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, 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, 2015. The annual financial information in respect of the three and twelve months ended December 31, 2014 (the "**Reporting Periods**") as compared to the three and twelve months ended December 31, 2013 (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, 2014 and 2013. 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 deficit" and "net debt". These measures do not have standardized meanings prescribed by generally accepted accounting principles ("**GAAP**") and therefore should not be considered in isolation. These reported amounts and their underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of other companies where similar terminology is used. Where these measures are used, they should be given careful consideration by the reader. These measures have been described and presented in the MD&A and 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 as determined in accordance with GAAP, as an indicator of Manitok's performance or liquidity. Funds from operations is used by Manitok to evaluate operating results and Manitok's ability to generate cash flow to fund capital expenditures and repay indebtedness. Funds from operations denotes cash flow from operating activities as it appears on the Corporation's Statement of Cash Flows before decommissioning expenditures and changes in non-cash operating working capital. Funds from operations is also derived from net income (loss) plus non-cash items including deferred income tax expense, 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 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 debt as a measure to assess its financial position. Net debt includes current assets less current liabilities excluding the current portion of the fair value of financial instruments and the deferred premium on financial instruments, plus the long-term financial obligation.

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 contain forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to future events or future performance and is based upon the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to reserves is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves exist in the quantities estimated and that it will be commercially viable to produce in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information. In particular, this MD&A and the Annual Report contains forward-looking information relating to the Corporation's planned strategy in terms of hedging; 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 2015 capital program, readers are cautioned that the Corporation may make adjustments to its 2015 capital program, depending on business conditions and commodity prices throughout the fiscal year. Actual spending may vary due to a variety of factors, including changes to certain key expectations and assumptions set out below.

By their nature, forward-looking information involves a variety of assumptions, known and unknown risks and uncertainties, and other factors, which may cause actual results, levels of activity, and achievements to differ materially from those expressed or implied by such statements. The material factors and assumptions used to develop the forward-looking statements herein include, but are not limited to the following: future commodity prices; currency exchange rates; inflation rates; well production rates; well drainage areas; success rates for future drilling; availability of labour and services; interest rates; and future availability of debt and equity financing being at levels and costs that allow the Corporation to manage, operate and finance its business, develop its properties and meet its future obligations. With respect to estimates of reserves, a key assumption is the validity of the data used by Sproule Associates Limited in its independent reserves evaluation. With respect to future wells to be drilled, a key assumption is that geological and other technical interpretations performed by the Corporation's technical staff, which indicate commercially economic reserves can be recovered from the Corporation's land as a result of drilling such future wells, are valid. Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, 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, 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
MMboe	million barrels of oil equivalent
NGLs	natural gas liquids

Natural Gas

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

Other

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

GUIDANCE

Previous updated 2014 guidance was provided in the Corporation's press release dated November 17, 2014, a copy of which is available under Manitok's profile on SEDAR at www.sedar.com or on Manitok's website at manitokenergy.com. The table below provides Manitok's guidance for 2014 along with actual results.

	Guidance	Actual	Average % Variance
Average Daily Production			
Annual (boe/d)	4,750 – 4,950	4,502	(7%)
% light oil and liquids	57% – 59%	57%	-
Exit rate (boe/d)	6,100 – 6,500	4,340	(31%)
% light oil and liquids	54% – 56%	56%	-
Funds from operations ($ millions)	48.0 – 50.0	46.0	(6%)
Capital expenditures, net of divestitures ($ millions)	82.0	69.7	(15%)
Net debt at year end ($ millions)	87.0 – 89.0	78.6	(11%)

Actual exit and annual production rates were lower than guidance due to facility construction issues in December 2014 that delayed new well production in the Entice area to January 2015. Funds from operations was negatively impacted by the lower actual production volumes and a decrease in realized oil and natural gas prices. The decrease in capital expenditures from guidance relates to the divestiture of oil and gas infrastructure for total cash consideration of $12.3 million, as disclosed in this MD&A (see "Major Transactions Affecting Financial Results"). Net debt has decreased from previous guidance due to the divestiture, partially offset by lower funds from operations and activity in the normal course issuer bid program.

Due to the current low commodity price environment, the Corporation will not drill any wells in the Entice or Stolberg areas during the first half of 2015. Manitok anticipates about $6.0 to $6.5 million of capital expenditures in the first half of 2015 that would include completions and facilities capital required on wells already drilled. Approximately 60% to 65% of cash flow will be applied towards debt reduction in the first half of 2015. Manitok will evaluate its production and the level of commodity prices in the second quarter of 2015 before planning and executing the bulk of its 2015 capital expenditure program in the second half of the year.

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

- On February 28, 2014, Manitok completed an asset divestiture of approximately 777 boe/d (94% natural gas) in the central Alberta foothills region ("**Foothills Asset Divestiture**"), with an effective date of January 1, 2014 for total cash consideration of $21.9 million after closing adjustments.
- On March 11, 2014, Manitok received approval of the TSX-V to commence a new Normal Course Issuer Bid ("**March 2014 NCIB**") program to purchase for cancellation up to 6.8 million common shares of Manitok ("**Manitok Shares**") on the open market during the period from March 17, 2014 and March 16, 2015.
- On October 30, 2014, Manitok received approval of the TSX-V to commence a new Normal Course Issuer Bid ("**November 2014 NCIB**") program to purchase for cancellation up to 6.3 million Manitok Shares on the open market during the period from November 3, 2014 and November 2, 2015.
- On October 31, 2014, the Corporation completed an acquisition of approximately 290 boe/d (15% oil and liquids) in the Stolberg area ("**Stolberg Acquisition**"), with an effective date of October 1, 2014, for total cash consideration of approximately $7.4 million. The acquisition was financed using the Corporation's credit facilities.
- On December 30, 2014, Manitok divested its interest in certain oil and gas infrastructure ("**Facility Divestiture**") for $12.3 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 (see "Contractual Obligations").

SELECTED ANNUAL INFORMATION

For the years ended December 31 *($000, except for production and share information)*	**2014**	2013	2012
Average daily production (boe/d)	**4,502**	4,113	2,389
Petroleum and natural gas revenue	**107,822**	85,950	37,349
Net revenue from petroleum and natural gas sales	**75,479**	65,401	32,455
Funds from operations(1)	**45,980**	41,554	19,081
Per share – basic(1)	**0.66**	0.59	0.30
Per share – diluted(1)	**0.65**	0.57	0.29
Net income (loss)	**(3,587)**	3,615	(2,657)
Per share – basic	**(0.05)**	0.05	(0.04)
Per share – diluted(2)	**(0.05)**	0.05	(0.04)
Capital expenditures, net of divestitures	**69,690**	79,365	36,965
Total assets	**211,284**	192,580	126,322
Adjusted working capital deficit(1)	**22,795**	16,277	6,861
Drawn on credit facilities	**53,258**	16,237	3,101
Long-term financial obligations	**2,500**	-	-
Total net debt(1)	**78,553**	32,514	9,962
Shareholders' equity	**84,333**	109,096	90,437
Common shares outstanding			
End of period – basic	**65,279,607**	74,492,340	70,339,014
End of period – diluted	**70,588,213**	80,099,780	75,122,847
Weighted average shares for period – basic	**69,365,940**	70,654,634	63,567,788
Weighted average shares for period – diluted	**70,321,234**	72,596,161	64,702,325

(1) Funds from operations, funds from operations per share, funds from operations netback, operating netback, adjusted working capital 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.

