MANITOK ENERGY INC.

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

Dear Fellow Shareholders,

Manitok is pleased to report its second quarter financial results for the three and six months ended June 30, 2013. Operational and financial highlights in the second quarter include:

- An increase in average production by 133% to 4,045 boe/d for the second quarter of 2013 from 1,733 boe/d for the comparable period in 2012.
- Increased the crude oil and NGLs weighting to 52% of total production in the second quarter of 2013 from 22% of total production in the second quarter of 2012.
- Funds from operations increased by 356% to $11.3 million ($0.16 per share) in the second quarter of 2013 from $2.5 million ($0.04 per share) for the comparable period in 2012.
- Operating netback increased by 47% to $34.73 per boe for the second quarter of 2013 from $23.60 per boe for the comparable period in 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 100% and 292%, respectively, while decreasing net debt to $9.2 million as at June 30, 2013 from $10.9 million as at June 30, 2012.
- Total operating costs in the second quarter of 2013 were $6.42 per boe net of recoveries and $7.06 per boe prior to recoveries, which is 27% and 36% lower, respectively, on a boe basis, than the comparable period last year. Transportation and marketing costs were $2.93 per boe, up from $1.87 per boe in the comparable period last year due mainly to the increased proportion of oil production.
- Manitok's capital expenditures before divestitures for the second quarter of 2013 were $9.6 million, which is down 11% from $10.8 million in the comparable quarter in 2012.
- Drilled 4 gross (1.5 net) wells in the second quarter of 2013, 3 (1.0 net) in the Stolberg area of Alberta and 1 (0.5 net) in the Cabin Creek area of Alberta.
- Completed a disposition of royalty interest properties for total cash consideration of $3.3 million.
- As at June 30, 2013, Manitok had net debt of approximately $9.2 million and unused credit facilities of $90.0 million.
- Purchased 282,700 shares at an average price of $2.54 in the quarter pursuant to its normal course issuer bid ("**NCIB**"). Subsequent to the second quarter, the Corporation has acquired an additional 1,087,100 shares at an average price of $2.65 per share under its NCIB program.
- Increased net income to $4.8 million ($0.07/share) for the second quarter of 2013 from $0.5 million ($0.01/share) for the comparable period in 2012. The income in the second quarter of 2013 included a gain on divestiture of $0.7 million compared to loss on divestiture of $0.4 million in the second quarter of 2012.

Operations Update

Based on recent field estimates, current corporate production is approximately 4,240 boe/d (47.5% crude oil and condensate, 0.5% NGLs). The field estimates include a contribution of about 300 bbls/d of oil from the four well pad, which was recently drilled in the Stolberg area. The 4 (1.33 net) wells on the pad are expected to be on full production by early October and are anticipated to add another 200 to 300 bbls/d to net production. Manitok is currently drilling 2 (1.5 net) wells at Stolberg. One is the first horizontal well of an expected 2 (1.6 net) well pad targeting Cardium oil on section 29, which has produced over 575,000 bbls of light oil (454,000 net) from 3 (2.4 net) wells over the last 14 months. The second is a liquids rich natural gas well (0.75 net), offsetting a Manitok liquids rich gas well drilled in 2011. That well initially flowed at approximately 5.0 Mmcf/d (3.75 net) with about 10.0 bbls/Mmcf (7.5 net) of wellhead condensate and has produced nearly 3.0 Bcf (2.25 net) of natural gas and approximately 22,000 bbls (16,500 net) of condensate over the course of about two years. The current drill will intersect the same Ostracod pool and is ultimately targeting a repeat of the same zone about 100 to 250 metres deeper. If successful, Manitok intends to produce the two zones separately within the same wellbore.

Normal Course Issuer Bid

As of today, Manitok has purchased a total of 1,369,800 shares for approximately $3.6 million (average price of $2.62 per share) in 2013, pursuant to its NCIB programs. Management believes that with potential acquisition values ranging from 5 to 7 times next year's projected funds from operations, buying Manitok shares at less than 3 to 4 times next year's projected funds from operations under its NCIB program is advantageous to Manitok shareholders with a longer term view.

2013 Guidance

Assuming drilling success based on Manitok's expected outcomes and applied risk parameters, Manitok expects to exit 2013 with production ranging from 5,300 to 5,500 boe/d (approximately 55% to 57% crude oil and condensate, 0.5% NGLs), which would be a 40% to 45% increase over the 2012 exit production rate. At that production level, funds from operations is estimated to be $5.7 to $6.0 million per month, which would be an increase of approximately 50% over the 2012 exit funds from operations rate. It is anticipated that there will be an additional 400 to 500 boe/d of production (about 85% crude oil) added in the first quarter of 2014 where the majority of the capital expenditures relating to that production will be incurred in the fourth quarter of 2013.

Manitok has increased its 2013 capital expenditure budget by 7% to approximately $76.0 million or $72.6 million net of dispositions. This is an increase of $5.0 million to the previously guided $71.0 million which was made up of $63.0 million for drilling, completions, tie-ins and equipping and $8.0 million for land and seismic. The increased $76.0 million of capital expenditures is made up of $70.0 million of drilling, completions, tie-ins and equipping and $6.0 million of land and seismic. The updated forecast includes 19 (12.1 net) wells with all but 2 (1.75 net) targeting Cardium light oil predominantly in the Stolberg area and also in the Cabin Creek and Quirk Creek areas. The first of the two wells not targeting Cardium is a vertical liquids rich natural gas well targeting an Ostracod pool (mentioned in the operations section above) and the second is an exploration well targeting an oil zone other than the Cardium in a new area. The increased capital budget will be financed with funds from operations and Manitok's existing $90.0 million credit facilities with the National Bank of Canada.

Average production in 2013 is expected to range between 4,200 to 4,400 boe/d (approximately 52% crude oil and condensate, 0.5% NGLs), which would be an increase of 76% to 84% over its 2012 average production. Manitok anticipates funds from operations to be $48.0 to $50.0 million, which is lower than the previous guidance of $55.0 to $57.0 million. However, it still results in an anticipated increase of over 150% from funds from operations in 2012. The main reasons for the decrease are timing delays of new production additions due to drilling four wells on one pad versus drilling four wells on two pads, lower working interests in wells than previously budgeted due to a pooling agreement, and a lower oil weighting than anticipated, decreasing from 57% to 52% on total production for 2013, due mostly to adding a liquids rich gas well to the 2013 drilling program in lieu of an additional Cardium oil well. Manitok would like to caution the readers that changes to the drilling and production schedules may be necessary from time to time in order to capture value from new opportunities or gain efficiencies in its operations. Given the relatively low number of drills Manitok will execute in a one year period and the potentially high initial production rates associated with these wells, these changes may initially have a negative short term impact to funds from operations; however that does not materially change the ultimate value created over the life of the well.

After adjusting for the increased capital expenditures in 2013 and the shares purchased through our NCIB, net debt at the end of 2013 is now expected to range between $38.0 to $40.0 million. The net debt to twelve month trailing funds from operations ratio is anticipated to be about 0.8 times as at December 31, 2013 and the net debt to the exit funds from operations rate ratio is anticipated to be about 0.6 times as at December 31, 2013.

The 2013 re-forecasted budget assumes an average price of US$99.00/bbl of WTI crude oil, an average differential of $6.00/bbl, an average $CAD/$US exchange rate of 1.03 and an average price of $3.08/mmbtu of AECO natural gas which results in about a $3.60/mcf realized field price due to heat content. For 2013, royalties, combined operating and transportation costs net of recoveries, general and administrative expenses ("G&A") and interest are expected to average approximately $16.09, $9.06, $3.42 and $0.47 per boe respectively. The average operating netback for 2013 is anticipated to be approximately $34.28/boe, with a range of $23.85/boe at the beginning of the year to $43.34/boe at year end. The average funds from operations netback (operating netback, net of G&A and interest), is anticipated to be approximately $30.39/boe, ranging from $18.27/boe at the beginning of the year to $40.57/boe at year end.

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

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.

Management Addition

The Corporation is extremely pleased to announce the appointment of Ms. Yvonne McLeod as Vice-President, Drilling and Facilities. Ms. McLeod has been with Manitok for about 18 months, most recently as our Drilling Manager and has proven she has the technical expertise, leadership skills, integrity and passion to be an excellent member of Manitok's executive team.

