GAAP measures that represent cash flow from operating activities as determined in accordance with International Financial Reporting Standards ("**IFRS**") before changes in non-cash operating working capital and decommissioning expenditures. Funds from operations should not be considered an alternative to, or more meaningful than cash flows from operating activities as determined in accordance with IFRS as an indicator of the Corporation's performance. Funds from operations, funds from operations per share (basic and diluted), and funds from operations netback do not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities.

(2) Working capital deficiency is defined as current assets less current liabilities excluding the current portion of the amount drawn on the credit facilities and the fair value of financial instruments.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Manitok Energy Inc. ("**Manitok**" or the "**Corporation**") is a junior oil and gas exploration, development and production company based in Calgary, Alberta. The Corporation conducts its operations in the Western Canadian Sedimentary Basin and currently all of its activities are in Alberta. Additional information relating to the Corporation, including its most recently filed 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 and on the Corporation's website at www.manitokenergy.com. Manitok's common shares are listed for trading on the TSX Venture Exchange ("**TSX-V**") under the symbol "**MEI**" and are included in Standard and Poor's S&P/TSX-V Select Index.

The following Management's Discussion and Analysis (**"MD&A"**) is dated May 28, 2013. The unaudited condensed interim financial statements with respect to the three months ended March 31, 2013 (the "**Reporting Period**") as compared to the three months ended March 31, 2012 (the "**Comparable Prior Period**") 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 interim financial statements and related notes for the Reporting Period and the 2012 Annual Report. All financial information is expressed in Canadian dollars, unless otherwise stated.

ADVISORIES

Unaudited Numbers

*All financial amounts referred to in this MD&A and the Corporation's first quarter report for the Reporting Period and the Comparable Prior Period ("**Q1 Report**") are management's best estimates and are unaudited.*

Non-GAAP Measures

*This MD&A and the Q1 Report contains references to measures used in the oil and natural gas industry such as "funds from operations", "operating netback", "funds from operations netback", "funds from operations per share", "working capital deficiency (surplus)" and "net debt". These measures do not have standardized meanings within International Financial Reporting Standards ("**IFRS**") and therefore reported amounts may not be comparable to similarly titled measures reported by other companies. These measures have been described and presented in the MD&A and Q1 Report in order to provide shareholders and potential investors with additional information regarding the Corporation's liquidity and its ability to generate funds to finance its operations.*

Funds from operations should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net earnings as determined in accordance with IFRS, as an indicator of Manitok's performance or liquidity. Funds from operations is used by Manitok to evaluate operating results and Manitok's ability to generate cash flow to fund capital expenditures and repay indebtedness. Funds from operations denotes cash flow from operating activities as it appears on the Corporation's Statement of Cash Flows before changes in non-cash operating working capital and decommissioning expenditures. Operating netback denotes petroleum and natural gas revenue and realized gain (loss) on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses. Funds from operations netback denotes net income (loss) plus non-cash items including deferred income tax expense (recovery), depletion and depreciation expense, exploration and evaluation expense, impairment expense, stock-based compensation expense, accretion expense, acquisition-related expenses, unrealized gains or losses on financial instruments and gains or losses on asset divestitures. Working capital deficiency (surplus) includes current assets less current liabilities excluding the current portion of the amount drawn on the credit facilities and the fair value of financial instruments. Manitok uses net debt as a measure to assess its financial position. Net debt includes current liabilities less current assets excluding the current portion of the fair value of financial instruments.

Barrels of Oil Equivalent

*The term barrels of oil equivalent ("**boe**") may be misleading, particularly if used in isolation. Per boe amounts have been calculated by using the conversion ratio of six thousand cubic feet of natural gas (6 mcf) to one barrel of oil (1 bbl). The boe conversion ratio of 6 mcf to 1 bbl is based on an energy equivalency conversion method* *primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.*

Thousands of Cubic Feet of Natural Gas Equivalent

*Thousands of cubic feet of natural gas equivalent ("**mcfe**") may be misleading, particularly if used in isolation. Per mcfe amounts have been calculated by using the conversion ratio of one barrel of oil (1 bbl) to six thousand cubic feet of natural gas (6 mcf). The mcfe conversion ratio of 1 bbl to 6 mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalent of 1:6, utilizing a conversion on a 1:6 basis may be misleading as an indication of value.*

Forward-Looking Information

This MD&A and the Q1 Report contain forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to future events or future performance and is based upon the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to reserves is forward-looking as it is a forecast of quantities of hydrocarbons that can be recovered and sold in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information.

In particular, this MD&A and the Q1 Report contains forward-looking information relating to expected production; planned production increases; planned capital spending and sources of funding; estimates of reserves and resource volumes; intention to drill and complete future wells, royalty rates and incentives; and treatment under tax laws.

The forward-looking information is based upon assumptions as to future commodity prices, currency exchange rates, inflation rates, interest rates, future availability of debt and equity financing being at levels and costs that allow the Corporation to manage, operate and finance its business, develop its properties and meet its future obligations, well production rates, well drainage areas, success rates for future drilling, and availability of labour and services. With respect to estimates of reserves, a key assumption is the validity of the data used by Sproule Associates Limited in its independent reserves evaluation. With respect to future wells, a key assumption is that geological and other technical interpretations performed by the Corporation's technical staff, which indicate commercially economic reserves can be recovered from the Corporation's land as a result of drilling such future wells, are valid.

Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intensions or expectations upon which it is based will occur. Although the Corporation believes that the expectations reflected in the forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ from those anticipated.

Forward-looking information necessarily involves both known and unknown risks associated with oil and gas exploration, production, transportation and marketing such as operational risks, environmental risks, loss of market demand, general economic conditions affecting the ability to access sufficient capital, changes in government regulation of the oil and gas industry and competition from others for scarce resources.

The foregoing list of risk factors is not exhaustive. Additional information on these other risk factors that could affect operations or financial results are included in the Corporation's most recent Annual Information Form and in other reports filed with Canadian securities regulatory authorities. Forward-looking information is based on estimates and opinions of management at the time the information is presented. The Corporation is not under any duty to update the forward-looking information 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
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
NGLs	natural gas liquids

Natural Gas

mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
Mmcf	million cubic feet
Mmcf/d	million cubic feet per day
mcfe	thousand cubic feet of natural gas equivalent
mcfe/d	thousand cubic feet of natural gas equivalent per day
Bcf	billion cubic feet
Bcfe	billion cubic feet of natural gas equivalent
mmbtu	million British thermal units
GJ	Gigajoule
GJs/d	Gigajoules per day

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

FIRST QUARTER OVERALL PERFORMANCE

Production

Production in the Reporting Period averaged 3,586 boe/d (50% crude oil and NGLs), which is a 62% increase from the average of 2,209 boe/d (24% crude oil and NGLs) in the Comparable Prior Period. The significant increase is due to the Corporation's development of the Stolberg area which contributed 2,428 boe/d (70% crude oil and NGLs) in the Reporting Period compared to 586 boe/d (10% crude oil and NGLs) in the Comparable Prior Period. The production increase was partially offset by the Corporation's disposition of heavy oil production in the Swimming area of Alberta in April 2012 (the "**Swimming Asset Divestiture**"), which produced 378 net bbls/d in the Comparable Prior Period.

Commodity Prices

Average realized light oil prices in the Reporting Period were $89.09/bbl, which is 5% higher than the average realized price of $85.23/bbl in the Comparable Prior Period. Natural gas sales prices at the wellhead averaged $3.70/mcf in the Reporting Period, a 57% increase from $2.36/mcf in the Comparable Prior Period, and NGL sales prices at the wellhead averaged $84.25/bbl in the Reporting Period, consistent with the $84.16/bbl received in the Comparable Prior Period.

Canadian Edmonton Par oil prices averaged $88.60/bbl in the Reporting Period, a decrease of 4% from $92.70/bbl in the Comparable Prior Period. The AECO daily natural gas spot price averaged $3.19/mmbtu in the Reporting Period, a 47% increase from $2.17/mmbtu in the Comparable Prior Period.

Manitok's average realized commodity price increased 86% to $55.39/boe in the Reporting Period from $29.77/boe in the Comparable Prior Period due to the increase in light oil production from 3% of total production in the Comparable Prior Period to 47% of total production in the Reporting Period and increased natural gas prices.

Manitok's petroleum and natural gas sales are impacted by world events that dictate the level of supply and demand for petroleum and natural gas. The Corporation is subject to fluctuations in commodity prices, which is partially mitigated with the use of derivative risk management contracts. See "Results of Operations – Financial Instruments."

Funds from Operations and Net Income (Loss)

Manitok considers funds from operations to be a key measure as it demonstrates the ability to generate the cash necessary to fund future growth through capital investments and repay indebtedness. Funds from operations 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. Funds from operations 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 funds from operations throughout this MD&A are based on cash flow from operating activities from the Statement of Cash Flows before changes in non-cash operating working capital and decommissioning expenditures. Funds from operations per share is calculated based on the weighted average number of shares outstanding.

The following schedule sets out the reconciliation of cash flow from operating activities to funds from operations:

	Three months ended March 31	
($000, except for share information)	**2013**	2012
Cash flow from operating activities	**5,219**	(196)
Adjustments		
Decommissioning expenditures	**110**	2
Changes in non-cash operating working capital	**2,532**	2,164
Funds from operations	**7,861**	1,970
per share – basic	**0.11**	0.03
per share – diluted	**0.11**	0.03

Funds from operations increased to $7.9 million ($0.11 per diluted share) for the Reporting Period as compared to $2.0 million ($0.03 per share) in the Comparable Prior Period. The increase in aggregate funds from operations and funds from operations per share were due to the significant increase in production volumes from the Stolberg light oil wells coming on-stream. Royalty expenses increased significantly in the Reporting Period, which negatively impacted funds from operations and funds from operations per share as a result of four light oil wells drilled in 2012 that each exceeded the royalty incentive production volume maximum of 50,000 bbls of oil in approximately four to five months of production and were subject to a maximum royalty rate of 40% for the entire Reporting Period, as compared to a 5% new well royalty rate before the production volume threshold of 50,000 bbls of oil was exceeded.

Manitok had a net loss of $0.1 million (loss of $NIL per share) in the Reporting Period as compared to a net loss of $2.5 million (loss of $0.04 per share) in the Comparable Prior Period. The decrease in the net loss was attributable to the increase in funds from operations, partially offset by a higher unrealized loss on financial instruments and an aggregate increase in depletion and depreciation expense.

Capital Expenditures

Capital expenditures before acquisitions and divestitures amounted to $11.2 million in the Reporting Period as compared to $9.6 million in the Comparable Prior Period. Of the total capital spent, approximately $6.3 million was directed to drilling and completions, $3.3 million to equipping, facilities and tie-ins, $1.4 million to undeveloped land acquisitions and $0.2 million to geophysical expenditures. The drilling program in the Reporting Period included 3 (1.7 net) light oil wells in the Stolberg area.

