

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 Annual Information Form dated April 29, 2015, 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**".

The following Management's Discussion and Analysis ("**MD&A**") is dated November 25, 2015. The unaudited condensed interim financial statements in respect of the three and nine months ended September 30, 2015 (the "**Reporting Periods**") as compared to the three and nine months ended September 30, 2014 (the "**Comparable Prior Periods**") and this MD&A has 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 2014 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 third quarter report for the Reporting Periods and the Comparable Prior Periods ("**Q3 Report**") are management's best estimates and are unaudited.*

Non-GAAP Measures

*This MD&A and the Q3 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", "adjusted working capital (surplus) deficit", "net bank debt" and "net debt". These measures do not have standardized meanings prescribed by generally accepted accounting principles ("**GAAP**") and therefore should not be considered in isolation. These reported amounts and their underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of other companies where similar terminology is used. Where these measures are used, they should be given careful consideration by the reader. These measures have been described and presented in the MD&A and Q3 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 income (loss) 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 operations denotes cash flow from operating activities as it appears on the Corporation's Statement of Cash Flows before decommissioning expenditures, acquisition-related expenses and changes in non-cash operating working capital. Funds from operations is also derived from net income (loss) plus acquisition-related expenses and non-cash items including deferred income tax expense (recovery), depletion and depreciation expense, impairment expense, stock-based compensation expense, accretion expense, unrealized gains or losses on financial instruments and gains or losses on asset divestitures. Funds from operations netback is calculated on a per boe basis and funds from operations per share is calculated as funds from operations divided by the weighted average number of basic and diluted common shares outstanding. Operating netback denotes petroleum and natural gas revenue and realized gains or losses on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses calculated on a per boe basis. Adjusted working capital (surplus) deficit includes current assets less current liabilities excluding the current portion of the amount drawn on the credit facilities, the current portion of the fair value of financial instruments and the deferred premium on financial instruments. Manitok uses net bank debt and net debt as a measure to assess its financial position. Net bank debt includes outstanding bank indebtedness plus adjusted working capital (surplus) deficit and net debt includes net bank debt plus the long-term financial obligations.

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 (6 mcf) of natural gas to one barrel (1 bbl) of crude oil. 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.

Forward-Looking Information

This MD&A and the Q3 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 involves the implied assessment, based on certain estimates and assumptions, that the reserves exist in the quantities estimated and that it will be commercially viable to produce 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 Q3 Report contains forward-looking information relating to the Corporation's operational and drilling and recompletion plans for the remainder of 2015, the anticipated timing of satisfying ManitoK's 2015 capital commitment with PrairieSky Royalty Ltd. ("**PSK**"), the anticipated amount of net bank debt as of December 31, 2015, the anticipated allocation of capital spend from a farm-out agreement to meet ManitoK's PSK capital commitment, ManitoK having the requisite liquidity based on current forward strip crude oil and natural gas prices to make its next required payment on its non-revolving reducing demand loan facility before March 31, 2016. Such statements reflect the Corporation's forecasts, estimates and expectations, as they relate to the Corporation's current views based on its experience and expertise with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation's actual results, performance or achievements to be materially different from any future results, performance or achievements that may be expressed or implied by such forward-looking statements. Given these risks and uncertainties, readers are cautioned not to place undue reliance on such forward-looking statements.

While the Corporation anticipates remaining disciplined with its capital program, readers are cautioned that the Corporation may make adjustments to its capital program, depending on business conditions and commodity prices throughout the fiscal year. Actual spending may vary due to a variety of factors, including changes to certain key expectations and assumptions set out below.

By their nature, forward-looking information involves a variety of assumptions, known and unknown risks and uncertainties, and other factors, which may cause actual results, levels of activity, and achievements to differ materially from those expressed or implied by such statements. The material factors and assumptions used to develop the forward-looking statements herein include, but are not limited to the following: future commodity prices; currency exchange rates; inflation rates; well production rates; well drainage areas; success rates for future drilling; availability of labour and services; interest rates; and 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. 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 to be drilled, 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, intentions 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 materially from those anticipated.

Forward-looking information necessarily involves both known and unknown risks associated with oil and natural gas exploration, production, transportation and marketing, such as uncertainty of geological and technical data, imprecision of reserves estimates, operational risks, uncertainty in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production, costs and expenses, health, safety and environmental risks,

uncertainty as to the availability of labour and services, commodity price and exchange rate fluctuations, unexpected adverse weather conditions, loss of market demand, general economic conditions affecting the ability to access sufficient capital, changes in law and 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 and does not intend or assume any obligation to update the forward-looking information after the date of this MD&A and Q3 Report 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. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are expressly qualified in their entirety by these cautionary statements.

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
MMboe	million 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
Bcf	billion cubic feet
mmbtu	million British thermal units
GJ	Gigajoule
GJ/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

GUIDANCE

The Corporation did not drill any wells during the first nine months of 2015, due to the current low commodity price environment. In the fourth quarter of 2015, one well (0.05 net carried) was drilled related to a farm-out agreement (see "Major Transactions Subsequent to the Reporting Period") and Manitok executed various recompletion activities in southeast Alberta which is anticipated to satisfy its 2015 capital commitment with PrairieSky Royalty Ltd. ("PSK").

The Corporation anticipates that net bank debt will be \$62.0 to \$63.0 million as at December 31, 2015, Based on current forward strip crude oil and natural gas prices, Manitok will have the requisite liquidity to make its next required payment of \$10.0 million on its non-revolving reducing demand loan facility before March 31, 2016. The Corporation continues to pursue alternative debt arrangements, joint venture opportunities, property acquisitions or divestitures and other recapitalization opportunities to satisfy the credit facility repayment requirements (see "Major Transactions Affecting Financial Results").

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

- On May 1, 2015, the Corporation announced revised terms and additional lands to the lease issuance and drilling commitment agreement with PSK ("**PSK LIDCA**"). The major terms include:
 - the acquisition of additional petroleum and natural gas leases covering about 180 net sections (115,200 acres) in southeast Alberta with access to proprietary 2D and 3D seismic data over the entire land base in exchange for a 4% gross overriding royalty with no deductions on its Stolberg lands ("**Stolberg GORR Divestiture**") of approximately 9,920 acres (5,555 net) from both the Cardium and Mannville formations effective as of January 1, 2015;
 - the amendment of the freehold royalty rate in the majority of the land to a flat rate of 17.5% retroactive to January 1, 2015, from the current royalty calculation of a minimum of 10% and maximum of 30%, providing a significant improvement in the payout period and the half cycle rate of return on the Corporation's lower Mannville drilling prospects in a high commodity price environment;
 - provisions to allow greater flexibility through capital deferral and reallocation of capital to additional lands in the area;
 - the extension of the primary term of the PSK LIDCA for an additional 16 months from December 31, 2016 to April 30, 2018 with Manitok's option to extend for an additional period of four years for all or a portion of the land; and
 - the decrease of the annual drilling and completion expenditure commitment; however, by extending the primary term, the remaining aggregate drilling and completion expenditure commitment increases from \$72.0 million to \$92.0 million.
- On June 12, 2015, the Corporation closed an asset acquisition in the Wayne area of southeast Alberta, including a 25,000 bbls/d fluid processing facility, for total cash consideration of approximately \$62.4 million after estimated post-closing adjustments ("**Wayne Acquisition**").
- On June 12, 2015, the Corporation divested of a 5% gross over-riding royalty of revenue with no deductions from the producing wells in the Wayne area ("**Wayne GORR Divestiture**") for total cash consideration of approximately \$6.2 million after estimated post-closing adjustments.
- On June 12, 2015, Manitok entered into a production volume royalty agreement ("**PVR Divestiture**") with a royalty corporation for approximately \$24.4 million after estimated post-closing adjustments. The PVR Divestiture royalty volume remains constant at 140 bbls/d of light crude oil for the first 8 years to May 31, 2023, and is then subject to a 10% decline per year thereafter. The royalty volumes are first allocated from the Corporation's Stolberg area, provided sufficient volumes are produced, and any short fall would be made up from oil production in the Wayne area and the Carseland area, if available. There is an associated capital commitment to spend a minimum of \$10.0 million per year in 2016, 2017 and 2018 on drilling, completion, re-completion, workover, equipping and tie-in for production of wells targeting production from the Wayne and/or Carseland areas. This commitment coincides with the PSK LIDCA commitment and

is not incremental to that commitment. Additionally, Manitok has committed to drill at least two gross wells per year in 2016, 2017 and 2018 in the Stolberg area.