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 June 30, **2013**	2012	Six months ended June 30, **2013**	2012
OPERATING				
Average daily production				
Natural gas (mcf/d)	**11,692**	8,134	**11,253**	9,091
Light oil (bbls/d)	**2,016**	301	**1,860**	184
Heavy oil (bbls/d)	**-**	-	**-**	189
NGLs (bbls/d)	**81**	76	**82**	82
Total (boe/d)	**4,045**	1,733	**3,817**	1,971
Average realized sales price (CAD$)				
Natural gas ($/mcf)	**3.95**	1.96	**3.83**	2.18
Light oil ($/bbl)	**89.77**	84.14	**89.46**	84.34
Heavy oil ($/bbl)	**-**	-	**-**	76.29
NGLs ($/bbl)	**73.92**	74.61	**79.14**	79.75
Total ($/boe)	**57.64**	27.08	**56.59**	28.59
Undeveloped Land (end of period)				
Gross (acres)	**258,069**	199,882	**258,069**	199,882
Net (acres)	**206,383**	147,908	**206,383**	147,908
NETBACK AND COST				
($ per boe)				
Petroleum and natural gas sales	**57.64**	27.08	**56.59**	28.59
Realized gain (loss) on financial instruments	**(0.96)**	2.11	**(0.11)**	0.95
Royalty income	**0.61**	0.32	**0.53**	0.35
Royalty (expenses) recovery	**(13.21)**	4.73	**(14.56)**	(0.51)
Operating expenses, net	**(6.42)**	(8.77)	**(7.69)**	(9.30)
Transportation and marketing expenses	**(2.93)**	(1.87)	**(2.86)**	(1.62)
Operating netback	**34.73**	23.60	**31.90**	18.46
General and administrative expenses, net	**(3.62)**	(7.71)	**(3.85)**	(5.92)
Interest and financing expenses	**(0.41)**	(0.17)	**(0.36)**	(0.14)
Interest and other income	**0.07**	0.03	**0.09**	0.01
Funds from operations netback(1)	**30.77**	15.75	**27.78**	12.41
FINANCIAL				
Petroleum and natural gas revenue ($000)	**21,441**	4,320	**39,462**	10,381
Funds from operations ($000)(1)	**11,324**	2,482	**19,185**	4,453
Per share – basic ($)(1)	**0.16**	0.04	**0.27**	0.07
Per share – diluted ($)(1)	**0.16**	0.04	**0.27**	0.07
Net income (loss) ($000)	**4,831**	499	**4,696**	(1,960)
Per share – basic ($)	**0.07**	0.01	**0.07**	(0.03)
Per share – diluted ($)	**0.07**	0.01	**0.06**	(0.03)
Common shares outstanding				
End of period – basic	**70,086,140**	61,736,031	**70,086,140**	61,736,031
End of period – diluted	**76,661,580**	66,571,531	**76,661,580**	66,571,531
Weighted average for the period – basic	**70,219,904**	61,797,394	**70,319,686**	61,798,962
Weighted average for the period – diluted	**72,139,108**	61,935,604	**72,290,765**	62,158,209
Capital expenditures, net ($000)	**6,335**	(2,364)	**17,630**	7,313
Working capital deficiency ($000)(2)	**9,226**	8,780	**9,226**	8,780
Drawn on credit facilities ($000)	**-**	2,135	**-**	2,135
Total net debt ($000)	**9,226**	10,915	**9,226**	10,915

(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 August 27, 2013. The unaudited condensed interim financial statements with respect to the three and six months ended June 30, 2013 (the "**Reporting Periods**") as compared to the three and six months ended June 30, 2012 (the "**Comparable Prior Periods**") and this MD&A have been prepared by management and approved by the Corporation's Audit Committee and Board of Directors. This MD&A should be read in conjunction with the unaudited condensed interim financial statements and related notes for the Reporting Periods 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 second quarter report for the Reporting Periods and the Comparable Prior Periods ("**Q2 Report**") are management's best estimates and are unaudited.*

Non-GAAP Measures

*This MD&A and the Q2 Report contains references to measures used in the oil and natural gas industry such as "funds from operations", "funds from operations netback", "funds from operations per share", "operating netback", "working capital deficiency (surplus)" and "net debt". These measures do not have standardized meanings prescribed by generally accepted accounting principles ("**GAAP**") 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 Q2 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 GAAP, 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 operation or funds from operations netback 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. Funds from operations or funds from operations netback is also derived from 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. Funds from operations per share denotes funds from operations divided by the weighted average number of shares outstanding. 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. 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 Q2 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 Q2 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

SECOND QUARTER OVERALL PERFORMANCE

Production

Production in the second quarter of 2013 averaged 4,045 boe/d (52% crude oil and NGLs), which is a 133% increase from the average of 1,733 boe/d (22% crude oil and NGLs) in the second quarter of 2012 and a 13% increase from the average of 3,586 boe/d (50% crude oil and NGLs) in the first quarter of 2013. The increase is due mainly to the Corporation's development of the Stolberg area which contributed 2,994 boe/d (67% crude oil and NGLs) in the second quarter of 2013 compared to 747 boe/d (37% crude oil and NGLs) in the second quarter of 2012 and 2,428 boe/d (70% crude oil and NGLs) in the first quarter of 2013.

No new wells were brought on-stream in the second quarter of 2013. The increased production from the first quarter of 2013 is due to a full quarter of production though permanent facilities in the southern end of the Stolberg trend, which was previously constrained under temporary facilities.

Commodity Prices

Average realized light oil prices in the second quarter of 2013 were $89.77/bbl, which is 7% higher than the average realized price of $84.14/bbl in the second quarter of 2012. Natural gas sales prices at the wellhead averaged $3.95/mcf in the second quarter of 2013, a 102% increase from $1.96/mcf in the second quarter of 2012, and NGL sales prices at the wellhead averaged $73.92/bbl in the second quarter of 2013, consistent with the $74.61/bbl received in the second quarter of 2012.

Canadian Edmonton Par oil prices averaged $92.94/bbl in the second quarter of 2013, an increase of 10% from $84.39/bbl in the second quarter of 2013. The AECO daily natural gas spot price averaged $3.54/mmbtu in the second quarter of 2013, an 86% increase from $1.90/mmbtu in the second quarter of 2012.

Manitok's average realized commodity price increased 113% to $57.64/boe in the second quarter of 2013 from $27.08/boe in the second quarter of 2012 due to the increase in light oil production from 18% of total production in the second quarter of 2012 to 50% of total production in the second quarter of 2013, 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 International Financial Reporting Standards ("**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 June 30,		**Six months ended June 30,**	
($000, except for share information)	**2013**	2012	**2013**	2012
Cash flow from operating activities	**10,187**	2,934	**15,406**	2,738
Adjustments				
Decommissioning expenditures	**20**	-	**130**	2
Changes in non-cash operating working capital	**1,117**	(452)	**3,649**	1,713
Funds from operations	**11,324**	2,482	**19,185**	4,453
per share – basic	**0.16**	0.04	**0.27**	0.07
per share – diluted	**0.16**	0.04	**0.27**	0.07

Funds from operations increased to $11.3 million ($0.16 per diluted share) for the second quarter of 2013 as compared to $2.5 million ($0.04 per share) in the second quarter of 2012. The increase in aggregate funds from operations and funds from operations per share were due to the significant increase in production volumes from the light oil drilling program in the Stolberg area.

Manitok had net income of $4.8 million ($0.07 per share) in the second quarter of 2013 as compared to net income of $0.5 million ($0.01 per share) in the second quarter of 2012. The increase in net income was attributable to the increase in revenue and funds from operations, coupled with the gain on divestiture during the quarter.

Capital Expenditures

Capital expenditures before acquisitions and divestitures amounted to $9.6 million in the second quarter of 2013 as compared to $10.8 million in the second quarter of 2012. Of the total capital spent, approximately $6.5 million was directed to drilling and completions, $1.8 million to equipping, facilities and tie-ins, $0.4 million to undeveloped land acquisitions and $0.4 million to recompletions. The drilling program in the quarter included 4 (1.5 net) wells, 3 (1.0 net) in the Stolberg area and 1 (0.5 net) in the Cabin Creek area.

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

On June 26, 2013, Manitok completed a disposition of the majority of its royalty interest properties, with an effective date of April 1, 2013, for total cash consideration of approximately $3.3 million after closing adjustments ("**Royalty Asset Divestiture**"). The net proceeds from the Royalty Asset Divestiture will be used to partially fund the Corporation's ongoing capital expenditure program.

GUIDANCE AND OUTLOOK

Assuming drilling success based on Manitok's expected outcomes and applied risk parameters, Manitok expects to exit 2013 with production ranging from 5,300 to 5,500 boe/d (approximately 55% to 57% crude oil and condensate, 0.5% NGLs), which would be a 40% to 45% increase over the 2012 exit production rate. At that production level, funds from operations is estimated to be $5.7 to $6.0 million per month, which would be an increase of approximately 50% over the 2012 exit funds from operations rate. It is anticipated that there will be an additional 400 to 500 boe/d of production (about 85% crude oil) added in the first quarter of 2014 where the majority of the capital expenditures relating to that production will be incurred in the fourth quarter of 2013.

Manitok has increased its 2013 capital expenditure budget by 7% to approximately $76.0 million or $72.6 million net of dispositions. This is an increase of $5.0 million to the previously guided $71.0 million which was made up of $63.0 million for drilling, completions, tie-ins and equipping and $8.0 million for land and seismic. The increased $76.0 million of capital expenditures is made up of $70.0 million of drilling, completions, tie-ins and equipping and $6.0 million of land and seismic. The updated forecast includes 19 (12.1 net) wells with all but 2 (1.75 net) targeting Cardium light oil predominantly in the Stolberg area and also in the Cabin Creek and Quirk Creek areas. The first of the two wells not targeting Cardium is a vertical liquids rich natural gas well targeting an Ostracod pool and the second is an exploration well targeting an oil zone other than the Cardium in a new area. The increased capital budget will be financed with funds from operations and Manitok's existing $90.0 million credit facilities with the National Bank of Canada.