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

On February 4, 2013, Manitok closed an arrangement with the National Bank of Canada ("**NBC**") for a $70.0 million revolving operating demand loan facility and a $20.0 million acquisition and development demand loan facility, for a total credit facility of $90.0 million. The revolving credit facility of $30.0 million with Alberta Treasury Branch was cancelled on February 4, 2013.

GUIDANCE AND OUTLOOK

Manitok provided guidance for projected 2013 results in the Corporation’s December 31, 2012 MD&A dated April 17, 2013, which is as follows.

Manitok anticipates a 2013 capital expenditure budget of approximately $71.0 million. Approximately $63.0 million is expected to be directed at drilling, completions, workovers and equipping for light oil in the Alberta Foothills and approximately $8.0 million is expected to be spent on land and seismic. The budget will be financed with cash flow and Manitok's existing $90.0 million credit facility with NBC.

Assuming drilling success based on Manitok's expected outcomes and applied risk parameters, Manitok expects to exit 2013 with about 5,300 to 5,500 boe/d (approximately 65% crude oil and NGLs). Average 2013 production is expected to be about 4,200 to 4,400 boe/d (approximately 57% crude oil and NGLs). The budget anticipates about $55.0 to $57.0 million of funds from operations in 2013, with net debt of approximately $25.5 to $27.5 million at the end of 2013, which is an increase of about $15.5 to $17.5 million from net debt of $10.0 million at the end of 2012. The net debt to twelve month trailing cash flow ratio is anticipated to be about 0.5 times as at December 31, 2013.

While the 2013 capital budget is focused on light oil, Manitok continues to take a balanced approach to building its asset base. Along with light oil, Manitok has an extensive drilling inventory of liquids-rich natural gas and large dry gas targets. Manitok is focusing on light oil due to the obvious economic advantage of current crude oil prices. Manitok believes that at some point in the future, natural gas prices will increase from these historically low levels. With its asset base and the financial flexibility provided by its balance sheet, Manitok has the ability to quickly add liquids-rich natural gas drilling to its 2013 capital expenditure program should the outlook for natural gas prices improve during the year.

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 deficiency (current assets less current liabilities), which excludes any current portion of the fair value of financial instruments and the amount drawn on the credit facilities, decreased to $6.4 million at March 31, 2013 as compared to $6.9 million at December 31, 2012. The working capital deficiency at March 31, 2013 is largely comprised of costs incurred on the Corporation's drilling program in Stolberg and will be financed with cash flow from operating activities and the Corporation's credit facilities.

At March 31, 2013, the major component of Manitok's current assets excluding the fair value of financial instruments was cash (11%), and revenue (59%) to be received from its marketers in respect of March 2013 production that was subsequently received in April 2013. Current liabilities excluding the amount drawn on the credit facilities and the fair value of financial instruments largely consisted of capital expenditure trade payables (53%) and accrued capital costs (10%) related to the Corporation's capital expenditure program. Manitok routinely assesses the financial strength of its marketers and joint venture partners. At this time, Manitok expects that such counterparties will be able to meet their financial obligations.

The Corporation manages its working capital using its cash flow from operating activities, advances under its credit facilities and excess funds from equity issuances or asset divestitures, if any. If applicable, Manitok will invest any excess cash in a short-term interest bearing account with its lender. The Corporation did not identify any liquidity issues with respect to the operation of its petroleum and natural gas business during the year.

Bank Indebtedness

The amount outstanding on the Corporation's credit facilities was $7.1 million as at March 31, 2013, with an aggregate limit of $90.0 million as compared to $3.1 million as at December 31, 2012, when the aggregate limit was $30.0 million. The amount drawn on the credit facilities is due mainly to the Corporation's ongoing capital expenditure program.

The following table shows the Corporation's total available credit:

As at, ($000)	**March 31, 2013**	December 31, 2012
Maximum borrowing base limit(1)(2)		
Revolving operating demand loan facility	**70,000**	30,000
Acquisition and development demand loan facility(3)	**20,000**	-
	90,000	30,000
Principle amount utilized		
Drawn revolving operating demand loan facility	**(7,130)**	(3,101)
Drawn acquisition and development demand loan facility	**-**	-
Outstanding letters of credit(4)	**-**	(100)
	(7,130)	(3,201)
Undrawn credit facilities	**82,870**	26,799

(1) The Corporation's credit facilities are subject to a review of the borrowing base limit by the lender at any time in its sole discretion, and at least annually, which is directly impacted by the value of Manitok's petroleum and natural gas reserves. The next review date for the credit facilities has been proposed for November 1, 2013.

(2) The Corporation's lender requires quarterly compliance that the working capital ratio (current assets excluding the fair value of financial instruments plus any undrawn portion of the credit facilities divided by current liabilities excluding any current portion of an amount drawn on the credit facilities and the fair value of financial instruments) is not less than 1:1. Manitok was in compliance with the financial covenant as at March 31, 2013 and December 31, 2012.

(3) The acquisition and development demand loan facility is restricted by the Corporation's lender to assist in the acquisition of producing petroleum and natural gas reserves and/or development of proved non-producing/undeveloped petroleum and natural gas reserves.

(4) Letters of credit are issued to service providers. The December 31, 2012 letter of credit was returned to the Corporation during the three months ended March 31, 2013. There were no amounts drawn on letters of credit during the three months ended March 31, 2013.

Contractual Obligations

The Corporation enters into contractual obligations in the course of conducting its day-to-day business. The following table identifies Manitok's material contractual obligations at March 31, 2013:

($000)	2013	2014	2015 - 2017	Thereafter
Accounts payable and accrued liabilities	17,198	-	-	-
Drawn credit facilities	7,130	-	-	-
Office lease[(1)]	570	1,534	916	-
Total estimated contractual obligations[(2)]	**24,898**	**1,534**	**916**	**-**

(1) The Corporation is committed to the current office lease which matures on February 28, 2017. Manitok does not presently use all of the leased premises and has sublet some offices 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. The Corporation's decommissioning obligations are excluded from the table as these obligations arise from a regulatory requirement rather than from a contractual arrangement. Manitok estimates the total undiscounted cash flow to settle its decommissioning obligations at March 31, 2013 to be approximately $19.4 million and will be incurred as follows: 2013 - $0.6 million, 2014 - $0.3 million, 2015 to 2017 - $0.1 million and $18.4 million thereafter. The estimate for undiscounted decommissioning obligations requires significant assumptions on both the abandonment cost and timing of the decommissioning and therefore the actual obligation may differ materially.

Related Party Transactions

The Corporation is a related party to Amarok Energy Inc. ("**Amarok**") as a result of common key management personnel. Currently, Manitok operates entirely in Canada and its strategy is to pursue opportunities within Canada. Currently, it is the Corporation's understanding that Amarok has implemented a strategy of pursuing opportunities outside of Canada. Manitok does not anticipate any changes to its strategy in the foreseeable future.

- Amarok participated in the drilling of one well in the Stolberg area in 2012. Under the terms of the farm-in agreement, Amarok paid 12% of the drilling and completion costs and 8% of the equipping costs to earn an 8% net revenue interest in the well. This participation was in the normal course of the Corporation's business and is measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties and is on comparable terms and conditions to those of other joint interest partners. Amarok made a total net capital expenditure payment of $0.8 million to Manitok. Included in accounts payable and accrued liabilities as at March 31, 2013 is $30,400 (December 31, 2012 - $24,700) due to Amarok, relating to its net interest in the operations of the well.
- During the three months ended March 31, 2013, the Corporation recorded $3,000 (March 31, 2012 – $NIL) as a reduction to rent expense related to the sub-lease of one office to Amarok, which commenced in September 2012. The office lease is in the normal course of operations and is measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties and which is comparable to those negotiated with third parties. Included in accounts receivable as at March 31, 2013 is $1,000 (December 31, 2012 - $2,100) related to March 2013 rent.
- The Corporation provides oil and gas technical services to Amarok. Consideration for providing these services is based on a reimbursement of costs incurred by Manitok. The Corporation recorded $101,000 as a reduction of administrative expenses in the three months ended March 31, 2013 (March 31, 2012 - $NIL). Included in accounts receivable as at March 31, 2013 is $106,000 (December 31, 2012 - $NIL) due from Amarok, related to the technical services provided by Manitok.

Off-balance Sheet Transactions

Manitok was not involved in any off-balance sheet transactions that would result in a material change to its financial position, performance or funds from operations as at or during the three months ended March 31, 2013.

OUTSTANDING SHARE DATA

The common shares of Manitok ("**Manitok Shares**") are the only class of shares issued and outstanding. 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:

	Manitok Shares
Outstanding, December 31, 2011	**61,800,531**
Issue of Manitok Shares on October 16, 2012[1]	8,456,316
Issue of Manitok Shares upon exercise of options	156,667
Normal course issuer bid[2]	(74,500)
Outstanding, December 31, 2012	**70,339,014**
Issue of Manitok Shares upon exercise of options	18,166
Outstanding, March 31, 2013	**70,357,180**

(1) On October 16, 2012, Manitok completed a bought deal equity issuance pursuant to a short form prospectus offering whereby Manitok issued an aggregate of 3,026,316 Manitok Shares issued at a price of $1.90 per Manitok Share, 1,430,000 Manitok Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian development expense ("**Manitok CDE Flow-through Shares**") at a price of $2.10 per Manitok CDE Flow-through Share and 4,000,000 Manitok Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian exploration expense ("**Manitok CEE Flow-through Shares**") at a price of $2.30 per Manitok CEE Flow-through Share for net proceeds of approximately $16.5 million. Proceeds of the equity issuance were used to temporarily eliminate the outstanding bank indebtedness from the Corporation's capital expenditure program, which was partially redrawn and applied as needed to fund the ongoing capital expenditure program.

(2) On June 15, 2012, the TSX-V authorized the Corporation's notice to make a normal course issuer bid (**"NCIB"**) to purchase for cancellation up to 4.4 million Manitok Shares on the open market during the period from June 18, 2012 to June 17, 2013. On January 28, 2013 received approval from the TSX-V to increase the number of Manitok Shares that may be purchased under the NCIB to 5.8 million. As at March 31, 2013, the Corporation has purchased a total of 74,500 Manitok Shares for cancellation at a weighted average price of $1.21 per share which excludes the fees incurred to implement the NCIB program.

