OPERATIONAL AND FINANCIAL SUMMARY

	Three months ended December 31		Twelve months ended December 31	
	2016	2015	**2016**	2015
OPERATING				
Average daily production				
Light oil (bbls/d)	**1,864**	2,002	**1,709**	2,077
Natural gas (mcf/d)	**22,281**	13,540	**15,417**	13,607
NGLs (bbls/d)	**545**	200	**323**	135
Total (boe/d)	**6,123**	4,459	**4,602**	4,480
Average realized sales price				
Light oil ($/bbl)	**56.43**	47.83	**48.11**	52.70
Natural gas ($/mcf)	**3.23**	2.73	**2.49**	2.92
NGLs ($/bbl)	**30.63**	27.88	**26.54**	35.64
Total ($/boe)	**31.67**	31.01	**28.07**	34.38
NETBACK AND COST ($ per boe)				
Petroleum and natural gas sales	**31.67**	31.01	**28.07**	34.38
Processing revenue	**0.31**	1.16	**0.49**	0.48
Realized gain (loss) on financial instruments	**1.64**	18.20	**12.25**	14.58
Royalty expenses	**(7.82)**	(8.30)	**(7.73)**	(8.92)
Operating expenses, net of recoveries	**(11.59)**	(12.67)	**(13.30)**	(12.69)
Transportation and marketing expenses	**(0.78)**	(1.72)	**(1.33)**	(2.16)
Operating netback(1)	**13.43**	27.68	**18.45**	25.67
General and administrative expenses, net of recoveries	**(3.39)**	(3.29)	**(3.90)**	(4.06)
Interest and financing expenses	**(3.10)**	(3.71)	**(3.62)**	(3.02)
Funds from operations netback(1)	**6.94**	20.68	**10.93**	18.59
FINANCIAL				
Petroleum and natural gas revenue ($000)	**17,848**	12,720	**47,280**	56,210
Funds from operations ($000)(1)	**4,038**	8,488	**18,540**	30,390
Per share – basic ($)(1)	**0.02**	0.10	**0.10**	0.40
Per share – diluted ($)(1)	**0.02**	0.10	**0.10**	0.40
Net loss ($000)	**(16,421)**	(5,258)	**(24,694)**	(27,195)
Per share – basic ($)	**(0.07)**	(0.06)	**(0.13)**	(0.36)
Per share – diluted ($)(2)	**(0.07)**	(0.06)	**(0.13)**	(0.36)
Common shares outstanding				
End of period – basic	**262,819,832**	143,936,115	**262,819,832**	143,936,115
End of period – diluted	**325,592,540**	150,334,260	**325,592,540**	150,334,260
Weighted average for the period – basic and diluted	**239,616,115**	85,729,418	**191,462,156**	76,292,523
Capital expenditures, net of divestitures ($000)	**27,569**	2,847	**39,793**	40,597
Adjusted working capital (surplus) deficit ($000)(1)	**9,074**	(8,951)	**9,074**	(8,951)
Drawn on credit facilities ($000)	**33,083**	62,398	**33,083**	62,398
Net bank debt ($000) (1)	**42,157**	53,447	**42,157**	53,447
Senior Secured Notes ($000)	**18,138**	-	**18,138**	-
Long-term financial obligations ($000)	**14,856**	14,948	**14,856**	14,948
Net debt ($000) (1)	**75,151**	68,395	**75,151**	68,395

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

Manitok Energy Inc. ("**Manitok**" or the "**Corporation**") is a junior oil and gas exploration, development and production company based in Calgary, Alberta. The Corporation conducts its operations in the Western Canadian Sedimentary Basin and currently all of its activities are in Alberta. 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**") of financial condition and results of operations for Manitok is dated May 1, 2017 and should be read in conjunction with the Corporation's audited consolidated financial statements ("**Consolidated Financial Statements**") and related notes as at and for the years ended December 31, 2016 and 2015, as well as the Corporation's Annual Information Form dated May 1, 2017 ("**AIF**"), that 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. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board. This MD&A in respect of the three and twelve months ended December 31, 2016 (the "**Reporting Periods**") as compared to the three and twelve months ended December 31, 2015 (the "**Comparable Prior Periods**") has been prepared by management and approved by the Corporation's Audit Committee and Board of Directors. All financial information is expressed in Canadian dollars, unless otherwise stated.