- On June 12, 2015, Manitok divested its interest in certain oil and gas infrastructure ("**Facility Divestiture**") in the Wayne area for approximately \$7.1 million after estimated post-closing adjustments and closed a facilities financing agreement ("**Facility Financing**") in the Wayne area for \$12.5 million with a third party for a total of \$19.6 million after estimated post-closing adjustments. The Corporation has entered into an agreement for the exclusive use of the oil and gas infrastructure, which include monthly facility fees over eight years related to the Facility Divestiture. Pursuant to the Facility Financing, the Corporation is required to make monthly payments over 20 years at an effective interest rate of 14.5% over the life of the obligation and the obligation is secured by certain oil batteries in the Wayne area.
- On June 12, and June 17, 2015, Manitok closed two tranches of a non-brokered private placement equity financing for the issuance of 12,587,600 common shares of Manitok ("**Manitok Shares**") at a price of \$0.80 per Manitok Share, 917,500 common shares of Manitok 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 \$0.85 per Manitok CDE Flow-through Share, and 6,305,077 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 \$0.95 per Manitok CEE Flow-through Share for gross proceeds of \$16.8 million (net proceeds - \$15.8 million).
- In June 2015 Manitok amended its \$90.0 million revolving operating demand loan facility with its lender. Upon amendment, the facilities consist of a \$45.0 million revolving operating demand loan facility drawn at \$30.4 million at September 30, 2015 and a fully drawn \$35.0 million non-revolving reducing demand loan facility for total credit facilities of \$80.0 million. The Corporation is required to repay the \$35.0 million outstanding amount on the non-revolving reducing demand loan as follows:
 - \$5.0 million on or before December 31, 2015, which has been paid as at November 25, 2015 (see "Major Transactions Subsequent to the Reporting Period");
 - \$10.0 million on or before March 31, 2016; and
 - \$20.0 million on or before May 31, 2016.

The condensed interim financial statements have been prepared in accordance with GAAP on a going concern basis, which asserts that the Corporation has the ability to realize its assets and discharge its liabilities and commitments in the normal course of business. The repayment requirements of the non-revolving reducing demand loan facility may be amended or eliminated upon a material increase in future commodity prices, an increase in proved producing reserves and future renegotiations with its lender. Based on the next twelve month forecasted funds from operations at current forward strip crude oil and natural gas prices, the Corporation is in the process of identifying and pursuing alternative debt arrangements, joint venture opportunities, property acquisitions or divestitures and other recapitalization opportunities and is taking steps to manage its spending and indebtedness, including the implementation of cost reduction and capital management initiatives to satisfy the non-revolving reducing demand loan facility repayment requirements. There is no assurance that the Corporation will be able to access the various financing opportunities in order to repay the non-revolving reducing demand loan facility in accordance with the timing required under the credit facility agreement. Should the Corporation fail to make repayments of the non-revolving reducing demand loan facility in accordance with the requirements of the credit facility agreement and is unable to renegotiate with its lender, outstanding borrowings may become due and payable immediately. These circumstances result in material uncertainty surrounding the Corporation's ability to continue as a going concern and lend additional risk as to the ability of the Corporation to meet its obligations as they come due and, accordingly the appropriateness of the use of accounting principles applicable to a going concern. The Corporation currently continues to meet all of its obligations with respect to ongoing operations.

MAJOR TRANSACTIONS SUBSEQUENT TO THE REPORTING PERIOD

- On November 25, 2015, the Corporation fully satisfied the \$5.0 million required repayment on the non-revolving reducing demand loan facility, which was due on or before December 31, 2015.
- In the fourth quarter of 2015, the Corporation entered into a binding letter of intent to execute a farm-out agreement with a private oil and gas company (the "Farmee") whereby the Farmee has committed to spend up to \$20.0 million from the fourth quarter of 2015 to the end of 2016 in the Rockyford area and depending on the level of success achieved with the drilling, may lead up to an additional \$20.0 million of capital spending, with the Farmee having an option to drill the offset wells before the end of 2017 ("Farm-out Agreement"). ManitoK will have the option but, not the obligation to participate in each well and will be carried for a 5% working interest by the Farmee in each well it does not participate. The entire capital spend from the Farm-out Agreement will be fully allocated to ManitoK's PSK capital commitment.

FUNDS FROM OPERATIONS AND NET INCOME (LOSS)

Funds from Operations

Management uses funds from operations to analyze operating performance. Funds from operations and funds from operations per share are non-GAAP measures defined as cash flow from operating activities from the Statements of Cash Flows before decommissioning expenditures, acquisition-related expenses and changes in non-cash operating working capital. Funds from operations should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net income (loss) as determined in accordance with GAAP, as an indicator of ManitoK's performance or liquidity. Funds from operations per share is calculated based on the weighted average number of basic and diluted common shares outstanding. ManitoK's calculation of funds from operations is considered to be a key measure of the ability to generate the cash necessary to fund capital expenditures and repay indebtedness.

The following schedule sets out the reconciliation of cash flow from operating activities, as determined in accordance with International Financial Reporting Standards ("IFRS") to funds from operations for the Reporting Periods and the Comparable Prior Periods:

	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
<i>(\$000, except per share information)</i>				
Cash flow from operating activities	6,329	7,633	23,014	40,468
Adjustments:				
Decommissioning expenditures	310	4	390	20
Acquisition-related expenses	20	-	1,974	-
Changes in non-cash operating working capital	(16)	919	(3,476)	(5,274)
Funds from operations	6,643	8,556	21,902	35,214
per share – basic	0.08	0.13	0.30	0.50
per share – diluted	0.08	0.12	0.30	0.49

Funds from operations decreased by 22% to \$6.6 million (\$0.08 per diluted share) for the third quarter of 2015 as compared to \$8.6 million (\$0.12 per diluted share) in the Comparable Prior Period. For the nine month Reporting Period, funds from operations decreased by 38% to \$21.9 million (\$0.30 per diluted share) as compared to \$35.2 million (\$0.49 per diluted share) in the Comparable Prior Period. The decreases are due primarily to a decrease in petroleum and natural gas revenue from the sharp decline in commodity prices and increases in operating and interest expenses, partially offset by increased realized gains on financial instruments and an aggregate decrease to royalty and transportation and marketing expenses.

Net Income (Loss)

The following table details ManitoK's net income (loss) for the Reporting Periods and the Comparable Prior Periods:

	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
<i>(\$000, except per share information)</i>				
Net income (loss)	8,316	7,900	(21,937)	(813)
per share – basic	0.10	0.12	(0.30)	(0.01)
per share – diluted	0.10	0.11	(0.30)	(0.01)

Net income increased by 5% to \$8.3 million (\$0.10 per diluted share) for the third quarter of 2015 as compared to net income of \$7.9 million (\$0.11 per diluted share) in the Comparable Prior Period. The increase in net income are due primarily to an increase in the unrealized gain on financial instruments, partially offset by decreased funds from operations.

The net loss increased to \$21.9 million (\$0.30 loss per diluted share) for the first nine months of 2015 as compared to a net loss of \$0.8 million (\$0.01 loss per diluted share) in the Comparable Prior Period. The increase in the net loss and net loss per share were due to decreased funds from operations, acquisition-related expenses, increased depletion and depreciation and impairment, an unrealized loss on financial instruments and a loss on divestiture of assets, partially offset by a larger deferred income tax recovery.

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 September 30, 2015				Three months ended September 30, 2014			
	Total Revenue (\$000)	Average Daily Production	%	Average (\$/unit)	Total Revenue (\$000)	Average Daily Production	%	Average (\$/unit)
Light oil (bbls)	10,377	2,176	49	51.85	18,089	2,066	52	95.17
Natural gas (mcf)	3,651	12,412	47	3.20	4,274	10,931	46	4.25
NGLs (bbls)	516	190	4	29.50	673	74	2	98.93
Total P&NG sales (boe)	14,544	4,434	100	35.65	23,036	3,962	100	63.20
Royalty revenue	4	-	-	-	1	-	-	-
Total P&NG revenue (boe)	14,548	4,434	100	35.65	23,037	3,962	100	63.20

	Nine months ended September 30, 2015				Nine months ended September 30, 2014			
	Total Revenue (\$000)	Average Daily Production	%	Average (\$/unit)	Total Revenue (\$000)	Average Daily Production	%	Average (\$/unit)
Light oil (bbls)	31,143	2,103	47	54.26	69,808	2,593	56	98.62
Natural gas (mcf)	11,106	13,630	51	2.98	17,094	11,891	43	5.27
NGLs (bbls)	1,236	112	2	40.31	2,002	73	1	101.03
Total P&NG sales (boe)	43,485	4,486	100	35.50	88,904	4,647	100	70.08
Royalty revenue	5	-	-	-	16	-	-	0.01
Total P&NG revenue (boe)	43,490	4,486	100	35.50	88,920	4,647	100	70.09

Total P&NG sales for the third quarter of 2015 decreased 37% to \$14.5 million compared to \$23.0 million in the Comparable Prior Period. The decrease of \$8.5 million consists of \$9.9 million due to lower realized prices, partially offset by \$1.4 million attributed to higher production volumes.

Year to date, total P&NG sales decreased 51% to \$43.5 million compared to \$88.9 million in the Comparable Prior Period. The decrease of \$45.4 million consists of \$9.8 million attributed to lower production volumes and \$35.6 million due to lower realized prices.

Production

Production averaged 4,434 boe/d, and 4,486 boe/d in the three and nine month Reporting Periods, as compared to 3,962 boe/d and 4,647 boe/d in the Comparable Prior Periods.

