OPERATIONAL AND FINANCIAL SUMMARY

	Three months ended December 31		Twelve months ended December 31	
	2015	2014	**2015**	2014
OPERATING				
Average daily production				
Light oil (bbls/d)	**2,002**	2,257	**2,077**	2,508
Natural gas (mcf/d)	**13,540**	10,713	**13,607**	11,594
NGLs (bbls/d)	**200**	30	**135**	62
Total (boe/d)	**4,459**	4,072	**4,480**	4,502
Average realized sales price				
Light oil ($/bbl)	**47.83**	71.96	**52.70**	92.57
Natural gas ($/mcf)	**2.73**	3.83	**2.92**	4.93
NGLs ($/bbl)	**27.88**	67.29	**35.64**	96.93
Total ($/boe)	**31.01**	50.45	**34.38**	65.60
Undeveloped land (end of period)				
Gross (acres)	**456,506**	306,776	**456,506**	306,776
Net (acres)	**426,783**	290,971	**426,783**	290,971
NETBACK AND COST ($ per boe)				
Petroleum and natural gas sales	**31.01**	50.45	**34.38**	65.61
Realized gain (loss) on financial instruments	**18.20**	6.67	**14.58**	(2.31)
Royalty expenses	**(8.30)**	(11.61)	**(8.92)**	(19.68)
Operating expenses, net of recoveries	**(11.51)**	(7.65)	**(12.21)**	(7.34)
Transportation and marketing expenses	**(1.72)**	(3.17)	**(2.16)**	(3.37)
Operating netback[(1)]	**27.68**	34.69	**25.67**	32.91
General and administrative expenses, net of recoveries	**(3.29)**	(4.59)	**(4.06)**	(4.18)
Interest and financing expenses	**(3.72)**	(1.39)	**(3.03)**	(0.76)
Interest and other income	**0.02**	0.02	**0.02**	0.02
Funds from operations netback[(1)]	**20.69**	28.73	**18.60**	27.99
FINANCIAL				
Petroleum and natural gas revenue ($000)	**12,720**	18,902	**56,210**	107,822
Funds from operations ($000)[(1)]	**8,488**	10,766	**30,390**	45,980
Per share – basic ($)[(1)]	**0.10**	0.16	**0.40**	0.66
Per share – diluted ($)[(1)]	**0.10**	0.16	**0.40**	0.65
Net loss ($000)	**(5,258)**	(2,774)	**(27,195)**	(3,587)
Per share – basic ($)	**(0.06)**	(0.04)	**(0.36)**	(0.05)
Per share – diluted ($)[(2)]	**(0.06)**	(0.04)	**(0.36)**	(0.05)
Common shares outstanding				
End of period – basic	**143,936,115**	65,279,607	**143,936,115**	65,279,607
End of period – diluted	**150,334,260**	70,588,213	**150,334,260**	70,588,213
Weighted average for the period – basic	**85,729,418**	65,924,473	**76,292,523**	69,365,940
Weighted average for the period – diluted	**85,729,418**	66,255,000	**76,292,523**	70,321,234
Capital expenditures, net of divestitures ($000)	**2,847**	26,949	**40,597**	69,690
Adjusted working capital (surplus) deficit ($000)[(1)]	**(8,951)**	22,795	**(8,951)**	22,795
Drawn on credit facilities ($000)	**62,398**	53,258	**62,398**	53,258
Net bank debt ($000) [(1)]	**53,447**	76,053	**53,447**	76,053
Long-term financial obligations ($000)	**14,948**	2,500	**14,948**	2,500
Net debt ($000) [(1)]	**68,395**	78,553	**68,395**	78,553

(1) Funds from operations, funds from operations per share, funds from operations netback, operating netback, adjusted working capital (surplus) deficit, net bank debt and net debt do not have standardized meanings prescribed by generally accepted accounting principles 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.

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, 2016 ("**Annual Information Form**"), is available electronically under the Corporation's profile on the System for Electronic Document Analysis and Retrieval ("**SEDAR**") website at www.sedar.com and on the Corporation's website at www.manitokenergy.com. Manitok's common shares are listed for trading on the TSX Venture Exchange ("**TSX-V**") under the symbol "**MEI**".

The following Management's Discussion and Analysis ("**MD&A**") is dated April 29, 2016. The annual financial information in respect of the three and twelve months ended December 31, 2015 (the "**Reporting Periods**") as compared to the three and twelve months ended December 31, 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 audited financial statements of the Corporation and related notes as at and for the years ended December 31, 2015 and 2014. All financial information is expressed in Canadian dollars, unless otherwise stated.

ADVISORIES

Non-GAAP Measures

*This MD&A and the Annual 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 International Financial Reporting Standards ("**IFRS**") 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 Annual 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 IFRS, as an indicator of Manitok's performance or liquidity. Funds from operations is used by Manitok to evaluate operating results and Manitok's ability to generate cash flow to fund capital expenditures and repay indebtedness. Funds from operations denotes cash flow from operating activities as it appears on the Corporation's Statement of Cash Flows before 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 Annual Report contains 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 the reserves 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 Annual Report contains forward-looking information relating to the Corporation's planned strategy in terms of planned capital spending and sources of funding; and the intention to drill and complete future wells. 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 2016 capital program, readers are cautioned that the Corporation may make adjustments 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 reserve volumes, 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 that commercially economic reserves can be recovered from the Corporation's land as a result of drilling such future wells, are valid. Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intensions or expectations upon which it is based will occur. Although the Corporation believes that the expectations reflected in the forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ 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 Annual 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
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
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 in 2015, due to the low commodity price environment. However, in the fourth quarter of 2015, a partner drilled one well (0.05 net carried interest) pursuant to a farm-out agreement (see "Major Transactions Affecting Financial Results"). Manitok did execute various recompletion activities in southeast Alberta which satisfied its 2015 capital commitment with PrairieSky Royalty Ltd. ("**PSK**").

Based on an average WTI oil price of US$44.00/bbl and an average AECO natural gas price of $2.00/GJ in 2016 and its current crude oil derivative financial instruments, Manitok expects its 2016 capital spending to remain within its funds from operations which will allow the Corporation to spend approximately $11.0 to $14.0 million on drilling and completions in the second half of the year, which will satisfy its drilling commitments for 2016.

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 on revenue 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 in southeast Alberta to a flat rate of 17.5% retroactive to January 1, 2015, from the previous royalty calculation of a minimum of 10% and maximum of 30%;
  - provisions to allow greater flexibility through capital deferment 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 16 months, the aggregate drilling and completion expenditure commitment increased by $20.0 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 $61.1 million after post-closing adjustments ("**Wayne Acquisition**").
- On June 12, 2015, the Corporation divested of a 5% gross overriding royalty on revenue with no deductions from the producing wells in the Wayne area ("**Wayne GORR Divestiture**") for net cash proceeds of $6.2 million after post-closing adjustments. The net cash proceeds from the Wayne GORR Divestiture were used to partially fund the Wayne Acquisition.
- On June 12, 2015, Manitok entered into a production volume royalty agreement ("**PVR Divestiture**") with a royalty corporation for net cash proceeds of $24.4 million after 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 it exists at that point in the future. 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 of wells targeting production from the Wayne and/or Carseland areas. This commitment is included in the PSK LIDCA commitment and is not additional to that commitment. Additionally, Manitok has agreed, but is not obligated, to drill at least two gross wells per year in 2016, 2017 and 2018 in the Stolberg area. The net cash proceeds from the PVR Divestiture were used to partially fund the Wayne Acquisition.

- On June 12, 2015, Manitok divested its interest in certain oil and gas infrastructure in the Wayne area ("**June 2015 Facility Divestiture**") for net cash proceeds of $7.1 million after post-closing adjustments and closed a facilities financing agreement in the Wayne area ("**June 2015 Facility Financing**") for net cash proceeds of $12.5 million with a third party for total net cash proceeds of $19.6 million after 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 June 2015 Facility Divestiture. Pursuant to the June 2015 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. The net cash proceeds from the June 2015 Facility Divestiture and the June 2015 Facility Financing were used to partially fund the Wayne Acquisition.