ADVISORIES

Non-GAAP Measures

*This MD&A and fourth quarter report contains references to measures used in the oil and natural gas industry such as "funds from operations", "funds from operations netback", "funds from operations per share", "operating netback", "adjusted working capital (surplus) deficit", "net bank debt" and "net debt". These measures do not have standardized meanings prescribed by generally accepted accounting principles ("**GAAP**"), including International Financial Reporting Standards ("**IFRS**") and therefore should not be considered in isolation. These reported amounts and their underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of other companies where similar terminology is used. Where these measures are used, they should be given careful consideration by the reader. These measures have been described and presented in the MD&A and Annual Report in order to provide shareholders and potential investors with additional information regarding the Corporation's liquidity and its ability to generate funds to finance its operations.*

Funds from operations should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net income (loss) as determined in accordance with IFRS, as an indicator of Manitok's performance or liquidity. Funds from operations is used by Manitok to evaluate operating results and Manitok's ability to generate cash flow to fund capital expenditures and repay indebtedness. Funds from operations denotes cash flow from operating activities as it appears on the Corporation's Statement of Cash Flows before decommissioning expenditures, acquisition-related expenses and changes in non-cash operating working capital. Funds from operations is also derived from net income (loss) plus acquisition-related expenses and non-cash items including deferred income tax expense (recovery), depletion and depreciation expense, impairment expense, stock-based compensation expense, accretion expense, unrealized gains or losses on financial instruments and gains or losses on asset divestitures. Funds from operations netback is calculated on a per boe basis and funds from operations per share is calculated as funds from operations divided by the weighted average number of basic and diluted common shares outstanding. Operating netback denotes petroleum and natural gas revenue and realized gains or losses on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses calculated on a per boe basis. Adjusted working capital (surplus) deficit includes current assets less current liabilities excluding the current portion of the amount drawn on the credit facilities, the current portion of the fair value of financial instruments, the deferred premium on financial instruments and provisions. Manitok uses net bank debt and net debt as a measure to assess its financial position. Net bank debt includes outstanding bank indebtedness plus adjusted working capital (surplus) deficit and net debt includes net bank debt plus the senior secured notes and the long-term financial obligations.

Oil and Gas Advisories

Reserves

All reserve references in this MD&A and fourth quarter report are "company share reserves". Company share reserves are the Corporation's total working interest reserves before the deduction of any royalties and including any royalty interests of the Corporation.

It should not be assumed that the present value of estimated future net revenue represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Manitok's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

All future net revenues are estimated using forecast prices, arising from the anticipated development and production of our reserves, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs and are stated prior to provision for interest and general and administrative expenses. Future net revenues have been presented on a before tax basis. Estimated values of future net revenue disclosed herein do not represent fair market value

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 fourth quarter report contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to future events or future performance and is based upon the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to reserves is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves exist in the quantities estimated and that it will be commercially viable to produce the reserves in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information. In particular, this MD&A and fourth quarter report contains forward-looking information relating to the Corporation's planned strategy in terms of planned capital spending and sources of funding; possibility of entering into physical sales contacts in the future; anticipated impact of the Modernized Royalty Framework of the Government of Alberta; anticipated likelihood of certain receivables being received by Manitok from certain of Manitok's marketers and joint venture partners; anticipated meeting of capital spending commitments by Manitok; likelihood of Manitok's ability to comply with its working capital covenant in the future; 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 2017 capital program, readers are cautioned that the Corporation may make adjustments depending on business conditions and commodity prices throughout the fiscal year. Actual spending may vary due to a variety of factors, including changes to certain key expectations and assumptions set out below.