Average production in 2013 is expected to range between 4,200 to 4,400 boe/d (approximately 52% crude oil and condensate, 0.5% NGLs), which would be an increase of 76% to 84% over its 2012 average production. Manitok anticipates funds from operations to be $48.0 to $50.0 million, which is lower than the previous guidance of $55.0 to $57.0 million. However, it still results in an anticipated increase of over 150% from funds from operations in 2012. The main reasons for the decrease are timing delays of new production additions due to drilling four wells on one pad versus drilling four wells on two pads, lower working interests in wells than previously budgeted due to a pooling agreement, and a lower oil weighting than anticipated, decreasing from 57% to 52% on total production for 2013, due mostly to adding a liquids rich gas well to the 2013 drilling program in lieu of an additional Cardium oil well. Manitok would like to caution the readers that changes to the drilling and production schedules may be necessary from time to time in order to capture value from new opportunities or gain efficiencies in its operations. Given the relatively low number of drills Manitok will execute in a one year period and the potentially high initial production rates associated with these wells, these changes may initially have a negative short term impact to funds from operations; however that does not materially change the ultimate value created over the life of the well.

After adjusting for the increased capital expenditures in 2013 and the shares purchased through our NCIB, net debt at the end of 2013 is now expected to range between $38.0 to $40.0 million. The net debt to twelve month trailing funds from operations ratio is anticipated to be about 0.8 times as at December 31, 2013 and the net debt to the exit funds from operations rate ratio is anticipated to be about 0.6 times as at December 31, 2013.

The 2013 re-forecasted budget assumes an average price of US$99.00/bbl of WTI crude oil, an average differential of $6.00/bbl, an average $CAD/$US exchange rate of 1.03 and an average price of $3.08/mmbtu of AECO natural gas which results in about a $3.60/mcf realized field price due to heat content. For 2013, royalties, combined operating and transportation costs net of recoveries, general and administrative expenses ("G&A") and interest are expected to average approximately $16.09, $9.06, $3.42 and $0.47 per boe respectively. The average operating netback for 2013 is anticipated to be approximately $34.28/boe, with a range of $23.85/boe at the beginning of the year to $43.34/boe at year end. The average funds from operations netback (operating netback, net of G&A and interest), is anticipated to be approximately $30.39/boe, ranging from $18.27/boe at the beginning of the year to $40.57/boe at year end.

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 ongoing capital expenditure program should the outlook for natural gas prices improve.

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, increased to $9.3 million at June 30, 2013 as compared to $6.9 million at December 31, 2012. The working capital deficiency at June 30, 2013 is largely comprised of costs incurred on the Corporation’s drilling program and will be financed with funds from operations and the Corporation’s credit facilities.

At June 30, 2013, the major component of Manitok’s current assets was cash (19%), and revenue (44%) to be received from its marketers in respect of June 2013 production that was subsequently received in July 2013. Current liabilities excluding the fair value of financial instruments largely consisted of capital expenditure trade payables (42%), accrued capital costs related to the Corporation’s capital expenditure program (7%), and cash calls received from non-operated partners (31%). 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 funds from operations, 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 Corporation's credit facilities were undrawn as at June 30, 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 following table indicates the Corporation's total available credit:

As at, ($000)	**June 30, 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	**-**	(3,101)
Drawn acquisition and development demand loan facility	**-**	-
Outstanding letters of credit(4)	**-**	(100)
	-	(3,201)
Undrawn credit facilities	**90,000**	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 set for October 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 June 30, 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 six months ended June 30, 2013. There were no amounts drawn on letters of credit during the six months ended June 30, 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 June 30, 2013:

($000)	**2013**	**2014**	**2015 - 2017**	**Thereafter**
Accounts payable and accrued liabilities	22,420	-	-	-
Drawn credit facilities	-	-	-	-
Office lease(1)	380	760	1,690	-
Total estimated contractual obligations(2)	**22,800**	**760**	**1,690**	**-**

(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 June 30, 2013 to be approximately $19.6 million and will be incurred as follows: 2013 - $0.6 million, 2014 - $0.3 million, 2015 to 2017 - $0.1 million and $18.6 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 in the Americas. 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 June 30, 2013 is $57,000 (December 31, 2012 - $24,700) due to Amarok, relating to its net interest in the operations of the well.

- During the three and six months ended June 30, 2013, the Corporation recorded $3,000 and $6,000 (June 30, 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. There were no amounts included in accounts receivable relating to rent as at June 30, 2013 (December 31, 2012 - $2,100).
- 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 $79,000 and $180,000 as a reduction of administrative expenses in the three and six months ended June 30, 2013 (June 30, 2012 - $NIL). Included in accounts receivable as at June 30, 2013 is $79,000 (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 and six months ended June 30, 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	8,456,316
Issue of Manitok Shares upon exercise of options	156,667
Normal course issuer bid(1)	(74,500)
Outstanding, December 31, 2012	**70,339,014**
Issue of Manitok Shares upon exercise of options	29,826
Normal course issuer bid(1)	(282,700)
Outstanding, June 30, 2013	**70,086,140**

(1) 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 June 30, 2013, the Corporation has purchased a total of 357,200 Manitok Shares for cancellation at a weighted average price of $2.27 per share which excludes the fees incurred to implement the NCIB program. On June 18, 2013, the TSX-V authorized the Corporation's notice to make a NCIB to purchase for cancellation up to 6.5 million Manitok Shares on the open market during the period from June 18, 2013 to June 17, 2014. As at June 30, 2013, the Corporation has not purchased any shares pursuant to this NCIB program.

At August 27, 2013, there were 68,999,040 Manitok Shares outstanding and 6,720,440 stock options to purchase an equivalent number of Manitok Shares. The reduction in Manitok Shares outstanding subsequent to June 30, 2013 is due to the activity in the current NCIB program.

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 Periods and the Comparable Prior Periods:

	Three months ended June 30, 2013				Three months ended June 30, 2012			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Natural gas (mcf)[(1)]	**4,206**	**11,692**	**48**	**3.95**	1,449	8,134	78	1.96
Light oil (bbls)	**16,470**	**2,016**	**50**	**89.77**	2,305	301	18	84.14
Heavy oil (bbls)	**-**	**-**	**-**	**-**	-	-	-	-
NGLs (bbls)	**542**	**81**	**2**	**73.92**	516	76	4	74.61
Total P&NG sales (boe)	**21,218**	**4,045**	**100**	**57.64**	4,270	1,733	100	27.08
Royalty revenue	**223**			**0.61**	50			0.32
Total P&NG revenue (boe)	**21,441**	**4,045**	**100**	**58.25**	4,320	1,733	100	27.40

	Six months ended June 30, 2013				Six months ended June 30, 2012			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Natural gas (mcf)[(1)]	**7,811**	**11,253**	**49**	**3.83**	3,609	9,091	77	2.18
Light oil (bbls)	**30,111**	**1,860**	**49**	**89.46**	2,831	184	9	84.34
Heavy oil (bbls)	**-**	**-**	**-**	**-**	2,621	189	10	76.29
NGLs (bbls)	**1,174**	**82**	**2**	**79.14**	1,194	82	4	79.75
Total P&NG sales (boe)	**39,096**	**3,817**	**100**	**56.59**	10,255	1,971	100	28.59
Royalty revenue	**366**			**0.53**	126			0.35
Total P&NG revenue (boe)	**39,462**	**3,817**	**100**	**57.12**	10,381	1,971	100	28.94

(1) Includes sulphur revenue in the Reporting Periods, but sulphur production volumes are excluded.

The significant increase in P&NG revenue in the Reporting Periods as compared to the Comparable Prior Periods was due to the increase in the average daily production volumes related to the successful Cardium light oil drilling program in the Stolberg area and the increase in realized commodity prices.

While crude oil and NGL volumes represent 52% and 51% of total P&NG production for the three and six month Reporting Periods, it represents 80% and 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 Periods and the Comparable Prior Periods:

	Three months ended June 30, 2013				Three months ended June 30, 2012			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Sweet natural gas (mcfe)(1)	**2,027**	**4,829**	**20**	**4.61**	1,428	5,663	55	2.77
Sour natural gas (mcfe)(2)	**1,264**	**3,449**	**14**	**4.03**	512	2,729	26	2.06
Light oil (boe)(3)	**17,927**	**2,666**	**66**	**73.90**	2,330	334	19	76.67
Heavy oil (bbl)	-	-	-	-	-	-	-	-
Total P&NG sales (boe)	**21,218**	**4,045**	**100**	**57.64**	4,270	1,733	100	27.08
Royalty revenue	**223**			**0.61**	50			0.32
Total P&NG revenue (boe)	**21,441**	**4,045**	**100**	**58.25**	4,320	1,733	100	27.40

	Six months ended June 30, 2013				Six months ended June 30, 2012			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Sweet natural gas (mcfe)(1)	**4,150**	**5,058**	**22**	**4.53**	3,396	6,010	51	3.10
Sour natural gas (mcfe)(2)	**2,564**	**3,678**	**16**	**3.85**	1,365	3,416	28	2.19
Light oil (boe)(3)	**32,382**	**2,361**	**62**	**75.78**	2,873	211	11	74.86
Heavy oil (bbl)	-	-	-	-	2,621	189	10	76.29
Total P&NG sales (boe)	**39,096**	**3,817**	**100**	**56.59**	10,255	1,971	100	28.59
Royalty revenue	**366**			**0.53**	126			0.35
Total P&NG revenue (boe)	**39,462**	**3,817**	**100**	**57.12**	10,381	1,971	100	28.94

(1) Includes revenue and production for associated by-products.
(2) Includes revenue and production for associated by-products, including sulphur revenue of $112,000 and $240,000 for the three and six month Reporting Periods (June 30, 2012 - $30,000 and $43,000). 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 14% and 18% higher than the sour natural gas wells in the three and six month Reporting Periods.