(2) The basic and diluted weighted average shares outstanding are the same for years in which the Corporation records a net loss.

The Corporation has had continued growth in production, revenue and funds from operations on an absolute and per share basis over the last three years summarized in the table above. Manitok's average daily production has increased as a result of the successful light oil drilling program in the Stolberg area offset by the Foothills Asset Divestiture. The decrease in shareholders' equity in 2014 is primarily a result of activity in the normal course issuer bid programs and an impairment charge of $47.6 million, partially offset by an unrealized gain on financial instruments of $27.8 million.

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 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 as determined in accordance with GAAP, as an indicator of Manitok's performance or liquidity. Funds from operations per share is calculated based on the weighted average number of basic and diluted common shares outstanding. Manitok's calculation of funds from operations is considered to be a key measure of the ability to generate the cash necessary to fund capital expenditures and repay indebtedness.

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

	Three months ended December 31		Twelve months ended December 31	
($000, except per share information)	**2014**	2013	**2014**	2013
Cash flow from operating activities	**8,626**	11,504	**49,094**	37,166
Adjustments:				
Decommissioning expenditures	**160**	38	**180**	222
Changes in non-cash operating working capital	**1,980**	2,575	**(3,294)**	4,166
Funds from operations	**10,766**	14,117	**45,980**	41,554
per share – basic	**0.16**	0.19	**0.66**	0.59
per share – diluted	**0.16**	0.19	**0.65**	0.57

Funds from operations decreased by 24% to $10.8 million ($0.16 per diluted share) for the fourth quarter of 2014 as compared to $14.1 million ($0.19 per diluted share) in the Comparable Prior Period. The decrease in funds from operations and funds from operations per share was due mainly to a $7.4 million decrease in petroleum and natural gas sales from lower average production volumes and the decline in commodity prices, partially offset by a realized gain on financial instruments of $2.5 million and an aggregate decrease to royalty, operating, transportation and marketing expenses.

Funds from operations increased by 11% to $46.0 million ($0.65 per diluted share) in 2014 as compared to $41.6 million ($0.57 per diluted share) in 2013. The increase in funds from operations and funds from operations per share were due mainly to a $21.9 million increase in petroleum and natural gas sales, partially offset by an increased realized loss on financial instruments and aggregate increases to royalty, operating, transportation and marketing, general and administrative and interest expenses.

Net Income (Loss)

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

	Three months ended December 31		Twelve months ended December 31	
($000, except per share information)	**2014**	2013	**2014**	2013
Net income (loss)	**(2,774)**	(1,417)	**(3,587)**	3,615
per share – basic	**(0.04)**	(0.02)	**(0.05)**	0.05
per share – diluted	**(0.04)**	(0.02)	**(0.05)**	0.05

Net loss increased to $2.8 million ($0.04 per diluted share) for the fourth quarter of 2014 as compared to $1.4 million ($0.02 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 increased impairment and depletion and depreciation, partially offset by an increased unrealized gain on financial instruments.

Manitok had a net loss of $3.6 million ($0.05 loss per diluted share) in 2014 as compared to net income of $3.6 million ($0.05 per diluted share) in 2013. The net loss is mainly attributable to the $47.6 million impairment charge coupled with an increase in depletion and depreciation and a loss on asset divestitures, partially offset by increased funds from operations, an increased unrealized gain on financial instruments and a decrease in deferred income tax expense.

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, 2014				Three months ended December 31, 2013			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Light oil (bbls)	**14,942**	**2,257**	**55**	**71.96**	20,857	2,755	55	82.30
Natural gas (mcf)(1)	**3,775**	**10,713**	**44**	**3.83**	4,772	12,868	43	4.03
NGLs (bbls)	**185**	**30**	**1**	**67.29**	628	89	2	76.48
Total P&NG sales (boe)	**18,902**	**4,072**	**100**	**50.45**	26,257	4,989	100	57.21
Royalty revenue	**-**			**-**	3			0.01
Total P&NG revenue (boe)	**18,902**	**4,072**	**100**	**50.45**	26,260	4,989	100	57.22

	Twelve months ended December 31, 2014				Twelve months ended December 31, 2013			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Light oil (bbls)	**84,750**	**2,508**	**56**	**92.57**	67,655	2,065	50	89.75
Natural gas (mcf)(1)	**20,869**	**11,594**	**43**	**4.93**	15,528	11,782	48	3.61
NGLs (bbls)	**2,187**	**62**	**1**	**96.93**	2,388	84	2	78.07
Total P&NG sales (boe)	**107,806**	**4,502**	**100**	**65.60**	85,571	4,113	100	57.00
Royalty revenue	**16**			**0.01**	379			0.25
Total P&NG revenue (boe)	**107,822**	**4,502**	**100**	**65.61**	85,950	4,113	100	57.25

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

Total P&NG sales for the fourth quarter of 2014 decreased 28% to $18.9 million compared to $26.3 million in the Comparable Prior Period. The decrease of $7.4 million consists of $5.0 million attributed to lower production volumes and $2.4 million due to lower realized prices. For the year, total P&NG sales increased 26% to $107.8 million compared to $85.6 million in 2013. The increase of $22.2 million consists of $13.9 million attributed to higher production volumes and $8.3 million due to higher realized prices.

Production

Production averaged 4,072 boe/d in the fourth quarter of 2014, as compared to 4,989 boe/d in the Comparable Prior Period. The decrease in average daily production was due mainly to the Foothills Asset Divestiture which contributed 879 boe/d in the Comparable Prior Period and maximum production rate limitations ("**MRLs**") imposed by the Alberta Energy Regulator along with natural production declines in the Stolberg area, partially offset by the Stolberg Acquisition of 290 boe/d in October 2014.

In 2014, production averaged 4,502 boe/d, as compared to 4,113 boe/d in 2013. The increase in average daily production was due mainly to the successful drilling program in the Stolberg area for light oil and associated gas from the Cardium Formation and liquids rich natural gas from the Ostracod Formation, partially offset by the Foothills Asset Divestiture, which contributed 955 boe/d in 2013.

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		
	2014	2013	Variance	**2014**	2013	Variance
Benchmark prices						
Light oil – WTI ($US/bbl)	**73.15**	97.46	(25%)	**93.00**	97.98	(5%)
Light oil – WTI ($CAD/bbl)	**83.07**	102.27	(19%)	**102.72**	100.91	2%
Light oil – Canadian light sweet ($/bbl)	**75.11**	86.38	(13%)	**94.18**	93.27	1%
Natural gas – AECO daily spot ($/mmbtu) (1)	**3.60**	3.53	2%	**4.50**	3.18	42%
Exchange rate – ($CAD/$US)	**1.1356**	1.0494	8%	**1.1045**	1.0300	7%
Average realized prices						
Light oil ($/bbl)	**71.96**	82.30	(13%)	**92.57**	89.75	3%
Natural gas ($/mcf)	**3.83**	4.03	(5%)	**4.93**	3.61	37%
NGLs ($/bbl)	**67.29**	76.48	(12%)	**96.93**	78.07	24%
Average realized price ($/boe)	**50.45**	57.21	(12%)	**65.60**	57.00	15%
Price differentials						
Canadian light sweet/WTI CAD ($/bbl)	**(7.96)**	(15.89)	(50%)	**(8.54)**	(7.64)	12%
Realized light oil/Canadian light sweet ($/bbl)	**(3.15)**	(4.08)	(23%)	**(1.61)**	(3.52)	(54%)
Realized natural gas/AECO daily spot ($/mcf)	**0.23**	0.50	(54%)	**0.43**	0.43	-

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

The price the Corporation receives for its P&NG production depends on a number of factors, including the average benchmark prices for crude oil and natural gas, the Canadian/US dollar exchange rate and transportation and product quality differentials.