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

Forward-looking information necessarily involves both known and unknown risks associated with oil and natural gas exploration, production, transportation and marketing, such as uncertainty of geological and technical data, imprecision of reserves estimates, operational risks, uncertainty in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production, costs and expenses, health, safety and environmental risks, uncertainty as to the availability of labour and services, commodity price and exchange rate fluctuations, unexpected adverse weather conditions, loss of market demand, general economic conditions affecting the ability to access sufficient capital, changes in law and government regulation of the oil and gas industry and competition from others for scarce resources.

The foregoing list of risk factors is not exhaustive. Additional information on these other risk factors that could affect operations or financial results are included in the Corporation's most recent Annual Information Form and in other reports filed with Canadian securities regulatory authorities. Forward-looking information is based on estimates and opinions of management at the time the information is presented. The Corporation is not under any duty to update and does not intend or assume any obligation to update the forward-looking information after the date of this MD&A and fourth quarter report to conform such information to actual results or to changes in the Corporation's plans or expectations, except as otherwise required by applicable securities laws. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are expressly qualified in their entirety by these cautionary statements.

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
bbls/d	barrels per day
Mbbls	thousand barrels
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
NGLs	natural gas liquids

Natural Gas

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

Other

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

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

- In the first quarter of 2016, Manitok monetized crude oil derivative financial instruments with its counter-party for a cash receipt of $12.3 million and the funds were used to reduce the Non-Conforming Credit Facility from $30.0 million to $20.0 million and as such, reduce the Credit Facilities from $60.0 million to $50.0 million.

- In the first quarter of 2016, Manitok closed the final two tranches of an equity financing for the issuance of 15,973,631 common shares of Manitok ("**Manitok Shares**") at a price of $0.13 per Manitok Share and 1,170,000 Manitok Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian exploration expense ("**Manitok CEE Flow-through Shares**") at a price of $0.15 per Manitok CEE Flow-through Share ("**Q1 2016 Equity Financing**") for net proceeds of $2.0 million. The net cash proceeds from the final two tranches of the equity financing of the Manitok Shares were used to reduce the Corporation's bank indebtedness and the net cash proceeds from the final tranche of the equity financing of the Manitok CEE Flow-through Shares will be used to incur eligible Canadian exploration expenses.

- In February 2016, Manitok closed a non-cash asset exchange agreement, in which Manitok divested of a 19.9% non-operated working interest in a gas plant in a non-core area, where it had no current throughput volumes or value in its reserve report, in exchange for a 17.5% average working interest in petroleum and natural gas assets, along with an average 45% working interest in associated undeveloped land in the Stolberg area of Alberta ("**Stolberg Asset Exchange**"). The estimated fair value was determined to be $7.0 million and was based on the fair value of the acquired assets. The net book value of the divested non-core asset was $0.1 million and as a result Manitok recorded a gain of $6.9 million for the twelve month Reporting Period.

- In March 2016, Manitok closed an asset acquisition of a 14 Mmcf/d natural gas processing plant in the Carseland area of Alberta along with approximately 450 mcf/d (75 boe/d) of natural gas production, the related gathering systems, undeveloped land and an 11 kilometre sales gas line tied into the ATCO south sales system ("**Carseland Acquisition**"), with an effective date of January 1, 2016. Total cash consideration for the Carseland Acquisition was $4.5 million after estimated post-closing adjustments and was financed using the Conforming Credit Facility.

- In May 2016, Manitok closed an equity financing for the issuance of 8,435,945 Manitok Shares at a price of $0.18 per Manitok Share and 7,994,980 Manitok CEE Flow-through Shares at a price of $0.21 per Manitok CEE Flow-through Share ("**May 2016 Equity Financing**") for net proceeds of $2.8 million. The net cash proceeds from the May 2016 Equity Financing of the Manitok Shares received in July 2016 were used to reduce the Corporation's bank indebtedness subsequent to the second quarter and the net cash proceeds from the May 2016 Equity Financing of the Manitok CEE Flow-through Shares will be used to incur eligible Canadian exploration expenses.