At May 28, 2013, there were 70,079,480 Manitok Shares outstanding and 6,482,100 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 ("**P&NG**") revenue, production and average realized sales prices by product for the Reporting Period and the Comparable Prior Period:

	Three months ended March 31, 2013				Three months ended March 31, 2012			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Natural gas (mcf)(1)	**3,605**	**10,810**	**50**	**3.70**	2,160	10,049	76	2.36
Light oil (bbls)	**13,642**	**1,701**	**47**	**89.09**	526	68	3	85.23
Heavy oil (bbls)	**-**	**-**	**-**	**-**	2,621	378	17	76.29
NGLs (bbls)	**631**	**83**	**3**	**84.25**	678	89	4	84.16
Total P&NG sales (boe)	**17,878**	**3,586**	**100**	**55.39**	5,985	2,209	100	29.77
Royalty revenue	**143**			**0.44**	76			0.38
Total P&NG revenue (boe)	**18,021**	**3,586**	**100**	**55.83**	6,061	2,209	100	30.15

(1) Includes sulphur revenue in the three month Reporting Periods. Sulphur production volumes are excluded.

The significant increase in P&NG revenue in the Reporting Period as compared to the Comparable Prior Period was due primarily to the increase in the average daily production volumes related to the successful drilling of Cardium light oil wells in the Stolberg area. The results from the Stolberg drilling program offset by the Swimming Asset Divestiture caused a significant change in the Corporation's liquid product mix from heavy to light oil in the Reporting Period.

While crude oil and NGL volumes represent 50% of total P&NG production for the Reporting Period, it represents 80% of the total P&NG sales.

The following table details Manitok's P&NG revenue, production and average realized sales price by product category, based upon the primary product produced at the well, for the Reporting Period and the Comparable Prior Period:

	Three months ended March 31, 2013				Three months ended March 31, 2012			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Sweet natural gas (mcfe)(1)	**2,123**	**5,290**	**25**	**4.46**	2,008	6,564	50	3.36
Sour natural gas (mcfe)(2)	**1,299**	**3,911**	**18**	**3.69**	831	3,909	30	2.34
Light oil (boe)(3)	**14,456**	**2,053**	**57**	**78.24**	525	86	3	67.50
Heavy oil (bbl)	**-**	**-**	**-**	**-**	2,621	378	17	76.29
Total P&NG sales (boe)	**17,878**	**3,586**	**100**	**55.39**	5,985	2,209	100	29.77
Royalty revenue	**143**			**0.44**	76			0.38
Total P&NG revenue (boe)	**18,021**	**3,586**	**100**	**55.83**	6,061	2,209	100	30.15

(1) Includes revenue and production for associated by-products.
(2) Includes revenue and production for associated by-products, including sulphur revenue of $129,000 (March 31, 2012 - $13,000). Sulphur production volumes are excluded.
(3) Includes revenue and production for solution gas and associated by-products.

The Corporation's sweet natural gas wells including associated by-products realized an average price of approximately 21% higher than the sour natural gas wells in the Reporting Period. While realized natural gas prices in aggregate have increased 57% in the Reporting Period, the realized price for the Corporation's sweet natural gas including associated by-products has increased by only 33% as compared to the Comparable Prior Period, due mainly to the increased liquids rich component of its production that had consistent prices with the Comparable Prior Period.

Commodity Prices

Manitok production is sold on a spot basis, with prices fixed at the time of transfer or on the basis of a monthly average market price. The following table details the average reference price for the Reporting Period and the Comparable Prior Period:

	Three months ended March 31,		
	2013	2012	Variance
Light oil - Edmonton par ($/bbl)	**88.60**	92.70	(4%)
Natural gas – AECO daily spot	**3.19**	2.17	47%

(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 Canadian dollar AECO spot market prices for natural gas, Canadian dollar Edmonton Par oil prices, US dollar oil prices, the US/Canadian dollar exchange rate and transportation and product quality differentials.

Financial Instruments

Commodities

The Corporation enters into commodity derivative financial instruments in order to reduce volatility in financial results and to ensure a certain level of funds from operations to execute the planned capital expenditure program. The Corporation may use puts, costless collars, swaps, swaptions and fixed price contracts to limit exposure to fluctuations in commodity prices while allowing for participation in commodity price increases. The Corporation's financial derivative trading activities are conducted within risk management tolerances that are reviewed by the Board of Directors.

These contracts had the following impact on net income:

	Three months ended March 31,			
	2013		2012	
	$000	**$/boe**	$000	$/boe
Realized gain on financial instruments	**278**	**0.86**	9	0.04
Unrealized loss on financial instruments	**(3,035)**	**(9.40)**	(526)	(2.62)

The significant increase in unrealized loss on financial instruments on an absolute and per boe basis is primarily due to higher crude oil forward price curves as at March 31, 2013 compared to December 31, 2012.

As at March 31, 2013, the Corporation held the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Remaining Term	Reference	Average Strike Price	Contract Traded	Fair Value
Oil	300 bbls/d	April 1, 2013 to December 31, 2013	CAD$ WTI	$97.65	Swap	(90)
Oil	150 bbls/d	April 1, 2013 to December 31, 2013	CAD$ WTI	$98.00	Swap	(31)
Oil	300 bbls/d	April 1, 2013 to June 30, 2013	CAD$ WTI	$98.00	Swap	(33)
Oil	300 bbls/d	April 1, 2013 to December 31, 2013	CAD$ WTI	$95.10	Swap	(296)
Oil	300 bbls/d	April 1, 2013 to December 31, 2013	CAD$ WTI	$100.50	Swap	146
Oil	250 bbls/d	May 1, 2013 to December 31, 2013	CAD$ WTI	$97.00	Swap	(103)
Oil	1,250 bbls/d	April 1, 2013 to June 30, 2013	CAD$ EDM-WTI Diff	$5.70	Swap	(371)
Oil	500 bbls/d	July 1, 2013 to December 31, 2013	CAD$ EDM-WTI Diff	$6.80	Swap	(85)
Natural gas	5,000 GJs/d	April 1, 2013 to December 31, 2013	CAD$ AECO	$3.40	Put(1)	(235)
Natural gas	5,000 GJs/d	April 1, 2013 to December 31, 2013	CAD$ AECO	$3.40	Put(2)	(292)
Oil	500 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$98.00	Swaption(3)	(269)
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$97.65	Swaption(4)	(713)
Oil	250 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$98.00	Swaption(5)	(344)
Oil	600 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$100.00	Swaption(6)	(528)
Oil	300 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$100.50	Swaption(7)	(246)
Total						**(3,490)**

(1) The counter-party to this contract receives a deferred put option premium of $0.35/Gigajoule.

(2) The counter-party to this contract receives a deferred put option premium of $0.39/Gigajoule.

(3) The counter-party to this contract holds a one-time option no later than June 28, 2013 to extend a swap on 500 bbls/d of oil at CAD$98.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

(4) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 500 bbls/d of oil at CAD$97.65 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

(5) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 250 bbls/d of oil at CAD$98.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

(6) The counter-party to this contract holds a one-time option no later than December 30, 2013 to extend a swap on 600 bbls/d of oil at CAD$100.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

(7) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 300 bbls/d of oil at CAD$100.50 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract

Subsequent to March 31, 2013, the Corporation entered into the following derivative commodity contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Contract Traded
Oil	400 bbls/d	June 1, 2013 to December 31, 2013	CAD$ WTI	$99.40	Swap(1)
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$96.00	Swap(2)

(1) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 400 bbls/d of oil at CAD$99.40 for the 2014 calendar period.

(2) The counter-party to this contract holds a one-time option no later than December 31, 2014 to extend a swap on 500 bbls/d of oil at CAD$96.00 for the 2015 calendar period.

Royalty Expenses

Royalties are paid to the Government of Alberta and other land and mineral rights owners. The following table illustrates the Corporation's royalty expenses by product category, based upon the primary product produced at the well, for the Reporting Period and the Comparable Prior Period:

	Three months ended March 31,		
	2013	2012	Variance
Sweet natural gas royalties ($000)(2)	**585**	330	77%
Sweet natural gas royalties ($/mcfe) (2)	**1.23**	0.55	124%
Effective royalty rate (1)	**27.6%**	16.4%	68%
Sour natural gas royalties ($000)(3)	**233**	213	9%
Sour natural gas royalties ($/mcfe) (3)	**0.66**	0.60	10%
Effective royalty rate (1)	**17.9%**	25.6%	(30%)
Light oil royalties ($000)(4)	**4,663**	143	-
Light oil royalties ($/boe) (4)	**25.24**	18.43	37%
Effective royalty rate (1)	**32.3%**	27.3%	18%
Heavy oil royalties ($000)	**-**	244	-
Heavy oil royalties ($/bbl)	**-**	7.11	-
Effective royalty rate (1)	**-**	9.3%	-
Total royalties before royalty credits ($000)	**5,481**	930	489%
Total royalties before royalty credits ($/boe)	**16.98**	4.63	267%
Effective royalty rate before royalty credits (1)	**30.7%**	15.5%	98%
Natural gas royalty credits ($000)(5)	**(279)**	(1)	-
Natural gas royalty credits ($/boe)	**(0.86)**	(0.01)	-
Total royalties ($000)	**5,202**	929	460%
Total royalties ($/boe)	**16.12**	4.62	249%
Effective royalty rate (1)	**29.1%**	15.5%	88%

(1) The effective royalty rate is calculated by dividing the royalties into the applicable P&NG sales category and in total P&NG sales for the period.
(2) Includes royalty expenses for associated by-products.
(3) Includes royalty expenses for associated by-products, including sulphur. Sulphur production volumes are excluded.
(4) Includes royalty expenses for solution gas and associated by-products.
(5) Includes natural gas cost allowance credits received from the Government of Alberta.

The significant increase in royalties on an absolute and per boe basis in the Reporting Period compared to the Comparable Prior Period is the result of the increase in light oil production volumes.

Manitok has benefited from the existing Alberta incentive royalty programs on its Stolberg light oil wells, with a new well royalty rate of 5% on the first 50,000 bbls of oil produced from each well. However, four wells drilled in 2012 have each exceeded the royalty incentive production volume maximum of 50,000 bbls of oil in approximately four to five months of production and are subject to a maximum royalty rate of 40%. As a result, the Corporation's effective royalty rate has increased to 29.1% of total P&NG sales in the Reporting Period compared to 15.5% in the Comparable Prior Period.

Operating Expenses

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

	Three months ended March 31, 2013		Three months ended March 31, 2012		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Field operating expenses	**3,185**	**9.87**	2,214	11.02	44%	(10%)
Recoveries	**(236)**	**(0.73)**	(306)	(1.52)	(23%)	(52%)
Field operating expenses, net	**2,949**	**9.14**	1,908	9.50	55%	(4%)
Expensed workovers and other	**-**	**-**	44	0.21	-	-
Total operating expenses	**2,949**	**9.14**	1,952	9.71	51%	(6%)

The following table compares operating expenses by product category, based upon the primary product produced at the well, for the Reporting Period and the Comparable Prior Period:

	Three months ended March 31, 2013		Three months ended March 31, 2012		Variance	
	$000	**$/unit**	$000	$/unit	$	$/unit
Sweet natural gas operating expenses (mcfe)(1)	**623**	**1.31**	724	1.21	(14%)	8%
Sour natural gas operating expenses (mcfe)(2)	**867**	**2.46**	636	1.79	36%	37%
Light oil operating expenses (boe)(3)	**1,459**	**7.89**	83	10.67	-	(26%)
Heavy oil operating expenses (bbl)	**-**	**-**	509	14.82	-	-
Total operating expenses (boe)	**2,949**	**9.14**	1,952	9.71	51%	(6%)

(1) Includes operating expenses for associated by-products.
(2) Includes operating expenses for associated by-products, including sulphur. Sulphur production volumes are excluded.
(3) Includes operating expenses for solution gas and associated by-products.