- 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 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 total net proceeds of $15.8 million ("**June 2015 Equity Financing**"). The net cash proceeds from the June 2015 Equity Financing of the Manitok Shares were used to partially fund the Wayne Acquisition and the net cash proceeds from the June 2015 Equity Financing of the Manitok CDE Flow-through Shares and the Manitok CEE Flow-through Shares will be used to earn eligible Canadian development expenses and Canadian exploration expenses.

- In June 2015 Manitok's credit facilities were reduced from $90.0 million to $80.0 million, which consisted of a $45.0 million revolving operating demand loan facility ("**Conforming Credit Facility**") and a fully drawn $35.0 million non-revolving reducing demand loan facility ("**Non-Conforming Credit Facility**" and together with the Conforming Credit Facility, the "**Credit Facilities**"). The Corporation was required to repay the $35.0 million outstanding amount on the Non-Conforming Credit Facility as follows:
  - $5.0 million on or before December 31, 2015, which was paid as at November 25, 2015 and reduced the Non-Conforming Credit Facility to $30.0 million and the Credit Facilities to $75.0 million;
  - $10.0 million on or before March 31, 2016; and
  - $20.0 million on or before May 31, 2016.

  See further discussions related to the Credit Facilities in "Major Transactions Subsequent to the Reporting Period".

- In the fourth quarter of 2015, the Corporation entered into a farm-out agreement with a private oil and gas company ("**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 has 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 LIDCA capital commitment.

- On December 30, 2015, Manitok closed the first tranche of a private placement equity financing for the issuance of 23,766,831 Manitok Shares at a price of $0.13 per Manitok Share and 35,079,500 Manitok CEE Flow-through Shares at a price of $0.15 per Manitok CEE Flow-through Share ("**December 2015 Equity Financing**") for total net proceeds of $7.5 million, which were received in January 2016. The net cash proceeds from the December 2015 Equity Financing of the Manitok Shares were used to reduce the Corporation's bank indebtedness and the net cash proceeds from the December 2015 Equity Financing of the Manitok CEE Flow-through Shares will be used to earn eligible Canadian exploration expenses. In connection with the December 2015 Equity Financing, Manitok has issued 1,170,712 Manitok Share purchase warrants ("**Broker Warrants**") to the agents of the December 2015 Equity Financing, with each Broker Warrant entitling the holder thereof to acquire one Manitok Share at an exercise price of $0.13 per Manitok Share for a period of 18 months after the date of issuance of such Broker Warrants.

MAJOR TRANSACTIONS SUBSEQUENT TO THE REPORTING PERIOD

- In January 2016, the $45.0 million Conforming Credit Facility was reduced to $30.0 million in conjunction with the December 2015 Equity Financing and the Non-Conforming Facility was maintained at $30.0 million. The following previously disclosed repayments are no longer required:
  - $10.0 million on or before March 31, 2016; and
  - $20.0 million on or before May 31, 2016.

  The Corporation is required to repay $0.4 million per month on the Non-Conforming Credit Facility beginning on February 1, 2016 and continuing every month thereafter until it is fully repaid.
- Subsequent to the above-noted amendment to the Credit Facilities, Manitok monetized crude oil derivative financial instruments with its counterparty for a cash receipt of $12.3 million and the funds were used to reduce the Non-Conforming Credit Facility from $30.0 million to $20.0 million and as such, reduce the Credit Facilities from $60.0 million to $50.0 million. The Credit Facilities will be up for a customary review in June 2016, but the current Credit Facility agreement has provided that the maximum amount of the Non-Conforming Credit Facility will be $20.0 million on June 1, 2016.
- In the first quarter of 2016, Manitok closed the final two tranches of the December 2015 Equity Financing for the issuance of 15,973,631 Manitok Shares at a price of $0.13 per Manitok Share and 1,170,000 Manitok CEE Flow-through Shares at a price of $0.15 per Manitok CEE Flow-through Share for gross proceeds of $2.3 million along with an additional 70,414 Broker Warrants. The net cash proceeds from the final two tranches of the December 2015 Equity Financing of the Manitok Shares were used to reduce the Corporation's bank indebtedness and the net cash proceeds from the final two tranches of the December 2015 Equity Financing of the Manitok CEE Flow-through Shares will be used to earn eligible Canadian exploration expenses. In connection with the December 2015 Equity Financing, Manitok has issued an aggregate of 1,241,127 Broker Warrants to the agents of the December 2015 Equity Financing, with each Broker Warrant entitling the holder thereof to acquire one Manitok Share at an exercise price of $0.13 per Manitok Share for a period of 18 months after the date of issuance of such Broker Warrants.
- In March 2016, Manitok closed an asset acquisition of a 14 Mmcf/d natural gas processing plant in the Carseland area along with approximately 450 mcf/d (75 boe/d) of natural gas production, the related gathering systems, undeveloped land and an 11 kilometre sales gas line tied into the ATCO south sales system. Total cash consideration for the acquisition was $4.8 million prior to customary closing adjustments ("**Carseland Acquisition**"). The Carseland Acquisition was financed using the Corporation's credit facilities.
- In March 2016, Manitok closed an asset acquisition of 122 boe/d (86% oil) from one partner in the Stolberg Cardium "F" pool. Manitok exchanged a 19.9% non-operated working interest in a gas plant in a non-core area, where it had no current throughput volumes, for a 17.5% average working interest in the Cardium "F" pool in Stolberg, along with an average 45% working interest in 10,500 acres of undeveloped land in Stolberg.
- In April 2016, Manitok entered into a letter agreement for a best-efforts private placement offering of up to $10.0 million ("**Offering**"). The Offering will consist of Manitok Shares issued at a price of $0.21 per Manitok Share and Manitok CEE Flow-through Shares at a price of $0.24 per Manitok CEE Flow-through Share with the gross proceeds from the issuance of the Manitok CEE Flow-through Shares not to exceed $4.5 million. The Offering is expected to close in tranches with the first tranche to close on or about May 5, 2016. The net cash proceeds from the Offering of the Manitok Shares will be used to reduce the Corporation's bank indebtedness and the net cash proceeds from the Offering of the Manitok CEE Flow-through Shares will be used to earn eligible Canadian exploration expenses.

SELECTED ANNUAL INFORMATION

For the years ended December 31 *($000, except for production and share information)*	**2015**	2014	2013
Average daily production (boe/d)	**4,480**	4,502	4,113
Petroleum and natural gas revenue	**56,210**	107,822	85,950
Net revenue from petroleum and natural gas sales	**41,624**	75,479	65,401
Funds from operations[1]	**30,390**	45,980	41,554
Per share – basic[1]	**0.40**	0.66	0.59
Per share – diluted[1]	**0.40**	0.65	0.57
Net income (loss)	**(27,195)**	(3,587)	3,615
Per share – basic	**(0.36)**	(0.05)	0.05
Per share – diluted[2]	**(0.36)**	(0.05)	0.05
Capital expenditures, net of divestitures	**40,597**	69,690	79,365
Total assets	**204,705**	211,284	192,580
Adjusted working capital (surplus) deficit[1]	**(8,951)**	22,795	16,277
Drawn on credit facilities	**62,398**	53,258	16,237
Long-term financial obligations	**14,948**	2,500	-
Net debt[1]	**68,395**	78,553	32,514
Shareholders' equity	**80,540**	84,333	109,096
Common shares outstanding			
End of period – basic	**143,936,115**	65,279,607	74,492,340
End of period – diluted	**150,334,260**	70,588,213	80,099,780
Weighted average shares for period – basic	**76,292,523**	69,365,940	70,654,634
Weighted average shares for period – diluted	**76,292,523**	70,321,234	72,596,161

(1) Funds from operations, funds from operations per share, adjusted working capital (surplus) deficit and net debt do not have standardized meanings prescribed by generally accepted accounting principles 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 years in which the Corporation records a net loss.

Production remained relatively consistent during 2015, although natural production declines, TransCanada Pipeline restrictions ("**TCPL Restrictions**") in the foothills and third party gas plant restrictions in Carseland were offset by the Wayne Acquisition. The Corporation did not add any new production from drilling in 2015. The Corporation has incurred reductions in 2015 revenue and funds from operations and an increase in the net loss on an absolute and per share basis due primarily to the significant decline in commodity prices. The adjusted working capital surplus at December 31, 2015 is largely comprised of the net proceeds of $7.5 million from the December 2015 Equity Financing, which were received in January 2016.