- In August 2016, Manitok completed an arrangement agreement with Raimount Energy Inc. ("**Raimount**") and 1977746 Alberta Inc. ("**Acquireco**"), being a wholly owned subsidiary of the Corporation ("**Arrangement Agreement**"). Under the terms of the Arrangement Agreement, Manitok acquired, indirectly through Acquireco, all of the issued and outstanding common shares of Raimount by way of a plan of arrangement under the *Business Corporations Act* (Alberta) ("**Raimount Arrangement**"). Each Raimount shareholder received six (6) Manitok Shares and one and one-half (1.5) Manitok Share purchase warrants ("**Raimount Arrangement Warrants**") in exchange for each Raimount common share held. Raimount's assets include approximately $5.0 million of cash, no indebtedness, 65 boe/d (95% gas) of production and about 20,000 acres of land in southern Alberta. Raimount had no debt and 6,867,866 common shares outstanding. As a result of the Raimount Arrangement, Manitok issued 41,207,196 Manitok Shares and 10,301,837 Raimount Arrangement Warrants, which have an exercise price of $0.30 per Manitok Share for a term of two years.

- In July 2016, the Corporation closed a non-brokered private placement offering of 8,333,334 subscription receipts ("**Subscription Receipts**") at a price of $0.18 per Subscription Receipt for net proceeds of $1.3 million ("**Subscription Receipts Offering**"). In August 2016, the Subscription Receipts were exchanged for Manitok Shares on a 1 to 1 basis.

- On October 27, 2016, the Corporation closed a marketed underwritten offering of 212,071 units of Manitok ("**Units**") for total aggregate gross proceeds of $21.2 million (the "**CEL Offering**"). Each Unit consisted of a

$100 principal amount senior secured note due 2021 with an interest rate of 10.5% per annum ("**Collateralized Exchange Listed Notes**" or "**CEL Notes**" or "**Senior Secured Notes**") and 164 common share purchase warrants ("**CEL Warrants**"). The Units immediately separated into CEL Notes and CEL Warrants upon issuance. The CEL Notes will mature on November 15, 2021. Interest on the CEL Notes will be payable quarterly in arrears. Each CEL Warrant will entitle the holder thereof to purchase one common share of Manitok at an exercise price equal to $0.18 per common share, subject to adjustment, at any time until November 15, 2021. The CEL Notes and the CEL Warrants are governed by a note indenture and a warrant indenture, respectively, between the Corporation and Computershare Trust Company of Canada. The Corporation used a portion of the net proceeds of the Offering for certain oil and gas assets as disclosed below and the remaining net proceeds of the Offering were used to reduce the amount drawn on its credit facility.

- On October 28, 2016, the Corporation closed an asset purchase agreement for the acquisition of approximately 1,750 boe/d of production (34% oil and liquids) which includes approximately 90,000 acres (55,800 net) of undeveloped land, and facilities in the Willesden Green area, which include an emulsion handling facility with capacity of approximately 2,500 bbls/d and a natural gas compressor station with capacity of 11 Mmcf/d ("**WG Acquisition**"), with an effective date of October 1, 2016. Total consideration for the acquisition was $13.5 million prior to transaction costs and customary closing adjustments, which included $9.0 million of cash and $4.5 million of CEL Notes.
- On November 29, 2016, Manitok closed an equity financing completed by way of a short form base shelf prospectus as supplemented by a prospectus supplement dated November 22, 2016 for the issuance of 7,562,923 Manitok Shares at a price of $0.13 per Manitok Share, 4,599,829 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 $0.14 per Manitok CDE Flow-through Share, and 23,605,879 Manitok CEE Flow-through Shares at a price of $0.145 per Manitok CEE Flow-through Share ("**November 2016 Equity Offering**") for net proceeds of $4.5 million.