The significant increase in aggregate operating expenses in the Reporting Period as compared to the Comparable Prior Period was due to the large increase in light oil production volumes. Total operating costs per boe decreased 6% in the Reporting Period as compared to the Comparable Prior Period due mainly to the high volume rate light oil wells in the Stolberg area and having a higher percentage of natural gas and light oil production relative to heavy oil. Operating expenses per boe of the new light oil wells in the Stolberg area are relatively low as the area produces a high volume of light oil. Heavy oil operating costs are higher on a per boe basis than natural gas and light oil operating costs, and heavy oil volumes represented 17% of production in the Comparable Prior Period. The Reporting Period had no heavy oil production as a result of the Swimming Asset Divestiture.

Transportation and Marketing Expenses

The following table illustrates the Corporation's transportation and marketing (**"T&M"**) expenses by product category, based upon the primary product produced at the well, for the Reporting Period and the Comparable Prior Period:

	Three months ended March 31, 2013		Three months ended March 31, 2012		Variance	
	$000	**$/unit**	$000	$/unit	$	$/unit
Sweet natural gas T&M expenses (mcfe)(1)	**93**	**0.20**	97	0.16	(4%)	25%
Sour natural gas T&M expenses (mcfe)(2)	**92**	**0.26**	82	0.23	12%	13%
Light oil T&M expenses (boe)(3)	**717**	**3.88**	2	0.27	-	-
Heavy oil T&M expenses (bbl)	**-**	**-**	104	3.03	-	-
Total T&M expenses (boe)	**902**	**2.79**	285	1.42	216%	96%

(1) Includes T&M expenses for associated by-products.
(2) Includes T&M expenses for associated by-products, including sulphur. Sulphur production volumes are excluded.
(3) Includes T&M expenses for solution gas and associated by-products.

These costs consist primarily of transportation costs, and the significant increase in aggregate T&M expenses in the Reporting Period as compared to the Comparable Prior Period was due to the large increase in light oil production volumes. Total T&M costs per boe increased 96% in the Reporting Period as compared to the Comparable Prior Period due mainly to having a higher percentage of crude oil production relative to natural gas. Crude oil transportation costs are higher on a per boe basis than natural gas transportation costs, and crude oil volumes represented 47% of total production volumes in the Reporting Period as compared to 20% in the Comparable Prior Period.

Operating Netback

The following table compares operating netbacks by product category, based upon the primary product produced at the well for the Reporting Period and the Comparable Prior Period:

	Three months ended March 31,		
	2013	2012	Variance
Sweet natural gas ($/mcfe)[1]			
Realized sales price	**4.46**	3.36	33%
Royalty income	**0.30**	0.12	150%
Royalty expenses	**(1.23)**	(0.55)	124%
Royalty recovery[4]	**0.33**	-	-
Operating expenses, net	**(1.31)**	(1.21)	8%
Transportation and marketing expenses	**(0.20)**	(0.16)	25%
Operating netback	**2.35**	1.56	51%
Sour natural gas ($/mcfe)[2]			
Realized sales price	**3.69**	2.34	58%
Royalty income	**0.01**	-	-
Royalty expenses	**(0.66)**	(0.60)	10%
Royalty recovery[4]	**0.34**	-	-
Operating expenses, net	**(2.46)**	(1.79)	37%
Transportation and marketing expenses	**(0.26)**	(0.23)	13%
Operating netback	**0.66**	(0.28)	336%
Light oil ($/boe)[3]			
Realized sales price	**78.24**	67.50	16%
Royalty income	**-**	0.06	-
Royalty expenses	**(25.24)**	(18.43)	37%
Operating expenses, net	**(7.89)**	(10.67)	(26%)
Transportation and marketing expenses	**(3.88)**	(0.27)	-
Operating netback	**41.23**	38.19	8%
Heavy oil ($/bbl)			
Realized sales price	**-**	76.29	-
Royalty income	**-**	-	-
Royalty expenses	**-**	(7.11)	-
Operating expenses, net	**-**	(14.82)	-
Transportation and marketing expenses	**-**	(3.03)	-
Operating netback	**-**	51.33	-
Total ($/boe)			
Realized sales price	**55.39**	29.77	86%
Royalty income	**0.44**	0.38	16%
Royalty expenses	**(16.98)**	(4.63)	267%
Royalty recovery[4]	**0.86**	0.01	-
Operating expenses, net	**(9.14)**	(9.71)	(6%)
Transportation and marketing expenses	**(2.79)**	(1.42)	96%
Operating netback before realized gain on financial instruments	**27.78**	14.40	93%
Realized gain on financial instruments	**0.86**	0.04	-
Operating netback	**28.64**	14.44	98%

(1) Includes revenue and royalty, operating and T&M expenses for associated by-products.
(2) Includes revenue and royalty, operating and T&M expenses for associated by-products, including sulphur. Sulphur production volumes are excluded.
(3) Includes revenue and royalty, operating and T&M expenses for solution gas and associated by-products.
(4) Relates to natural gas cost allowance credits received from the Government of Alberta.

Administrative Expenses

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

	Three months ended March 31, 2013		Three months ended March 31, 2012		Variance
	$000	**%**	$000	%	$
Cash					
Salaries and benefits[(1)]	**1,043**	**58**	789	64	32%
Other[(2)]	**748**	**42**	437	36	71%
	1,791	**100**	1,226	100	46%
Operating overhead recoveries	**(152)**	**(8)**	(27)	(2)	-
Capitalized overhead recoveries[(3)]	**(313)**	**(18)**	(290)	(24)	8%
General and administrative expenses, net	**1,326**	**74**	909	74	46%
General and administrative expenses, net per boe	**4.11**		4.52		(9%)
Non-cash					
Stock-based compensation	**700**	**100**	443	100	58%
Capitalized stock-based compensation[(3)]	**(256)**	**(37)**	(172)	(39)	49%
Stock-based compensation, net	**444**	**63**	271	61	64%
Stock-based compensation, net per boe	**1.37**		1.35		1%
Total administrative expenses, net	**1,770**	**71**	1,180	71	50%
Total administrative expenses, net per boe	**5.48**		5.87		(7%)

(1) Includes salaries and benefits paid to all officers, employees and consultants of the Corporation.
(2) Includes costs such as rent, professional fees, insurance, computer software licenses and other business expenses incurred by the Corporation.
(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 Period as compared to the Comparable Prior Period due primarily to an increase in the number of professional staff and informational technology costs to accommodate the Corporation's growth. The addition of experienced foothills professionals in the areas of drilling, completions, operations and geosciences has substantially increased Manitok's ability to successfully execute its operations in a much shorter time frame and on a larger scale.

On a per boe basis, G&A has decreased by 9% in the Reporting Period as compared to the Comparable Prior Period due to higher production volumes from the successful capital expenditure program.

Stock-based compensation (non-cash)

The increase in the Reporting Period was mainly due to the granting of additional stock options subsequent to the Comparable Prior Period partially offset by a higher capitalized amount which is attributable to the increase in development and exploration activities.

A summary of the Corporation's outstanding stock options is presented below:

	Number	**Weighted Average Exercise Price ($)**
Outstanding, December 31, 2011	**3,845,000**	**1.30**
Granted	1,380,500	1.88
Exercised	(156,667)	1.34
Cancelled or forfeited	(285,000)	1.38
Outstanding, December 31, 2012	**4,783,833**	**1.46**
Granted	1,656,100	3.12
Exercised	(18,166)	1.17
Cancelled or forfeited	(19,667)	1.64
Outstanding, March 31, 2013	**6,402,100**	**1.89**

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

Depletion and Depreciation Expenses

The following table compares depletion and depreciation expenses ("**D&D**") for the Reporting Period and the Comparable Prior Period:

	Three months ended March 31		
	2013	2012	Variance
Depletion and depreciation ($000)	**4,214**	3,299	28%
Depletion and depreciation ($/boe)	**13.06**	16.42	(20%)

D&D 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. The Corporation determines its D&D expenses on an area basis.

D&D expenses increased on an aggregate basis due to the significant increase in production volumes from the Comparable Prior Period. On a boe basis, D&D expense has decreased by 20% in the Reporting Period as compared to the Comparable Prior Period due to proved plus probable reserves being added during the past four quarters, at a lower cost than the cumulative amounts for prior periods.

Impairment Review

The Corporation's cash-generating units ("**CGUs**") are reviewed at each reporting date for indicators of potential impairment. Such indicators may include, but are not limited to, changes in the Corporation's business plan, deterioration in commodity prices or a significant downward revision of estimated recoverable reserves. If indicators of asset impairment exist, an impairment test is performed by comparing the carrying value of Manitok's CGUs to its recoverable amount.

Manitok performed an impairment assessment of its exploration and evaluation and petroleum and natural gas properties and equipment on a CGU basis and determined there were no impairment indicators identified in the Reporting Period. As a result, an impairment test was not required as at March 31, 2013.

Finance Expenses

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

	Three months ended March 31, 2013		Three months ended March 31, 2012		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Cash:						
Interest and financing expenses	**95**	**0.29**	25	0.12	280%	142%
Acquisition-related expenses	**-**	**-**	185	0.92	-	-
	95	**0.29**	210	1.04	(55%)	(72%)
Non-cash:						
Accretion on decommissioning obligations	**70**	**0.22**	72	0.36	(3%)	(39%)
Total finance expenses	**165**	**0.51**	282	1.40	(41%)	(64%)

The aggregate interest and financing expenses for the Reporting Period increased from the Comparable Prior Period due mainly to the Corporation expensing financing costs related to the new credit facilities and an increase in standby charges on the undrawn portion of the credit facilities. The Corporation's average outstanding bank indebtedness was approximately $3.9 million as compared to $4.7 million in the Comparable Prior Period, calculated as the simple average of the daily amounts. The effective interest rate applicable to the credit facilities was 3.6% at the end of the Reporting period as compared to 4.0% for the Comparable Prior Period.

Income Taxes

Manitok recorded a deferred income tax expense of $233,000 ($0.72 per boe) in the Reporting Period as compared to $57,000 ($0.28 per boe) in the Comparable Prior Period. The expense in the Reporting Period is attributed to the net taxable income in the period and a $31,000 charge related to exploration and development expenditures to be utilized for a flow-through share renunciation.