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 IFRS to funds from operations for the Reporting Periods and the Comparable Prior Periods:

	Three months ended December 31		**Twelve months ended December 31**	
($000, except per share information)	**2015**	2014	**2015**	2014
Cash flow from (used in) operating activities	**4,489**	8,626	**27,503**	49,094
Adjustments:				
Decommissioning expenditures	**674**	160	**1,064**	180
Acquisition-related expenses	**(82)**	-	**1,892**	-
Changes in non-cash operating working capital	**3,407**	1,980	**(69)**	(3,294)
Funds from operations	**8,488**	10,766	**30,390**	45,980
per share – basic	**0.10**	0.16	**0.40**	0.66
per share – diluted	**0.10**	0.16	**0.40**	0.65

Funds from operations decreased by 21% to $8.5 million ($0.10 per diluted share) for the fourth quarter of 2015 as compared to $10.8 million ($0.16 per diluted share) in the Comparable Prior Period. For the twelve month Reporting Period, funds from operations decreased by 34% to $30.4 million ($0.40 per diluted share) in 2015 as compared to $46.0 million ($0.65 per diluted share) in 2014. 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 Loss

The following table details Manitok's net loss for the Reporting Periods and the Comparable Prior Periods:

	Three months ended December 31		**Twelve months ended December 31**	
($000, except per share information)	**2015**	2014	**2015**	2014
Net loss	**(5,258)**	(2,774)	**(27,195)**	(3,587)
per share – basic	**(0.06)**	(0.04)	**(0.36)**	(0.05)
per share – diluted	**(0.06)**	(0.04)	**(0.36)**	(0.05)

Net loss increased to $5.3 million ($0.06 per diluted share) for the fourth quarter of 2015 as compared to $2.8 million ($0.04 per diluted share) in the Comparable Prior Period. The increase in the net loss and net loss per share were due primarily to decreased funds from operations and a decreased unrealized gain on financial instruments partially offset by decreased impairment and depletion and depreciation and an increased deferred income tax recovery.

Manitok had a net loss of $27.2 million ($0.36 per diluted share) in 2015 as compared to $3.6 million ($0.05 per diluted share) in 2014. The increase in the net loss and net loss per share were due primarily to decreased funds from operations and a decreased unrealized gain on financial instruments partially offset by decreased impairment and an increased 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 December 31, 2015				Three months ended December 31, 2014			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Light oil (bbls)	**8,809**	**2,002**	**45**	**47.83**	14,942	2,257	55	71.96
Natural gas (mcf)[(1)]	**3,397**	**13,540**	**51**	**2.73**	3,775	10,713	44	3.83
NGLs (bbls)	**514**	**200**	**4**	**27.88**	185	30	1	67.29
Total P&NG sales (boe)	**12,720**	**4,459**	**100**	**31.01**	18,902	4,072	100	50.45
Royalty revenue	**-**			**-**	-			-
Total P&NG revenue (boe)	**12,720**	**4,459**	**100**	**31.01**	18,902	4,072	100	50.45

	Twelve months ended December 31, 2015				Twelve months ended December 31, 2014			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Light oil (bbls)	**39,953**	**2,077**	**46**	**52.70**	84,750	2,508	56	92.57
Natural gas (mcf)[(1)]	**14,503**	**13,607**	**51**	**2.92**	20,869	11,594	43	4.93
NGLs (bbls)	**1,749**	**135**	**3**	**35.64**	2,187	62	1	96.93
Total P&NG sales (boe)	**56,205**	**4,480**	**100**	**34.38**	107,806	4,502	100	65.60
Royalty revenue	**5**			**-**	16			0.01
Total P&NG revenue (boe)	**56,210**	**4,480**	**100**	**34.38**	107,822	4,502	100	65.61

(1) Includes sulphur revenue, but sulphur production volumes are excluded.

Total P&NG sales for the fourth quarter of 2015 decreased 33% to $12.7 million compared to $18.9 million in the Comparable Prior Period. The decrease of $6.2 million consists of $5.8 million due to lower realized prices and $0.4 million attributed to lower volumes of light oil, partially offset by higher natural gas volumes. For the year, total P&NG sales decreased 48% to $56.2 million compared to $107.8 million in 2014. The decrease of $51.6 million consists of $8.8 million attributed to lower light oil production volumes partially offset by higher natural gas volumes and $42.8 million due to lower realized prices.

Production

Production averaged 4,459 boe/d, and 4,480 boe/d in the three and twelve month Reporting Periods, as compared to 4,072 boe/d and 4,502 boe/d in the Comparable Prior Periods. Although the Corporation has incurred natural declines due to no new drilling in 2015, TCPL Restrictions and third party gas plant restrictions in the Carseland area it was offset by an increase in production from 4 (4.0 net) wells drilled in 2014, completed and tied-in in the Carseland area and the assets acquired in the Wayne Acquisition that contributed approximately 1,048 boe/d and 567 boe/d of production in the three and twelve month Reporting Periods, or 1,383 boe/d from June 12, 2015 to December 31, 2015.

Light oil production has decreased to 2,002 bbls/d and 2,077 bbls/d in the three and twelve month Reporting Periods, as compared to 2,257 bbls/d and 2,508 bbls/d in the Comparable Prior Periods and natural gas production has increased to 13.5 Mmcf/d and 13.6 Mmcf/d in the three and twelve month Reporting Periods, as compared to 10.7 Mmcf/d and 11.6 Mmcf/d in the Comparable Prior Periods. The increase in gas production and decrease in oil production can be attributed to natural declines of oil and additional Mannville gas from a drill along with additional gas production from the Cardium pool in the Stolberg area.

Commodity Prices

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

	Three months ended December 31			Twelve months ended December 31		
	2015	2014	Variance	**2015**	2014	Variance
Benchmark prices						
Light oil – WTI ($US/bbl) [1]	**42.18**	73.15	(42%)	**48.80**	93.00	(48%)
Light oil – WTI ($CAD/bbl)	**56.33**	83.07	(32%)	**62.40**	102.72	(39%)
Light oil – Canadian light sweet ($/bbl) [1]	**52.55**	74.38	(29%)	**57.45**	93.99	(39%)
Natural gas – AECO daily spot ($/mmbtu) [2]	**2.46**	3.60	(32%)	**2.69**	4.50	(40%)
Exchange rate – ($CAD/$US)	**1.3354**	1.1356	18%	**1.2787**	1.1045	16%
Average realized prices						
Light oil ($/bbl)	**47.83**	71.96	(34%)	**52.70**	92.57	(43%)
Natural gas ($/mcf)	**2.73**	3.83	(29%)	**2.92**	4.93	(41%)
NGLs ($/bbl)	**27.88**	67.29	(59%)	**35.64**	96.93	(63%)
Average realized price ($/boe)	**31.01**	50.45	(39%)	**34.38**	65.60	(48%)
Price differentials						
Canadian light sweet/WTI CAD ($/bbl)	**(3.78)**	(8.69)	(57%)	**(4.95)**	(8.73)	(43%)
Realized light oil/Canadian light sweet ($/bbl)	**(4.72)**	(2.42)	95%	**(4.75)**	(1.42)	235%
Realized natural gas/AECO daily spot ($/mcf)	**0.27**	0.23	17%	**0.23**	0.43	(47%)

(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 twelve month Reporting Periods, Manitok's average realized commodity price decreased 39% and 48% respectively to $31.01/boe and $34.38/boe from $50.45/boe and $65.60/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 compared to the Comparable Prior Periods as a result of the Wayne Acquisition assets, which include a higher proportion of propane and butane volumes.

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 December 31			Twelve months ended December 31		
	2015	2014	Variance	**2015**	2014	Variance
Natural gas – AECO daily spot ($/mmbtu) [1]	**2.46**	3.60	(32%)	**2.69**	4.50	(40%)
Heat/quality differential ($/mcf)[2]	**0.27**	0.17	59%	**0.23**	0.51	(55%)
Physical sales/AECO daily spot differential ($/mcf)	**-**	0.06	-	**-**	(0.08)	-
Realized natural gas ($/mcf)	**2.73**	3.83	(29%)	**2.92**	4.93	(41%)

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

(2) Includes sulphur revenue.