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 Periods and the Comparable Prior Periods:

	Three months ended June 30,			**Six months ended June 30,**		
	2013	2012	Variance	**2013**	2012	Variance
Light oil - Edmonton par ($/bbl)	**92.94**	84.39	10%	**90.77**	88.54	3%
Natural gas – AECO daily spot ($/mmbtu)	**3.54**	1.90	86%	**3.37**	2.03	66%

(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 June 30,				**Six months ended June 30,**			
	2013		2012		**2013**		2012	
	$000	**$/boe**	$000	$/boe	**$000**	**$/boe**	$000	$/boe
Realized gain (loss) on financial instruments	**(355)**	**(0.96)**	332	2.11	**(77)**	**(0.11)**	341	0.95
Unrealized gain (loss) on financial instruments	**148**	**0.40**	1,392	8.83	**(2,887)**	**(4.18)**	866	2.42

As at June 30, 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	July 1, 2013 to December 31, 2013	CAD$ WTI	$97.65	Swap	(143)
Oil	150 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$98.00	Swap	(62)
Oil	500 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$98.00	Swap(1)	(209)
Oil	300 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$95.10	Swap	(285)
Oil	300 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$100.50	Swap	12
Oil	250 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$97.00	Swap	(150)
Oil	400 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$99.40	Swap	(65)
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$96.00	Swap	91
Oil	500 bbls/d	July 1, 2013 to December 31, 2013	CAD$ EDM-WTI Diff	$6.80	Swap	5
Natural gas	5,000 GJs/d	July 1, 2013 to December 31, 2013	CAD$ AECO	$3.40	Put(2)	63
Natural gas	5,000 GJs/d	July 1, 2013 to December 31, 2013	CAD$ AECO	$3.40	Put(3)	27
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$97.65	Swaption(4)	(575)
Oil	250 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$98.00	Swaption(5)	(275)
Oil	600 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$100.00	Swaption(6)	(465)
Oil	300 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$100.50	Swaption(7)	(215)
Oil	400 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$99.40	Swaption(8)	(342)
Oil	500 bbls/d	January 1, 2015 to December 31, 2015	CAD$ WTI	$96.00	Swaption(9)	(754)
Total						**(3,342)**

(1) In July 2013, the contract was terminated effective July 1, 2013 and the payment related to the termination has been included in the calculation of the fixed price of the transaction disclosed in the table below regarding derivative financial instruments entered subsequent to June 30, 2013.

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

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

(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) In August 2013, the contract was terminated effective January 1, 2014 and the payment related to the termination has been included in the calculation of the fixed price of the transaction disclosed in the table below regarding derivative financial instruments entered subsequent to June 30, 2013.

(8) 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 period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

(9) 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 period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

Subsequent to June 30, 2013, the Corporation entered into the following derivative financial instruments:

Subject of Contract	**Volume**	**Term**	**Reference**	**Strike Price**	**Contract Traded**
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$93.35	Swap
Oil	300 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$94.00	Swap

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 Periods and the Comparable Prior Periods:

	Three months ended June 30,			Six months ended June 30,		
	2013	2012	Variance	**2013**	2012	Variance
Gross sweet natural gas royalties ($000)[2]	**285**	178	60%	**870**	498	75%
Natural gas royalty credits ($000)[5]	**(399)**	(405)	(1%)	**(558)**	(407)	37%
Sweet natural gas royalties, net ($000)[2]	**(114)**	(227)	50%	**312**	91	243%
Sweet natural gas royalties, net ($/mcfe) [2]	**(0.26)**	(0.45)	42%	**0.34**	0.09	278%
Effective royalty rate [1]	**(5.6%)**	(15.9%)	65%	**7.5%**	2.7%	178%
Gross sour natural gas royalties ($000)[3]	**221**	86	157%	**454**	307	48%
Natural gas royalty credits ($000)[5]	**(314)**	(837)	(62%)	**(434)**	(836)	(48%)
Sour natural gas royalties, net ($000)[3]	**(93)**	(751)	88%	**20**	(529)	104%
Sour natural gas royalties, net ($/mcfe) [3]	**(0.30)**	(3.02)	90%	**0.03**	(0.86)	103%
Effective royalty rate [1]	**(7.4%)**	(146.7%)	95%	**0.8%**	(38.8%)	102%
Light oil royalties ($000)[4]	**5,070**	233	-	**9,733**	378	-
Light oil royalties ($/boe) [4]	**20.90**	7.67	172%	**22.78**	9.84	132%
Effective royalty rate [1]	**28.3%**	10.0%	183%	**30.1%**	13.2%	128%
Heavy oil royalties ($000)	**-**	-	-	**-**	244	-
Heavy oil royalties ($/bbl)	**-**	-	-	**-**	7.11	-
Effective royalty rate [1]	**-**	-	-	**-**	9.3%	-
Total royalties ($000)	**4,863**	(745)	-	**10,065**	184	-
Total royalties ($/boe)	**13.21**	(4.73)	-	**14.56**	0.51	-
Effective royalty rate [1]	**22.9%**	(17.5%)	-	**25.7%**	1.8%	-

(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 Periods as compared to the Comparable Prior Periods is primarily 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 for light oil has increased to 28.3% and 30.1% of total P&NG sales in the three and six month Reporting Periods compared to 10.0% and 13.2% in the Comparable Prior Periods.

Operating Expenses

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

	Three months ended June 30, 2013		Three months ended June 30, 2012		Variance	
	$000	$/boe	$000	$/boe	$	$/boe
Field operating expenses	2,474	6.72	1,717	10.89	44%	(38%)
Recoveries	(235)	(0.64)	(352)	(2.23)	(33%)	(71%)
Field operating expenses, net	2,238	6.08	1,365	8.66	64%	(30%)
Expensed workovers and other	123	0.34	18	0.11	583%	209%
Total operating expenses	2,362	6.42	1,383	8.77	71%	(27%)

	Six months ended June 30, 2013		Six months ended June 30, 2012		Variance	
	$000	$/boe	$000	$/boe	$	$/boe
Field operating expenses	5,658	8.19	3,931	10.96	44%	(25%)
Recoveries	(471)	(0.68)	(657)	(1.83)	(28%)	(63%)
Field operating expenses, net	5,187	7.51	3,274	9.13	58%	(18%)
Expensed workovers and other	124	0.18	61	0.17	103%	6%
Total operating expenses	5,311	7.69	3,335	9.30	59%	(17%)

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

	Three months ended June 30, 2013		Three months ended June 30, 2012		Variance	
	$000	$/unit	$000	$/unit	$	$/unit
Sweet natural gas operating expenses (mcfe)(1)	396	0.91	758	1.47	(48%)	(38%)
Sour natural gas operating expenses (mcfe)(2)	636	2.03	381	1.53	67%	33%
Light oil operating expenses (boe)(3)	1,330	5.48	215	7.07	519%	(22%)
Heavy oil operating expenses (bbl)	-	-	29	-	-	-
Total operating expenses (boe)	2,362	6.42	1,383	8.77	71%	(27%)

	Six months ended June 30, 2013		Six months ended June 30, 2012		Variance	
	$000	$/unit	$000	$/unit	$	$/unit
Sweet natural gas operating expenses (mcfe)(1)	1,019	1.11	1,526	1.39	(33%)	(20%)
Sour natural gas operating expenses (mcfe)(2)	1,504	2.26	973	1.57	55%	44%
Light oil operating expenses (boe)(3)	2,788	6.52	298	7.76	836%	(16%)
Heavy oil operating expenses (bbl)	-	-	538	15.66	-	-
Total operating expenses (boe)	5,311	7.69	3,335	9.30	59%	(17%)

(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 Periods as compared to the Comparable Prior Periods was due to the large increase in light oil production volumes. Total operating costs per boe decreased 27% and 17% in the three and six month Reporting Periods as compared to the Comparable Prior Periods.

Sweet natural gas operating expenses per boe have decreased 38% and 20% in the three and six month Reporting Periods as compared to the Comparable Prior Periods. The decrease is primarily related to increased third party utilization of a non-operated sweet natural gas facility, which lowered Manitok's 2013 throughput charges. As a result, plant operating expenses on a per unit basis have decreased for Manitok.

Sour natural gas operating expenses per boe have increased 33% and 44% in the three and six month Reporting Periods as compared to the Comparable Prior Periods. The increase is primarily related to unscheduled plant costs at a non-operated sour gas facility and a turnaround of an operated compressor station.

Light oil operating expenses per boe have decreased 22% and 16% in the three and six month Reporting Periods as compared to the Comparable Prior Periods, due to the significant increase in production volumes. Light oil operating expenses per boe have decreased 31% from the first quarter of 2013 due primarily to a full quarter of production through permanent facilities in the southern trend of the Stolberg area that was previously producing through temporary facilities, which have significantly higher operating expenses.