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

Capital Expenditures

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

	Three months ended March 31,	
($000)	**2013**	2012
Land	**1,386**	973
Seismic	**162**	159
Workovers and recompletions	**75**	9
Drilling and completions	**5,898**	8,147
Well equipment and facilities	**3,334**	6
Capitalized overhead[(1)]	**313**	290
Total finding and development costs (F&D)	**11,168**	9,584
Property acquisitions, net	**(67)**	187
Total finding, development and acquisition costs (FD&A)	**11,101**	9,771
Administrative and other assets	**194**	(94)
Total capital expenditures[(2)]	**11,295**	9,677

(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 obligations.

Capital Resources

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

	Three months ended March 31	
($000)	**2013**	2012
Funds from operations	**7,861**	1,970
Changes in non-cash operating working capital	**(2,532)**	(2,164)
Decommissioning expenditures	**(110)**	(2)
Increase (decrease) in revolving credit facility	**4,029**	9,630
Proceeds from issue of stock options	**22**	-
Changes in non-cash investing working capital	**3,049**	243
Total capital resources	**12,319**	9,677
Exploration and evaluation asset expenditures	**(1,484)**	(9,459)
Petroleum and natural gas properties and equipment expenditures	**(9,878)**	(31)
Property acquisitions	**67**	(187)
Net increase (decrease) in cash	**1,024**	-

SUMMARY OF QUARTERLY INFORMATION

	2013	2012				2011		
Quarters Ended	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
OPERATING								
Average daily production								
Natural gas (mcf/d)	**10,810**	8,344	7,706	8,134	10,049	8,314	1,449	616
Light oil (bbls/d)	**1,701**	1,618	1,171	301	68	29	-	-
Heavy oil (bbls/d)	**-**	-	-	-	378	332	171	195
NGLs (bbls/d)	**83**	69	70	76	89	59	2	2
Total (boe/d)	**3,586**	3,078	2,525	1,733	2,209	1,806	414	300
Average realized sales price (CAD$)								
Natural gas ($/mcf)	**3.70**	3.64	2.52	1.96	2.36	3.33	3.73	3.70
Light oil ($/bbl)	**89.09**	82.53	82.88	84.14	85.23	96.94	-	-
Heavy oil ($/bbl)	**-**	-	-	-	76.29	73.52	63.31	74.61
NGLs ($/bbl)	**84.25**	77.71	72.46	74.61	84.16	91.97	86.40	86.23
Total ($/boe)	**55.39**	54.99	48.14	27.08	29.77	33.41	39.52	56.80
OPERATING NETBACK ($ per boe)								
Petroleum and natural gas sales	**55.39**	54.99	48.14	27.08	29.77	33.41	39.52	56.80
Realized gain (loss) on financial instruments	**0.86**	3.37	2.07	2.11	0.04	-	-	-
Royalty income	**0.44**	0.43	0.38	0.32	0.38	0.39	-	-
Royalty (expenses) recovery	**(16.12)**	(11.22)	(6.60)	4.73	(4.62)	(4.37)	(3.49)	(3.62)
Operating expenses, net	**(9.14)**	(10.48)	(7.26)	(8.77)	(9.71)	(12.08)	(12.16)	(22.74)
Transportation and marketing expenses	**(2.79)**	(3.17)	(2.62)	(1.87)	(1.42)	(1.14)	(2.03)	(2.79)
Operating netback	**28.64**	33.92	34.11	23.60	14.44	16.21	21.84	27.65
FINANCIAL								
Petroleum and natural gas revenue ($000)	**18,021**	15,696	11,272	4,320	6,061	5,615	1,505	1,552
Royalty (expenses) recovery ($000)	**(5,202)**	(3,177)	(1,534)	745	(929)	(727)	(133)	(99)
Realized gain (loss) on financial instruments ($000)	**278**	955	480	332	9	-	-	-
Interest and other revenue ($000)	**36**	29	-	5	-	20	84	104
Total revenue, net ($000)	**13,133**	13,503	10,218	5,402	5,141	4,908	1,456	1,557
Net income (loss) ($000)	**(135)**	(2,157)	1,461	499	(2,459)	(4,327)	(796)	(470)
Per share - basic ($)	**-**	(0.03)	0.02	0.01	(0.04)	(0.08)	(0.02)	(0.01)
Per share - diluted ($)	**-**	(0.03)	0.02	0.01	(0.04)	(0.08)	(0.02)	(0.01)
Funds from operations ($000)[1]	**7,861**	7,651	6,977	2,483	1,970	1,503	231	291
Per share - basic ($)[1]	**0.11**	0.11	0.11	0.04	0.03	0.03	0.00	0.01
Per share - diluted ($)[1]	**0.11**	0.11	0.11	0.04	0.03	0.03	0.00	0.01
Capital expenditures, net ($000)	**11,295**	13,421	16,230	(2,364)	9,677	55,526	8,126	6,352
Book value of total assets ($000)	**135,648**	126,322	120,553	104,319	109,961	104,290	70,462	68,312
Working capital deficiency (surplus) ($000)[2]	**6,354**	6,861	10,668	8,781	4,073	5,994	(27,635)	(35,531)
Drawn on revolving credit facility ($000)	**7,130**	3,101	9,638	2,135	11,590	1,960	-	-
Total net debt ($000)[3]	**13,484**	9,962	20,306	10,916	15,663	7,954	-	-
Shareholders' equity ($000)	**91,024**	90,437	77,027	75,112	74,297	76,313	62,703	63,177
Common shares outstanding								
End of period - basic	**70,357,180**	70,339,014	61,726,031	61,736,031	61,800,531	61,800,531	51,665,531	51,665,531
End of period - diluted	**76,759,280**	75,122,847	66,541,531	66,571,531	66,756,031	65,645,531	54,893,031	54,601,031
Weighted average for the period - basic	**70,348,151**	68,908,419	61,726,357	61,797,394	61,800,531	54,639,933	51,665,531	48,901,108
Weighted average for the period - diluted	**72,758,478**	70,986,540	62,735,423	61,935,604	62,856,623	55,665,947	52,266,109	49,845,473

(1) Funds from operations and funds from operations per share are non-GAAP measures that represent cash flow from operating activities as per the Statements of Cash Flows before changes in non-cash operating working capital and decommissioning expenditures.

(2) Working capital deficiency (surplus) is defined as current assets less current liabilities excluding the current portion of the amount drawn on the credit facilities and the fair value of financial instruments.

(3) Working capital (surplus) is only included in total net debt, if the Corporation is in a net debt position.

Discussion of Quarterly Results

The P&NG industry is cyclical in nature and the Corporation's financial position, results of operations and funds from operations are principally impacted by production levels and commodity prices.

Overall, the Corporation has had continued growth over the last two years summarized in the table above. Manitok's average daily production has increased significantly over the past eight quarters as a result of the successful light oil drilling program and an acquisition of P&NG assets in the central Alberta foothills area on October 31, 2011 **("Asset Acquisition")**. This has resulted in significant growth in funds from operations on an absolute and per share basis.

Significant events that have impacted the Corporation's results during the past eight quarters include:

- In the second quarter of 2011, the Corporation completed an equity financing issuing 18.0 million Manitok Shares for net proceeds of approximately $26.7 million, which resulted in the significant increase to total assets and shareholders' equity.
- In the fourth quarter of 2011, the Corporation closed the Asset Acquisition for approximately $41.9 million after final closing adjustments which resulted in a significant increase in production, revenue, funds from operations, total assets and shareholders' equity.
- In the fourth quarter of 2011, the Corporation completed an equity financing issuing 6.5 million Manitok Shares and 3.6 million Manitok CEE Flow-Through Shares for net proceeds of approximately $18.5 million, which resulted in the significant increase to total assets and shareholders' equity.
- In the second quarter of 2012, the Corporation completed the Swimming Asset Divestiture for total cash consideration of approximately $13.2 million after final closing adjustments, which resulted in a reduction of production volumes and negative net capital expenditures in the quarter.
- In the fourth quarter of 2012, the Corporation completed an equity financing issuing 3.0 million Manitok Shares, 1.4 million Manitok CDE Flow-Through Shares and 4.0 million Manitok CEE Flow-Through Shares for net proceeds of approximately $16.5 million, which resulted in the significant increase to total assets and shareholders' equity.
- In the fourth quarter of 2012, Manitok recorded a net loss of $2.2 million, which was primarily a result of an impairment expense of $4.4 million and an exploration and evaluation expense of $1.0 million.
- In the first quarter of 2013, the Corporation recorded a net loss of $0.1 million, which was primarily a result of an unrealized loss on financial instruments of $3.0 million.
- Royalty expenses increased 64% in the first quarter of 2013 compared to the fourth quarter of 2012 as a result of four light oil wells drilled in 2012 that each exceeded the royalty incentive production volume maximum of 50,000 bbls of oil in approximately four to five months of production and were subject to a maximum royalty rate of 40% for the entire first quarter of 2013 as compared to a 5% new well royalty rate before the production volume threshold of 50,000 bbls of oil was exceeded.
- P&NG revenue was $2.3 million higher in the first quarter of 2013 compared to the fourth quarter of 2012; however, net total revenue was $0.4 million lower as a result of the significant increase in royalty expenses and a decreased in the realized gain on financial instruments.

POTENTIAL TRANSACTIONS

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 as well as the terms on which such a potential transaction would be available. As a result, the Corporation 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. 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.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the 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 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 the Corporation's financial statements:

Critical Judgments in Applying Accounting Policies

(i) Reserves

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 their 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 P&NG interests are independently evaluated by reserve engineers at least annually.

The Corporation's P&NG reserves represent the estimated quantities of petroleum, natural gas and NGLs 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 P&NG 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 in accordance with the standards contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the *Canadian Oil and Gas Evaluation Handbook*.

(ii) Identification of cash-generating units

Manitok's assets are aggregated into CGUs for the purpose of calculating impairment based on their ability to generate largely independent cash inflows. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, operating structure, commodity type and similar exposures to market risks. By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Corporation's assets in future periods.

(iii) Identification of impairment indicators

IFRS requires Manitok to assess, at each reporting date, whether there are any indicators that its assets may be impaired. Manitok is required to consider information from both external sources (such as a negative downturn in commodity prices, significant adverse changes in the technological, market, economic or legal environment in which the entity operates) and internal sources (such as downward revisions in reserves, significant adverse effect on the financial and operational performance of a CGU, evidence of obsolescence or physical damage to the asset). By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Corporation's assets in future periods.

(iv) Deferred income taxes

Deferred income 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 profits 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.

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 within the next financial year.

(i) 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, weighted average expected life of the instrument, expected dividend yield, risk-free interest rate and estimated forfeiture rate at the initial grant date.

(ii) Decommissioning obligations

The Corporation estimates future remediation costs of production facilities, well sites, gathering systems and facilities 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 an estimate 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.

(iii) Impairment of non-financial assets

For the purposes of determining whether impairment of P&NG 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 P&NG 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 carrying amount of the Corporation’s assets, and impairment charges and reversals will affect income or loss.