Manitok's P&NG 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 December 31, 2015, the Corporation held the following derivative financial instruments:

Product	Notional Quantity	Term	Reference	Strike Price	Type of Contract	Fair Value ($000)
Oil	500 bbls/d	January 1, 2016 to December 31, 2016	CAD$ WTI	$80.15	Swap[1]	4,160
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD$ WTI	$79.75	Swap[2]	6,936
Oil	500 bbls/d	January 1, 2017 to December 31, 2017	CAD$ WTI	$80.15	Option[1]	(170)
Oil	500 bbls/d	January 1, 2018 to December 31, 2018	CAD$ WTI	$79.75	Option[2]	(438)
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD$ WTI	$75.00 -$90.00	Collar[3]	5,794
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD$ WTI	$70.00 -$90.00	Collar[4]	4,369
Total						**20,651**
Current assets						**14,172**
Non-current assets						**6,479**

(1) 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.

(2) 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.

(3) 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.

(4) 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 December 31				**Twelve months ended December 31**			
	2015		2014		**2015**		2014	
	$000	**$/boe**	$000	$/boe	**$000**	**$/boe**	$000	$/boe
Realized gain (loss) on financial instruments	**7,464**	**18.20**	2,499	6.67	**23,844**	**14.58**	(3,804)	(2.31)
Unrealized gain (loss) on financial instruments	**2,518**	**6.14**	27,577	73.61	**(910)**	**(0.56)**	27,760	16.89

Subsequent to December 31, 2015, the Corporation monetized the following derivative financial instruments for a cash receipt of $12.3 million to reduce bank indebtedness:

Product	Notional Quantity	Term	Reference	Strike Price	Type of Contract
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD$ WTI	$79.75	Swap
Oil	500 bbls/d	January 1, 2018 to December 31, 2018	CAD$ WTI	$79.75	Option
Oil	500 bbls/d	January 1, 2017 to December 31, 2017	CAD$ WTI	$75.00 -$90.00	Collar
Oil	500 bbls/d	January 1, 2017 to December 31, 2017	CAD$ WTI	$70.00 -$90.00	Collar

Subsequent to the above-noted monetization the Corporation holds the following derivative financial instruments:

Product	Notional Quantity	Term	Reference	Strike Price	Type of Contract
Oil	500 bbls/d	January 1, 2016 to December 31, 2016	CAD$ WTI	$80.15	Swap
Oil	500 bbls/d	January 1, 2017 to December 31, 2017	CAD$ WTI	$80.15	Option
Oil	500 bbls/d	January 1, 2016 to December 31, 2016	CAD$ WTI	$75.00 -$90.00	Collar
Oil	500 bbls/d	January 1, 2016 to December 31, 2016	CAD$ WTI	$70.00 -$90.00	Collar

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 December 31, 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 December 31, 2015			Three months ended December 31, 2014		
	($000)	**Effective Royalty Rate[1]**	**Average ($/unit)**	($000)	Effective Royalty Rate[1]	Average ($/unit)
Light oil and NGLs (bbls)	**3,341**	**35.8%**	**16.49**	4,552	30.1%	21.64
Natural Gas (mcf)[2][3]	**65**	**1.9%**	**0.05**	(203)	(5.4%)	(0.21)
Total Royalties (boe)	**3,406**	**26.8%**	**8.30**	4,349	23.0%	11.61

	Twelve months ended December 31, 2015			Twelve months ended December 31, 2014		
	($000)	**Effective Royalty Rate[1]**	**Average ($/unit)**	($000)	Effective Royalty Rate[1]	Average ($/unit)
Light oil and NGLs (bbls)	**13,142**	**31.5%**	**16.28**	30,082	34.6%	32.07
Natural Gas (mcf)[2][3]	**1,444**	**10.0%**	**0.29**	2,261	10.8%	0.53
Total Royalties (boe)	**14,586**	**26.0%**	**8.92**	32,343	30.0%	19.68

(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 royalty expenses for sulphur, but sulphur production volumes are excluded.
(3) Includes natural gas cost allowance credits received from the government of Alberta.

Royalties for the three and twelve month Reporting Periods decreased 22% and 55% to $3.4 million and $14.6 million, as compared to $4.3 million and $32.3 million for the Comparable Prior Periods. The decrease is due to the lower Crown royalties associated with the decrease in commodity prices, partially offset by an increase in royalties of $1.2 million and $3.0 million in the three and twelve month Reporting Periods associated with the Stolberg GORR Divestiture, the Wayne GORR Divestiture and the PVR Divestiture (see "Major Transactions Affecting Financial Results") 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 December 31, 2015		Three months ended December 31, 2014		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Field operating expenses	**5,208**	**12.70**	3,087	8.23	69%	54%
Recoveries	**(638)**	**(1.55)**	(220)	(0.58)	190%	167%
Field operating expenses, net	**4,570**	**11.15**	2,867	7.65	59%	46%
Expensed workovers and other	**149**	**0.36**	-	-	-	-
Total operating expenses	**4,719**	**11.51**	2,867	7.65	65%	50%

	Twelve months ended December 31, 2015		Twelve months ended December 31, 2014		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Field operating expenses	**21,261**	**13.00**	13,373	8.14	59%	60%
Recoveries	**(1,614)**	**(0.99)**	(1,311)	(0.80)	23%	24%
Field operating expenses, net	**19,647**	**12.01**	12,062	7.34	63%	64%
Expensed workovers and other	**333**	**0.20**	-	-	-	-
Total operating expenses	**19,980**	**12.21**	12,062	7.34	66%	66%

Operating expenses for the three and twelve month Reporting Periods were $4.7 million and $20.0 million, as compared to $2.9 million and $12.1 million for the Comparable Prior Periods. Higher costs can be attributed to the Wayne Acquisition, the facility fees associated with a December 2014 oil and gas infrastructure divestiture in the Carseland and Stolberg areas ("**December 2014 Facility Divestiture**") and the June 2015 Facility Divestiture and workover costs incurred in the Wayne area. On a per boe basis, operating expenses increased to $11.51/boe and $12.21/boe as compared to $7.65/boe and $7.34/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 and higher per unit costs at Wayne. The facility fees associated with the December 2014 Facility Divestiture and the June 2015 Facility Divestiture represented $1.79/boe and $1.49/boe in the three and twelve 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 December 31			**Twelve months ended December 31**		
	2015	2014	Variance	**2015**	2014	Variance
Total T&M expenses ($000)	**703**	1,186	(41%)	**3,531**	5,545	(36%)
Total T&M expenses ($/boe)	**1.72**	3.17	(46%)	**2.16**	3.37	(36%)

Total T&M expenses for the three and twelve month Reporting Periods were $0.7 million and $3.5 million, as compared to $1.2 million and $5.5 million for the Comparable Prior Periods. On a per boe basis, T&M expenses decreased to $1.72/boe and $2.16/boe as compared to $3.17/boe and $3.37/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 three and twelve month Reporting Periods. Natural gas transportation costs are lower on a per boe basis than crude oil transportation costs, and natural gas volumes represented 51% in both the three and twelve month Reporting Periods, as compared to 44% and 43% in the Comparable Prior Periods.