In the fourth quarter of 2014, Manitok's average realized commodity price decreased 12% to $50.45/boe from $57.21/boe in the Comparable Prior Period, due to decreased benchmark prices for crude oil, natural gas and NGLs.

Manitok's average realized commodity price increased 15% to $65.60/boe in 2014 from $57.00/boe in 2013, due mainly to increased prices for natural gas and NGLs. Additionally, higher priced crude oil and NGL production increased from 52% of total production in 2013 to 57% of total production in 2014.

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		
	2014	2013	Variance	**2014**	2013	Variance
Natural gas – AECO daily spot ($/mmbtu) (1)	**3.60**	3.53	2%	**4.50**	3.18	42%
Heat/quality differential ($/mcf)(2)	**0.17**	0.50	(66%)	**0.51**	0.43	19%
Physical sales/AECO daily spot differential ($/mcf)	**0.06**	-	-	**(0.08)**	-	-
Realized natural gas ($/mcf)	**3.83**	4.03	(5%)	**4.93**	3.61	37%

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

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

Financial Instruments

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

Financial Derivatives

As at December 31, 2014, the Corporation held the following derivative financial instruments:

Product	Notional Quantity	Term	Reference	Strike Price	Type of Contract	Fair Value
Oil	1,000 bbls/d	January 1, 2015 to December 31, 2015	CAD$ WTI	$95.00	Swap	10,455
Oil	500 bbls/d	January 1, 2015 to December 31, 2015	CAD$ WTI	$91.00	Swap	4,488
Natural gas	1,000 GJ/d	January 1, 2015 to December 31, 2015	CAD$ AECO	$3.73	Put option(1)	396
Natural gas	5,000 GJ/d	January 1, 2015 to December 31, 2015	CAD$ AECO	$3.85	Put option(1)	2,184
Natural gas	5,000 GJ/d	January 1, 2015 to December 31, 2015	CAD$ AECO	$3.85	Put option(1)	2,184
Natural gas	5,000 GJ/d	January 1, 2015 to December 31, 2015	CAD$ AECO	$3.80	Put option(1)	2,100
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CAD$ WTI	$95.00	Swaption(2)	(556)
Oil	500 bbls/d	January 1, 2016 to December 31, 2016	CAD$ WTI	$91.00	Swaption(3)	(468)
Total						**20,783**
Current assets						**20,783**

(1) Manitok recorded $2.0 million as a deferred premium on financial instruments, which represents the amount payable to the counter-party on these contracts for the deferred put option premium of $0.35/GJ.
(2) The counter-party to this contract holds a one-time option no later than December 31, 2015 to extend a swap on 1,000 bbls/d of oil at CAD$95.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.
(3) The counter-party to this contract holds a one-time option no later than December 31, 2015 to extend a swap on 500 bbls/d of oil at CAD$91.00 for the period indicated. The fair value amount represents the cost the Corporation would incur to exit the contract.

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**			
	2014		2013		**2014**		2013	
	$000	**$/boe**	$000	$/boe	**$000**	**$/boe**	$000	$/boe
Realized gain (loss) on financial instruments	**2,499**	**6.67**	(220)	(0.48)	**(3,804)**	**(2.31)**	(1,911)	(1.27)
Unrealized gain (loss) on financial instruments	**27,577**	**73.61**	(3,591)	(7.82)	**27,760**	**16.89**	(8,541)	(5.69)

Subsequent to December 31, 2014, the Corporation entered into the following derivative financial instrument:

Product	Notional Quantity	Term	Reference	Strike Price	Type of Contract
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD$ WTI	$75.00 -$90.00	Collar(1)
Oil	500 bbls/d	January 1, 2016 to December 31, 2017	CAD$ WTI	$70.00 -$90.00	Collar(2)

(1) The counter-party to this contract receives a deferred premium of $4.50/bbl.
(2) The counter-party to this contract receives a deferred premium of $3.15/bbl.

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, 2014.

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, 2014			Three months ended December 31, 2013		
	($000)	**Effective Royalty Rate(1)**	**Average ($/unit)**	($000)	Effective Royalty Rate(1)	Average ($/unit)
Light oil and NGLs (bbls)	**4,552**	**30.1%**	**21.64**	4,329	20.1%	16.55
Natural Gas (mcf)(2)(3)	**(203)**	**(5.4%)**	**(0.21)**	341	7.1%	0.29
Total Royalties (boe)	**4,349**	**23.0%**	**11.61**	4,670	17.8%	10.18

	Twelve months ended December 31, 2014			Twelve months ended December 31, 2013		
	($000)	**Effective Royalty Rate(1)**	**Average ($/unit)**	($000)	Effective Royalty Rate(1)	Average ($/unit)
Light oil and NGLs (bbls)	**30,082**	**34.6%**	**32.07**	19,585	28.0%	24.97
Natural Gas (mcf)(2)(3)	**2,261**	**10.8%**	**0.53**	964	6.2%	0.22
Total Royalties (boe)	**32,343**	**30.0%**	**19.68**	20,549	24.0%	13.69

(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 fourth quarter of 2014 were $4.3 million as compared to $4.7 million for the Comparable Prior Period. The decrease is due to decreased production volumes and decreased realized commodity prices, partially offset by higher effective light oil and NGL royalty rates in the Reporting Period. The higher effective royalty rate for light oil and NGLs is due to an increased percentage of production subject to a maximum royalty rate of 40% in the Reporting Period compared to the Comparable Prior Period. Natural gas royalty expense in the fourth quarter of 2014 is a net recovery of $0.2 million due to a credit received in the fourth quarter relating to the Crown's natural gas deep drilling program.

Royalties for 2014 were $32.3 million, as compared to $20.5 million in 2013. The increase is due to increased production volumes and higher effective royalty rates in the year. The higher effective royalty rate for light oil and NGLs is due to an increased percentage of production subject to a maximum royalty rate of 40% in 2014 compared to 2013. The effective royalty rate for natural gas increased in 2014 compared to 2013 due to increased natural gas sales prices and a higher average gas production rate per well as a result of the Foothills Asset Divestiture, which included many low rate gas wells.

Operating Expenses

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

	Three months ended December 31, 2014		Three months ended December 31, 2013		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Field operating expenses	**3,087**	**8.23**	4,589	10.00	(33%)	(18%)
Recoveries	**(220)**	**(0.58)**	(535)	(1.17)	(59%)	(50%)
Total operating expenses	**2,867**	**7.65**	4,054	8.83	(29%)	(13%)

	Twelve months ended December 31, 2014		Twelve months ended December 31, 2013		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Field operating expenses	**13,373**	**8.14**	12,890	8.59	4%	(5%)
Recoveries	**(1,311)**	**(0.80)**	(1,452)	(0.97)	(10%)	(18%)
Total operating expenses	**12,062**	**7.34**	11,438	7.62	5%	(4%)

Operating expenses for the fourth quarter of 2014 decreased to $2.9 million as compared to $4.1 million in 2013 due to lower production volumes and increased efficiencies. On a per boe basis, operating expenses decreased to $7.65/boe as compared to $8.83/boe in the comparable prior period. The decrease is attributable to increased production volumes through permanent facilities in the fourth quarter of 2014, which have lower operating expenses than temporary facilities.