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 Periods and the Comparable Prior Periods:

	Three months ended June 30, 2013		Three months ended June 30, 2012		Variance	
	$000	**$/unit**	$000	$/unit	$	$/unit
Sweet natural gas T&M expenses (mcfe)(1)	**86**	**0.20**	127	0.25	(32%)	(20%)
Sour natural gas T&M expenses (mcfe)(2)	**80**	**0.25**	57	0.23	40%	9%
Light oil T&M expenses (boe)(3)	**910**	**3.75**	111	3.65	720%	3%
Heavy oil T&M expenses (bbl)	**-**	**-**	-	-	-	-
Total T&M expenses (boe)	**1,076**	**2.93**	295	1.87	265%	57%

	Six months ended June 30, 2013		Six months ended June 30, 2012		Variance	
	$000	**$/unit**	$000	$/unit	$	$/unit
Sweet natural gas T&M expenses (mcfe)(1)	**179**	**0.20**	219	0.20	(18%)	-
Sour natural gas T&M expenses (mcfe)(2)	**171**	**0.26**	144	0.23	19%	13%
Light oil T&M expenses (boe)(3)	**1,628**	**3.81**	113	2.94	-	30%
Heavy oil T&M expenses (bbl)	**-**	**-**	104	3.03	-	-
Total T&M expenses (boe)	**1,978**	**2.86**	580	1.62	241%	77%

(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 Periods as compared to the Comparable Prior Periods was due to the large increase in light oil production volumes. Total T&M costs per boe increased 57% and 77% in the three and six month Reporting Periods as compared to the Comparable Prior Periods 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 50% and 49% of total production volumes in the three and six month Reporting Periods as compared to 18% and 19% in the Comparable Prior Periods.

Operating Netback

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

	Three months ended June 30,			Six months ended June 30,		
	2013	2012	Variance	**2013**	2012	Variance
Sweet natural gas ($/mcfe)[1]						
Realized sales price	**4.61**	2.77	66%	**4.53**	3.10	46%
Royalty income	**0.50**	0.09	456%	**0.40**	0.11	264%
Royalty expenses	**(0.65)**	(0.34)	91%	**(0.95)**	(0.46)	107%
Royalty recovery[4]	**0.91**	0.79	15%	**0.61**	0.37	65%
Operating expenses, net	**(0.91)**	(1.47)	(38%)	**(1.11)**	(1.39)	(20%)
Transportation and marketing expenses	**(0.20)**	(0.25)	(20%)	**(0.20)**	(0.20)	-
Operating netback	**4.26**	1.59	168%	**3.28**	1.53	114%
Sour natural gas ($/mcfe)[2]						
Realized sales price	**4.03**	2.06	96%	**3.85**	2.19	76%
Royalty income	**0.01**	0.01	-	**0.01**	-	-
Royalty expenses	**(0.70)**	(0.35)	100%	**(0.68)**	(0.49)	39%
Royalty recovery[4]	**1.00**	3.37	(70%)	**0.65**	1.35	(52%)
Operating expenses, net	**(2.03)**	(1.53)	33%	**(2.26)**	(1.57)	44%
Transportation and marketing expenses	**(0.25)**	(0.23)	9%	**(0.26)**	(0.23)	13%
Operating netback	**2.06**	3.33	(38%)	**1.31**	1.25	5%
Light oil ($/boe)[3]						
Realized sales price	**73.90**	76.67	(4%)	**75.78**	74.86	1%
Royalty income	**-**	-	-	**-**	-	-
Royalty expenses	**(20.90)**	(7.67)	172%	**(22.78)**	(9.84)	132%
Operating expenses, net	**(5.48)**	(7.07)	(22%)	**(6.52)**	(7.76)	(16%)
Transportation and marketing expenses	**(3.75)**	(3.65)	3%	**(3.81)**	(2.94)	30%
Operating netback	**43.77**	58.28	(25%)	**42.67**	54.32	(21%)
Heavy oil ($/bbl)						
Realized sales price	**-**	-	-	**-**	76.29	-
Royalty income	**-**	-	-	**-**	-	-
Royalty expenses	**-**	-	-	**-**	(7.11)	-
Operating expenses, net	**-**	-	-	**-**	(15.66)	-
Transportation and marketing expenses	**-**	-	-	**-**	(3.03)	-
Operating netback	**-**	-	-	**-**	50.49	-
Total ($/boe)						
Realized sales price	**57.64**	27.08	113%	**56.59**	28.59	98%
Royalty income	**0.61**	0.32	91%	**0.53**	0.35	51%
Royalty expenses	**(15.15)**	(3.15)	381%	**(16.00)**	(3.98)	302%
Royalty recovery[4]	**1.94**	7.88	(75%)	**1.44**	3.47	(59%)
Operating expenses, net	**(6.42)**	(8.77)	(27%)	**(7.69)**	(9.30)	(17%)
Transportation and marketing expenses	**(2.93)**	(1.87)	57%	**(2.86)**	(1.62)	77%
Operating netback before realized gain (loss) on financial instruments	**35.69**	21.49	66%	**32.01**	17.51	83%
Realized gain (loss) on financial instruments	**(0.96)**	2.11	(145%)	**(0.11)**	0.95	(112%)
Operating netback	**34.73**	23.60	47%	**31.90**	18.46	73%

(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 Periods and the Comparable Prior Periods are as follows:

	Three months ended June 30, 2013		Three months ended June 30, 2012		Variance
	$000	**%**	$000	%	$
Cash					
Salaries and benefits(1)	**1,050**	**60**	833	54	26%
Other(2)	**707**	**40**	700	46	1%
	1,757	**100**	1,533	100	15%
Operating overhead recoveries	**(101)**	**(6)**	(32)	(2)	216%
Capitalized overhead recoveries(3)	**(321)**	**(18)**	(285)	(19)	13%
General and administrative expenses, net	**1,335**	**76**	1,216	79	10%
General and administrative expenses, net per boe	**3.62**		7.71		(53%)
Non-cash					
Stock-based compensation	**734**	**100**	411	100	79%
Capitalized stock-based compensation(3)	**(232)**	**(32)**	(181)	(44)	28%
Stock-based compensation, net	**502**	**68**	230	56	118%
Stock-based compensation, net per boe	**1.37**		1.46		(6%)
Total administrative expenses, net	**1,837**	**74**	1,446	74	27%
Total administrative expenses, net per boe	**4.99**		9.17		(46%)

	Six months ended June 30, 2013		Six months ended June 30, 2012		Variance
	$000	**%**	$000	%	$
Cash					
Salaries and benefits(1)	**2,093**	**59**	1,622	59	29%
Other(2)	**1,455**	**41**	1,137	41	28%
	3,548	**100**	2,759	100	29%
Operating overhead recoveries	**(253)**	**(7)**	(60)	(2)	322%
Capitalized overhead recoveries(3)	**(634)**	**(18)**	(575)	(21)	10%
General and administrative expenses, net	**2,661**	**75**	2,124	77	25%
General and administrative expenses, net per boe	**3.85**		5.92		(35%)
Non-cash					
Stock-based compensation	**1,434**	**100**	855	100	68%
Capitalized stock-based compensation(3)	**(488)**	**(34)**	(353)	(41)	38%
Stock-based compensation, net	**946**	**66**	502	59	88%
Stock-based compensation, net per boe	**1.37**		1.40		(2%)
Total administrative expenses, net	**3,607**	**72**	2,626	73	37%
Total administrative expenses, net per boe	**5.22**		7.32		(29%)

(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 Periods as compared to the Comparable Prior Periods 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 53% and 35% in the three and six month Reporting Periods as compared to the Comparable Prior Periods due to higher production volumes from the successful capital expenditure program.

Stock-based compensation (non-cash)

The increase in the Reporting Periods was mainly due to the granting of additional stock options subsequent to the Comparable Prior Periods 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	1,841,100	3.09
Exercised	(29,826)	1.20
Cancelled or forfeited	(19,667)	1.64
Outstanding, June 30, 2013	**6,575,440**	**1.92**

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 Periods and the Comparable Prior Periods:

	Three months ended June 30,			**Six months ended June 30,**		
	2013	2012	Variance	**2013**	2012	Variance
Depletion and depreciation ($000)	**4,855**	2,464	97%	**9,069**	5,763	57%
Depletion and depreciation ($/boe)	**13.19**	15.63	(16%)	**13.13**	16.07	(18%)

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 in the Reporting Periods due to the significant increase in production volumes from the Comparable Prior Periods. On a boe basis, D&D expense has decreased by 16% and 18% in the three and six month Reporting Periods as compared to the Comparable Prior Periods 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 Periods. As a result, an impairment test was not required as at June 30, 2013.

Finance Expenses

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

	Three months ended June 30, 2013		Three months ended June 30, 2012		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Cash:						
Interest and financing expenses	**150**	**0.41**	26	0.17	477%	141%
Acquisition-related expenses	**-**	**-**	(20)	(0.13)	-	-
	150	**0.41**	6	0.04	-	-
Non-cash:						
Accretion on decommissioning obligations	**78**	**0.21**	65	0.41	20%	(49%)
Total finance expenses	**228**	**0.62**	71	0.45	221%	38%

	Six months ended June 30, 2013		Six months ended June 30, 2012		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Cash:						
Interest and financing expenses	**245**	**0.36**	51	0.14	380%	157%
Acquisition-related expenses	**-**	**-**	165	0.46	-	-
	245	**0.36**	216	0.60	13%	(40%)
Non-cash:						
Accretion on decommissioning obligations	**148**	**0.21**	137	0.38	8%	(45%)
Total finance expenses	**393**	**0.57**	353	0.98	11%	(42%)

The aggregate interest and financing expenses for the Reporting Periods increased from the Comparable Prior Periods 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 $2.4 million and $3.1 million in the three and six month Reporting Periods as compared to $0.4 million and $2.6 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 3.5% and 3.6% in the three and six month Reporting Periods as compared to 4.0% in the Comparable Prior Periods.