Operating Netback

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

	Three months ended December 31			**Twelve months ended December 31**		
($/boe)	**2015**	2014	Variance	**2015**	2014	Variance
Realized P&NG sales price	**31.01**	50.45	(39%)	**34.38**	65.61	(48%)
Royalty expenses	**(8.30)**	(11.61)	(29%)	**(8.92)**	(19.68)	(55%)
Operating expenses, net of recoveries	**(11.51)**	(7.65)	50%	**(12.21)**	(7.34)	66%
Transportation and marketing expenses	**(1.72)**	(3.17)	(46%)	**(2.16)**	(3.37)	(36%)
Operating netback before realized gain (loss) on financial instruments	**9.48**	28.02	(66%)	**11.09**	35.22	(69%)
Realized gain (loss) on financial instruments	**18.20**	6.67	173%	**14.58**	(2.31)	-
Operating netback	**27.68**	34.69	(20%)	**25.67**	32.91	(22%)

Manitok's operating netback was $27.68/boe in the fourth quarter of 2015, which is 20% lower than $34.69/boe in the Comparable Prior Period and in 2015 the operating netback decreased 22% to $25.67/boe as compared to $32.91/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 December 31, 2015		Three months ended December 31, 2014		Variance
	$000	**%**	$000	%	$
Cash:					
Salaries and benefits(1)	**1,067**	**53**	1,353	52	(21%)
Other(2)	**927**	**47**	1,253	48	(26%)
	1,994	**100**	2,606	100	(23%)
Operating overhead recoveries	**(57)**	**(3)**	(130)	(5)	(56%)
Capitalized overhead recoveries(3)	**(591)**	**(30)**	(756)	(29)	(22%)
General and administrative expenses, net	**1,346**	**67**	1,720	66	(22%)
General and administrative expenses, net per boe	**3.29**		4.59		(28%)
Non-cash:					
Stock-based compensation	**190**	**100**	438	100	(57%)
Capitalized stock-based compensation(3)	**(85)**	**(45)**	(199)	(45)	(57%)
Stock-based compensation, net	**105**	**55**	239	55	(56%)
Stock-based compensation, net per boe	**0.25**		0.64		(61%)
Total administrative expenses, net	**1,451**	**66**	1,959	64	(26%)
Total administrative expenses, net per boe	**3.54**		5.23		(32%)

	Twelve months ended December 31, 2015		Twelve months ended December 31, 2014		Variance
	$000	**%**	$000	%	$
Cash:					
Salaries and benefits(1)	**5,597**	**55**	6,180	60	(9%)
Other(2)	**4,520**	**45**	4,118	40	10%
	10,117	**100**	10,298	100	(2%)
Operating overhead recoveries	**(302)**	**(3)**	(622)	(6)	(51%)
Capitalized overhead recoveries(3)	**(3,181)**	**(31)**	(2,806)	(27)	13%
General and administrative expenses, net	**6,634**	**66**	6,870	67	(3%)
General and administrative expenses, net per boe	**4.06**		4.18		(3%)
Non-cash:					
Stock-based compensation	**1,269**	**100**	973	100	30%
Capitalized stock-based compensation(3)	**(631)**	**(50)**	(376)	(39)	68%
Stock-based compensation, net	**638**	**50**	597	61	7%
Stock-based compensation, net per boe	**0.39**		0.36		8%
Total administrative expenses, net	**7,272**	**64**	7,467	66	(3%)
Total administrative expenses, net per boe	**4.45**		4.54		(2%)

(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 decreased 22% and 3% on an aggregate basis to $1.3 million and $6.6 million in the three and twelve month Reporting Periods as compared to $1.7 million and $6.9 million in the Comparable Prior Periods. The decrease is due mainly to initiatives implemented by the Corporation to reduce G&A in the fourth quarter of 2015.

Stock-based compensation (non-cash)

Stock-based compensation decreased in the three month Reporting Period to $0.1 million as compared to $0.2 million in the Comparable Prior Period. For the twelve month Reporting Period, 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	1,302,500	0.77
Expired	(667,340)	(1.10)
Forfeited	(716,333)	(1.89)
Outstanding, December 31, 2015	**5,227,433**	**1.79**

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 December 31			Twelve months ended December 31		
	2015	2014	Variance	**2015**	2014	Variance
Depletion and depreciation ($000)	**5,026**	7,663	(34%)	**27,382**	26,552	3%
Depletion and depreciation ($/boe)	**12.25**	20.45	(40%)	**16.75**	16.16	4%

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 fourth quarter of 2015 to $5.0 million ($12.25/boe) as compared to $7.7 million ($20.45/boe) for the Comparable Prior Period. The decrease is due mainly to the reduction in production volumes and the overall reduction in the depletable net book asset value in the Stolberg area due to the Stolberg GORR Divestiture and the PVR Divestiture, partially offset by depletable assets obtained in the Wayne Acquisition.

For the twelve month Reporting Period, D&D expenses remained consistent at $27.4 million ($16.75/boe) as compared to $26.6 million ($16.16/boe) for the Comparable Prior Period. Although the D&D expenses per unit was higher in the first and second quarter of 2015 due mainly to negative technical revisions of proved plus probable reserves as at December 31, 2014 in the Stolberg area, a decrease occurred in the second half of 2015 related to a reduction in production volumes in the Stolberg area, a reduction in the net book value due to the Stolberg GORR Divestiture, the Wayne GORR Divestiture, the PVR Divestiture and the June 2015 Facility Divestiture along with the increase in proved plus probable reserves associated with the Wayne Acquisition.

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 decrease in forward benchmark commodity prices. 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 to E&E assets related mainly to land expiries. The impairment test on P&NG assets determined that the net book value exceeded the recoverable amount in two of the three CGUs and Manitok recognized a $15.7 million impairment charge to P&NG assets.

In the fourth 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 decrease in forward benchmark commodity prices. It was determined that the net book value of certain E&E assets exceeded the recoverable amount and Manitok recognized a $5.3 million impairment charge to E&E assets. The impairment test on P&NG assets determined that the net book value exceeded the recoverable amount in two of the three CGUs and Manitok recognized a $26.1 million impairment charge to P&NG assets. However, due to activities in the Wayne area subsequent to the Wayne Acquisition and the year-end 2015 third party reserve evaluation, it was determined the recoverable amount exceeded the net book value in the third CGU and Manitok recognized a reversal of prior impairment charges of $18.7 million in its P&NG assets.

For the three and twelve month Reporting Periods, Manitok has recorded an impairment of its E&E assets of $5.3 million and $7.5 million respectively as compared to $17.8 million and $31.4 million in the Comparable Prior Periods. For the three and twelve month Reporting Periods, Manitok has recorded an impairment net of reversals of its P&NG assets of $7.4 million and $23.1 million respectively as compared to $16.2 million in both the Comparable Prior Periods.

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

2015 Asset Divestitures

In May 2015, the Corporation entered into the Stolberg GORR Divestiture in exchange for revised terms and additional undeveloped lands in 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 Divestiture assets. Manitok recorded a loss of $0.8 million ($0.6 million, net of tax) on the asset divestiture for the year ended December 31, 2015.

In June 2015, the Corporation closed the Wayne GORR Divestiture for net cash proceeds of $6.2 million after post-closing adjustments. The Corporation did not record a gain or loss on the divesture as the carrying value approximated the proceeds received, as the assets had just been acquired at fair value.

In June 2015, Manitok closed the PVR Divestiture for net cash proceeds of $24.4 million after post-closing adjustments. Manitok recorded a loss of $2.8 million ($2.0 million, net of tax) on the asset divestiture for the year ended December 31, 2015.

In June 2015, Manitok closed the June 2015 Facility Divestiture agreement for net cash proceeds of $7.1 million after post-closing adjustments. The Corporation did not record a gain or loss on the divesture as the carrying value approximated the proceeds received, as the assets had just been acquired at fair value.

2014 Asset Divestitures

In February 2014, Manitok divested of assets in the Alberta foothills for net cash proceeds of $21.8 million after post-closing adjustments ("**Foothills Asset Divestiture**"). Manitok recorded a loss of $1.3 million ($1.0 million, net of tax) on the divestiture during the year ended December 31, 2014.

In May 2014, the Corporation divested of minor non-producing properties for net cash proceeds of $0.9 million. The Corporation recorded a net gain of $0.3 million ($0.2 million, net of tax) on the divestiture during the year ended December 31, 2014.

In December 2014, Manitok closed the December 2014 Facility Divestiture agreement for net cash proceeds of $12.3 million after post-closing adjustments. The Corporation did not record a gain or loss on the divesture as the carrying value approximated the proceeds received.