In 2014, operating expenses increased to $12.1 million as compared to $11.4 million in 2013 due to higher production volumes. On a per boe basis, operating expenses decreased to $7.34/boe as compared to $7.62/boe in 2013. The decrease is attributable to increased production volumes through permanent facilities in 2014 which have lower operating expenses than temporary facilities.

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**		
	2014	2013	Variance	**2014**	2013	Variance
Total T&M expenses ($000)	**1,186**	1,424	(17%)	**5,545**	4,302	29%
Total T&M expenses ($/boe)	**3.17**	3.10	2%	**3.37**	2.87	17%

In the fourth quarter of 2014, T&M expenses decreased to $1.2 million as compared to $1.4 million in the Comparable Prior Period due to lower production volumes. On a per boe basis, T&M expenses in the fourth quarter of 2014 were consistent with the Comparable Prior Period.

In 2014, T&M expenses increased to $5.5 million as compared to $4.3 million in the Comparable Prior Period due to higher production volumes. On a per boe basis, T&M expenses in 2014 increased to $3.37/boe compared to $2.87/boe due primarily to a higher percentage of crude oil production relative to natural gas. Crude oil transportation costs are higher on a per boe basis than natural gas transportation costs, and crude oil volumes represented 56% of total production volumes in 2014, as compared to 50% in 2013.

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)	**2014**	2013	Variance	**2014**	2013	Variance
Realized P&NG sales price	**50.45**	57.21	(12%)	**65.60**	57.00	15%
Royalty income	**-**	0.01	-	**0.01**	0.25	(96%)
Royalty expenses	**(11.61)**	(10.18)	14%	**(19.68)**	(13.69)	44%
Operating expenses, net of recoveries	**(7.65)**	(8.83)	(13%)	**(7.34)**	(7.62)	(4%)
Transportation and marketing expenses	**(3.17)**	(3.10)	2%	**(3.37)**	(2.87)	17%
Operating netback before realized gain (loss) on financial instruments	**28.02**	35.11	(20%)	**35.22**	33.07	7%
Realized gain (loss) on financial instruments	**6.67**	(0.48)	1,490%	**(2.31)**	(1.27)	82%
Operating netback	**34.69**	34.63	-	**32.91**	31.80	3%

Manitok's operating netback was $34.69/boe in the fourth quarter of 2014, which is consistent with $34.63/boe in the Comparable Prior Period. However, realized P&NG prices were $6.76/boe lower, offset by an increase in the realized gain on financial instruments of $7.15/boe.

In 2014, the operating netback was $32.91/boe compared to $31.80/boe in 2013. The increase was due to higher realized P&NG prices, partially offset by higher royalties and an increased realized loss on financial instruments.

Administrative Expenses

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

	Three months ended December 31, 2014		Three months ended December 31, 2013		Variance
	$000	**%**	$000	%	$
Cash:					
Salaries and benefits[1]	**1,353**	**52**	1,571	63	(14%)
Other[2]	**1,253**	**48**	938	37	34%
	2,606	**100**	2,509	100	4%
Operating overhead recoveries	**(130)**	**(5)**	(96)	(4)	35%
Capitalized overhead recoveries[3]	**(756)**	**(29)**	(793)	(31)	(5%)
General and administrative expenses, net	**1,720**	**66**	1,620	65	6%
General and administrative expenses, net per boe	**4.59**		3.53		30%
Non-cash:					
Stock-based compensation	**438**	**100**	167	100	162%
Capitalized stock-based compensation[3]	**(199)**	**(45)**	(270)	(162)	(26%)
Stock-based compensation, net	**239**	**55**	(103)	(62)	332%
Stock-based compensation, net per boe	**0.64**		(0.22)		391%
Total administrative expenses, net	**1,959**	**64**	1,517	57	29%
Total administrative expenses, net per boe	**5.23**		3.31		58%

	Twelve months ended December 31, 2014		Twelve months ended December 31, 2013		Variance
	$000	**%**	$000	%	$
Cash:					
Salaries and benefits[1]	**6,180**	**60**	4,913	61	26%
Other[2]	**4,118**	**40**	3,077	39	34%
	10,298	**100**	7,990	100	29%
Operating overhead recoveries	**(622)**	**(6)**	(460)	(6)	35%
Capitalized overhead recoveries[3]	**(2,806)**	**(27)**	(1,800)	(22)	56%
General and administrative expenses, net	**6,870**	**67**	5,730	72	20%
General and administrative expenses, net per boe	**4.18**		3.82		9%
Non-cash:					
Stock-based compensation	**973**	**100**	2,355	100	(59%)
Capitalized stock-based compensation[3]	**(376)**	**(39)**	(1,054)	(45)	(64%)
Stock-based compensation, net	**597**	**61**	1,301	55	(54%)
Stock-based compensation, net per boe	**0.36**		0.86		(58%)
Total administrative expenses, net	**7,467**	**66**	7,031	68	6%
Total administrative expenses, net per boe	**4.54**		4.68		(3%)

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

(2) Includes costs such as rent, professional fees, insurance, computer software licenses and other business expenses incurred by the Corporation.

(3) Represents a portion of salaries, benefits, software and stock-based compensation that are directly attributable to the exploration and development activities of the Corporation.

General and administrative (cash)

Net General and Administrative ("**G&A**") expenses increased 6% on an aggregate basis to $1.7 million in the fourth quarter of 2014 as compared to $1.6 million in the Comparable Prior Period due mainly to increased office rent costs related to the office move in October 2014, partially offset by lower salaries and benefits due to decreased management and employee bonuses for 2014.

In 2014, net G&A expenses increased 20% on an aggregate basis to $6.9 million as compared to $5.7 million in 2013, due mainly to severance costs related to employee terminations in 2014, higher salaries and benefits due to an increase in the number of new professional staff to accommodate the Corporation's activities in the Entice area and increased office rent costs related to the office move in October 2014.

Stock-based compensation (non-cash)

Net stock-based compensation expense increased in the fourth quarter of 2014 to $0.2 million as compared to a net recovery of $0.1 million in the Comparable Prior Period due to forfeitures of unvested stock options related to staff departures in 2013.

In 2014, net stock-based compensation expense decreased in 2014 to $0.6 million as compared to $1.3 million in 2013. The decrease is related to increased forfeitures of unvested stock options due to staff departures, partially offsetting the amount expensed in the year.

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

	Number	Weighted Average Exercise Price ($)
Outstanding, December 31, 2012	**4,783,833**	**1.46**
Granted	2,171,100	2.99
Exercised	(742,826)	(1.23)
Forfeited	(604,667)	(2.41)
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**

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		
	2014	2013	Variance	**2014**	2013	Variance
Depletion and depreciation ($000)	**7,663**	5,911	30%	**26,552**	19,644	35%
Depletion and depreciation ($/boe)	**20.45**	12.88	59%	**16.16**	13.09	23%

D&D expense is a function of the estimated proved plus probable reserve additions, the finding and development costs attributable to those reserves, the associated future development capital required to recover those reserves and production in the period. The Corporation determines its D&D expenses on an area basis.

D&D expenses increased in the fourth quarter of 2014 to $7.7 million ($20.45/boe) as compared to $5.9 million ($12.88/boe) for the Comparable Prior Period. In 2014, D&D expenses increased to $26.6 million ($16.16/boe) as compared to $19.6 million ($13.09/boe) for the Comparable Prior Period. The increase in D&D expenses in the three and twelve month periods is due to proved plus probable reserves being added during 2014, at a higher cost than the cumulative amounts for prior periods, mainly related to negative technical revisions of proved plus probable reserves in the Stolberg area.