Light oil production was 2,176 bbls/d and 2,103 bbls/d in the three and nine month Reporting Periods, as compared to 2,066 bbls/d and 2,593 bbls/d in the Comparable Prior Periods. Light oil volumes in the Stolberg area decreased in the nine month Reporting period, due to no new drilling in the first nine months of 2015, restrictions imposed by TransCanada Pipeline ("TCPL Restrictions") as a result of maintenance on their system along with natural production declines. The decline in light oil production in the Stolberg area was partially offset by production from 4 (4.0 net) new wells drilled, completed and tied-in in the Carseland area which contributed approximately 298 bbls/d of light

oil production compared to nil in the Comparable Prior Period, and the Wayne Acquisition that contributed approximately 356 bbls/d of light oil production, or 875 bbls/d from June 12, 2015 to September 30, 2015.

Natural gas production increased to 12.4 Mmcf/d and 13.6 Mmcf/d in the three and nine month Reporting Periods, as compared to 10.9 Mmcf/d and 11.9 Mmcf/d in the Comparable Prior Periods due to gas production from the Carseland area and the Wayne Acquisition, partially offset by the TCPL Restrictions in the Stolberg area and the February 28, 2014 asset divestiture in the central Alberta foothills region ("**Foothills Asset Divestiture**") which contributed 0.9 Mmcf/d in the nine month Comparable Prior Period.

Commodity Prices

Manitok sells all of its crude oil on a spot basis and its natural gas production for prices based on the AECO daily spot price and may enter into physical sales contracts. The following table details the average reference price for the Reporting Periods and the Comparable Prior Periods:

	Three months ended September 30			Nine months ended September 30		
	2015	2014	Variance	2015	2014	Variance
Benchmark prices						
Light oil – WTI (\$US/bbl) ⁽¹⁾	46.43	97.17	(52%)	51.00	99.61	(49%)
Light oil – WTI (\$CAD/bbl)	60.77	105.82	(43%)	64.26	108.99	(41%)
Light oil – Canadian light sweet (\$/bbl) ⁽¹⁾	55.09	97.71	(44%)	59.09	100.53	(41%)
Natural gas – AECO daily spot (\$/mmbtu) ⁽²⁾	2.90	4.02	(28%)	2.77	4.81	(42%)
Exchange rate – (\$CAD/\$US)	1.3089	1.0890	20%	1.2600	1.0942	15%
Average realized prices						
Light oil (\$/bbl)	51.85	95.17	(46%)	54.26	98.62	(45%)
Natural gas (\$/mcf)	3.20	4.25	(25%)	2.98	5.27	(43%)
NGLs (\$/bbl)	29.50	98.93	(70%)	40.31	101.03	(60%)
Average realized price (\$/boe)	35.65	63.20	(44%)	35.50	70.08	(49%)
Price differentials						
Canadian light sweet/WTI CAD (\$/bbl)	(5.68)	(8.11)	(30%)	(5.17)	(8.46)	(39%)
Realized light oil/Canadian light sweet (\$/bbl)	(3.24)	(2.54)	28%	(4.83)	(1.91)	153%
Realized natural gas/AECO daily spot (\$/mcf)	0.30	0.23	30%	0.21	0.46	(54%)

(1) Information obtained from the Sproule Associates Limited website at www.sproule.com.

(2) \$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 the average benchmark prices for crude oil and natural gas, the Canadian/US dollar exchange rate and transportation and product quality differentials.

In the three and nine month Reporting Periods, Manitok's average realized commodity price decreased 44% and 49% respectively to \$35.65/boe and \$35.50/boe from \$63.20/boe and \$70.08/boe in the Comparable Prior Periods, due to decreased benchmark prices for crude oil, natural gas and NGLs. In addition, the realized prices for NGLs were reduced due to a different NGL product mix as a result of the Wayne Acquisition assets, which include a higher proportion of propane and butane volumes as compared to the Comparable Prior Periods.

The following table provides a reconciliation of the AECO daily spot price to the Corporation's realized average natural gas price for the Reporting Periods and the Comparable Prior Periods:

	Three months ended September 30			Nine months ended September 30		
	2015	2014	Variance	2015	2014	Variance
Natural gas – AECO daily spot (\$/mmbtu) ⁽¹⁾	2.90	4.02	(28%)	2.77	4.81	(42%)
Heat/quality differential (\$/mcf)	0.30	0.27	11%	0.21	0.59	(64%)
Physical sales/AECO daily spot differential (\$/mcf)	-	(0.04)	-	-	(0.13)	-
Realized natural gas (\$/mcf)	3.20	4.25	(25%)	2.98	5.27	(43%)

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

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 "Financial Instruments").

Financial Instruments

The Corporation has entered into certain commodity price risk management contracts in order to reduce volatility in its financial results and to protect its funds from operations and anticipated capital expenditure program. The Corporation's current strategy is to hedge a portion of its oil and natural gas production, using a combination of financial derivatives and/or physical delivery sales contracts to manage commodity risk.

Financial Derivatives

As at September 30, 2015, the Corporation held the following derivative financial instruments:

Product	Notional Quantity	Term	Reference	Strike Price	Type of Contract	Fair Value (\$000)
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CAD\$ WTI	\$95.00	Swap	3,113
Oil	500 bbls/d	October 1, 2015 to December 31, 2015	CAD\$ WTI	\$91.00	Swap	1,373
Oil	500 bbls/d	October 1, 2015 to December 31, 2015	CAD\$ WTI	\$75.00	Swap	638
Oil	500 bbls/d	January 1, 2016 to December 31, 2016	CAD\$ WTI	\$80.15	Swap	2,618
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD\$ WTI	\$79.75	Swap	4,232
Natural gas	1,000 GJ/d	October 1, 2015 to December 31, 2015	CAD\$ AECO	\$3.73	Put option ⁽¹⁾	99
Natural gas	5,000 GJ/d	October 1, 2015 to December 31, 2015	CAD\$ AECO	\$3.85	Put option ⁽¹⁾	551
Natural gas	5,000 GJ/d	October 1, 2015 to December 31, 2015	CAD\$ AECO	\$3.85	Put option ⁽¹⁾	551
Natural gas	5,000 GJ/d	October 1, 2015 to December 31, 2015	CAD\$ AECO	\$3.80	Put option ⁽¹⁾	528
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CAD\$ WTI	\$95.00	Option ⁽²⁾	(2)
Oil	500 bbls/d	January 1, 2016 to December 31, 2016	CAD\$ WTI	\$91.00	Option ⁽³⁾	(10)
Oil	500 bbls/d	January 1, 2017 to December 31, 2017	CAD\$ WTI	\$80.15	Option ⁽⁴⁾	(467)
Oil	500 bbls/d	January 1, 2018 to December 31, 2018	CAD\$ WTI	\$79.75	Option ⁽⁵⁾	(889)
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD\$ WTI	\$75.00-\$90.00	Collar ⁽⁶⁾	3,694
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD\$ WTI	\$70.00-\$90.00	Collar ⁽⁷⁾	2,612
Total						18,641

- (1) Manitok recorded \$0.5 million as a deferred premium on financial instruments liability, which represents the amount payable to the counter-party on these contracts for the deferred put option premium of \$0.35/GJ.
- (2) The counter-party to this contract holds a one-time option no later than December 31, 2015 to extend a swap on 1,000 bbls/d of oil at CAD\$95.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.
- (3) The counter-party to this contract holds a one-time option no later than December 31, 2015 to extend a swap on 500 bbls/d of oil at CAD\$91.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.
- (4) The counter-party to this contract holds a one-time option no later than December 30, 2016 to extend a swap on 500 bbls/d of oil at CAD\$80.15 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 29, 2017 to extend a swap on 500 bbls/d of oil at CAD\$79.75 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.
- (6) Manitok recorded \$1.6 million as a deferred premium on financial instruments liability, which represents the amount payable to the counter-party on this contract for the deferred premium of \$4.50/bbl.
- (7) Manitok recorded \$1.2 million as a deferred premium on financial instruments liability, which represents the amount payable to the counter-party on this contract for the deferred premium of \$3.15/bbl.

The following table provides a summary of the realized and unrealized gain (loss) on financial instruments:

	Three months ended September 30				Nine months ended September 30			
	2015		2014		2015		2014	
	\$000	\$/boe	\$000	\$/boe	\$000	\$/boe	\$000	\$/boe
Realized gain (loss) on financial instruments	6,426	15.75	(1,709)	(4.69)	16,380	13.37	(6,303)	(4.97)
Unrealized gain (loss) on financial instruments	11,014	27.00	8,394	23.03	(3,428)	(2.80)	183	0.14

Physical Sales Contracts

In addition to the financial derivative contracts discussed above, the Corporation may enter into physical sales contracts to manage commodity risk. These contracts are considered normal executory contracts and are not recorded at fair value in the financial statements. There are no physical sales contracts outstanding as at September 30, 2015.