Gain on Divestiture of Assets

During the Reporting Periods, the Corporation completed the Royalty Asset Divestiture for net proceeds of approximately $3.3 million after closing adjustments. As a result of the divestiture, Manitok records a gain of approximately $0.7 million or $1.96 and $1.05 per boe during the three and six month Reporting Periods.

Income Taxes

The following table compares deferred income taxes for the Reporting Periods and the Comparable Prior Periods:

	Three months ended June 30,			**Six months ended June 30,**		
	2013	2012	Variance	**2013**	2012	Variance
Deferred income tax expense ($000)	**1,928**	213	-	**2,161**	270	-
Deferred income tax expense ($/boe)	**5.24**	1.36	285%	**3.13**	0.75	317%

The expense in the three and six month Reporting Periods is attributed to the increase in net taxable income as compared to the Comparable Prior Periods.

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

Capital Expenditures

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

	Three months ended June 30,		Six months ended June 30,	
($000)	**2013**	2012	**2013**	2012
Land	**440**	312	**1,826**	1,285
Seismic	**78**	557	**240**	717
Workovers and recompletions	**430**	58	**505**	66
Drilling and completions	**6,545**	7,611	**12,443**	15,759
Well equipment, facilities and other	**1,796**	2,016	**5,130**	2,022
Capitalized overhead[(1)]	**321**	285	**634**	575
Total finding and development costs (F&D)	**9,610**	10,839	**20,778**	20,424
Property acquisitions (divestitures), net	**(3,378)**	(13,246)	**(3,445)**	(13,059)
Total finding, development and acquisition costs (FD&A)	**6,232**	(2,407)	**17,333**	7,365
Administrative and other assets	**103**	43	**297**	(52)
Total capital expenditures[(2)]	**6,335**	(2,364)	**17,630**	7,313

(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.

The Corporation drilled 4 (1.5 net) wells in the second quarter of 2013, 3 (1.0 net) in the Stolberg area and 1 (0.5 net) in the Cabin Creek area. Facility work for the Stolberg wells drilled in the quarter are anticipated to be completed in the third quarter of 2013.

Capital expenditures in the three and six month Reporting Periods and Comparable Prior Periods were allocated as follows:

	Three months ended June 30,		Six months ended June 30,	
($000)	**2013**	2012	**2013**	2012
Exploration and evaluation	**3,108**	8,730	**4,592**	18,189
Petroleum and natural gas properties and equipment, net	**3,227**	(11,094)	**13,038**	(10,876)
Total capital expenditures[(1)]	**6,335**	(2,364)	**17,630**	7,313

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

The Corporation incurred $2.6 million of exploration and evaluation additions in the second quarter of 2013 which related to drilling and completing a light oil well in the Cabin Creek area.

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 June 30,		Six months ended June 30,	
($000)	**2013**	2012	**2013**	2012
Funds from operations	**11,324**	2,482	**19,185**	4,453
Changes in non-cash operating working capital	**(1,117)**	452	**(3,649)**	(1,713)
Decommissioning expenditures	**(20)**	-	**(130)**	(2)
Increase (decrease) in revolving credit facility	**(7,130)**	(9,455)	**(3,101)**	176
Proceeds from issue of stock options	**14**	-	**35**	-
Share issue costs	**-**	(15)	**-**	(15)
Normal course issuer bid	**(725)**	(85)	**(725)**	(85)
Changes in non-cash investing working capital	**5,379**	4,257	**8,429**	4,499
Total capital resources	**7,725**	(2,364)	**20,044**	7,313
Exploration and evaluation asset expenditures	**(3,108)**	(8,730)	**(4,592)**	(18,189)
Petroleum and natural gas properties and equipment expenditures	**(6,605)**	(2,152)	**(16,483)**	(2,183)
Property divestitures (acquisitions), net	**3,378**	13,246	**3,445**	13,059
Net increase (decrease) in cash	**1,390**	-	**2,414**	-

SUMMARY OF QUARTERLY INFORMATION

	2013		2012				2011	
Quarters Ended	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
OPERATING								
Average daily production								
Natural gas (mcf/d)	**11,692**	10,810	8,344	7,706	8,134	10,049	8,314	1,449
Light oil (bbls/d)	**2,016**	1,701	1,618	1,171	301	68	29	-
Heavy oil (bbls/d)	**-**	-	-	-	-	378	332	171
NGLs (bbls/d)	**81**	83	69	70	76	89	59	2
Total (boe/d)	**4,045**	3,586	3,078	2,525	1,733	2,209	1,806	414
Average realized sales price (CAD$)								
Natural gas ($/mcf)	**3.95**	3.70	3.64	2.52	1.96	2.36	3.33	3.73
Light oil ($/bbl)	**89.77**	89.09	82.53	82.88	84.14	85.23	96.94	-
Heavy oil ($/bbl)	**-**	-	-	-	-	76.29	73.52	63.31
NGLs ($/bbl)	**73.92**	84.25	77.71	72.46	74.61	84.16	91.97	86.40
Total ($/boe)	**57.64**	55.39	54.99	48.14	27.08	29.77	33.41	39.52
OPERATING NETBACK ($ per boe)								
Petroleum and natural gas sales	**57.64**	55.39	54.99	48.14	27.08	29.77	33.41	39.52
Realized gain (loss) on financial instruments	**(0.96)**	0.86	3.37	2.07	2.11	0.04	-	-
Royalty income	**0.61**	0.44	0.43	0.38	0.32	0.38	0.39	-
Royalty (expenses) recovery	**(13.21)**	(16.12)	(11.22)	(6.60)	4.73	(4.62)	(4.37)	(3.49)
Operating expenses, net	**(6.42)**	(9.14)	(10.48)	(7.26)	(8.77)	(9.71)	(12.08)	(12.16)
Transportation and marketing expenses	**(2.93)**	(2.79)	(3.17)	(2.62)	(1.87)	(1.42)	(1.14)	(2.03)
Operating netback	**34.73**	28.64	33.92	34.11	23.60	14.44	16.21	21.84
FINANCIAL								
Petroleum and natural gas revenue ($000)	**21,441**	18,021	15,696	11,272	4,320	6,061	5,615	1,505
Royalty (expenses) recovery ($000)	**(4,863)**	(5,202)	(3,177)	(1,534)	745	(929)	(727)	(133)
Realized gain (loss) on financial instruments ($000)	**(355)**	278	955	480	332	9	-	-
Interest and other revenue ($000)	**24**	36	29	-	5	-	20	84
Total revenue, net ($000)	**16,247**	13,133	13,503	10,218	5,402	5,141	4,908	1,456
Net income (loss) ($000)	**4,831**	(135)	(2,157)	1,461	499	(2,459)	(4,327)	(796)
Per share - basic ($)	**0.07**	-	(0.03)	0.02	0.01	(0.04)	(0.08)	(0.02)
Per share - diluted ($)	**0.07**	-	(0.03)	0.02	0.01	(0.04)	(0.08)	(0.02)
Funds from operations ($000)(1)	**11,324**	7,861	7,651	6,977	2,482	1,970	1,503	231
Per share - basic ($)(1)	**0.16**	0.11	0.11	0.11	0.04	0.03	0.03	0.00
Per share - diluted ($)(1)	**0.16**	0.11	0.11	0.11	0.04	0.03	0.03	0.00
Capital expenditures, net ($000)	**6,335**	11,295	13,421	16,230	(2,364)	9,677	55,526	8,126
Book value of total assets ($000)	**139,671**	135,648	126,322	120,553	104,319	109,961	104,290	70,462
Working capital deficiency (surplus) ($000)(2)	**9,226**	6,354	6,861	10,668	8,780	4,073	5,994	(27,635)
Drawn on revolving credit facility ($000)	**-**	7,130	3,101	9,638	2,135	11,590	1,960	-
Total net debt ($000)(3)	**9,226**	13,484	9,962	20,306	10,915	15,663	7,954	-
Shareholders' equity ($000)	**95,877**	91,024	90,437	77,027	75,112	74,297	76,313	62,703
Common shares outstanding								
End of period - basic	**70,086,140**	70,357,180	70,339,014	61,726,031	61,736,031	61,800,531	61,800,531	51,665,531
End of period - diluted	**76,661,580**	76,759,280	75,122,847	66,541,531	66,571,531	66,756,031	65,645,531	54,893,031
Weighted average for the period - basic	**70,219,904**	70,348,151	68,908,419	61,726,357	61,797,394	61,800,531	54,639,933	51,665,531
Weighted average for the period - diluted	**72,139,108**	72,758,478	70,986,540	62,735,423	61,935,604	62,856,623	55,665,947	52,266,109

(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 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 Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian exploration expense ("**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 disposition of its heavy oil assets in the Swimming area of Alberta 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 Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian development expense ("**Manitok CDE Flow-Through Shares**") 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 decrease in the realized gain on financial instruments.
- The Corporation completed the Royalty Asset Divestiture in the second quarter of 2013 for cash consideration of approximately $3.3 million.
- In the second quarter of 2013, Manitok recorded net income of $4.8 million, which was primarily the result of increased revenue and a $722,000 gain with respect to the Royalty Asset Divestiture.
- In the second quarter of 2013, the Corporation decreased net debt by $4.3 million from the first quarter of 2013 from increased funds from operations, reduced capital spending and proceeds from the Royalty Asset Divestiture.