Asset Impairment Assessment

The Corporation reviews its exploration and evaluation assets and petroleum and natural gas 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 (ie. 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.

The Corporation performed an impairment assessment of its exploration and evaluation assets and petroleum and natural gas assets on a CGU basis and determined there were impairment indicators relating to the decline in forecasted crude oil and natural gas prices and a downward revision of estimated proved plus probable recoverable reserves as at December 31, 2014. As a result, the Corporation tested all of its CGUs for impairment. For all CGUs, fair value less costs to sell were based on the net present value of the before tax cash flow from proved plus probable oil and natural gas reserves estimated by the Corporation's third party reserve evaluators using discount rates of 10% to 20% and the internally estimated fair value of undeveloped lands based on land sales and industry activity in the area. In determining the appropriate discount rate, the Corporation referenced recent market transactions completed on assets similar to those in the CGUs.

It was determined that the net book value of exploration and evaluation assets exceeded the recoverable amount and Manitok recognized a $46.1 million impairment charge in 2014, primarily related to exploratory drilling, geological and geophysical, and land costs. In 2013, the Corporation recorded a $3.3 million impairment charge related to exploration and evaluation assets.

The impairment test on petroleum and natural gas assets determined that the net book value exceeded the recoverable amount and Manitok recognized a $1.6 million impairment charge in 2014 compared to a $1.5 million impairment charge in 2013.

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.

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, 2014		Three months ended December 31, 2013		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Cash:						
Interest and fees on credit facilities	**519**	**1.39**	168	0.37	209%	276%
Non-cash:						
Accretion on decommissioning obligations	**51**	**0.15**	81	0.18	(37%)	(17%)
Total finance expenses	**570**	**1.54**	249	0.55	129%	180%

	Twelve months ended December 31, 2014		Twelve months ended December 31, 2013		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Cash:						
Interest and fees on credit facilities	**1,249**	**0.76**	573	0.38	118%	100%
Non-cash:						
Accretion on decommissioning obligations	**185**	**0.11**	306	0.20	(40%)	(45%)
Total finance expenses	**1,434**	**0.87**	879	0.58	63%	50%

The aggregate cash finance expenses in the three and twelve month Reporting Periods included increased interest charges from higher average outstanding bank indebtedness as compared to the Comparable Prior Periods.

The Corporation's average outstanding bank indebtedness was approximately $47.2 million and $26.5 million in the three and twelve month Reporting Periods as compared to $10.6 million and $4.3 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 3.4% and 3.5% in the three and twelve month Reporting Periods as compared to 3.5% and 3.5% in the Comparable Prior Periods.

The aggregate non-cash finance expenses in the three and twelve month Reporting Periods decreased 37% and 40% from the Comparable Prior Periods due mainly to the Foothills Asset Divestiture.

(Gain) Loss on Divestiture of Assets

In February 2014, Manitok completed the Foothills Asset Divestiture for total cash consideration of approximately $21.9 million after post-closing adjustments. Manitok recorded a loss of approximately $1.3 million ($1.0 million, net of tax), as a result of the disposition. In May 2014, the Corporation divested of minor non-producing properties for total cash consideration of $0.9 million. The Corporation recorded a net gain of $0.4 million ($0.3 million, net of tax) on the divestiture. In December 2014, Manitok completed the Facility Divestiture for approximately $12.3 million after post-closing adjustments. The Corporation did not record a gain or loss on the Facility Divesture as the carrying value approximated the proceeds received.

In June 2013, the Corporation divested of non-core royalty interest properties for total cash consideration of $3.4 million after post-closing adjustments. The Corporation recorded a gain of $0.7 million on the divestiture during the year ended December 31, 2013.

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		
	2014	2013	Variance	**2014**	2013	Variance
Deferred income tax expense (recovery) ($000)	**(825)**	1,239	(167%)	**1,372**	4,049	(66%)
Deferred income tax expense (recovery) ($/boe)	**(2.20)**	2.70	(181%)	**0.84**	2.70	(69%)

For the fourth quarter of 2014, the Corporation recorded a deferred income tax recovery of $0.8 million compared to a deferred income tax expense of $1.2 million in the Comparable Prior Period due mainly to an increase in the net loss before income taxes in 2014 compared to 2013.

In 2014, the deferred income tax expense decreased to $1.4 million from $4.0 million in 2013 due to decreased net income before taxes, partially offset by exploration expenditures utilized in a flow through share renunciation.

The Corporation's estimated income tax pools were $121.7 million as at December 31, 2014. 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)	**2014**	2013
Cumulative Canadian Exploration Expense	**30,018**	18,451
Cumulative Canadian Development Expense	**42,901**	26,660
Cumulative Canadian Oil and Gas Property Expense	**31,241**	46,559
Undepreciated Capital Cost	**15,084**	17,041
Share issue costs	**2,478**	4,301
	121,722	113,012

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

Capital Expenditures

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

	Three months ended December 31		Twelve months ended December 31	
($000)	**2014**	2013	**2014**	2013
Land	**170**	20,698	**1,014**	23,338
Seismic	**259**	478	**1,484**	898
Workovers and recompletions	**254**	250	**1,336**	738
Drilling and completions	**20,362**	19,780	**72,625**	46,542
Well equipment and facilities	**10,000**	2,188	**17,888**	9,082
Capitalized overhead(1)	**756**	793	**2,806**	1,800
Total finding and development costs (F&D)	**31,801**	44,187	**97,153**	82,398
Property acquisition(2)	**7,393**	-	**7,393**	-
Property divestitures(3)	**(12,291)**	(20)	**(35,083)**	(3,413)
Total finding, development and acquisition costs (FD&A)	**26,903**	44,167	**69,463**	78,985
Administrative and other assets	**46**	69	**227**	380
Total capital expenditures(4)	**26,949**	44,236	**69,690**	79,365

(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 Stolberg Acquisition.
(3) Includes the Foothills Asset Divestiture, the divestiture of minor non-producing properties, and the Facility Divestiture.
(4) Excludes non-cash items such as capitalized stock-based compensation and decommissioning obligations.

In the fourth quarter of 2014, the Corporation drilled a total of 7 gross (4.9 net) wells. Of these 7 wells, 3 (0.9 net) were drilled in the Stolberg area and 4 (4.0 net) were drilled in the Entice area. The equipping and facilities capital spent relates to facilities construction and tie-in costs in both the Entice and Stolberg areas.

In 2014, Manitok has drilled a total of 29 gross (20.8 net) wells. Of these 29 wells, 15 (6.8 net) were drilled in the Stolberg area and 14 (14.0 net) were drilled in the Entice area.

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

($000)	Three months ended December 31 2014	2013	Twelve months ended December 31 2014	2013
Exploration and evaluation	**17,567**	30,874	**46,778**	36,641
Petroleum and natural gas properties and equipment, net	**9,382**	13,362	**22,912**	42,724
Total capital expenditures(1)	**26,949**	44,236	**69,690**	79,365

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

The Corporation incurred $17.6 million of exploration and evaluation additions in the fourth quarter of 2014. Approximately $17.4 million related to drilling and completion costs in the Entice area, and $0.2 million related to other costs.