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 for the Reporting Periods and the Comparable Prior Periods:

	Three months ended September 30, 2015			Three months ended September 30, 2014		
	(\$000)	Effective Royalty Rate ⁽¹⁾	Average (\$/unit)	(\$000)	Effective Royalty Rate ⁽¹⁾	Average (\$/unit)
Light oil and NGLs (bbls)	3,516	32.3%	16.15	6,901	36.8%	35.05
Natural Gas (mcf) ⁽²⁾	618	16.9%	0.54	256	6.0%	0.25
Total Royalties (boe)	4,134	28.4%	10.13	7,157	31.1%	19.64

	Nine months ended September 30, 2015			Nine months ended September 30, 2014		
	(\$000)	Effective Royalty Rate ⁽¹⁾	Average (\$/unit)	(\$000)	Effective Royalty Rate ⁽¹⁾	Average (\$/unit)
Light oil and NGLs (bbls)	9,801	30.3%	16.21	25,530	35.6%	35.08
Natural Gas (mcf) ⁽²⁾	1,379	12.4%	0.37	2,464	14.4%	0.76
Total Royalties (boe)	11,180	25.7%	9.13	27,994	31.5%	22.07

(1) The effective royalty rate is calculated by dividing the royalties into the applicable P&NG sales category and into total sales for the period.

(2) Includes natural gas cost allowance credits received from the government of Alberta.

Royalties for the three and nine month Reporting Periods decreased 42% and 60% to \$4.1 million and \$11.2 million, as compared to \$7.2 million and \$28.0 million for the Comparable Prior Periods. The decrease is due to the lower effective royalty rates in the Reporting Periods, which are the result of lower Crown royalties associated with the decrease in commodity prices, partially offset by an increase in royalties of \$1.3 million and \$1.9 million associated with the Stolberg GORR Divestiture, the Wayne GORR Divestiture and the PVR Divestiture which occurred in the second quarter of 2015 (see "Major Transactions Affecting Financial Results") in the three and nine month Reporting Periods as compared to nil 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 September 30, 2015		Three months ended September 30, 2014		Variance	
	\$000	\$/boe	\$000	\$/boe	\$	\$/boe
Field operating expenses	6,488	15.90	2,737	7.51	137%	112%
Recoveries	(258)	(0.63)	(284)	(0.78)	(10%)	(19%)
Field operating expenses, net	6,230	15.27	2,453	6.73	154%	127%
Expensed workovers and other	184	0.45	-	-	-	-
Total operating expenses	6,414	15.72	2,453	6.73	161%	134%

	Nine months ended September 30, 2015		Nine months ended September 30, 2014		Variance	
	\$000	\$/boe	\$000	\$/boe	\$	\$/boe
Field operating expenses	16,053	13.11	10,230	8.06	57%	63%
Recoveries	(976)	(0.80)	(1,091)	(0.86)	(11%)	(7%)
Field operating expenses, net	15,077	12.31	9,139	7.20	65%	71%
Expensed workovers and other	184	0.15	56	0.04	229%	275%
Total operating expenses	15,261	12.46	9,195	7.24	66%	72%

Operating expenses for the three and nine month Reporting Periods were \$6.4 million and \$15.3 million, as compared to \$2.5 million and \$9.2 million for the Comparable Prior Periods. On a per boe basis, operating expenses increased to \$15.72/boe and \$12.46/boe as compared to \$6.73/boe and \$7.24/boe in the Comparable Prior Periods. The increases per unit are attributable to higher operating costs in the Stolberg area due to lower average daily

production, new production in the Carseland and Wayne areas that had higher operating expenses than the corporate average in the Comparable Prior Periods and workover costs incurred in the Wayne area. The fluid processing facility and higher well count in the Wayne area contributed to the higher operating expenses. In addition, the facility fees associated with the December 2014 oil and gas infrastructure divestiture and the June 2015 Facility Divestiture represented \$1.79/boe and \$1.39/boe in the three and nine month Reporting Periods as compared to nil in the Comparable Prior Periods.

Transportation and Marketing Expenses

The following table illustrates the Corporation's transportation and marketing ("T&M") expenses for the Reporting Periods and the Comparable Prior Periods:

	Three months ended September 30			Nine months ended September 30		
	2015	2014	Variance	2015	2014	Variance
Total T&M expenses (\$000)	698	1,265	(45%)	2,828	4,359	(35%)
Total T&M expenses (\$/boe)	1.71	3.47	(51%)	2.31	3.44	(33%)

Total T&M expenses for the three and nine month Reporting Periods were \$0.7 million and \$2.8 million, as compared to \$1.3 million and \$4.4 million for the Comparable Prior Periods. On a per boe basis, T&M expenses decreased to \$1.71/boe and \$2.31/boe as compared to \$3.47/boe and \$3.44/boe in the Comparable Prior Periods. The decreases are a result of reduced light oil production in the Stolberg area and increased crude oil production in the Wayne area, which is considered emulsion hauling included in operating expenses. Also there was a lower percentage of crude oil production relative to natural gas for the nine month Reporting Period. Natural gas transportation costs are lower on a per boe basis than crude oil transportation costs, and natural gas volumes represented 51% in the nine month Reporting Period, as compared to 43% in both the Comparable Prior Period.

Operating Netback

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

(\$/boe)	Three months ended September 30			Nine months ended September 30		
	2015	2014	Variance	2015	2014	Variance
Realized P&NG revenue price	35.65	63.20	(44%)	35.50	70.09	(49%)
Royalty expenses	(10.13)	(19.64)	(48%)	(9.13)	(22.07)	(59%)
Operating expenses, net of recoveries	(15.72)	(6.73)	134%	(12.46)	(7.24)	72%
Transportation and marketing expenses	(1.71)	(3.47)	(51%)	(2.31)	(3.44)	(33%)
Operating netback before realized gain (loss) on financial instruments	8.09	33.36	(76%)	11.60	37.34	(69%)
Realized gain (loss) on financial instruments	15.75	(4.69)	436%	13.37	(4.97)	369%
Operating netback	23.84	28.67	(17%)	24.97	32.37	(23%)

Manitok's operating netback was \$23.84/boe in the third quarter of 2015, which is 17% lower than \$28.67/boe in the Comparable Prior Period. In the first nine months of 2015, the operating netback decreased 23% to \$24.97/boe as compared to \$32.37/boe in the Comparable Prior Period. The decreases were due to lower realized P&NG prices and higher operating expenses, partially offset by the realized gain on financial instruments and lower royalties and T&M expenses.

Administrative Expenses

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

	Three months ended September 30, 2015		Three months ended September 30, 2014		Variance
	\$000	%	\$000	%	\$
<i>Cash:</i>					
Salaries and benefits ⁽¹⁾	1,329	51	1,361	58	(2%)
Other ⁽²⁾	1,265	49	975	42	30%
	2,594	100	2,336	100	11%
Operating overhead recoveries	(67)	(3)	(112)	(5)	(40%)
Capitalized overhead recoveries ⁽³⁾	(881)	(34)	(727)	(31)	21%
General and administrative expenses, net	1,646	63	1,497	64	10%
General and administrative expenses, net per boe	4.03		4.11		(2%)
<i>Non-cash:</i>					
Stock-based compensation	305	100	162	100	88%
Capitalized stock-based compensation ⁽³⁾	(164)	(54)	(41)	(25)	300%
Stock-based compensation, net	141	46	121	75	17%
Stock-based compensation, net per boe	0.35		0.33		6%
Total administrative expenses, net	1,787	62	1,618	65	10%
Total administrative expenses, net per boe	4.38		4.44		(1%)

	Nine months ended September 30, 2015		Nine months ended September 30, 2014		Variance
	\$000	%	\$000	%	\$
<i>Cash:</i>					
Salaries and benefits ⁽¹⁾	4,530	56	4,827	63	(6%)
Other ⁽²⁾	3,593	44	2,865	37	25%
	8,123	100	7,692	100	6%
Operating overhead recoveries	(245)	(3)	(492)	(6)	(50%)
Capitalized overhead recoveries ⁽³⁾	(2,590)	(32)	(2,050)	(27)	26%
General and administrative expenses, net	5,288	65	5,150	67	3%
General and administrative expenses, net per boe	4.32		4.06		6%
<i>Non-cash:</i>					
Stock-based compensation	1,079	100	535	100	102%
Capitalized stock-based compensation ⁽³⁾	(546)	(51)	(177)	(33)	208%
Stock-based compensation, net	533	49	358	67	49%
Stock-based compensation, net per boe	0.44		0.28		57%
Total administrative expenses, net	5,821	63	5,508	67	6%
Total administrative expenses, net per boe	4.76		4.34		10%

(1) Includes salaries and benefits paid to all Officers, Directors, 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, benefits, software 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 10% and 3% on an aggregate basis to \$1.6 million and \$5.3 million in the three and nine month Reporting Period as compared to \$1.5 million and \$5.2 million in the Comparable Prior Periods. The increase is due mainly to higher office and software costs in the third quarter of 2015, however the Corporation has implemented initiatives to reduce G&A in the fourth quarter of 2015 and in 2016.

Stock-based compensation (non-cash)

Stock-based compensation increased in the nine month Reporting Period to \$0.5 million as compared to \$0.4 million in the Comparable Prior Period. In the third quarter, stock-based compensation expenses are consistent with the Comparable Prior Period.