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.

Critical Judgments in Applying Accounting Policies

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:

(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.**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.

(iv) 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.

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. Estimates of future taxable income are based on forecasted cash flows from operations. To the extent that any interpretation of tax law is challenged by the tax authorities or future cash flows and taxable income differ significantly from estimates, the ability of Manitok to realize the deferred tax assets could be impacted.

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, property and business interruption 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	**June 30, 2013**	December 31, 2012
ASSETS		
Current assets:		
Cash	**2,559**	145
Accounts receivable	**10,028**	7,023
Deposits and prepaid expenses	**607**	529
Fair value of financial instruments (note 12)	**-**	1,423
	13,194	9,120
Non-current assets:		
Exploration and evaluation (note 5)	**25,088**	20,311
Petroleum and natural gas properties and equipment (note 6)	**101,389**	96,891
	126,477	117,202
	139,671	126,322
LIABILITIES		
Current liabilities:		
Accounts payable and accrued liabilities	**22,420**	14,558
Credit facilities (note 7)	**-**	3,101
Fair value of financial instruments (note 12)	**2,741**	1,878
	25,161	19,537
Non-current liabilities:		
Fair value of financial instruments (note 12)	**601**	-
Flow-through share premium (note 9e)	**685**	877
Decommissioning obligations (note 8)	**10,998**	11,476
Deferred income taxes	**6,349**	3,995
	18,633	16,348
	43,794	35,885
SHAREHOLDERS' EQUITY		
Share capital (note 9)	**102,309**	102,668
Contributed surplus	**5,119**	3,753
Deficit	**(11,551)**	(15,984)
	95,877	90,437
Commitments (note 15)		
	139,671	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 INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

Unaudited *(Expressed in thousands of Canadian dollars, except per share amounts)*

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	**2013**	2012
REVENUE				
Petroleum and natural gas	**21,441**	4,320	**39,462**	10,381
Royalty (expenses) recovery	**(4,863)**	745	**(10,065)**	(184)
Realized gain (loss) on financial instruments	**(355)**	332	**(77)**	341
Interest and other	**24**	5	**60**	5
	16,247	5,402	**29,380**	10,543
EXPENSES				
Operating, net	**2,362**	1,383	**5,311**	3,335
Transportation and marketing	**1,076**	295	**1,978**	580
Administrative, net	**1,837**	1,446	**3,607**	2,626
Depletion and depreciation (note 6)	**4,855**	2,464	**9,069**	5,763
	10,130	5,588	**19,965**	12,304
INCOME (LOSS) FROM OPERATIONS	**6,117**	(186)	**9,415**	(1,761)
Finance expenses	**228**	71	**393**	353
(Gain) loss on divestitures (note 6)	**(722)**	423	**(722)**	442
Unrealized (gain) loss on financial instruments (note 12)	**(148)**	(1,392)	**2,887**	(866)
INCOME (LOSS) BEFORE INCOME TAXES	**6,759**	712	**6,857**	(1,690)
Deferred income tax expense	**1,928**	213	**2,161**	270
TOTAL NET INCOME (LOSS) AND COMPREHENSIVE (INCOME) LOSS	**4,831**	499	**4,696**	(1,960)
Net income (loss) per common share (note 11)				
basic	**0.07**	0.01	**0.07**	(0.03)
diluted	**0.07**	0.01	**0.06**	(0.03)

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 income (loss) for the period	-	-	-	(1,960)	(1,960)
Share issue costs, net of tax	-	(11)	-	-	(11)
Normal course issuer bid (note 9g)	(64,500)	(98)	13	-	(85)
Stock-based compensation expensed (note 10)	-	-	502	-	502
Stock-based compensation capitalized (note 10)	-	-	353	-	353
As at June 30, 2012	61,736,031	87,374	3,025	(15,287)	75,112
As at December 31, 2012	70,339,014	102,668	3,753	(15,984)	90,437
Net income (loss) for the period	-	-	-	4,696	4,696
Issued on exercise of stock options (note 9)	29,826	59	(24)	-	35
Normal course issuer bid (note 9g)	(282,700)	(418)	(44)	(263)	(725)
Stock-based compensation expensed (note 10)	-	-	946	-	946
Stock-based compensation capitalized (note 10)	-	-	488	-	488
As at June 30, 2013	**70,086,140**	**102,309**	**5,119**	**(11,551)**	**95,877**

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 June 30,		Six months ended June 30,	
	2013	2012	**2013**	2012
Cash provided by (used in):				
OPERATING ACTIVITIES				
Net income (loss)	**4,831**	499	**4,696**	(1,960)
Adjustments for items not affecting operating cash:				
Deferred income tax expense	**1,928**	213	**2,161**	270
Depletion and depreciation expense	**4,855**	2,464	**9,069**	5,763
Stock-based compensation expense	**502**	230	**946**	502
Finance expenses	**228**	71	**393**	353
Unrealized (gain) loss on financial instruments	**(148)**	(1,392)	**2,887**	(866)
(Gain) loss on divestitures	**(722)**	423	**(722)**	442
Interest expense	**(150)**	(26)	**(245)**	(51)
Decommissioning expenditures (note 8)	**(20)**	-	**(130)**	(2)
Changes in non-cash operating working capital	**(1,117)**	452	**(3,649)**	(1,713)
	10,187	2,934	**15,406**	2,738
FINANCING ACTIVITIES				
Increase (decrease) in credit facilities	**(7,130)**	(9,455)	**(3,101)**	176
Proceeds from the exercise of stock options	**14**	-	**35**	-
Share issue costs	**-**	(15)	**-**	(15)
Normal course issuer bid	**(725)**	(85)	**(725)**	(85)
	(7,841)	(9,555)	**(3,791)**	76
INVESTING ACTIVITIES				
Divestiture (acquisition) of petroleum and natural gas properties and equipment	**3,378**	13,246	**3,445**	13,059
Exploration and evaluation asset expenditures	**(3,108)**	(8,730)	**(4,592)**	(18,189)
Petroleum and natural gas properties and equipment expenditures	**(6,605)**	(2,152)	**(16,483)**	(2,183)
Changes in non-cash investing working capital	**5,379**	4,257	**8,429**	4,499
	(956)	6,621	**(9,201)**	(2,814)
NET INCREASE (DECREASE) IN CASH	**1,390**	-	**2,414**	-
CASH, BEGINNING OF PERIOD	**1,169**	145	**145**	145
CASH, END OF PERIOD	**2,559**	145	**2,559**	145
Cash interest paid	**150**	26	**245**	51
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's common shares are listed for trading on the TSX Venture Exchange ("**TSX-V**") under the symbol "**MEI**".

These unaudited condensed interim financial statements (the "**Financial Statements**") were approved and authorized for issuance by the Board of Directors on August 27, 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 and six months ended June 30, 2013, including the 2012 comparative periods. 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, as disclosed in the annual audited financial statements for the year ended December 31, 2012, except as indicated 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.

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.

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

- 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 June 30, 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 liabilities					
Drawn credit facilities (note 7)	-	-	-	-	-
Fair value of financial instruments					
Current	2,741	2,741	-	2,741	-
Non-current	601	601	-	601	-

5. EXPLORATION AND EVALUATION ASSETS

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

	Total
As at 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)
As at December 31, 2012	20,311
Additions(1)	4,777
As at June 30, 2013	**25,088**

(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 $340,000 in the six months ended June 30, 2013 (June 30, 2012 – $839,000). There were no costs reclassified from E&E to petroleum and natural gas properties and equipment during the six months ended June 30, 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 Assets	Corporate Assets	Total Assets
Cost			
As at December 31, 2011	88,143	604	88,747
Additions	17,060	285	17,345
Asset acquisition	75	-	75
Asset divestiture	(23,177)	-	(23,177)
Transfer from E&E assets (note 5)	37,003	-	37,003
Change in decommissioning obligations	(509)	-	(509)
As at December 31, 2012	118,595	889	119,484
Additions	16,679	297	16,976
Asset acquisition	(103)	-	(103)
Asset divestiture[1]	(2,620)	-	(2,620)
Change in decommissioning obligations	(686)	-	(686)
As at June 30, 2013	**131,865**	**1,186**	**133,051**
Accumulated depletion and depreciation and impairment			
As at December 31, 2011	(15,102)	(130)	(15,232)
Asset divestiture	9,526	-	9,526
Depletion and depreciation expense	(12,362)	(135)	(12,497)
Impairment expense	(4,390)	-	(4,390)
As at December 31, 2012	(22,328)	(265)	(22,593)
Depletion and depreciation expense	(8,942)	(127)	(9,069)
As at June 30, 2013	**(31,270)**	**(392)**	**(31,662)**
Net book value			
As at December 31, 2012	96,267	624	96,891
As at June 30, 2013	**100,595**	**794**	**101,389**

(1) In June 2013, the Corporation completed a transaction whereby it disposed of royalty interest properties, with an effective date of April 1, 2013, for total cash consideration of $3.3 million after post-closing adjustments. As a result of the disposition, the Corporation recorded a gain of $0.7 million in the three and six months ended June 30, 2013.