Finance Expenses

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

	Three months ended December 31, 2015		Three months ended December 31, 2014	
	$000	**$/boe**	$000	$/boe
Cash:				
Interest and fees on credit facilities	**1,528**	**3.72**	519	1.39
Acquisition-related expenses[1]	**(82)**	**(0.20)**	-	-
	1,446	**3.52**	519	1.39
Non-cash:				
Accretion on decommissioning obligations	**140**	**0.34**	51	0.15
Total finance expenses	**1,586**	**3.86**	570	1.54

	Twelve months ended December 31, 2015		Twelve months ended December 31, 2014	
	$000	**$/boe**	$000	$/boe
Cash:				
Interest and fees on credit facilities	**4,960**	**3.03**	1,249	0.76
Acquisition-related expenses[1]	**1,892**	**1.16**	-	-
	6,852	**4.19**	1,249	0.76
Non-cash:				
Accretion on decommissioning obligations	**411**	**0.25**	185	0.11
Total finance expenses	**7,263**	**4.44**	1,434	0.87

(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 twelve 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, increases to the Credit Facilities commitment fee and interest on the increased long-term financial obligations.

The Corporation's average outstanding bank indebtedness was approximately $65.2 and $67.7 million in the three and twelve month Reporting Periods as compared to $57.0 million and $28.9 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 5.9% and 4.6% in the three and twelve month Reporting Periods as compared to 3.4% and 3.5% in the Comparable Prior Periods.

The acquisition-related expenses are associated with closing the Wayne Acquisition in June 2015.

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

Income Taxes

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

	Three months ended December 31		**Twelve months ended December 31**	
	2015	2014	**2015**	2014
Deferred income tax expense (recovery) ($000)	**(1,643)**	(825)	**(7,925)**	1,372
Deferred income tax expense (recovery) ($/boe)	**(4.00)**	(2.20)	**(4.85)**	0.84

The increase in the deferred income tax recovery to $1.6 million for the three month Reporting Period from $0.8 million in the Comparable Prior Period was due mainly to the increased net loss before taxes in the period.

The increase in deferred income tax recovery to $7.9 million for the twelve month Reporting Period from a $1.4 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%.

The Corporation's estimated income tax pools were $134.5 million as at December 31, 2015. Management expects that future taxable income will be available to utilize the accumulated tax pools. The components of the Corporation's estimated income tax pools are indicated in the table below.

As at December 31 ($000)	**2015**	2014
Cumulative Canadian Exploration Expense	**33,087**	30,018
Cumulative Canadian Development Expense	**30,691**	42,901
Cumulative Canadian Oil and Gas Property Expense	**47,518**	31,241
Undepreciated Capital Cost	**20,350**	15,084
Non-capital losses	**459**	-
Share issue costs	**2,398**	2,478
	134,503	121,722

CAPITAL EXPENDITURES

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 December 31 **2015**	2014	Twelve months ended December 31 **2015**	2014
Land	**15**	170	**948**	1,014
Seismic	**396**	259	**1,086**	1,484
Workovers and recompletions	**2,143**	254	**2,722**	1,336
Drilling and completions	**155**	20,362	**2,335**	72,625
Well equipment and facilities	**832**	10,000	**5,646**	17,888
Capitalized overhead[1]	**591**	756	**3,181**	2,806
Total finding and development costs (F&D)	**4,132**	31,801	**15,918**	97,153
Acquisition[2]	**(1,297)**	7,393	**61,549**	7,393
Divestitures[3]	**6**	(12,291)	**(37,049)**	(35,083)
Total finding, development and acquisition costs (FD&A)	**2,841**	26,903	**40,418**	69,463
Administrative and other assets	**6**	46	**179**	227
Total capital expenditures[4]	**2,847**	26,949	**40,597**	69,690

(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 June 2015 Facility Divestiture.

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

In the twelve month Reporting Period, the Corporation drilled 1 gross (0.05 net carried interest) well pursuant to the Farm-out Agreement in the Rockyford area, completed 1 gross (1.0 net) well in the Carseland area, recompleted 4 gross (4.0 net) wells in southeast Alberta and 1 gross (1.0 net) well in the Stolberg area, executed workovers of 7 gross (7.0 net) wells in southeast Alberta 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 December 31 **2015**	2014	Twelve months ended December 31 **2015**	2014
E&E assets	**1,222**	17,567	**9,651**	46,778
P&NG properties and equipment, net	**1,625**	9,382	**30,946**	22,912
Total capital expenditures[1]	**2,847**	26,949	**40,597**	69,690

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

Decommissioning Liability

At December 31, 2015, Manitok has recorded a decommissioning liability of $27.7 million (2014 - $8.5 million) for the future abandonment and reclamation of Manitok's properties. The estimated decommissioning liability includes assumptions in respect of actual costs to abandon wells or reclaim the property, the time frame in which such costs will be incurred as well as annual inflation factors in order to calculate the undiscounted total future liability. The future liability has been discounted at the risk free rate of 2.2% (2014 – 2.3%). Abandonment cost estimates are derived from both third party and government sources and operational knowledge of the properties. The estimates are reviewed quarterly and adjusted as new information regarding the liability is determined. The increase in liability is due to the decrease in the risk free rate combined with assets from the Wayne Acquisition and revisions to cost estimates.

Accretion expense is the increase in the decommissioning liability resulting from the passage of time. For the twelve months ended December 31, 2015, accretion expense totaled $0.4 million (2014 - $0.2 million).

The Corporation's Liability Management Rating ("**LMR**") with the Alberta Energy Regulator ("**AER**") was 7.86 at December 31, 2015. The LMR reflects the results of a comparison of the Corporation's deemed assets to its deemed

liabilities and is updated monthly. An LMR rating less than 1.0 would require the Corporation to pay a deposit to the AER.

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:

	Three months ended December 31		Twelve months ended December 31	
($000)	**2015**	2014	**2015**	2014
Funds from operations	**8,488**	10,766	**30,390**	45,980
Changes in non-cash operating working capital	**(3,407)**	(1,980)	**69**	3,294
Decommissioning expenditures	**(674)**	(160)	**(1,064)**	(180)
Acquisition-related expenses	**82**	-	**(1,892)**	-
Increase (decrease) in credit facilities	**(2,973)**	5,160	**9,140**	37,021
Increase (decrease) in long-term financial obligations	**(18)**	2,500	**12,448**	2,500
Proceeds from share issuances	**8,351**	-	**25,191**	-
Share issue costs	**(860)**	-	**(1,870)**	-
Proceeds from the exercise of stock options	**-**	212	**-**	1,865
Repurchase of common shares	**-**	(3,257)	**-**	(24,014)
Changes in non-cash financing working capital	**(7,491)**		**(7,491)**	
Changes in non-cash investing working capital	**1,349**	13,708	**(24,324)**	3,224
Total capital resources	**2,847**	26,949	**40,597**	69,690
E&E asset expenditures	**(1,222)**	(17,567)	**(4,678)**	(46,778)
P&NG properties and equipment expenditures	**(2,916)**	(14,280)	**(11,419)**	(50,602)
Property acquisitions	**1,297**	(7,393)	**(61,549)**	(7,393)
Property divestitures	**(6)**	12,291	**37,049**	35,083
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)	**December 31, 2015**	December 31, 2014
Working capital deficit	**40,675**	57,289
Current portion of the Credit Facilities	**(62,398)**	(53,258)
Current portion of the deferred premium on financial instruments	**(1,400)**	(2,019)
Current portion of the fair value of financial instruments	**14,172**	20,783
Adjusted working capital (surplus) deficit	**(8,951)**	22,795

The Corporation's adjusted working capital surplus increased to $8.9 million at December 31, 2015 as compared to an adjusted working capital deficit of $22.8 million at December 31, 2014. The adjusted working capital surplus at December 31, 2015 is largely comprised of the net proceeds of $7.5 million from the December 2015 Equity Financing, which were received in January 2016 and the significant reduction of accounts payables due to reduced activity in 2015.