MAJOR TRANSACTIONS SUBSEQUENT TO THE REPORTING PERIOD

- On May 1, 2017, the Corporation announced that Manitok and Craft Oil Ltd. ("**Craft**") have entered into an arrangement agreement dated as of April 28, 2017 (the "**Arrangement Agreement**"). Under the terms of the Arrangement Agreement, Manitok will acquire all of the issued and outstanding common shares of Craft by way of a plan of arrangement under the *Business Corporations Act* (Alberta) for $6.6 million of Manitok Shares.

SELECTED ANNUAL INFORMATION

For the years ended December 31 *($000, except for production and share information)*	**2016**	**2015**	2014
Average daily production (boe/d)	**4,602**	4,480	4,502
Petroleum and natural gas revenue	**47,280**	56,210	107,822
Net revenue from petroleum and natural gas sales	**34,993**	42,247	75,911
Funds from operations[1]	**18,540**	30,390	45,980
Per share – basic[1]	**0.10**	0.40	0.66
Per share – diluted[1]	**0.10**	0.40	0.65
Net loss	**(24,694)**	(27,195)	(3,587)
Per share – basic	**(0.13)**	(0.36)	(0.05)
Per share – diluted[2]	**(0.13)**	(0.36)	(0.05)
Capital expenditures, net of divestitures	**39,793**	40,597	69,690
Total assets	**252,865**	204,705	211,284
Adjusted working capital (surplus) deficit[1]	**9,074**	(8,951)	22,795
Drawn on credit facilities	**33,083**	62,398	53,258
Senior secured notes	**18,138**	-	-
Long-term financial obligations	**14,856**	14,948	2,500
Net debt[1]	**75,151**	68,395	78,553
Shareholders' equity	**74,237**	80,540	84,333
Common shares outstanding			
End of period – basic	**262,819,832**	143,936,115	65,279,607
End of period – diluted	**325,592,540**	150,334,260	70,588,213
Weighted average shares for period – basic and diluted	**191,462,156**	76,292,523	70,321,234

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

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

Production remained relatively consistent during 2016 as natural production declines, TransCanada Pipeline restrictions in the foothills and third party gas plant restrictions in Carseland were offset by the WG Acquisition and a drilling program initiated in the fourth quarter of 2016. The Corporation has incurred reductions in 2016 revenue and funds from operations and an increase in the net loss on an absolute basis due primarily to the significant decline in commodity prices and lower average light oil production volumes. The adjusted working capital surplus at December 31, 2015 was largely comprised of the net proceeds of $7.5 million from an equity financing in December 2015, which were received in January 2016. The Corporation initiated a 6 well drill program in the fourth quarter of 2016, which increased the working capital deficit as at December 31, 2016. The amount drawn of the credit facilities was reduced significantly due to the monetization of crude oil derivative financial instruments with its counter-party for a cash receipt of $12.3 million in the first quarter of 2016, proceeds from various equity issuances throughout 2016, the Raimount Arrangement and the Senior Secured Note offering (see "Major Transactions Affecting Financial Results").

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

The following schedule sets out the reconciliation of cash flow from operating activities, as determined in accordance with GAAP 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)	**2016**	2015	**2016**	2015
Cash flow from operating activities	**3,499**	4,489	**19,763**	27,503
Adjustments:				
Decommissioning expenditures	**372**	674	**545**	1,064
Acquisition-related expenses	**571**	(82)	**952**	1,892
Changes in non-cash operating working capital	**(404)**	3,407	**(2,720)**	(69)
Funds from operations	**4,038**	8,488	**18,540**	30,390
per share – basic	**0.02**	0.10	**0.10**	0.40
per share – diluted	**0.02**	0.10	**0.10**	0.40

Funds from operations decreased by 52% to $4.0 million ($0.02 per diluted share) for the fourth quarter of 2016 as compared to $8.5 million ($0.10 per diluted share) in the Comparable Prior Period. The reduction is due primarily to a decrease in realized gains on financial instruments and increase in royalty and operating expenses, partially offset by increased petroleum and natural gas revenue from higher natural gas production volumes.