Capital Resources and Liquidity

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

($000)	Three months ended December 31 2014	2013	Twelve months ended December 31 2014	2013
Funds from operations	**10,766**	14,117	**45,980**	41,554
Changes in non-cash operating working capital	**(1,980)**	(2,575)	**3,294**	(4,166)
Decommissioning expenditures	**(160)**	(38)	**(180)**	(222)
Increase in credit facilities	**5,160**	11,672	**37,021**	13,136
Proceeds from long-term financial obligation	**2,500**	-	**2,500**	-
Proceeds from share issuances	**-**	25,000	**-**	25,000
Share issue costs	-	(1,512)	-	(1,512)
Proceeds from the exercise of stock options	**212**	881	**1,865**	916
Repurchase of common shares	**(3,257)**	(5,307)	**(24,014)**	(8,923)
Changes in non-cash investing working capital	**13,708**	1,998	**3,224**	13,437
Total capital resources	**26,949**	44,236	**69,690**	79,220
Exploration and evaluation asset expenditures	**(17,567)**	(30,874)	**(46,778)**	(36,641)
Petroleum and natural gas properties and equipment expenditures	**(14,280)**	(13,382)	**(50,602)**	(46,137)
Property acquisitions	**(7,393)**	-	**(7,393)**	-
Property divestitures	**12,291**	20	**35,083**	3,413
Net increase (decrease) in cash	**-**	-	**-**	(145)

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, 2014**	December 31, 2013
Working capital deficit	**57,289**	37,634
Current portion of the credit facilities	**(53,258)**	(16,237)
Current portion of the deferred premium on financial instruments	**(2,019)**	(1,278)
Current portion of the fair value of financial instruments	**20,783**	(3,842)
Adjusted working capital deficit	**22,795**	16,277

The Corporation's adjusted working capital deficit increased to $22.8 million at December 31, 2014 as compared to $16.3 million at December 31, 2013. The adjusted working capital deficit at December 31, 2014 is largely comprised of costs incurred on the Corporation's drilling program in the Stolberg and Entice areas and will be financed with funds from operations and the Corporation's credit facilities.

At December 31, 2014, the major component of Manitok's current assets, excluding the fair value of financial instruments, was revenue (22%) to be received from its marketers in respect of December 2014 production and accounts receivable from joint venture partners (60%) related to joint capital and operating activities in which Manitok is the operator. Approximately 60% of the receivables from marketers and joint venture partners has been received subsequent to December 31, 2014. Current liabilities excluding the amount drawn on the credit facilities, the fair value of financial instruments and the deferred premium on financial instruments largely consist of trade payables (67%) and accrued liabilities (15%) related to the Corporation's capital expenditure program. 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.

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. The Corporation did not identify any liquidity issues with respect to the operation of its petroleum and natural gas business during the year.

Bank Indebtedness

The amount outstanding on the Corporation's credit facilities was $53.3 million as at December 31, 2014, with an aggregate limit on the revolving operating demand loan facility of $90.0 million as compared to $16.2 million as at December 31, 2013, with an aggregate limit of $85.0 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 were reviewed by the lender subsequent to December 31, 2014, and due to the current commodity price environment and negative technical revisions of proved plus probable reserves in the Stolberg area, the acquisition and development demand loan facility, which has never been utilized was cancelled and the operating demand loan facility was reduced from $90.0 million to $75.0 million, comprised of a $30.0 million revolving operating demand loan facility and a $45 million non-revolving reducing demand loan facility. The Corporation has evaluated the reductions of the credit facilities and management believes the Corporation will be able to fulfill its 2015 commitments with its current resources and anticipated 2015 funds from operations. Additionally, Manitok is evaluating various measures, such as asset divestitures and other third party funding alternatives that will reduce the Corporation's bank indebtedness.

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

As at December 31 ($000)	**Credit facilities reduction**	2014	2013
Maximum borrowing base limit			
Revolving operating demand loan facility(1)	**30,000**	90,000	85,000
Non-revolving reducing demand loan facility(1)	**45,000**	-	-
Acquisition and development demand loan facility(1)(2)	**-**	15,000	20,000
Long-term financial obligation	**2,500**	2,500	-
	77,500	107,500	105,000
Principle amount utilized			
Drawn credit facilities	**(53,258)**	(53,258)	(16,237)
Long- term financial obligation	**(2,500)**	(2,500)	-
	(55,758)	(55,758)	(16,237)
Undrawn credit facilities	**21,742**	51,742	88,763

(1) The Corporation's lender requires quarterly compliance that the working capital ratio (current assets excluding the fair value of financial instruments plus any undrawn portion of the revolving operating demand loan facility divided by current liabilities excluding any current portion of an amount drawn on the credit facilities, the fair value of financial instruments and the deferred premium on financial instruments) is not less than 1:1. As at December 31, 2014 the Corporation's working capital ratio was 1.3:1.

(2) The acquisition and development demand loan facility is 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.

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, 2014:

($000)	2015	2016	2017 - 2019	Thereafter
Accounts payable and accrued liabilities	47,573	-	-	-
Drawn on credit facilities	53,258	-	-	-
Long-term financial obligation(1)	360	360	1,080	5,400
Deferred premium on financial instruments(2)	2,019	-	-	-
Minimum drilling and completion expenditures(3)	21,008	51,000	-	-
Firm transportation agreement(4)	315	393	-	-
Facility fees(5)	1,812	1,812	5,436	5,436
Office leases(6)	2,503	2,514	1,484	-
Total estimated contractual obligations(7)	**128,848**	**56,079**	**8,000**	**10,836**

(1) Pursuant to a facilities financing agreement, Manitok is committed to pay annual facility fees of $360,000 for 20 years, including interest payments.

(2) Manitok is committed to pay a deferred premium on financial instruments, which represents the deferred put option premium payable to the counter-party of the contracts at a weighted average of $0.35/GJ.

(3) Pursuant to a lease issuance and drilling commitment agreement with Encana Corporation, Manitok has agreed to an annual work program including minimum annual drilling and completion expenditures over a three year term. In May 2014, Encana Corporation assigned the agreement to PrairieSky Royalty Ltd. ("**PrairieSky Agreement**").

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

(5) In conjunction with the Facility Divestiture, the Corporation is required to pay monthly facility fees of $150,990 for a maximum period of 96 months starting in January 2015.

(6) Manitok is committed to operating leases relating to new office premises commencing on November 1, 2014 and expiring on November 30, 2017 and its old office premises which expires on February 28, 2017. The Corporation has subleased approximately 70% of its old premises to arm's length parties, effective from November 1, 2014 for the remainder of the lease term and is currently attempting to sublease the remaining available office space. The recovery of rental costs from the subleases are not included in the table.

(7) Contractual commitments that are routine in nature and form part of the normal course of operations for Manitok are not included in the above table. The Corporation's decommissioning obligations are excluded from the table as these obligations arise from a regulatory requirement rather than from a contractual arrangement. Manitok estimates the total undiscounted cash flow to settle its decommissioning obligations at December 31, 2014 to be approximately $13.2 million and will be incurred as follows: 2015 - $0.5 million, 2016 - $0.3 million, 2017 to 2019 - $1.1 million and $11.3 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 obligation may differ materially.

OFF-BALANCE SHEET TRANSACTIONS

Manitok was not involved in any off-balance sheet transactions that would result in a material change to its financial position, performance or funds from operations during the Reporting Periods and Comparable Prior Periods.