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

	Number	Weighted Average Exercise Price (\$)
Outstanding, December 31, 2013	5,607,440	1.98
Granted	2,601,500	2.09
Exercised	(1,279,167)	(1.46)
Forfeited	(1,621,167)	(2.61)
Outstanding, December 31, 2014	5,308,606	1.97
Granted	1,215,000	0.81
Expired	(667,340)	(1.10)
Forfeited	(392,833)	(1.93)
Outstanding, September 30, 2015	5,463,433	1.82

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

Depletion and Depreciation Expense

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

	Three months ended September 30			Nine months ended September 30		
	2015	2014	Variance	2015	2014	Variance
Depletion and depreciation (\$000)	5,781	6,004	(4%)	22,356	18,889	18%
Depletion and depreciation (\$/boe)	14.17	16.47	(14%)	18.25	14.89	23%

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 decreased in the third quarter of 2015 to \$5.8 million (\$14.17/boe) as compared to \$6.0 million (\$16.47/boe) for the Comparable Prior Period. The decrease is due mainly to the reduction in production volumes in the Stolberg area and the reduction in the depletable net book asset value due to the Stolberg GORR Divestiture, the Wayne GORR Divestiture, the PVR Divestiture and the Facility Divestiture and the impairment recorded in the second quarter of 2015.

For the nine month Reporting Period, D&D expenses increased to \$22.4 million (\$18.25/boe) as compared to \$18.9 million (\$14.89/boe) for the Comparable Prior Period. The increase is due mainly to negative technical revisions of proved plus probable reserves as at December 31, 2014 in the Stolberg area.

Asset Impairment Assessment

The Corporation reviews its exploration and evaluation ("E&E") assets and P&NG assets for impairment in accordance with International Accounting Standards ("IAS") 36 under IFRS. Manitok's assets are grouped into cash generating units ("CGUs") for the purpose of determining impairment. A CGU represents the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. In determining the Corporation's CGUs, the Corporation took into consideration all available information including, but not limited to, the geographical proximity, geological similarities (i.e. reservoir characteristic, production profiles), degree of shared infrastructure, independent versus interdependent cash flows, operating structure, regulatory environment, management decision-making and overall business strategy.

Manitok reviews CGUs at each reporting date for both internal and external indicators of potential impairment. Potential CGU impairment indicators include, but are not limited to, changes to Manitok's business plan; deterioration in commodity prices; negative changes in technological, economic, legal, capital or operating environment; adverse changes to the physical condition of a CGU; current expectation that a material CGU (or a

significant component thereof), is more likely than not to be sold or otherwise disposed of before the end of its previously estimated useful life; non-compliance of financial debt covenants; deterioration in the financial and operational performance of a CGU; net assets exceeding market capitalization; and significant downward revisions of estimated recoverable proved plus probable reserves of a CGU. If impairment indicators exist, an impairment test is performed by comparing a CGU's carrying value to its recoverable amount.

In the second quarter of 2015, the Corporation performed an impairment assessment of its E&E assets and P&NG assets on a CGU basis and determined there were impairment indicators relating to the loss on the PVR Divestiture and the Stolberg GORR Divestiture, along with the general decline in forecasted crude oil and natural gas prices. The impairment test on P&NG assets determined that the net book value exceeded the recoverable amount and Manitok recognized a \$15.7 million impairment charge in the second quarter of 2015.

In the second quarter of 2015, it was determined that the net book value of certain E&E assets exceeded the recoverable amount and Manitok recognized a \$2.2 million impairment charge in the second quarter of 2015, related to land expiries. In the second quarter of 2014, the Corporation recorded impairment of \$13.6 million to its E&E assets related to exploration activities in the Quirk Creek area of Alberta.

The Corporation performed an impairment assessment of its E&E assets and P&NG assets on a CGU basis and determined there were no impairment indicators identified in the three month Reporting Period. As a result, an impairment test was not required as at September 30, 2015.

As the recoverable amount of the CGUs are sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods. Alternatively, an improvement of commodity prices could reverse any impairment charges recorded to date, less applicable depletion and depreciation charges.

(Gain) Loss on Divestiture of Assets

In June 2015, the Corporation entered into an asset swap arrangement, which Manitok completed the Stolberg GORR Divestiture in exchange for revised terms and additional undeveloped lands to the PSK LIDCA. The estimated fair market value was determined to be \$7.1 million and was based on the fair value of the Stolberg GORR sold. Manitok recorded a loss of \$0.8 million (\$0.6 million, net of tax) on the asset divestiture for the nine month period ended September 30, 2015.

In June 2015, Manitok closed the PVR Divestiture for approximately \$24.4 million after estimated post-closing adjustments. Manitok recorded a loss of \$2.8 million (\$2.0 million, net of tax) on the asset divestiture for the nine month period ended September 30, 2015.

In June 2015, the Corporation divested the Wayne GORR Divestiture for total cash consideration of approximately \$6.2 million after estimated post-closing adjustments. The Corporation did not record a gain or loss on the divestiture as the carrying value approximated the proceeds received.

In June 2015, Manitok closed the Facility Divestiture agreement for approximately \$7.1 million after estimated post-closing adjustments. The Corporation did not record a gain or loss on the divestiture as the carrying value approximated the proceeds received.

In the second quarter of 2014, the Corporation divested of minor non-producing properties for total cash consideration of \$0.9 million. The Corporation recorded a net gain of \$0.4 million (\$0.3 million, net of tax) on the divestiture during the nine month period ended September 30, 2014.

In the first half of 2014, Manitok completed the Foothills Asset Divestiture for total cash consideration of approximately \$22.0 million after post-closing adjustments. Manitok recorded a loss of approximately \$1.2 million (\$0.9 million, net of tax), as a result of the disposition.

Finance Expenses

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

	Three months ended September 30, 2015		Three months ended September 30, 2014	
	\$000	\$/boe	\$000	\$/boe
<i>Cash:</i>				
Interest and fees on credit facilities	1,445	3.54	422	1.16
Acquisition-related expenses ⁽¹⁾	20	0.05	-	-
	1,465	3.59	422	1.16
<i>Non-cash:</i>				
Accretion on decommissioning obligations	143	0.35	34	0.09
Total finance expenses	1,608	3.94	456	1.25

	Nine months ended September 30, 2015		Nine months ended September 30, 2014	
	\$000	\$/boe	\$000	\$/boe
<i>Cash:</i>				
Interest and fees on credit facilities	3,432	2.80	730	0.58
Acquisition-related expenses ⁽¹⁾	1,974	1.61	-	-
	5,406	4.41	730	0.58
<i>Non-cash:</i>				
Accretion on decommissioning obligations	271	0.22	134	0.11
Total finance expenses	5,677	4.63	864	0.69

(1) Acquisition-related expenses are associated with the Wayne Acquisition. See "Major Transactions Affecting Financial Results."

The aggregate cash finance expenses in the three and nine month Reporting Periods included increased interest charges due to higher average outstanding bank indebtedness and higher interest rates as compared to the Comparable Prior Periods, increased credit facility commitment fees and interest on the long-term financial obligations.

The Corporation's average outstanding bank indebtedness was approximately \$68.6 million in both the three and nine month Reporting Periods as compared to \$32.6 million and \$19.5 million in the Comparable Prior Periods, calculated as the simple average of the daily amounts. The effective interest rate applicable to the credit facilities was 5.1% and 4.2% in the three and nine month Reporting Periods as compared to 3.5% in both the Comparable Prior Periods.

The acquisition-related expenses are associated with closing the Wayne Acquisition in the second quarter of 2015.

The accretion on decommissioning obligations in the three and nine month Reporting Periods increased from the Comparable Prior Periods due to a significant increase in the decommissioning obligation associated with the assets from the Wayne Acquisition.

Income Taxes

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

	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Deferred income tax expense (recovery) (\$000)	3,238	2,695	(6,282)	2,197
Deferred income tax expense (recovery) (\$/boe)	7.94	7.39	(5.13)	1.73

The increase in deferred income tax expense to \$3.2 million for the three month Reporting Period from \$2.7 million in the Comparable Prior Period was due mainly to the increase in the Alberta corporate tax rate from 10% to 12%.

The increase in deferred income tax recovery to \$6.3 million for the nine month Reporting Period from a \$2.1 million deferred income tax expense in the Comparable Prior Period was due to the increase in the net loss before taxes,

partially offset by a reduction to the deferred income tax recovery of approximately \$1.0 million related to the Alberta corporate tax rate increase from 10% to 12%.

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:

(\$000)	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Land	244	719	933	844
Geologic and geophysical	408	160	690	1,225
Workovers and recompletions	501	44	579	1,082
Drilling and completions	260	17,598	2,180	52,263
Well equipment and facilities	1,562	3,432	4,814	7,888
Capitalized overhead ⁽¹⁾	881	727	2,590	2,050
Total finding and development costs (F&D)	3,856	22,680	11,786	65,352
Acquisitions ⁽²⁾	-	-	62,846	-
Divestitures ⁽³⁾	26	146	(37,055)	(22,792)
Total finding, development and acquisition costs (FD&A)	3,882	22,826	37,577	42,560
Administrative and other assets	8	6	173	181
Total capital expenditures⁽⁴⁾	3,890	22,832	37,750	42,741

(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) Includes the Wayne Acquisition and a minor acquisition for \$0.3 million.

(3) Includes the Wayne GORR Divestiture, the PVR Divestiture and the Facility Divestiture.

(4) Excludes non-cash items such as capitalized stock-based compensation, asset swap transactions and decommissioning obligations.