At June 30, 2013, estimated future development costs of $52.9 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 $782,000 in the six months ended June 30, 2013 (June 30, 2012 - $89,000).

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:

	June 30, 2013	December 31, 2012
Revolving operating demand loan facility	**-**	3,101
Acquisition and development demand loan facility	**-**	-
Credit facilities	**-**	3,101

In July 2013, the Corporation amended the agreement with its lender at similar terms and conditions to the prior agreement. The credit facilities consist of 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 fees 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 June 30, 2013, the Company was compliant with the covenant.

The credit facilities are subject to review by the lender at any time in its sole discretion, and at least annually and any change in or redetermination of the borrowing base limit which results in a borrowing base shortfall must be eliminated by the Corporation. The next review date for the credit facilities has been set for October 1, 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 June 30, 2013 to be approximately $19.6 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 2.9% (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:

	June 30, 2013	December 31, 2012
Opening Balance	**11,476**	11,721
Obligations incurred	**498**	659
Obligations acquired (disposed), net	**-**	(1,836)
Actual expenditures	**(130)**	(703)
Changes in estimates(1)	**(993)**	1,372
Accretion expense	**147**	263
Ending Balance	**10,998**	11,476

(1) Changes are largely due to the revision 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)	29,826	59
Normal course issuer bid (note 9g)	(282,700)	(418)
Outstanding, June 30, 2013	**70,086,140**	**102,309**

(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 June 30, 2013, the Corporation had fulfilled $5.3 million of eligible exploration expenditures and has reversed $0.9 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 June 30, 2013, the Corporation has purchased a total of 357,200 Manitok Shares for cancellation at a weighted average price of $2.27 per share which excludes the fees incurred to implement the NCIB program. The excess of the purchase price over the book value of $263,000 has been charged to retained earnings.

On June 18, 2013, the TSX-V authorized the Corporation's notice to make a NCIB to purchase for cancellation up to 6.5 million Manitok Shares on the open market during the period from June 18, 2013 to June 17, 2014. As at June 30, 2013, the Corporation has not purchased any shares pursuant to this NCIB program.

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 June 30, 2013, the Corporation's Plan permitted the grant of options to a maximum of 7,008,614 Manitok Shares and there remained available for issuance stock options in respect of 433,174 Manitok Shares.

A summary of the Corporation's outstanding stock options as at June 30, 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	1,841,100	3.09
Exercised	(29,826)	1.20
Cancelled or forfeited	(19,667)	1.64
Outstanding, June 30, 2013	**6,575,440**	**1.92**

The range of exercise prices for stock options outstanding and exercisable under the plan at June 30, 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	2,804,840	2.4	$1.17	1,747,007	2.4	$1.17
$1.51	$3.25	3,770,600	4.0	$2.47	603,669	3.4	$1.80
		6,575,440	**3.3**	**$1.92**	**2,350,676**	**2.6**	**$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 and six months ended June 30, 2013, the Corporation recorded $502,000 and $946,000 (June 30, 2012 – $230,000 and $502,000) of stock-based compensation expense, net of $232,000 and $488,000 (June 30, 2012 – $181,000 and $353,000) 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 3.9% and 4.3% for vesting option tranches during the three and six months ended June 30, 2013 (June 30, 2012 – 1.6% and 1.0%).

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 June 30,		Six months ended June 30,	
	2013	2012	**2013**	2012
Weighted average fair value of options granted	**$1.60**	$0.82	**$1.88**	$1.22
Risk-free interest rate	**1.26%**	1.35%	**1.37%**	1.17%
Expected life (years)	**3.7**	3.7	**4.1**	4.1
Expected volatility	**79.3%**	90.4%	**82.8%**	95.1%
Expected dividends	**-**	-	**-**	-

11. PER SHARE INFORMATION

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	**2013**	2012
Net income (loss) ($000)	**4,831**	499	**4,696**	(1,960)
Weighted average Manitok Shares outstanding - basic	**70,219,904**	61,797,394	**70,319,686**	61,798,962
Weighted average Manitok Shares outstanding - diluted	**72,139,108**	61,935,604	**72,290,765**	61,798,962
Net income (loss) per share – basic ($)	**0.07**	0.01	**0.07**	(0.03)
Net income (loss) per share – diluted ($)	**0.07**	0.01	**0.06**	(0.03)

As the Corporation reported a net loss for the six months ended June 30, 2012, the basic and diluted weighted average Manitok Shares outstanding are the same.

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

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.

As at June 30, 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	July 1, 2013 to December 31, 2013	CAD$ WTI	$97.65	Swap	(143)
Oil	150 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$98.00	Swap	(62)
Oil	500 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$98.00	Swap(1)	(209)
Oil	300 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$95.10	Swap	(285)
Oil	300 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$100.50	Swap	12
Oil	250 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$97.00	Swap	(150)
Oil	400 bbls/d	July 1, 2013 to December 31, 2013	CAD$ WTI	$99.40	Swap	(65)
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$96.00	Swap	91
Oil	500 bbls/d	July 1, 2013 to December 31, 2013	CAD$ EDM-WTI Diff	$6.80	Swap	5
Natural gas	5,000 GJs/d	July 1, 2013 to December 31, 2013	CAD$ AECO	$3.40	Put(2)	63
Natural gas	5,000 GJs/d	July 1, 2013 to December 31, 2013	CAD$ AECO	$3.40	Put(3)	27
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$97.65	Swaption(4)	(575)
Oil	250 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$98.00	Swaption(5)	(275)
Oil	600 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$100.00	Swaption(6)	(465)
Oil	300 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$100.50	Swaption(7)	(215)
Oil	400 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$99.40	Swaption(8)	(342)
Oil	500 bbls/d	January 1, 2015 to December 31, 2015	CAD$ WTI	$96.00	Swaption(9)	(754)
Total						**(3,342)**

(1) In July 2013, the contract was terminated effective July 1, 2013 and the payment related to the termination has been included in the calculation of the fixed price of the transaction disclosed in the table regarding derivative financial instruments entered subsequent to June 30, 2013.

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

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

(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) In August 2013, the contract was terminated effective January 1, 2014 and the payment related to the termination has been included in the calculation of the fixed price of the transaction disclosed in the table regarding derivative financial instruments entered subsequent to June 30, 2013.

(8) 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 period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

(9) 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 period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

As at June 30, 2013, a 10% decrease to the forward price curves outlined in the swap contracts above would result in approximately $6.6 million of additional pre-tax income.

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

Subsequent to June 30, 2013, the Corporation entered into the following derivative financial instruments:

Subject of Contract	Volume	Term	Reference	Strike Price	Contract Traded
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$93.35	Swap
Oil	300 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$94.00	Swap

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.

There were no changes in the Corporation's approach to capital management during the June 30, 2013 reporting period.

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

As at,	**June 30, 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	**-**	(3,101)
Drawn acquisition and development demand loan facility	**-**	-
Outstanding letters of credit(4)	**-**	(100)
	-	(3,201)
Undrawn credit facilities	**90,000**	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 set for October 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 June 30, 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 six months ended June 30, 2013. There were no amounts drawn on letters of credit during the six months ended June 30, 2013.

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

The capital structure of the Corporation is as follows:

As at,	**June 30, 2013**	December 31, 2012
Shareholders' equity(1)	**95,877**	90,437
Shareholders' equity as a % of total capital	**91%**	90%
Working capital deficiency(2)	**9,226**	6,861
Drawn on credit facilities	**-**	3,101
Total net debt	**9,226**	9,962
Total net debt as a % of total capital	**9%**	10%
Total Capital	**105,103**	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 in the Americas. 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 June 30, 2013 is $57,000 (December 31, 2012 - $24,700) due to Amarok, relating to its net interest in the operations of the well.
- During the three and six months ended June 30, 2013, the Corporation recorded $3,000 and $6,000 (June 30, 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. There were no amounts included in accounts receivable relating to rent as at June 30, 2013 (December 31, 2012 - $2,100).
- 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 $79,000 and $180,000 as a reduction of administrative expenses in the three and six months ended June 30, 2013 (June 30, 2012 - $NIL). Included in accounts receivable as at June 30, 2013 is $79,000 (December 31, 2012 - $NIL) due from Amarok, related to the technical services provided by Manitok.

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

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 $15,000 as at June 30, 2013. As at June 30, 2013, the costs incurred for exploration expenditures were approximately $5.3 million leaving about $3.9 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	Total
2013	380
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

Yvonne McLeod, P. Eng.
Vice President, Drilling and Facilities

Gregory E. Peterson, LL.B.
Corporate Secretary

DIRECTORS

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Chairman of the Board
Calgary, Alberta

Robert J. Dales (1) (2)
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Chartered Accountants
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INDEPENDENT RESERVE EVALUATOR
Sproule Associates Limited
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(1) Reserve and Occupational Health & Safety Committee Member
(2) Audit Committee Member
(3) Compensation Committee Member

MANITOK ENERGY INC.