For the twelve month Reporting Period, funds from operations decreased by 39% to $18.5 million ($0.10 per diluted share) as compared to $30.4 million ($0.40 per diluted share) in the Comparable Prior Period. The reduction is due to a decrease in petroleum and natural gas revenue from lower average light oil production volumes, the decline in commodity prices, the increase in interest expense and the decrease in realized gains on financial instruments, partially offset by the decrease to royalty and transportation and marketing expenses.

Net Loss

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

	Three months ended December 31		**Twelve months ended December 31**	
($000, except per share information)	**2016**	2015	**2016**	2015
Net loss	**(16,421)**	(5,258)	**(24,694)**	(27,195)
per share – basic	**(0.07)**	(0.06)	**(0.13)**	(0.36)
per share – diluted	**(0.07)**	(0.06)	**(0.13)**	(0.36)

Net loss increased to $16.4 million ($0.07 per diluted share) for the fourth quarter of 2016 as compared to $5.3 million ($0.06 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, an increase in the unrealized loss on financial instruments, impairment and depletion and depreciation, partially offset by a gain on the acquisition of assets and an increased deferred income tax recovery.

Manitok had a net loss of $24.7 million ($0.13 per diluted share) in 2016 as compared to a net loss of $27.2 million ($0.36 per diluted share) in 2015. The increase in the unrealized loss on financial instruments was offset by decreases in impairment, depletion and depreciation and gains on the disposition and acquisition of assets.

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, 2016				Three months ended December 31, 2015			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Light oil (bbls)	**9,672**	**1,864**	**30**	**56.41**	8,809	2,002	45	47.83
Natural gas (mcf)(1)	**6,624**	**22,281**	**61**	**3.23**	3,397	13,540	51	2.73
NGLs (bbls)	**1,541**	**545**	**9**	**30.72**	514	200	4	27.88
Total P&NG sales (boe)	**17,837**	**6,123**	**100**	**31.67**	12,720	4,459	100	31.01
Royalty revenue	**11**			**.02**	-			-
Total P&NG revenue (boe)	**17,848**	**6,123**	**100**	**31.69**	12,720	4,459	100	31.01
Processing revenue	**175**			**0.31**	480			0.65
Total	**18,023**	**6,123**	**100**	**32.00**	13,200	4,459	100	31.66

	Twelve months ended December 31, 2016				Twelve months ended December 31, 2015			
	Total Revenue ($000)	**Average Daily Production**	**%**	**Average ($/unit)**	Total Revenue ($000)	Average Daily Production	%	Average ($/unit)
Light oil (bbls)	**30,096**	**1,709**	**37**	**48.11**	39,953	2,077	46	52.70
Natural gas (mcf)(1)	**14,033**	**15,417**	**56**	**2.49**	14,503	13,607	51	2.92
NGLs (bbls)	**3,140**	**323**	**7**	**26.58**	1,749	135	3	35.64
Total P&NG sales (boe)	**47,269**	**4,602**	**100**	**28.07**	56,205	4,480	100	34.38
Royalty revenue	**11**			**.01**	5			-
Total P&NG revenue (boe)	**47,280**	**4,602**	**100**	**28.08**	56,210	4,480	100	34.38
Processing revenue	**823**			**0.44**	773			0.38
Total	**48,103**	**4,602**	**100**	**28.52**	56,983	4,480	100	34.76

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

Total P&NG revenue for the fourth quarter of 2016 increased 40% to $17.8 million compared to $12.7 million in the Comparable Prior Period. The increase of $5.1 million consists of $2.0 million attributed to higher natural gas and NGL production volumes and $3.1 million due to higher realized commodity prices.