In the nine month Reporting Period, the Corporation completed 1 gross (1.0 net) well in the Carseland area, recompleted 2 gross (2.0 net) wells in the Wayne area, completed workovers of 2 gross (2.0 net) wells in the Wayne area and incurred lease construction costs for future drilling locations in southeast Alberta. The equipping and facilities capital spent relates to facilities construction and tie-in costs in the Carseland, Stolberg and Wayne areas.

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

(\$000)	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
E&E assets	1,244	12,673	8,429	29,211
P&NG properties and equipment, net	2,646	10,159	29,321	13,530
Total capital expenditures⁽¹⁾	3,890	22,832	37,750	42,741

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

Capital Resources and Liquidity

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

(\$000)	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Funds from operations	6,643	8,556	21,902	35,214
Changes in non-cash operating working capital	16	(919)	3,476	5,274
Decommissioning expenditures	(310)	(4)	(390)	(20)
Acquisition-related expenses	(20)	-	(1,974)	-
Increase (decrease) in credit facilities	(4,578)	25,787	12,113	31,861
Increase (decrease) in long-term financial obligations	(18)	-	12,466	-
Proceeds from share issuance	-	-	16,840	-
Share issue costs	-	-	(1,010)	-
Proceeds from the exercise of stock options	-	73	-	1,653
Repurchase of common shares	-	(4,971)	-	(20,757)
Changes in non-cash investing working capital	2,157	(5,690)	(25,673)	(10,484)
Total capital resources	3,890	22,832	37,750	42,741
E&E asset expenditures	(1,244)	(12,673)	(3,456)	(29,211)
P&NG properties and equipment expenditures	(2,620)	(10,013)	(8,503)	(36,322)
Acquisitions	-	-	(62,846)	-
Divestitures	(26)	(146)	37,055	22,792
Net increase (decrease) in cash	-	-	-	-

Working Capital

The following schedule sets out the reconciliation of working capital in accordance with IFRS to adjusted working capital:

As at, (\$000)	September 30, 2015	December 31, 2014
Working capital deficit	53,801	57,289
Current portion of the credit facilities	(65,371)	(53,258)
Current portion of the deferred premium on financial instruments	(1,557)	(2,019)
Current portion of the fair value of financial instruments - assets	13,725	20,783
Adjusted working capital deficit	598	22,795

The Corporation's adjusted working capital deficit decreased from \$22.8 million at December 31, 2014 to \$0.6 million as at September 30, 2015 as a result of the significant decrease in capital expenditures in the nine month Reporting Period as compared to the Comparable Prior Period.

At September 30, 2015, the major component of ManitoK's current assets, excluding the fair value of financial instruments, was revenue (44%) to be received from its marketers in respect of September 2015 production and accounts receivable from joint venture partners (24%) related to joint capital and operating activities in which ManitoK is the operator. ManitoK routinely assesses the financial strength of its marketers and joint venture partners and at this time, ManitoK expects that such counterparties will be able to meet their financial obligations. Current liabilities excluding the amount drawn on the credit facilities and the deferred premium on financial instruments largely consist of trade and joint venture payables (40%) and accrued liabilities (47%) related to the Corporation's operations.

The Corporation manages its working capital using a combination of its funds from operations and advances under its credit facilities and if applicable funds from debt and equity issuances and asset divestitures. If applicable, ManitoK will invest any excess cash in a short-term interest bearing account with its lender.

Bank Indebtedness

In June 2015 Manitok amended its \$90.0 million revolving operating demand loan facility with its lender. Upon amendment, the facilities consist of a \$45.0 million revolving operating demand loan facility drawn at \$30.4 million at September 30, 2015 and a fully drawn \$35.0 million non-revolving reducing demand loan facility, for total credit facilities of \$80.0 million. The Corporation is required to repay the \$35.0 million outstanding amount on the non-revolving reducing demand loan as follows:

- \$5.0 million on or before December 31, 2015, which has been paid as at November 25, 2015 (see "Major Transactions Subsequent to the Reporting Period");
- \$10.0 million on or before March 31, 2016; and
- \$20.0 million on or before May 31, 2016.

The interest rates applicable on the non-revolving reducing demand loan facility are based on the same pricing margin as the revolving operating demand loan facility plus:

- an additional 3.0% from September 1, 2015 to November 30, 2015;
- an additional 4.0% from December 1, 2015 to February 29, 2016; and
- an additional 5.0% from March 1, 2016 to May 31, 2016.

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 amount outstanding on the Corporation's credit facilities were \$65.4 million as at September 30, 2015, with an aggregate limit on the revolving operating demand loan facility and the non-revolving reducing demand loan facility of \$80.0 million as compared to \$53.3 million outstanding as at December 31, 2014, with an aggregate limit of \$90.0 million.

Management recognizes the difficulties of operating in the current commodity price environment and has taken steps to manage spending and indebtedness. The Corporation plans to remedy the repayment requirements on the non-revolving reducing demand loan facility through issuing new Manitok Shares or debt, obtaining other third party funding alternatives, or asset divestiture opportunities. Additionally, cost reduction and capital management initiatives have been implemented and as such, the Corporation has been able to maintain positive funds from operations. The Corporation continually monitors its capital structure and capital program in response to changes in business conditions, including changes in economic conditions, forecasted commodity prices and resulting funds from operations, indebtedness and the risk and timing of capital investments.

The condensed interim financial statements have been prepared in accordance with GAAP on a going concern basis, which asserts that the Corporation has the ability to realize its assets and discharge its liabilities and commitments in the normal course of business. The repayment requirements of the non-revolving reducing demand loan facility may be amended or eliminated upon a material increase in future commodity prices, an increase in proved producing reserves and future renegotiations with its lender. Based on the next twelve month forecasted funds from operations at current forward strip crude oil and natural gas prices, the Corporation is in the process of identifying and pursuing alternative debt arrangements, joint venture opportunities, property acquisitions or divestitures and other recapitalization opportunities and is taking steps to manage its spending and indebtedness, including the implementation of cost reduction and capital management initiatives to satisfy the non-revolving reducing demand loan facility repayment requirements. There is no assurance that the Corporation will be able to access the various financing opportunities in order to repay the non-revolving reducing demand loan facility in accordance with the timing required under the credit facility agreement. Should the Corporation fail to make repayments of the non-revolving reducing demand loan facility in accordance with the requirements of the credit facility agreement and is unable to renegotiate with its lender, outstanding borrowings may become due and payable immediately. These circumstances result in material uncertainty surrounding the Corporation's ability to continue as a going concern and lend additional risk as to the ability of the Corporation to meet its obligations as they come due and, accordingly the appropriateness of the use of accounting principles applicable to a going concern.

The Corporation currently continues to meet all of its obligations with respect to ongoing operations. The condensed interim financial statements do not reflect the adjustments to the carrying amounts of the Corporation's assets, liabilities, revenues, expenses and balance sheet classifications that would be necessary if the going concern assumption is not appropriate. Such adjustments could be material.

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

As at	September 30, 2015	December 31, 2014
Maximum borrowing base limit		
Revolving operating demand loan facility ⁽¹⁾	45,000	90,000
Non-revolving reducing demand loan facility ⁽¹⁾	35,000	-
Acquisition and development demand loan facility ⁽²⁾	-	15,000
Long-term financial obligations (note 10)	14,966	2,500
	94,966	107,500
Principle amount utilized		
Drawn revolving operating demand loan facility	(30,371)	(53,258)
Drawn non-revolving reducing demand loan facility	(35,000)	-
Long-term financial obligations (note 10)	(14,966)	(2,500)
Outstanding letters of credit	(200)	-
	(80,537)	(55,758)
Undrawn credit facilities	14,429	51,742

- (1) 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 revolving operating demand loan facility divided by current liabilities excluding any current portion of an amount drawn on the credit facilities, the fair value of financial instruments and the deferred premium on financial instruments) is not less than 1:1. As at September 30, 2015, the Corporation's working capital ratio was 2.3:1.
- (2) The acquisition and development demand loan facility was restricted and subject to approval by the Corporation's lender, when utilized 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. This facility was canceled in 2015.