(iv) Fair value of financial instruments

The fair value of financial instruments where active market quotes are not available is estimated using the Corporation’s assessment of available market inputs. These estimates may vary from the actual prices received upon settlement of the financial instruments.

(v) Deferred 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.

ACCOUNTING POLICIES ADOPTED

On January 1, 2013, the Corporation adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), fair value measurements (IFRS 13) and amendments to financial instruments disclosures (IFRS 7). A brief description of each new standard is as follows:

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. The adoption of IFRS 10 did not have an impact on the Corporation's 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. The adoption of IFRS 11 did not have an impact on the Corporation's financial statements.

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 adoption of IFRS 12 did not have an impact on the Corporation's financial statements.

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. The adoption of IFRS 13 did not have an impact on the Corporation's financial statements.

IFRS 7 *Financial Instruments: Disclosures* develop common disclosure requirements for financial assets and financial liabilities that are offset in the financial statements, or that are subject to enforceable master netting arrangements or similar agreements. The adoption of IFRS 7 did not have an impact on the Corporation's financial statements.

FUTURE CHANGES IN ACCOUNTING POLICIES

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 de-recognition. 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, 2015, 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.

RISK FACTORS AND UNCERTAINTIES

Manitok monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations or taxation. In addition, Manitok maintains a level of liability and property insurance which is believed to be adequate for the Corporation's size and activities, but is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims. See "Forward-Looking Information" in this MD&A and "Risk Factors" in Manitok's most recently filed Annual Information Form for additional information.

IMPACT OF NEW ENVIRONMENTAL REGULATIONS

Environmental legislation, including the Kyoto Accord, the federal government's "EcoACTION" plan and Alberta's Bill 3 - *Climate Change and Emissions Management Amendment Act*, is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Given the evolving nature of the debate related to climate change and the resulting requirements, it is not possible to determine the operational or financial impact of those requirements on Manitok.

CONDENSED INTERIM STATEMENTS OF FINANCIAL POSITION

Unaudited *(Expressed in thousands of Canadian dollars)*

As at	**March 31, 2013**	December 31, 2012
ASSETS		
Current assets:		
Cash	**1,169**	145
Accounts receivable	**9,209**	7,023
Deposits and prepaid expenses	**466**	529
Fair value of financial instruments (note 12)	**146**	1,423
	10,990	9,120
Non-current assets:		
Exploration and evaluation (note 5)	**21,838**	20,311
Petroleum and natural gas properties and equipment (note 6)	**102,820**	96,891
	124,658	117,202
	135,648	126,322
LIABILITIES		
Current liabilities:		
Accounts payable and accrued liabilities	**17,198**	14,558
Credit facilities (note 7)	**7,130**	3,101
Fair value of financial instruments (note 12)	**3,636**	1,878
	27,964	19,537
Non-current liabilities:		
Flow-through share premium (note 9e)	**827**	877
Decommissioning obligations (note 8)	**11,555**	11,476
Deferred income taxes	**4,278**	3,995
	16,660	16,348
	44,624	35,885
SHAREHOLDERS' EQUITY		
Share capital (note 9)	**102,704**	102,668
Contributed surplus	**4,439**	3,753
Deficit	**(16,119)**	(15,984)
	91,024	90,437
Commitments (note 15)		
	135,648	126,322

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

APPROVED BY THE BOARD

(signed) *"Bruno P. Geremia"*
Bruno P. Geremia CA, Director

(signed) *"Massimo M. Geremia"*
Massimo M. Geremia, Director

CONDENSED INTERIM STATEMENTS OF NET LOSS AND COMPREHENSIVE LOSS

Unaudited *(Expressed in thousands of Canadian dollars, except for share information)*

Three months ended,	**March 31, 2013**	March 31, 2012
REVENUE		
Petroleum and natural gas	**18,021**	6,061
Royalty expenses	**(5,202)**	(929)
Realized gain on financial instruments	**278**	9
Interest and other	**36**	-
	13,133	5,141
EXPENSES		
Operating, net	**2,949**	1,952
Transportation and marketing	**902**	285
Administrative, net	**1,770**	1,180
Depletion and depreciation (note 6)	**4,214**	3,299
	9,835	6,716
INCOME (LOSS) FROM OPERATIONS	**3,298**	(1,575)
Finance expenses	**165**	282
Loss on divestitures	**-**	19
Unrealized loss on financial instruments (note 12)	**3,035**	526
INCOME (LOSS) BEFORE INCOME TAXES	**98**	(2,402)
Deferred income tax expense	**233**	57
TOTAL NET LOSS AND COMPREHENSIVE LOSS	**(135)**	(2,459)
Net loss per common share (note 11)		
basic	**-**	(0.04)
diluted	**-**	(0.04)

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

CONDENSED INTERIM STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

Unaudited *(Expressed in thousands of Canadian dollars, except for share information)*

	Number of Common Shares	Share Capital	Contributed Surplus	Deficit	Total
As at December 31, 2011	61,800,531	87,483	2,157	(13,327)	76,313
Net loss for the period	-	-	-	(2,459)	(2,459)
Stock-based compensation expensed (note 10)	-	-	271	-	271
Stock-based compensation capitalized (note 10)	-	-	172	-	172
As at March 31, 2012	61,800,531	87,483	2,600	(15,786)	74,297
As at December 31, 2012	70,339,014	102,668	3,753	(15,984)	90,437
Net loss for the period	-	-	-	(135)	(135)
Issued on exercise of stock options (note 9)	18,166	36	(14)	-	22
Stock-based compensation expensed (note 10)	-	-	444	-	444
Stock-based compensation capitalized (note 10)	-	-	256	-	256
As at March 31, 2013	**70,357,180**	**102,704**	**4,439**	**(16,119)**	**91,024**

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

CONDENSED INTERIM STATEMENTS OF CASH FLOWS

Unaudited *(Expressed in thousands of Canadian dollars)*

Three months ended,	**March 31, 2013**	March 31, 2012
Cash provided by (used in):		
OPERATING ACTIVITIES:		
Net loss	**(135)**	(2,459)
Adjustments for items not affecting operating cash:		
Deferred income tax expense	**233**	57
Depletion and depreciation expense	**4,214**	3,299
Stock-based compensation expense	**444**	271
Finance expenses	**165**	282
Unrealized loss on financial instruments	**3,035**	526
Loss on divestitures	**-**	19
Interest expense	**(95)**	(25)
Decommissioning expenditures (note 8)	**(110)**	(2)
Changes in non-cash operating working capital	**(2,532)**	(2,164)
	5,219	(196)
FINANCING ACTIVITIES:		
Increase (decrease) in credit facilities	**4,029**	9,630
Proceeds from the exercise of stock options	**22**	-
	4,051	9,630
INVESTING ACTIVITIES:		
Acquisition of petroleum and natural gas properties and equipment	**67**	(187)
Exploration and evaluation asset expenditures	**(1,484)**	(9,459)
Petroleum and natural gas properties and equipment expenditures	**(9,878)**	(31)
Changes in non-cash investing working capital	**3,049**	243
	(8,246)	(9,434)
NET INCREASE (DECREASE) IN CASH	**1,024**	-
CASH, BEGINNING OF PERIOD	**145**	145
CASH, END OF PERIOD	**1,169**	145
Cash interest paid	**66**	25
Cash taxes paid	**-**	-

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

1. REPORTING ENTITY AND NATURE OF OPERATIONS

Manitok Energy Inc. ("**Manitok**" or the "**Corporation**") is domiciled and incorporated in Canada. The Corporation is engaged in the exploration for, and the development, production and acquisition of petroleum and natural gas reserves in Western Canada. Manitok conducts its operations in the Western Canadian Sedimentary Basin and 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. Manitok is listed on the TSX Venture Exchange ("**TSX-V**") under the symbol "**MEI**".

These unaudited interim condensed financial statements (the "**Financial Statements**") were approved and authorized for issuance by the Board of Directors on May 28, 2013.

2. BASIS OF PREPARATION

The Financial Statements present Manitok's financial results of operations and financial position under International Financial Reporting Standards ("**IFRS**") as at and for the three months ended March 31, 2013, including the 2012 comparative period. The Financial Statements have been prepared in accordance with International Accounting Standard ("**IAS**") 34 *Interim Financial Reporting*, as issued by the International Accounting Standards Board ("**IASB**").

The Financial Statements have been prepared following the same IFRS accounting policies and methods of computation, including significant accounting judgments, estimates, and assumptions, as the annual audited financial statements for the year ended December 31, 2012, except as detailed below in note 3. Certain information and disclosures normally required to be included in the notes to the annual audited financial statements have been condensed, omitted or have been disclosed on an annual basis only. Accordingly, these Financial Statements should be read in conjunction with the annual audited financial statements and the notes thereto for the year ended December 31, 2012.

The 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. The Financial Statements include the accounts of Manitok only and are expressed in Canadian dollars, unless otherwise stated. There are no subsidiary companies.

3. CHANGES IN ACCOUNTING POLICIES

On January 1, 2013, the Corporation adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), fair value measurements (IFRS 13) and amendments to financial instruments disclosures (IFRS 7). The adoption of these standards had no impact on the amounts recorded in the Financial Statements as at January 1, 2013 or on the comparative periods.

4. DETERMINATION OF FAIR VALUES

A number of the Corporation's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Unaudited (Tabular amounts expressed in thousands of Canadian dollars, except for share information)

The Corporation's financial instruments recorded at fair value require disclosure about how the fair value was determined based on significant levels of inputs described in the following hierarchy:

- 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 following table provides fair value measurement information for financial assets and liabilities as of March 31, 2013. The carrying value of cash, accounts receivables, deposits and accounts payables and accrued liabilities included in the Statement of Financial Position approximate fair value due to the short-term nature of those instruments and are not included in the following table.

	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Financial assets					
Fair value of financial instruments	146	146	-	146	-
Financial liabilities					
Drawn credit facilities (note 7)	7,130	7,130	7,130	-	-
Fair value of financial instruments	3,636	3,636	-	3,636	-

5. EXPLORATION AND EVALUATION ASSETS

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

	Total
Balance, December 31, 2011	24,308
Additions(1)	33,957
Transfer to petroleum and natural gas properties and equipment(1)	(37,003)
Exploration and evaluation expense	(951)
Balance, December 31, 2012	20,311
Additions(1)	1,527
Balance, March 31, 2013	**21,838**

(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 $143,000 in the three months ended March 31, 2013 (March 31, 2012 – $373,000). There were no costs reclassified from E&E to petroleum and natural gas properties and equipment during the three months ended March 31, 2013.