For the twelve month Reporting Period, total P&NG sales decreased 16% to $47.3 million compared to $56.2 million in the Comparable Prior Period. The decrease of $8.9 million consists of $4.3 million attributed to lower light oil production volumes and $4.6 million due to lower realized prices.

Production

Production averaged 6,123 boe/d in the three month Reporting Period as compared to 4,459 boe/d in the Comparable Prior Period. The average light oil production decreased to 1,864 bbls/d in the three month Reporting Period from 2,002 bbls/d in the Comparable Prior Period, while the average natural gas production increased to 22.3 Mmcf/d in the three month Reporting Period from 13.5 Mmcf/d in the Comparable Prior Period. The reduction in light oil production is due mainly to natural declines in the Stolberg area, partially offset by wells drilled in the Carseland and Wayne areas in the fourth quarter of 2016 and the WG Acquisition which contributed about 153 bbls/d in the three month Reporting Period. The increase in natural gas volumes is due mainly to the acquisition of the Carseland gas plant in the first quarter of 2016, which reduced gas plant restrictions resulting in increased sales gas volumes and the WG Acquisition which contributed about 4.5 Mmcf/d in the three month Reporting Period.

Production averaged 4,602 boe/d in the twelve month Reporting Period, as compared to 4,480 boe/d in the Comparable Prior Period. The average light oil production decreased to 1,709 bbls/d in the twelve month Reporting Period from 2,077 bbls/d in the Comparable Prior Period and average natural gas production has decreased to 15.4 Mmcf/d in the twelve month Reporting Period from 13.6 Mmcf/d in the Comparable Prior Period. The reduction in light oil production is due mainly to natural declines, the Corporation not drilling any wells since 2014 to late 2016 and curtailed production due to TransCanada Pipeline restrictions in the foothills area, partially offset with light oil production from assets acquired in the Wayne area of southeast Alberta in June 2015 ("**Wayne Acquisition**") which contributed approximately 739 bbls/d in the twelve month Reporting Period as compared to 479 bbls/d in the Comparable Prior Period. The increase in natural gas volumes is due mainly to reduced gas plant restrictions in the Carseland area and natural gas production from the Wayne Acquisition assets, which contributed approximately 3.4 Mmcf/d in the twelve month Reporting Period as compared to 1.3 Mmcf/d in the Comparable Prior Period and the WG Acquisition which contributed about 1.1 Mmcf/d, partially offset by natural declines in the Stolberg area.

Commodity Prices

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

	Three months ended December 31			Twelve months ended December 31		
	2016	2015	Variance	**2016**	**2015**	Variance
Benchmark prices						
Light oil – WTI ($US/bbl) [1]	**49.29**	42.18	17%	**43.32**	**48.80**	(11%)
Light oil – WTI ($CAD/bbl)	**65.76**	56.33	17%	**57.39**	**62.40**	(8%)
Light oil – Canadian light sweet ($/bbl) [1]	**60.76**	52.55	16%	**52.80**	**57.45**	(8%)
Natural gas – AECO daily spot ($/mmbtu) [2]	**3.09**	2.46	26%	**2.16**	**2.69**	(20%)
Exchange rate – ($CAD/$US)	**1.3341**	1.3354	-	**1.3248**	**1.2787**	4%
Average realized prices						
Light oil ($/bbl)	**56.43**	47.83	18%	**48.11**	**52.70**	(9%)
Natural gas ($/mcf)	**3.23**	2.73	18%	**2.49**	**2.92**	(15%)
NGLs ($/bbl)	**30.63**	27.88	10%	**26.54**	**35.64**	(26%)
Average realized price ($/boe)	**31.67**	31.01	2%	**28.07**	**34.38**	(18%)
Price differentials						
Canadian light sweet/WTI CAD ($/bbl)	**(5.00)**	(3.78)	32%	**(4.59)**	**(4.95)**	(7%)
Realized light oil/Canadian light sweet ($/bbl)	**(4.33)**	(4.72)	(8%)	**(4.69)**	**(4.75)**	(1%)
Realized natural gas/AECO daily spot ($/mcf)	**0.14**	0.27	(48%)	**0.33**	**0.23**	43%

(1) Information obtained from the Sproule Associates Limited website at www.sproule.com
(2) $1.00/mmbtu = $1.00/mcf based on a standard heat value mcf.