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 September 30, 2015:

(\$000)	2015	2016	2017 - 2019	Thereafter
Accounts payable and accrued liabilities	10,741	-	-	-
Drawn on credit facilities	65,371	-	-	-
Long-term financial obligations ⁽¹⁾	559	2,235	6,705	34,369
Deferred premium on financial instruments ⁽²⁾	509	1,400	1,396	-
Minimum drilling and completion expenditures ⁽³⁾	3,575	30,750	56,000	-
Firm transportation agreement ⁽⁴⁾	201	603	764	-
Facility fees ⁽⁵⁾	734	2,937	8,811	9,317
Office leases ⁽⁶⁾	627	2,514	1,484	-
Total estimated contractual obligations⁽⁷⁾	82,317	40,439	75,160	43,686

- (1) In conjunction with the December 2014 facilities financing agreement and the Facility Financing in June 2015, Manitok is committed to pay monthly facility payments of \$186,250 to June 2035, which relates primarily to interest charges.
- (2) Manitok is committed to pay a deferred premium on certain financial instruments. See "Financial Instruments" section.
- (3) Pursuant to the revised terms of the PSK LIDCA agreement, Manitok has agreed to an annual work program including minimum annual drilling and completion expenditures until April 30, 2018. Based on current oil prices as of November 24, 2015, Manitok has been allowed to defer \$15.75 million of the 2015 minimum drilling and completion expenditures to 2016 through to 2018 in accordance with the revised PSK LIDCA agreement, resulting in a \$3.6 million remaining commitment for 2015.
- (4) The Corporation is committed to transport natural gas from a gas processing facility in the Ricinus area to the NOVA pipeline system.
- (5) In conjunction with the December 2014 oil and gas infrastructure divestiture and the Facility Divestiture in June 2015, the Corporation is required to pay monthly facility fees of \$244,740 until June 2023, which are included in operating expenses.
- (6) Manitok is committed to operating leases relating to office premises expiring on November 30, 2017 and its previous office premises expiring on February 28, 2017. The Corporation has subleased approximately 70% of its previous office space to arm's length parties for the remainder of the lease term and is currently attempting to sublease the remaining available office space. The recovery of rental costs from the subleases are not included in the table.
- (7) 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 inflation adjusted undiscounted cash flow to settle its decommissioning obligations at September 30, 2015 to be approximately \$36.7 million and will be incurred as follows: 2015 - \$1.7 million, 2016 - \$0.3 million, 2017 to 2019 - \$3.7 million and \$31.0 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.

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 during the Reporting Periods and Comparable Prior Periods.

OUTSTANDING SHARE DATA

At September 30, 2015, the 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, 2013	74,492,340
Issue of Manitok Shares upon exercise of options	1,279,167
Repurchase of Manitok Shares	(10,491,900)
Outstanding, December 31, 2014	65,279,607
Issue of Manitok Shares in June 2015 ⁽¹⁾	19,810,177
Outstanding, September 30, 2015	85,089,784

(1) On June 12, 2015 and June 17, 2015, Manitok closed two tranches of a non-brokered private placement equity financing for the issuance of 12,587,600 Manitok Shares at a price of \$0.80 per Manitok Share, 917,500 Manitok CDE Flow-through Shares at a price of \$0.85 per Manitok CDE Flow-through Share, and 6,305,077 Manitok CEE Flow-through Shares at a price of \$0.95 per Manitok CEE Flow-through Share for gross proceeds of \$16.8 million (net proceeds - \$15.8 million).

At November 25, 2015, there were 85,089,784 Manitok Shares outstanding and 5,139,933 stock options to purchase an equivalent number of Manitok Shares.

SUMMARY OF QUARTERLY INFORMATION

Quarters Ended	2015			2014				2013
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
OPERATING								
Average daily production								
Light oil (bbls/d)	2,176	1,864	2,269	2,257	2,066	2,695	3,028	2,755
Natural gas (mcf/d)	12,412	15,435	13,049	10,713	10,931	11,417	13,352	12,868
NGLs (bbls/d)	190	84	61	30	74	46	98	89
Total (boe/d)	4,434	4,521	4,504	4,072	3,962	4,644	5,351	4,989
Average realized sales price (CAD\$)								
Light oil (\$/bbl)	51.85	63.71	48.77	71.96	95.17	103.18	96.92	82.30
Natural gas (\$/mcf)	3.20	2.89	2.89	3.83	4.25	4.81	6.51	4.03
NGLs (\$/bbl)	29.50	55.98	52.85	67.29	98.93	110.86	97.92	76.48
Total (\$/boe)	35.65	37.18	33.66	50.45	63.20	72.80	72.88	57.21
OPERATING NETBACK (\$ per boe)⁽¹⁾								
Petroleum and natural gas revenue	35.65	37.18	33.66	50.45	63.20	72.81	72.90	57.22
Realized gain (loss) on financial instruments	15.75	10.86	13.54	6.67	(4.69)	(6.19)	(4.10)	(0.48)
Royalty expenses	(10.13)	(8.78)	(8.47)	(11.61)	(19.64)	(23.98)	(22.23)	(10.18)
Operating expenses, net	(15.72)	(11.28)	(10.38)	(7.65)	(6.73)	(7.58)	(7.35)	(8.83)
Transportation and marketing expenses	(1.71)	(2.35)	(2.87)	(3.17)	(3.47)	(3.66)	(3.21)	(3.10)
Operating netback ⁽¹⁾	23.84	25.63	25.48	34.69	28.67	31.40	36.01	34.63
FINANCIAL								
Petroleum and natural gas revenue (\$000)	14,548	15,297	13,645	18,902	23,037	30,771	35,112	26,260
Royalty expenses (\$000)	(4,134)	(3,613)	(3,433)	(4,349)	(7,157)	(10,132)	(10,705)	(4,670)
Realized gain (loss) on financial instruments (\$000)	6,426	4,466	5,488	2,499	(1,709)	(2,618)	(1,976)	(220)
Unrealized gain (loss) on financial instruments (\$000)	11,014	(10,328)	(4,114)	27,577	8,394	(2,036)	(6,175)	(3,591)
Interest and other revenue (\$000)	7	7	7	6	22	-	3	13
Total revenue, net (\$000)	27,861	5,829	11,593	44,635	22,587	15,985	16,259	17,792
Funds from operations (\$000) ⁽¹⁾	6,643	7,341	7,918	10,766	8,556	11,197	15,461	14,117
Per share - basic (\$) ⁽¹⁾	0.08	0.11	0.12	0.16	0.13	0.16	0.21	0.19
Per share - diluted (\$) ⁽¹⁾	0.08	0.11	0.12	0.16	0.12	0.16	0.21	0.19
Net income (loss) (\$000)	8,316	(26,852)	(3,401)	(2,774)	7,900	(9,044)	331	(1,417)
Per share - basic (\$)	0.10	(0.39)	(0.05)	(0.04)	0.12	(0.13)	-	(0.02)
Per share - diluted (\$) ⁽²⁾	0.10	(0.39)	(0.05)	(0.04)	0.11	(0.13)	-	(0.02)
Capital expenditures, net (\$000)	3,890	28,959	4,901	26,949	22,832	17,669	2,240	44,236
Book value of total assets (\$000)	206,644	199,995	196,945	211,284	197,362	178,300	185,390	192,580
Adjusted working capital (surplus) deficit (\$000) ⁽¹⁾	598	(1,575)	(2,313)	22,795	11,067	17,676	19,947	16,277
Drawn on credit facilities (\$000)	65,371	69,949	75,379	53,258	48,098	22,311	6,685	16,237
Net bank debt (\$000) ⁽¹⁾	65,969	68,374	73,066	76,053	59,165	39,987	26,632	32,514
Long-term financial obligations (\$000)	14,966	14,984	2,494	2,500	-	-	-	-
Net debt (\$000) ⁽¹⁾	80,935	83,358	75,560	78,553	59,165	39,987	26,632	32,514
Shareholders' equity (\$000)	78,586	69,965	81,348	84,333	89,714	86,550	102,256	109,096
Common shares outstanding								
End of period - basic	85,089,784	85,089,784	65,279,607	65,279,607	66,996,440	69,020,407	71,615,406	74,492,340
End of period - diluted	90,553,217	91,564,557	71,719,880	70,588,213	71,566,714	74,114,181	77,689,147	80,099,780
Weighted average for the period - basic	85,089,784	68,749,889	65,279,607	65,924,473	68,143,633	70,390,367	73,097,543	72,638,096
Weighted average for the period - diluted	85,089,784	68,750,556	65,279,607	66,255,000	69,108,544	71,402,527	74,334,096	74,371,392

(1) Funds from operations, funds from operations per share, operating netback, adjusted working capital (surplus) deficit, net bank debt and net debt do not have standardized meanings prescribed by GAAP and therefore should not be considered in isolation. These reported amounts and their underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of other companies where similar terminology is used. Where these measures are used they should be given careful consideration by the reader. Refer to the Non-GAAP Measures paragraph in the Advisories section of this MD&A.

(2) The basic and diluted weighted average shares outstanding are the same for periods in which the Corporation records a net loss and when all the outstanding stock options are anti-dilutive.

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.