OUTSTANDING SHARE DATA

At December 31, 2014, the common shares of Manitok ("**Manitok Shares**") are the only class of shares issued and outstanding. Manitok Shares began trading on the TSX-V on July 29, 2010 under the symbol "**MEI**". The following table summarizes the Manitok Shares issued and outstanding:

	Manitok Shares
Outstanding, December 31, 2012	**70,339,014**
Issue of Manitok Shares on November 8, 2013(1)	7,041,900
Issue of Manitok Shares upon exercise of options	742,826
Repurchase of Manitok Shares(2)	(3,631,400)
Outstanding, December 31, 2013	**74,492,340**
Issue of Manitok Shares upon exercise of options	1,279,167
Repurchase of Manitok Shares(2)	(10,491,900)
Outstanding, December 31, 2014	**65,279,607**

(1) On November 8, 2013, Manitok completed a bought deal equity issuance pursuant to a short form prospectus offering whereby Manitok issued an aggregate of 1,403,000 Manitok Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian development expense ("**Manitok CDE Flow-through Shares**") at a price of $3.35 per Manitok CDE Flow-through Share and 5,638,900 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 $3.60 per Manitok CEE Flow-through Share for net proceeds of approximately $23.5 million. Proceeds of the equity issuance were used to temporarily reduce the outstanding bank indebtedness from the Corporation's 2013 capital expenditure program, which has been redrawn and applied to fund a portion of the 2014 capital expenditure program.

(2) On June 15, 2012, the TSX-V authorized the Corporation's notice to make a normal course issuer bid (**"2012 NCIB"**) to purchase for cancellation up to 4.4 million Manitok Shares on the open market during the period from June 18, 2012 to June 17, 2013. On January 28, 2013 the Corporation received approval from the TSX-V to increase the number of Manitok Shares that may be purchased under the 2012 NCIB to 5.8 million. For the year ended December 31, 2013, the Corporation purchased a total of 282,700 Manitok Shares for cancellation at a weighted average price of $2.54 per Manitok Share pursuant to the 2012 NCIB program. On June 18, 2013, the TSX-V authorized the Corporation's notice to make a normal course issuer bid ("**2013 NCIB**") to purchase for cancellation up to 6.5 million Manitok Shares on the open market during the period from June 18, 2013 to June 17, 2014. For the year ended December 31, 2013, the Corporation purchased a total of 3,348,700 Manitok Shares for cancellation at a weighted average price of $2.44 per Manitok Share pursuant to the 2013 NCIB program. For the year ended December 31, 2014, the Corporation purchased a total of 2,865,900 Manitok Shares for cancellation at a weighted average price of $2.39 per Manitok Share pursuant to the 2013 NCIB program. On March 11, 2014, the TSX-V authorized the Corporation's notice to make a normal course issuer bid ("**March 2014 NCIB**") to purchase for cancellation up to 6.8 million Manitok Shares on the open market during the period from March 17, 2014 to March 16, 2015. For the year ended December 31, 2014, the Corporation purchased a total of 6,773,100 Manitok Shares for cancellation at a weighted average price of $2.33 per Manitok share pursuant to the March 2014 NCIB program. On October 30, 2014, the TSX-V authorized the Corporation's notice to make a normal course issuer bid ("**November 2014 NCIB**") to purchase for cancellation up to 6.3 million Manitok Shares on the open market during the period from November 3, 2014 to November 2, 2015. For the year ended December 31, 2014, the Corporation purchased a total of 852,900 Manitok Shares for cancellation at a weighted average price of $1.45 per Manitok Share pursuant to the November 2014 NCIB.

At April 29, 2015, there were 65,279,607 Manitok Shares outstanding and 6,435,773 stock options to purchase an equivalent number of Manitok Shares.

SUMMARY OF QUARTERLY INFORMATION

	2014				2013			
Quarters Ended	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
OPERATING								
Average daily production								
Light oil (bbls/d)	**2,257**	2,066	2,695	3,028	2,755	1,781	2,016	1,701
Natural gas (mcf/d)	**10,713**	10,931	11,417	13,352	12,868	11,735	11,692	10,810
NGLs (bbls/d)	**30**	74	46	98	89	82	81	83
Total (boe/d)	**4,072**	3,962	4,644	5,351	4,989	3,819	4,045	3,586
Average realized sales price (CAD$)								
Light oil ($/bbl)	**71.96**	95.17	103.18	96.92	82.30	101.86	89.77	89.09
Natural gas ($/mcf)	**3.83**	4.25	4.81	6.51	4.03	2.73	3.95	3.70
NGLs ($/bbl)	**67.29**	98.93	110.86	97.92	76.48	77.70	73.92	84.25
Total ($/boe)	**50.45**	63.20	72.80	72.88	57.21	57.55	57.64	55.39
OPERATING NETBACK ($ per boe)(1)								
Petroleum and natural gas sales	**50.45**	63.20	72.80	72.88	57.21	57.55	57.64	55.39
Realized gain (loss) on financial instruments	**6.67**	(4.69)	(6.19)	(4.10)	(0.48)	(4.59)	(0.96)	0.86
Royalty income	**-**	-	0.01	0.02	0.01	0.03	0.61	0.44
Royalty expenses	**(11.61)**	(19.64)	(23.98)	(22.23)	(10.18)	(16.55)	(13.21)	(16.12)
Operating expenses, net	**(7.65)**	(6.73)	(7.58)	(7.35)	(8.83)	(5.90)	(6.42)	(9.14)
Transportation and marketing expenses	**(3.17)**	(3.47)	(3.66)	(3.21)	(3.10)	(2.56)	(2.93)	(2.79)
Operating netback(1)	**34.69**	28.67	31.40	36.01	34.63	27.98	34.73	28.64
FINANCIAL								
Petroleum and natural gas revenue ($000)	**18,902**	23,037	30,771	35,112	26,260	20,228	21,441	18,021
Royalty expenses ($000)	**(4,349)**	(7,157)	(10,132)	(10,705)	(4,670)	(5,814)	(4,863)	(5,202)
Realized gain (loss) on financial instruments ($000)	**2,499**	(1,709)	(2,618)	(1,976)	(220)	(1,614)	(355)	278
Unrealized gain (loss) on financial instruments ($000)	**27,577**	8,394	(2,036)	(6,175)	(3,591)	(2,063)	148	(3,035)
Interest and other revenue ($000)	**6**	22	-	3	13	34	24	36
Total revenue, net ($000)	**44,635**	22,587	15,985	16,259	17,792	10,771	16,395	10,098
Funds from operations ($000)(1)	**10,766**	8,556	11,197	15,461	14,117	8,252	11,324	7,861
Per share - basic ($)(1)	**0.16**	0.13	0.16	0.21	0.19	0.12	0.16	0.11
Per share - diluted ($)(1)	**0.16**	0.12	0.16	0.21	0.19	0.12	0.16	0.11
Net income (loss) ($000)	**(2,774)**	7,900	(9,044)	331	(1,417)	336	4,831	(135)
Per share - basic ($)	**(0.04)**	0.12	(0.13)	-	(0.02)	-	0.07	-
Per share - diluted ($)(2)	**(0.04)**	0.11	(0.13)	-	(0.02)	-	0.07	-
Capital expenditures, net ($000)	**26,949**	22,832	17,669	2,240	44,236	17,499	6,335	11,295
Book value of total assets ($000)	**211,284**	197,362	178,300	185,390	192,580	150,129	139,671	135,648
Adjusted working capital deficit ($000)(1)	**22,795**	11,067	17,676	19,947	16,277	16,855	9,226	6,354
Drawn on credit facilities ($000)	**53,258**	48,098	22,311	6,685	16,237	4,565	-	7,130
Long-term financial obligation ($000)	**2,500**	-	-	-	-	-	-	-
Total net debt ($000)(1)	**78,553**	59,165	39,987	26,632	32,514	21,420	9,226	13,484
Shareholders' equity ($000)	**84,333**	89,714	86,550	102,256	109,096	94,076	95,877	91,024
Common shares outstanding								
End of period - basic	65,279,607	66,996,440	69,020,407	71,615,406	74,492,340	68,999,040	70,086,140	70,357,180
End of period - diluted	70,588,213	71,566,714	74,114,181	77,689,147	80,099,780	75,704,480	76,661,580	76,759,280
Weighted average for the period - basic	65,924,473	68,143,633	70,390,367	73,097,543	72,638,096	69,401,001	70,219,904	70,348,151
Weighted average for the period - diluted	66,255,000	69,108,544	71,402,527	74,334,096	74,371,392	71,431,314	72,139,108	72,758,478

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

(2) The basic and diluted weighted average shares outstanding are the same for periods in which the Corporation records a net loss.