Unaudited (Tabular amounts expressed in thousands of Canadian dollars, except for share information)

6. 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			
Balance, December 31, 2011	88,143	604	88,747
Additions	17,060	285	17,345
Asset acquisition	75	-	75
Asset divestiture[1]	(23,177)	-	(23,177)
Transfer from E&E assets (note 5)	37,003	-	37,003
Change in decommissioning obligations	(509)	-	(509)
Balance, December 31, 2012	118,595	889	119,484
Additions	10,001	194	10,195
Asset acquisition	(67)	-	(67)
Change in decommissioning obligations	15	-	15
Balance, March 31, 2013	**128,544**	**1,083**	**129,627**
Accumulated depletion and depreciation and impairment			
Balance, December 31, 2011	(15,102)	(130)	(15,232)
Asset divestiture[1]	9,526	-	9,526
Depletion and depreciation expense	(12,362)	(135)	(12,497)
Impairment expense	(4,390)	-	(4,390)
Balance, December 31, 2012	(22,328)	(265)	(22,593)
Depletion and depreciation expense	(4,154)	(60)	(4,214)
Balance, March 31, 2013	**(26,482)**	**(325)**	**(26,807)**
Net book value			
Balance, December 31, 2012	96,267	624	96,891
Balance, March 31, 2013	**102,062**	**758**	**102,820**

(1) In April 2012, the Corporation completed a transaction whereby it disposed of non-core petroleum assets in the Swimming area of Alberta for proceeds of $13.2 million after post-closing adjustments and related expenses. As a result of the disposition, the Corporation recorded a loss of $0.5 million in 2012.

At March 31, 2013, estimated future development costs of $58.1 million (December 31, 2012 – $69.4 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 $425,000 in the three months ended March 31, 2013 (March 31, 2012 - $89,000).

Manitok credited asset acquisitions for $67,000 in the three months ended March 31, 2013, which relates to post-closing adjustments to the asset acquisition as described in note 8 of the Corporation's annual audited financial statements for the year ended December 31, 2012.

Unaudited (Tabular amounts expressed in thousands of Canadian dollars, except for share information)

7. CREDIT FACILITIES

The components of the Corporation's credit facilities include:

	March 31, 2013	December 31, 2012
Revolving operating demand loan facility	**7,130**	3,101
Acquisition and development demand loan facility	**-**	-
Credit facilities	**7,130**	3,101

On February 4, 2013, the Corporation closed an arrangement with the National Bank of Canada for a $70.0 million revolving operating demand loan facility and a $20.0 million acquisition and development demand loan facility, for total credit facilities of $90.0 million. The credit facilities are secured by a fixed charge debenture on the assets of the Corporation.

Advances under the credit facilities are available by way of Canadian prime rate loans and bankers' acceptances at the prevailing interest rates plus borrowing margins based on a pricing grid dependent on the net debt to cash flow ratio (as defined by the lender) calculated at the Corporation's previous quarter end. Standby fee are charged on the undrawn facilities.

The lending agreement provides for a financial covenant that requires the Corporation to maintain a working capital ratio (current assets excluding the fair value of financial instruments plus any undrawn portion of the credit facilities divided by current liabilities excluding any current portion of an amount drawn on the credit facilities and the fair value of financial instruments) of at least 1:1. As of March 31, 2013, the Company was compliant with the covenant.

The credit facilities review is currently underway, and the Corporation does not anticipate any changes. The lender may initiate a review 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 review date for the credit facilities has been proposed for November 1, 2013.

The revolving credit facility of $30.0 million with Alberta Treasury Branch was cancelled on February 4, 2013.

8. DECOMMISSIONING OBLIGATIONS

The Corporation's decommissioning obligations result from net ownership interests in petroleum and natural gas properties and equipment including well sites and facilities. Manitok estimates the total undiscounted amount of cash flows required to settle its decommissioning obligations as at March 31, 2013 to be approximately $19.4 million (December 31, 2012 – $18.8 million) with the majority of costs anticipated to be incurred between 2017 and 2035. A risk-free discount rate of 2.5% (December 31, 2012 – 2.4%) and an inflation rate of 2% (December 31, 2012 – 2%) was used to calculate the fair value of the decommissioning obligation.

A reconciliation of the decommissioning obligations is provided below:

	March 31, 2013	December 31, 2012
Opening Balance	**11,476**	11,721
Obligations incurred	**395**	659
Obligations acquired (disposed), net	**-**	(1,836)
Actual expenditures	**(110)**	(703)
Changes in estimates[(1)]	**(276)**	1,372
Accretion expense	**70**	263
Ending Balance	**11,555**	11,476

(1) Changes are largely due to the revision in both the abandonment and remediation cost estimates and future abandonment dates of Manitok's wells and facilities along with a change in the risk-free discount rate.

Unaudited (Tabular amounts expressed in thousands of Canadian dollars, except for share information)

9. 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
Outstanding, December 31, 2011	**61,800,531**	**87,483**
Issued, net of costs (note 9c)	3,026,316	5,266
Issued, net of costs (note 9d)	1,430,000	2,471
Issued, net of costs (note 9e)	4,000,000	6,847
Tax effect of share issue costs (note 9f)	-	371
Issued on exercise of stock options (note 10)	156,667	343
Normal course issuer bid (note 9g)	(74,500)	(113)
Outstanding, December 31, 2012	**70,339,014**	**102,668**
Issued on exercise of stock options (note 10)	18,166	36
Outstanding, March 31, 2013	**70,357,180**	**102,704**

(c) On October 16, 2012, Manitok closed a bought deal equity financing completed by way of a short form prospectus, for the issuance of 3,026,316 common shares of Manitok ("**Manitok Shares**") at a price of $1.90 per Manitok Share for net proceeds of $5.3 million.

(d) On October 16, 2012, Manitok closed a bought deal equity financing completed by way of a short form prospectus, for the issuance of 1,430,000 Manitok Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian development expense ("**Manitok CDE Flow-through Shares**") at a price of $2.10 per Manitok CDE Flow-through Share for total net proceeds of $2.8 million. The Corporation had until December 31, 2012 to incur the $3.0 million in development expenditures. The amount recorded to share capital from the issuance of Manitok CDE Flow-through Shares reflects the fair market value of Manitok Shares, which was $1.90 per Manitok Share less share issue costs. The difference between the total value of Manitok CDE Flow-through Shares and the fair value of Manitok Shares of $0.3 million was initially recognized as a liability on the Statement of Financial Position when the Manitok CDE Flow-through Shares were issued. In the year ended December 31 2012, the Corporation had fulfilled the entire $3.0 million of eligible development expenditures and had fully reversed the $0.3 million liability.

(e) On October 16, 2012, Manitok closed a bought deal equity financing completed by way of a short form prospectus, for the issuance of 4,000,000 Manitok Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian exploration expense ("**Manitok CEE Flow-through Shares**") at a price of $2.30 per Manitok CEE Flow-through Share for total net proceeds of $8.4 million. The Corporation has until December 31, 2013 to incur the $9.2 million in exploration expenditures. The amount recorded to share capital from the issuance of Manitok CEE Flow-through Shares reflects the fair market value of Manitok Shares, which was $1.90 per Manitok Share less share issue costs. The difference between the total value of Manitok CEE Flow-through Shares and the fair value of Manitok Shares of $1.6 million was initially recognized as a liability on the Statement of Financial Position when the Manitok CEE Flow-through Shares were issued. As at March 31, 2013, the Corporation had fulfilled $4.5 million of eligible exploration expenditures and has reversed $0.8 million of the liability.

(f) Manitok recognized a future income tax benefit of $0.4 million in respect of share issue costs of $1.5 million incurred with respect to the issuance of 3,026,316 Manitok Shares, 1,430,000 Manitok CDE Flow-through Shares and 4,000,000 Manitok CEE Flow-through Shares on October 16, 2012.

Unaudited (Tabular amounts expressed in thousands of Canadian dollars, except for share information)

(g) On June 15, 2012, the TSX-V authorized the Corporation's notice to make a normal course issuer bid (**"NCIB"**) to purchase for cancellation up to 4.4 million Manitok Shares on the open market during the period from June 18, 2012 to June 17, 2013. On January 28, 2013, Manitok received approval of the TSX-V to increase the number of Manitok Shares that may be repurchased under the NCIB to an aggregate of up to 5.8 million Manitok Shares. As at March 31, 2013, the Corporation has purchased a total of 74,500 Manitok Shares for cancellation at a weighted average price of $1.21 per share which excludes the fees incurred to implement the NCIB program. The excess of the book value over the purchase price of $14,000 has been charged to contributed surplus.

10. STOCK-BASED COMPENSATION

Stock Options

The Corporation established an Incentive Stock Option Plan (the "**Plan**") on June 25, 2010 whereby officers, directors and employees of, and consultants and advisors to, the Corporation 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 March 31, 2013, the Corporation's Plan permitted the grant of options to a maximum of 7,035,718 Manitok Shares and there remained available for issuance stock options in respect of 633,618 Manitok Shares.

A summary of the Corporation's outstanding stock options as at March 31, 2013 is presented below:

	Number	Weighted Average Exercise Price ($)
Outstanding, December 31, 2011	**3,845,000**	**1.30**
Granted	1,380,500	1.88
Exercised	(156,667)	1.34
Cancelled or forfeited	(285,000)	1.38
Outstanding, December 31, 2012	**4,783,833**	**1.46**
Granted	1,656,100	3.12
Exercised	(18,166)	1.17
Cancelled or forfeited	(19,667)	1.64
Outstanding, March 31, 2013	**6,402,100**	**1.89**

The range of exercise prices for stock options outstanding and exercisable under the plan at March 31, 2013 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	$1.50	2,816,500	2.7	$1.17	1,730,334	2.6	$1.16
$1.51	$3.25	3,585,600	4.2	$2.45	597,003	3.6	$1.80
		6,402,100	**3.5**	**$1.89**	**2,327,337**	**2.9**	**$1.33**

Stock-Based Compensation Expense

In order to calculate stock-based 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 months ended March 31, 2013, the Corporation recorded $444,000 (March 31, 2012 – $271,000) of stock-based compensation expense, net of $256,000 (March 31, 2012 – $172,000) 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 4.4% for vesting option tranches during the three months ended March 31, 2013 (March 31, 2012 – 0.9%).

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 March 31,	
	2013	2012
Weighted average fair value of options granted	**$1.91**	$1.25
Risk-free interest rate	**1.39%**	1.16%
Expected life (years)	**4.1**	4.2
Expected volatility	**83.2%**	95.5%
Expected dividends	**-**	-

11. PER SHARE INFORMATION

	Three months ended March 31,	
	2013	2012
Net loss ($000)	**(135)**	(2,459)
Weighted average Manitok Shares outstanding - basic	**70,348,151**	61,800,531
Weighted average Manitok Shares outstanding - diluted	**70,348,151**	61,800,531
Net loss per share – basic ($)	**-**	(0.04)
Net loss per share – diluted ($)	**-**	(0.04)

As the Corporation reported a net loss for the three months ended March 31, 2013 and 2012, the basic and diluted weighted average Manitok Shares outstanding are the same for these periods.