At December 31, 2015, the major component of Manitok's current assets, excluding the fair value of financial instruments, was the realized gain of financial instruments of $2.9 million for the month of December 2015 and the net proceeds of $7.5 million from the December 2015 Equity Financing (58%) was received in January 2016, revenue (22%) to be received from its marketers in respect of December 2015 production and accounts receivable from joint venture partners (15%) 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 (58%) and accrued liabilities (27%) 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's Credit Facilities were reduced from $90.0 million to $80.0 million, which consisted of a $45.0 million Conforming Credit Facility and a fully drawn $35.0 million Non-Conforming Credit Facility. The Corporation was required to repay the $35.0 million outstanding amount on the Non-Conforming Credit Facility as follows:

- $5.0 million on or before December 31, 2015, which was paid as at November 25, 2015 and reduced the Non-Conforming Credit Facility to $30.0 million and the Credit Facilities to $75.0 million;
- $10.0 million on or before March 31, 2016; and
- $20.0 million on or before May 31, 2016.

In 2016 advances under the Credit Facilities are available by way of Canadian prime rate loans. The interest rates applicable to the advances are prime plus 3.0% on the Conforming Credit Facility and prime plus 5.0% on the Non-Conforming Credit Facility.

The following table indicates the Corporation's total available credit as at December 31, 2015 and 2014:

As at	**December 31, 2015**	December 31, 2014
Maximum borrowing base limit		
Conforming Credit Facility(1)	**45,000**	90,000
Non-Conforming Credit Facility(1)	**30,000**	-
Acquisition and development demand loan facility(2)	**-**	15,000
Long-term financial obligations	**14,948**	2,500
	89,948	107,500
Principle amount utilized		
Drawn Conforming Credit Facility	**(32,398)**	(53,258)
Drawn Non-Conforming Credit Facility	**(30,000)**	-
Long-term financial obligations	**(14,948)**	(2,500)
Outstanding letters of credit(3)	**(290)**	-
	(77,636)	(55,758)
Undrawn credit facilities	**12,312**	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 Conforming Credit 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 December 31, 2015 the Corporation's working capital ratio was 3.2:1 and anticipates being in compliance with the covenant throughout the next twelve months.

(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.

(3) Letters of credit are issued to service providers.

Subsequent to December 31, 2015, the $45.0 million Conforming Credit Facility was reduced to $30.0 million in conjunction with the December 2015 Equity Financing and the Non-Conforming Facility was maintained at $30.0 million. The following previously disclosed repayments are no longer required:

- $10.0 million on or before March 31, 2016; and
- $20.0 million on or before May 31, 2016.

The Corporation is required to repay $0.4 million per month on the Non-Conforming Credit Facility beginning on February 1, 2016 and continuing every month thereafter until it is fully repaid. Subsequent to the above, Manitok monetized crude oil derivative financial instruments with its counterparty for a cash receipt of $12.3 million and the funds were used to reduce the Non-Conforming Credit Facility from $30.0 million to $20.0 million and as such, further reduce the available Credit Facilities from $60.0 million to $50.0 million.

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 Credit Facilities are demand in nature and the lender may reduce the borrowing base at its sole discretion at any time. The Corporation believes it has sufficient funds from operations to meet its operating and capital commitments as they come due, however it is dependent on its lender. Manitok has not received an indication if its lender will demand repayment in the next twelve months, however, the demand nature including the Non-Conforming Facility does create uncertainty. The next review date for the Credit Facilities has been set for June 1, 2016, but the current Credit Facilities agreement has provided that the maximum amount of the Non-Conforming Credit Facility will be $20.0 million on June 1, 2016.

Management recognizes the difficulties of operating in the current commodity price environment and has taken steps to manage spending and indebtedness. 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 Corporation currently continues to meet all of its obligations with respect to ongoing operations and anticipates it will meet the capital commitments of the PSK LIDCA with the Farm-out Agreement, funds from operations which are enhanced with the commodity financial instruments in place for calendar 2016 and its Credit Facilities.

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 December 31, 2015:

($000)	2016	2017	2018 - 2020	Thereafter
Accounts payable and accrued liabilities	9,956	-	-	-
Drawn on Credit Facilities	62,398	-	-	-
Long-term financial obligations(1)	2,235	2,235	6,705	32,134
Deferred premium on financial instruments(2)	1,400	1,396	-	-
Minimum drilling and completion expenditures(3)(4)(5)	30,750	35,750	20,250	-
Firm transportation agreement(6)	603	764	-	-
Facility fees(7)	2,937	2,937	8,811	6,380
Office leases(8)	2,540	1,476	-	-
Total estimated contractual obligations(9)	**112,819**	**44,558**	**35,766**	**38,514**

(1) In conjunction with a facilities financing agreement incurred in December 2014 and the June 2015 Facility Financing, Manitok is committed to pay monthly facility payments of $0.2 million 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 PSK LIDCA, Manitok has agreed to an annual work program including minimum annual drilling and completion expenditures until April 30, 2018. In an effort to reduce the Corporation's PSK LIDCA commitment in 2016 and potentially 2017, the Corporation entered into the Farm-out Agreement in the fourth quarter of 2015 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. The entire capital spend from the Farm-out Agreement will be fully allocated to Manitok's PSK LIDCA capital commitment (see "Major Transactions Affecting Financial Results"). Should the Farmee fail to meet its $20.0 million spending commitment in 2016, the Farmee shall compensate Manitok in an amount equal to the difference between the actual amount spent by the Farmee and the $20.0 million commitment amount. The anticipated expenditures pursuant to the Farm-out Agreement are not included in the table.

(4) Pursuant to the PVR Divestiture, Manitok is committed to incur a minimum capital commitment of $10.0 million per year in 2016, 2017 and 2018 on drilling, completion, re-completion, workover, equipping and tie-in for the production of wells targeting the Carseland and/or Wayne areas. This commitment is included in the PSK LIDCA commitment and is not an additional commitment. Additionally, Manitok has agreed, but is not obligated to drill at least two gross wells per year in 2016, 2017 and 2018 in the Stolberg area. In the event Manitok does not meet this commitment, the royalty corporation may either grant an extension to Manitok, drill the wells itself or elect to do nothing.

(5) The flow-through share commitments related to the June 2015 Equity Financing and the December 2015 Equity Financing will be included in the PSK LIDCA commitment as there are several exploration opportunities within the undeveloped land acreage in the PSK LIDCA.

(6) The Corporation is committed to transport natural gas from a gas processing facility in the Ricinus area to the NOVA pipeline system.

(7) In conjunction with the December 2014 Facility Divestiture and the June 2015 Facility Divestiture, the Corporation is required to pay monthly facility fees of $0.2 million until June 2023, which are included in operating expenses.

(8) 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 all of its previous office space to arm's length parties for the remainder of the lease term. The recovery of rental costs from the subleases are not included in the table.

(9) 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 December 31, 2015 to be approximately $39.2 million and will be incurred as follows: 2016 - $0.3 million, 2017 - $0.1 million, 2018 to 2020 - $7.5 million and $31.3 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 obligations 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.

RELATED PARTY TRANSACTIONS

The Corporation has not entered into any related party transactions in the Reporting Periods.

OUTSTANDING SHARE DATA

At December 31, 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
Issue of Manitok Shares in December 2015[2]	58,846,331
Outstanding, December 31, 2015	**143,936,115**

(1) On June 12, 2015 and June 17, 2015, Manitok closed the June 2015 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).

(2) On December 30, 2015, Manitok closed the December 2015 Equity Financing for the issuance of 23,766,831 Manitok Shares at a price of $0.13 per Manitok Share and 35,079,500 Manitok CEE Flow-through Shares at a price of $0.15 per Manitok CEE Flow-through Share for gross proceeds of $8.4 million (net proceeds - $7.5 million). In connection with the December 2015 Equity Financing, Manitok has issued 1,170,712 Broker Warrants to the agents of the December 2015 Equity Financing, with each Broker Warrant entitling the holder thereof to acquire one Manitok Share at an exercise price of $0.13 per Manitok Share for a period of 18 months after the date of issuance of such Broker Warrants.

At April 29, 2016, there were 161,079,746 Manitok Shares outstanding, 15,121,833 stock options to purchase an equivalent number of Manitok Shares and 1,241,126 Broker Warrants to purchase an equivalent number of Manitok Shares. The increase in Manitok Shares is due to the closing of the final tranches of a private placement equity financing in the first quarter of 2016 for the issuance of an additional 15,973,631 Manitok Shares at a price of $0.13 per Manitok Share and 1,170,000 Manitok CEE Flow-through Shares at a price of $0.15 per Manitok CEE Flow-through Share for gross proceeds of $2.3 million.