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 second quarter of 2013, Manitok recorded net income of $4.8 million, which was primarily the result of increased revenue and a $0.7 million gain with respect to the divestiture of royalty interest properties.
- Total net debt increased by $12.2 million in the third quarter of 2013 to $21.4 million as at September 30, 2013 due primarily to the $11.2 million increase in capital expenditures compared to the second quarter of 2013.
- The Corporation repurchased 1,087,100 Manitok Shares in the third quarter of 2013 at an average price of $2.65 per share, pursuant to its 2013 NCIB program.
- In the fourth quarter of 2013, Manitok increased average production to 4,989 boe/d compared to 3,819 boe/d in the third quarter of 2013 from bringing on new wells that were drilled in the second half of 2013. The higher production levels increased total revenue and funds from operations.
- In the fourth quarter of 2013, Manitok recorded a net loss of $1.4 million, which was primarily the result of an impairment expense of $4.9 million.
- The Corporation completed an equity financing in the fourth quarter of 2013, issuing 1.4 million Manitok CDE Flow-through Shares and 5.6 million Manitok CEE Flow-through Shares for net proceeds of approximately $23.5 million, which contributed to the significant increase in total assets and shareholders' equity.
- In the fourth quarter of 2013, Manitok closed a lease issuance and drilling commitment agreement for approximately $19.7 million and incurred additional seismic processing costs of about $0.4 million in the Entice area for total capital expenditures of $20.1 million.
- The Corporation repurchased 2,261,600 Manitok Shares in the fourth quarter of 2013 at an average price of $2.34 per share, pursuant to its 2013 NCIB program.
- Total net debt increased by $11.1 million in the fourth quarter of 2013 to $32.5 million as at December 31, 2013 due primarily to the $44.2 million of capital expenditures, which was partially offset by the equity financing and funds from operations in the quarter.
- 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.
- In the first quarter of 2014, petroleum and natural gas revenue increased 34% from the fourth quarter of 2013 as a result of increased production volumes and higher commodity prices.
- Royalty expenses increased 129% in the first quarter of 2014 compared to the fourth quarter of 2013 as a result of higher commodity prices and three light oil wells drilled in 2013 that each exceeded the royalty incentive production volume maximum of 50,000 bbls of oil in approximately three to four months of production and were subject to a maximum royalty rate of 40% for the majority of the first quarter of 2014 as compared to a 5% new well royalty rate before the production volume threshold of 50,000 bbls of oil was exceeded.
- The Corporation repurchased 3,350,300 Manitok Shares in the first quarter of 2014 at an average price of $2.39 per share, pursuant to its 2013 NCIB and March 2014 NCIB programs.
- Total net debt decreased by $5.9 million to $26.6 million as at March 31, 2014 from December 31, 2013 due primarily to proceeds from the Foothills Asset Divestiture and funds from operations, which was partially offset by the share repurchases and capital expenditures in the first quarter of 2014.
- 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 March 2014 NCIB program.

- 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 March 2014 NCIB program.
- P&NG revenue decreased by $4.1 million in the fourth quarter of 2014 from the third quarter of 2014 as a result of the decreased realized commodity prices.
- Funds from operations increased by $2.2 million in the fourth quarter of 2014 from the third quarter of 2014 mainly attributable to a realized gain on financial instruments and a decrease in royalty expenses, partially offset by lower P&NG revenue.
- In the fourth quarter of 2014, the unrealized gain on financial instruments increased by $19.2 million from the third quarter of 2014 due to the significant decrease in commodity prices.
- Net income (loss) for the fourth quarter of 2014 was a loss of $2.8 million, compared to net income of $7.9 million in the third quarter of 2014. The decrease was primarily the result of an impairment charge of $34.0 million in the fourth quarter of 2014, partially offset by the increase in the unrealized gain on financial instruments.
- Total net debt increased by $19.4 million to $78.6 million as at December 31, 2014 from September 30, 2014 due primarily to capital expenditures and the Stolberg Acquisition in the fourth quarter of 2014, partially offset by the 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 March 2014 NCIB and November 2014 NCIB programs.

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.

CRITICAL ACCOUNTING ESTIMATES

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

Critical Judgments in Applying Accounting Policies

The following are critical judgments that management has made in the process of applying the Corporation's IFRS accounting policies and that have the most significant effect on the amounts recognized in the financial statements:

(i) Identification of CGUs

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

(ii) Identification of impairment indicators

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

Key Sources of Estimation Uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the Reporting Period that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities within the next financial year.

(i) Reserves

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

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

(ii) Share-based payments

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

(iii) Decommissioning obligations

The Corporation estimates future remediation costs of production facilities, well sites and gathering systems at different stages of development and construction of assets. In most instances, removal of assets occurs many years into the future. This requires an estimate regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future 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 cash flows taking into account key assumptions including future petroleum and natural gas prices, expected forecasted production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of the Corporation's assets, and impairment charges and reversals will affect income or loss.

(v) Taxes

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

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

Deferred tax assets are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. Estimates of future taxable income are based on forecasted cash flows from operations. To the extent that any interpretation of tax law is challenged by the tax authorities or future cash flows and taxable income differ significantly from estimates, the ability of Manitok to realize the deferred tax assets recorded at the balance sheet date could be impacted.

CHANGES IN ACCOUNTING POLICIES

Accounting Policies Adopted

On January 1, 2014, the Corporation adopted the following new standards:

(i) Levies

IFRS Interpretations Committee ("**IFRIC**") 21 *Levies* is effective January 1, 2014, and addresses payments made to government bodies. There was no impact to the Corporation's financial statements as a result of adopting this new standard.

(ii) Financial Instruments: Presentation

IAS 32 *Financial Instruments: Presentation* is effective January 1, 2014, and has been amended to clarify certain requirements for offsetting financial assets and liabilities. There was no impact to the Corporation's financial statements as a result of adopting this new standard.

Future Changes in Accounting Policies

On May 28, 2014, the IASB issued *IFRS 15 Revenue From Contracts With Customers* replacing IAS 11 *Construction Contracts,* IAS 18 *Revenue* and several revenue-related interpretations. IFRS 15 contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. IFRS 15 is effective for annual periods beginning on or after January 1, 2017, 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 Manitok's financial statements.

RISK FACTORS & RISK MANAGEMENT

Manitok monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations or taxation. In addition, Manitok maintains a level of liability, 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.