12. FINANCIAL RISK MANAGEMENT & RISK MANAGEMENT CONTRACTS

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. Management identifies and analyzes the risks faced by the Corporation, sets appropriate risk limits and controls, monitors risks and market conditions and the Corporation’s activities.

The Corporation attempts to mitigate commodity price risk through the use of various derivative financial instruments. The Corporation does not apply hedge accounting for these contracts. Manitok’s production is sold on a spot basis, with prices fixed at the time of transfer or on the basis of a monthly average market price. The Corporation does not enter into commodity derivative financial instruments other than to meet its expected sale requirements.

The fair value of derivative financial instruments is based on option models that use published information with respect to volatility, prices and interest rates. The fair value of derivative financial instruments are determined by discounting the difference between the contracted prices and published forward price curves as at the date of the Statement of Financial Position, using the remaining contracted volumes and a risk-free interest rate.

Unaudited (Tabular amounts expressed in thousands of Canadian dollars, except for share information)

As at March 31, 2013, the Corporation held the following derivative financial instruments:

Subject of Contract	Notional Quantity	Remaining Term	Reference	Average Strike Price	Contract Traded	Fair Value
Oil	300 bbls/d	April 1, 2013 to December 31, 2013	CAD$ WTI	$97.65	Swap	(90)
Oil	150 bbls/d	April 1, 2013 to December 31, 2013	CAD$ WTI	$98.00	Swap	(31)
Oil	300 bbls/d	April 1, 2013 to June 30, 2013	CAD$ WTI	$98.00	Swap	(33)
Oil	300 bbls/d	April 1, 2013 to December 31, 2013	CAD$ WTI	$95.10	Swap	(296)
Oil	300 bbls/d	April 1, 2013 to December 31, 2013	CAD$ WTI	$100.50	Swap	146
Oil	250 bbls/d	May 1, 2013 to December 31, 2013	CAD$ WTI	$97.00	Swap	(103)
Oil	1,250 bbls/d	April 1, 2013 to June 30, 2013	CAD$ EDM-WTI Diff	$5.70	Swap	(371)
Oil	500 bbls/d	July 1, 2013 to December 31, 2013	CAD$ EDM-WTI Diff	$6.80	Swap	(85)
Natural gas	5,000 GJs/d	April 1, 2013 to December 31, 2013	CAD$ AECO	$3.40	Put(1)	(235)
Natural gas	5,000 GJs/d	April 1, 2013 to December 31, 2013	CAD$ AECO	$3.40	Put(2)	(292)
Oil	500 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$98.00	Swaption(3)	(269)
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$97.65	Swaption(4)	(713)
Oil	250 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$98.00	Swaption(5)	(344)
Oil	600 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$100.00	Swaption(6)	(528)
Oil	300 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$100.50	Swaption(7)	(246)
Total						**(3,490)**

(1) The counter-party to this contract receives a deferred put option premium of $0.35/Gigajoule.
(2) The counter-party to this contract receives a deferred put option premium of $0.39/Gigajoule.
(3) The counter-party to this contract holds a one-time option no later than June 28, 2013 to extend a swap on 500 barrels per day of oil at CAD$98.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.
(4) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 500 barrels per day of oil at CAD$97.65 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.
(5) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 250 barrels per day of oil at CAD$98.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.
(6) The counter-party to this contract holds a one-time option no later than December 30, 2013 to extend a swap on 600 barrels per day of oil at CAD$100.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.
(7) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 300 barrels per day of oil at CAD$100.50 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract

As at March 31, 2013, a 10% decrease to the forward price curves outlined in the swap contracts above would result in approximately $2.3 million of additional pre-tax income.

Subsequent to March 31, 2013, the Corporation entered into the following derivative financial instruments:

Subject of Contract	Volume	Term	Reference	Strike Price	Contract Traded
Oil	400 bbls/d	June 1, 2013 to December 31, 2013	CAD$ WTI	$99.40	Swap(1)
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$96.00	Swap(2)

(1) The counter-party to this contract holds a one-time option no later than December 31, 2013 to extend a swap on 400 barrels per day of oil at CAD$99.40 for the 2014 calendar period.
(2) The counter-party to this contract holds a one-time option no later than December 31, 2014 to extend a swap on 500 barrels per day of oil at CAD$96.00 for the 2015 calendar period.

13. 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 execute its capital expenditure program; preserve its ability to meet financial obligations, including potential obligations arising from acquisitions; to maintain a capital structure that allows Manitok to finance its growth strategy using primarily 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.

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 Manitok Shares or debt, increase 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.

Unaudited (Tabular amounts expressed in thousands of Canadian dollars, except for share information)

There were no changes in the Corporation's approach to capital management during the March 31, 2013 reporting period.

The following table shows the Corporation's total available credit:

As at,	**March 31, 2013**	December 31, 2012
Maximum borrowing base limit(1)(2)		
Revolving operating demand loan facility	**70,000**	30,000
Acquisition and development demand loan facility(3)	**20,000**	-
	90,000	30,000
Principle amount utilized		
Drawn revolving operating demand loan facility	**(7,130)**	(3,101)
Drawn acquisition and development demand loan facility	**-**	-
Outstanding letters of credit(4)	**-**	(100)
	(7,130)	(3,201)
Undrawn credit facilities	**82,870**	26,799

(1) The Corporation's credit facilities are subject to a review of the borrowing base limit by the lender at any time in its sole discretion, and at least annually, which is directly impacted by the value of Manitok's petroleum and natural gas reserves. The next review date for the credit facilities has been proposed for November 1, 2013.
(2) The Corporation's lender requires quarterly compliance that the working capital ratio (current assets excluding the fair value of financial instruments plus any undrawn portion of the credit facilities divided by current liabilities excluding any current portion of an amount drawn on the credit facilities and the fair value of financial instruments) is not less than 1:1. Manitok was in compliance with the financial covenant as at March 31, 2013 and December 31, 2012.
(3) The acquisition and development demand loan facility is restricted by the Corporation's lender to assist in the acquisition of producing petroleum and natural gas reserves and/or development of proved non-producing/undeveloped petroleum and natural gas reserves.
(4) Letters of credit are issued to service providers. The December 31, 2012 letter of credit was returned to the Corporation during the three months ended March 31, 2013. There were no amounts drawn on letters of credit during the three months ended March 31, 2013.

The capital structure of the Corporation is as follows:

As at,	**March 31, 2013**	December 31, 2012
Shareholders' equity(1)	**91,024**	90,437
Shareholders' equity as a % of total capital	**87%**	90%
Working capital deficiency(2)	**6,354**	6,861
Drawn on credit facilities	**7,130**	3,101
Total net debt	**13,484**	9,962
Total net debt as a % of total capital	**13%**	10%
Total Capital	**104,508**	100,399

(1) Shareholders' equity is defined as share capital plus contributed surplus plus retained earnings (deficit).
(2) Working capital deficiency is defined as current assets less current liabilities excluding the current portion of the amount drawn on the credit facilities and the fair value of financial instruments.

14. RELATED PARTY TRANSACTIONS

The Corporation is a related party to Amarok Energy Inc. ("**Amarok**") as a result of common key management personnel. Currently, Manitok operates entirely in Canada and its strategy is to pursue opportunities within Canada. Currently, it is the Corporation's understanding that Amarok has implemented a strategy of pursuing opportunities outside of Canada. Manitok does not anticipate any changes to its strategy in the foreseeable future.

- Amarok participated in the drilling of one well in the Stolberg area in 2012. Under the terms of the farm-in agreement, Amarok paid 12% of the drilling and completion costs and 8% of the equipping costs to earn an 8% net revenue interest in the well. This participation was in the normal course of the Corporation's business and is measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties and is on comparable terms and conditions to those of other joint interest partners. Amarok made a total net capital expenditure payment of $0.8 million to Manitok.

Unaudited (Tabular amounts expressed in thousands of Canadian dollars, except for share information)

Included in accounts payable and accrued liabilities as at March 31, 2013 is $30,400 (December 31, 2012 - $24,700) due to Amarok, relating to its net interest in the operations of the well.

- During the three months ended March 31, 2013, the Corporation recorded $3,000 (March 31, 2012 – $NIL) as a reduction to rent expense related to the sub-lease of one office to Amarok, which commenced in September 2012. The office lease is in the normal course of operations and is measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties and which is comparable to those negotiated with third parties. Included in accounts receivable as at March 31, 2013 is $1,000 (December 31, 2012 - $2,100) related to March 2013 rent.
- The Corporation provides oil and gas technical services to Amarok. Consideration for providing these services is based on a reimbursement of costs incurred by Manitok. The Corporation recorded $101,000 as a reduction of administrative expenses in the three months ended March 31, 2013 (March 31, 2012 - $NIL). Included in accounts receivable as at March 31, 2013 is $106,000 (December 31, 2012 - $NIL) due from Amarok, related to the technical services provided by Manitok.

15. COMMITMENTS

The Corporation is committed to incur exploration expenditures of $9.2 million on or before December 31, 2013, related to the Manitok CEE Flow-through Share issuance completed on October 16, 2012, as indicated in note 9e. Manitok will be subject to Part XII.6 tax pursuant to the *Income Tax Act* (Canada), based on the prescribed rate on the balance of exploration expenditures not yet incurred at the end of each month subsequent to January 31, 2013, which is estimated to be $8,000 at March 31, 2013. As at March 31, 2013, the costs incurred for exploration expenditures were approximately $4.5 million leaving about $4.7 million to be spent on or before December 31, 2013.

The Corporation is committed to the following aggregate minimum lease payments including expected operating costs and taxes relating to its current office lease which expires on February 28, 2017**:**

Year	
2013	570
2014	760
2015	774
2016	785
2017	131

OFFICERS

Massimo M. Geremia
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

DIRECTORS

Bruno P. Geremia, C.A. [1,2,3]
Chairman of the Board
Calgary, Alberta

Robert J. Dales [1,2]
Calgary, Alberta

Wilfred A. Gobert [2,3]
Calgary, Alberta

Gregory E. Peterson, LL.B. [3]
Calgary, Alberta

Tom Spoletini [1,2,3]
Calgary, Alberta

Cameron G. Vouri, P. Eng. [1]
Calgary, Alberta

Massimo M. Geremia [1,2]
Calgary, Alberta

SOLICITOR
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Calgary, Alberta

AUDITOR
Kenway Mack Slusarchuk Stewart LLP
Chartered Accountants
Calgary, Alberta

INDEPENDENT RESERVE EVALUATOR
Sproule Associates Limited
Calgary, Alberta

BANKER
National Bank of Canada
Calgary, Alberta

TRANSFER AGENT
Valiant Trust Company
Calgary, Alberta

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TSX Venture Exchange
Symbol: MEI

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[1] *Reserve and Occupational Health & Safety Committee Member*
[2] *Audit Committee Member*
[3] *Compensation Committee Member*

MANITOK ENERGY INC.