SUMMARY OF QUARTERLY INFORMATION

Quarters Ended	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1
OPERATING								
Average daily production								
Light oil (bbls/d)	**2,002**	2,176	1,864	2,269	2,257	2,066	2,695	3,028
Natural gas (mcf/d)	**13,540**	12,412	15,435	13,049	10,713	10,931	11,417	13,352
NGLs (bbls/d)	**200**	190	84	61	30	74	46	98
Total (boe/d)	**4,459**	4,434	4,521	4,504	4,072	3,962	4,644	5,351
Average realized sales price (CAD$)								
Light oil ($/bbl)	**47.83**	51.85	63.71	48.77	71.96	95.17	103.18	96.92
Natural gas ($/mcf)	**2.73**	3.20	2.89	2.89	3.83	4.25	4.81	6.51
NGLs ($/bbl)	**27.88**	29.50	55.98	52.85	67.29	98.93	110.86	97.92
Total ($/boe)	**31.01**	35.65	37.18	33.66	50.45	63.20	72.80	72.88
OPERATING NETBACK ($ per boe)[1]								
Petroleum and natural gas sales	**31.01**	35.65	37.18	33.66	50.45	63.20	72.81	72.90
Realized gain (loss) on financial instruments	**18.20**	15.75	10.86	13.54	6.67	(4.69)	(6.19)	(4.10)
Royalty expenses	**(8.30)**	(10.13)	(8.78)	(8.47)	(11.61)	(19.64)	(23.98)	(22.23)
Operating expenses, net	**(11.51)**	(15.72)	(11.28)	(10.38)	(7.65)	(6.73)	(7.58)	(7.35)
Transportation and marketing expenses	**(1.72)**	(1.71)	(2.35)	(2.87)	(3.17)	(3.47)	(3.66)	(3.21)
Operating netback[1]	**27.68**	23.84	25.63	25.48	34.69	28.67	31.40	36.01
FINANCIAL								
Petroleum and natural gas revenue ($000)	**12,720**	14,548	15,297	13,645	18,902	23,037	30,771	35,112
Royalty expenses ($000)	**(3,406)**	(4,134)	(3,613)	(3,433)	(4,349)	(7,157)	(10,132)	(10,705)
Realized gain (loss) on financial instruments ($000)	**7,464**	6,426	4,466	5,488	2,499	(1,709)	(2,618)	(1,976)
Unrealized gain (loss) on financial instruments ($000)	**2,518**	11,014	(10,328)	(4,114)	27,577	8,394	(2,036)	(6,175)
Interest and other revenue ($000)	**7**	7	7	7	6	22	-	3
Total revenue, net ($000)	**19,303**	27,861	5,829	11,593	44,635	22,587	15,985	16,259
Funds from operations ($000)[1]	**8,488**	6,643	7,341	7,918	10,766	8,556	11,197	15,461
Per share - basic ($)[1]	**0.10**	0.08	0.11	0.12	0.16	0.13	0.16	0.21
Per share - diluted ($)[1]	**0.10**	0.08	0.11	0.12	0.16	0.12	0.16	0.21
Net income (loss) ($000)	**(5,258)**	8,316	(26,852)	(3,401)	(2,774)	7,900	(9,044)	331
Per share - basic ($)	**(0.06)**	0.10	(0.39)	(0.05)	(0.04)	0.12	(0.13)	-
Per share - diluted ($)[2]	**(0.06)**	0.10	(0.39)	(0.05)	(0.04)	0.11	(0.13)	-
Capital expenditures, net of divestitures ($000)	**2,847**	3,890	28,959	4,901	26,949	22,832	17,669	2,240
Book value of total assets ($000)	**204,705**	206,644	199,995	196,945	211,284	197,362	178,300	185,390
Adjusted working capital (surplus) deficit ($000)[1]	**(8,951)**	598	(1,575)	(2,313)	22,795	11,067	17,676	19,947
Drawn on Credit Facilities ($000)	**62,398**	65,371	69,949	75,379	53,258	48,098	22,311	6,685
Net bank debt ($000)[1]	**53,447**	65,969	68,374	73,066	76,053	59,165	39,987	26,632
Long-term financial obligations ($000)	**14,948**	14,966	14,984	2,494	2,500	-	-	-
Net debt ($000)[1]	**68,395**	80,935	83,358	75,560	78,553	59,165	39,987	26,632
Shareholders' equity ($000)	**80,540**	78,586	69,965	81,348	84,333	89,714	86,550	102,256
Common shares outstanding								
End of period - basic	143,936,115	85,089,784	85,089,784	65,279,607	65,279,607	66,996,440	69,020,407	71,615,406
End of period - diluted	150,334,260	90,553,217	91,564,557	71,719,880	70,588,213	71,566,714	74,114,181	77,689,147
Weighted average for the period - basic	85,729,418	85,089,784	68,749,889	65,279,607	65,924,473	68,143,633	70,390,367	73,097,543
Weighted average for the period - diluted	85,729,418	85,089,784	68,750,556	65,279,607	66,255,000	69,108,544	71,402,527	74,334,096

(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 generally accepted accounting principles 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 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 Foothills Asset Divestiture of $1.3 million.
- 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 its normal course issuer bid programs.
- 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 Divesture.
- 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 its normal course issuer bid programs.
- In the third quarter of 2014, average production volumes decreased to 3,962 boe/d compared to 4,644 boe/d in the second quarter of 2014. Approximately 450 boe/d of the decrease is attributed to 3 gross (1.5 net) Cardium oil wells that were shut-in July 2014 in order to properly manage the Stolberg reservoir pressure to ensure the maximum recovery of its oil in place and about 230 boe/d is attributed to natural production declines in the Stolberg area with limited new well production additions in the quarter.
- 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 its normal course issuer bid programs.
- 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 in the fourth quarter of 2014, partially offset by the December 2014 Facility Divestiture.
- The Corporation repurchased 1,878,500 Manitok Shares in the fourth quarter of 2014 at an average price of $1.73 per share, pursuant to its normal course issuer bid programs.
- 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 PVR Divestiture and the Stolberg GORR Divestiture.
- In the second quarter of 2015, Manitok closed the Wayne Acquisition for cash consideration of $61.1 million after post-closing adjustments.
- The Corporation closed the June 2015 Equity Financing for net proceeds of $15.8 million.
- The Corporation completed the Wayne GORR Divestiture, the PVR Divestiture, the June 2015 Facility Divestiture in the second quarter of 2015 for net cash proceeds of $37.7 million along with the June 2015 Facility Financing for additional net cash proceeds of $12.5 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, a loss on the PVR Divestiture and the Stolberg GORR Divestiture of $3.6 million and an impairment charge of $17.9 million in the second quarter of 2015.
- The Corporation closed the December 2015 Equity Financing for net proceeds of $7.5 million.
- Adjusted working capital changed to a surplus of $9.0 million at December 31, 2015, compared to a deficit as at September 30, 2015 due mainly to the net proceeds of $7.5 million from the December 2015 Equity Financing being received in January 2016.
- Net loss for the fourth quarter of 2015 was $5.3 million, compared to net income of $8.3 million in the third quarter of 2015. The net loss was due mainly to an impairment charge of $12.7 million in the fourth 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.

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 future net revenue 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 removal 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 net revenue 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) Fair value of financial instruments

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

(vi) Income 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.

FUTURE ACCOUNTING PRONOUNCEMENTS

In January 2016, the International Accounting Standards Board ("**IASB**") issued IFRS 16 *Leases*. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 *Revenue from Contracts with Customers*, has been applied, or is applied at the same date as IFRS 16. Manitok is currently evaluating the impact of adopting IFRS 16 on the financial statements.

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 the Corporation's financial statements.

RISK FACTORS & RISK MANAGEMENT

The liquidity position of Manitok is restricted and the continued operation of Manitok 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 equity financings, 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. Ongoing exploration and development of Manitok's properties will require substantial additional capital investment. Failure to secure additional financing may 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 Manitok.

Manitok 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, Manitok 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 Manitok'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. Manitok focuses on conducting transparent, safe and responsible operations in the communities in which its people live and work.