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

- In the fourth quarter of 2013, Manitok recorded a net loss of \$1.4 million, which was primarily the result of an impairment expense of \$4.9 million.
- The Corporation completed an equity financing in the fourth quarter of 2013, issuing 1.4 million Manitok CDE Flow-through Shares and 5.6 million Manitok CEE Flow-through Shares for net proceeds of approximately \$23.5 million, which contributed to the significant increase in total assets and shareholders' equity.
- In the fourth quarter of 2013, Manitok closed a lease issuance and drilling commitment agreement for approximately \$19.7 million and incurred additional seismic processing costs of about \$0.4 million in southeast Alberta for total capital expenditures of \$20.1 million.
- The Corporation repurchased 2,261,600 Manitok Shares in the fourth quarter of 2013 at an average price of \$2.34 per share, pursuant to a NCIB program.
- In the first quarter of 2014, the Corporation completed the Foothills Asset Divestiture, which resulted in a reduction of production volumes, lower net capital expenditures in the quarter and a loss on the divestiture of \$1.2 million.
- In the first quarter of 2014, petroleum and natural gas revenue increased 34% from the fourth quarter of 2013 as a result of increased production volumes and higher commodity prices.
- Royalty expenses increased 129% in the first quarter of 2014 compared to the fourth quarter of 2013 as a result of higher commodity prices and three light oil wells drilled in 2013 that each exceeded the royalty incentive production volume maximum of 50,000 bbls of oil in approximately three to four months of production and were subject to a maximum royalty rate of 40% for the majority of the first quarter of 2014 as compared to a 5% new well royalty rate before the production volume threshold of 50,000 bbls of oil was exceeded.
- The Corporation repurchased 3,350,300 Manitok Shares in the first quarter of 2014 at an average price of \$2.39 per share, pursuant to a NCIB program.
- In the second quarter of 2014, average production volumes decreased to 4,644 boe/d compared to 5,351 boe/d in the first quarter of 2014 mainly attributed to the Foothills Asset Divestiture.
- P&NG revenue decreased by \$4.3 million in the second quarter of 2014 from the first quarter of 2014 as a result of the decreased production volumes.
- Funds from operations decreased by \$4.3 million in the second quarter of 2014 from the first quarter of 2014 mainly attributable to lower revenue and an increase to the realized loss on financial instruments.
- In the second quarter of 2014, Manitok recorded a net loss of \$9.0 million, which was primarily the result of an impairment expense of \$13.6 million.
- The Corporation repurchased 3,194,800 Manitok shares in the second quarter of 2014 at an average price of \$2.41 per share, pursuant to a NCIB program.
- P&NG revenue decreased by \$7.7 million in the third quarter of 2014 from the second quarter of 2014 as a result of the decreased production volumes and decreased commodity prices.
- Funds from operations decreased by \$2.6 million in the third quarter of 2014 from the second quarter of 2014 mainly attributable to lower P&NG revenue.
- In the third quarter of 2014, Manitok recorded net income of \$7.9 million, which was primarily the result of an unrealized gain on financial instruments of \$8.4 million as a result of the decrease in WTI crude oil price.
- The Corporation repurchased 2,068,300 Manitok Shares in the third quarter of 2014 at an average price of \$2.39 per share, pursuant to a NCIB program.
- P&NG revenue decreased by \$4.1 million in the fourth quarter of 2014 from the third quarter of 2014 as a result of the decreased realized commodity prices.
- Funds from operations increased by \$2.2 million in the fourth quarter of 2014 from the third quarter of 2014 mainly attributable to a realized gain on financial instruments and a decrease in royalty expenses, partially offset by lower P&NG revenue.

- In the fourth quarter of 2014, the unrealized gain on financial instruments increased by \$19.2 million from the third quarter of 2014 due to the significant decrease in commodity prices.
- Net loss for the fourth quarter of 2014 was \$2.8 million, compared to net income of \$7.9 million in the third quarter of 2014. The decrease was primarily the result of an impairment charge of \$34.0 million in the fourth quarter of 2014, partially offset by the increase in the unrealized gain on financial instruments.
- Total net debt increased by \$19.4 million to \$78.6 million as at December 31, 2014 from September 30, 2014 due primarily to capital expenditures and an asset acquisition in the fourth quarter of 2014, partially offset by the oil and gas infrastructure divestiture.
- The Corporation repurchased 1,878,500 Manitoq Shares in the fourth quarter of 2014 at an average price of \$1.73 per share, pursuant to a NCIB program.
- P&NG revenue decreased by \$5.3 million in the first quarter of 2015 from the fourth quarter of 2014 as a result of the decreased realized commodity prices.
- Funds from operations decreased by \$2.8 million in the first quarter of 2015 from the fourth quarter of 2014 mainly attributable to lower P&NG revenue and increased operating expenses, partially offset by an increased realized gain on financial instruments and a decrease in royalty expenses.
- Adjusted working capital changed to a surplus of \$2.3 million at March 31, 2015, compared to a deficit as at December 31, 2014 as a result of the significant decrease in capital expenditures in the first quarter of 2015 compared to the fourth quarter of 2014.
- Net loss for the second quarter of 2015 was \$26.9 million, compared to a net loss of \$3.4 million in the first quarter of 2015. The increase was primarily the result of an impairment charge of \$17.9 million, an increased unrealized loss on financial instruments and losses on the divestiture of assets.
- In the second quarter of 2015, Manitoq closed the Wayne Acquisition for cash consideration of \$62.4 million.
- The Corporation closed a non-brokered private placement equity financing in June 2015 for the issuance of 12,587,600 Manitoq Shares at a price of \$0.80 per Manitoq Share, 917,500 common shares of Manitoq CDE Flow-through Shares at a price of \$0.85 per Manitoq CDE Flow-through Share, and 6,305,077 Manitoq CEE Flow-through Shares at a price of \$0.95 per Manitoq CEE Flow-through Share for gross proceeds of \$16.8 million (net proceeds - \$15.8 million).
- The Corporation completed the Stolberg GORR Divestiture, the Wayne GORR Divestiture, the Facility Divestiture and the PVR Divestiture in the second quarter of 2015 for cash proceeds of \$37.7 million.
- Net income for the third quarter of 2015 was \$8.4 million, compared to a net loss of \$26.9 million in the second quarter of 2015. The increase was primarily the result of an increased unrealized gain on financial instruments in the third quarter of 2015 and a loss on the divestiture of assets of \$3.6 million and an impairment charge of \$17.9 million in the second quarter of 2015.

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 signed by the relevant parties.

The Corporation may fail to realize the perceived benefits of any proposed acquisition. The Corporation may not realize the expected benefits and synergies from any proposed acquisition or may encounter difficulties in achieving these anticipated benefits. There can be no assurance that the Corporation will realize these benefits in the time expected or at all. This could have a negative impact on the business, operating profit or overall financial condition of the Corporation.

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 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 financial statements:

(i) *Identification of CGUs*

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.

(ii) *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 and 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 and 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) *Reserves*

Reported recoverable quantities of proved and probable reserves requires estimation 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 the reservoir, and the anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Corporation's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Manitok's petroleum and natural gas interests are evaluated by independent reserve engineers at least annually.

The Corporation's petroleum and natural gas 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 petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proved 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) *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.

(iii) *Decommissioning obligations*

The Corporation estimates future remediation costs of production facilities, well sites and gathering systems at different stages of development and construction of assets. 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 technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

(iv) *Impairment of non-financial assets*

For the purposes of determining the extent of any impairment or its reversal, estimates must be made regarding future cash flows taking into account key assumptions including future petroleum and natural gas prices, expected forecasted 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.

(v) *Taxes*

Manitok files corporate income tax, goods and service tax and other tax returns with various provincial and federal taxation authorities in Canada. There can be differing interpretations of applicable tax laws and regulations. The resolution of any differing tax positions through negotiations or litigation with tax authorities can take several years to complete. The Corporation does not anticipate that there will be any material impact upon the results of its operations, financial position or liquidity.

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

Deferred tax assets 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 funds from operations. To the extent that any interpretation of tax law is challenged by the tax authorities or future funds from operations and taxable income differ significantly from estimates, the ability of Manitok to realize the deferred tax assets recorded at the balance sheet date could be impacted.

CHANGES IN ACCOUNTING POLICIES

Future Changes in Accounting Policies

On May 28, 2014, the IASB issued *IFRS 15 Revenue From Contracts With Customers* replacing IAS 11 *Construction Contracts*, IAS 18 *Revenue* and several revenue-related interpretations. IFRS 15 contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. IFRS 15 is effective for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. Manitok is currently assessing the impact of adopting IFRS 15, however, it anticipates that this standard will not have a material impact on the Corporation's financial statements.

On July 24, 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 aligns hedge accounting more closely with risk management. The new standard does not fundamentally change the types of hedging relationships or the requirement to measure and recognize ineffectiveness, however under the new standard, more hedging strategies that are used for risk management will qualify for hedge accounting. IFRS 9 is effective for years beginning on or after January 1, 2018. As the Corporation does not currently apply hedge accounting it anticipates that this standard will not have a material impact on Manitoak's financial statements.

RISK FACTORS & RISK MANAGEMENT

The liquidity position of Manitoak is restricted and the continued operation of Manitoak will be improved by a material increase in future commodity prices and an increase in proved and probable reserves based on the Corporation's drilling program. The Corporation is involved in regular discussions with its lender and is continually pursuing other financing opportunities such as alternative debt arrangements, joint venture opportunities, property acquisitions or divestitures and other recapitalization opportunities and is taking steps to manage its spending and leverage including the implementation of cost reduction and capital management initiatives. If the Corporation is unable to obtain additional financing or come to some other arrangement with its lender, it will be required to curtail activities and may be required to liquidate its assets. Ongoing exploration and development of Manitoak's properties will require substantial additional capital investment. Failure to secure additional financing, and/or secure other funds from asset sales, would result in a delay or postponement of development of these properties. There can be no assurance that additional financing will be available or that, if available, will be on terms favourable or acceptable to Manitoak.

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

IMPACT OF NEW ENVIRONMENTAL REGULATIONS

The oil and gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

The use of fracture stimulations has been ongoing safely in an environmentally responsible manner in western Canada for decades. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of the Corporation's business more expensive or prevent the Corporation from conducting its business as currently conducted. Manitoak focuses on conducting transparent, safe and responsible operations in the communities in which its people live and work.