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

Manitok's average realized commodity price increased 2% to $31.67/boe from $31.01/boe in the three month Reporting Period and decreased 18% to $28.07/boe from $34.38/boe in the twelve month Reporting Period compared to the Comparable Prior Periods.

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

	Three months ended December 31			Twelve months ended December 31		
	2016	2015	Variance	**2016**	2015	Variance
Natural gas – AECO daily spot ($/mmbtu) [1]	**3.09**	2.46	26%	**2.16**	2.69	(20%)
Heat/quality differential ($/mcf)[2]	**0.23**	0.27	(15%)	**0.36**	0.23	57%
Physical sales/AECO daily spot differential ($/mcf)	**(0.09)**	-	-	**(0.03)**	-	-
Realized natural gas ($/mcf)	**3.23**	2.73	18%	**2.49**	2.92	(15%)

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

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

Financial Instruments

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

Financial Derivatives

As at December 31, 2016, the Corporation held the following derivative financial instruments:

Product	Notional Quantity	Term	Reference	Strike Price	Type of Contract	Fair Value ($000)
Oil	250 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	$46.00	Option(1)	(556)
Oil	250 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	$41.00	Option(2)	(607)
Oil	250 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	$42.60	Option(3)	(613)
Oil	250 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	$42.00	Option(4)	(464)
Natural gas	4,000 GJs/d	January 1, 2017 to December 31, 2017	CAD$ AECO	$2.28	Option(5)	(387)
Natural gas	4,000 GJs/d	January 1, 2017 to December 31, 2017	CAD$ AECO	$2.52	Option(6)	(249)
Total liability						**(2,876)**

(1) Manitok entered an option contract with a floor price of US$46.00/bbl for the period indicated and upside participation of 50% in the event the US$ WTI reference price is above the floor price.
(2) Manitok entered an option contract with a floor price of US$41.00/bbl for the period indicated and upside participation of 65% in the event the US$ WTI reference price is above the floor price.
(3) Manitok entered an option contract with a floor price of US$42.60/bbl for the period indicated and upside participation of 60% in the event the US$ WTI reference price is above the floor price.
(4) Manitok entered an option contract with a floor price of US$42.00/bbl for the period indicated and upside participation of 70% in the event the US$ WTI reference price is above the floor price.
(5) Manitok entered an option contract with a floor price of CAD$2.28/GJ for the period indicated and upside participation of 70% in the event the CAD$ AECO reference price is above the floor price.
(6) Manitok entered an option contract with a floor price of CAD$2.52/GJ for the period indicated and upside participation of 70% in the event the CAD$ AECO reference price is above the floor price.

Subsequent to December 31, 2016, the Corporation entered into the following derivative financial instruments:

Product	Notional Quantity	Term	Reference	Strike Price	Type of Contract
Natural gas	2,000 GJs/d	January 1, 2017 to December 31, 2017	CAD$ AECO	$2.20	Option(1)
Natural gas	2,000 GJs/d	January 1, 2017 to December 31, 2017	CAD$ AECO	$2.10	Option(2)

(1) Manitok entered an option contract with a floor price of CAD$2.20 per gigajoule for the period indicated and upside participation of 70% in the event the CAD$ AECO reference price is above the floor price.
(2) Manitok entered an option contract with a floor price of CAD$2.10 per gigajoule for the period indicated and upside participation of 70% in the event the CAD$ AECO reference price is above the floor price.

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**			
	2016		2015		**2016**		2015	
	$000	**$/boe**	$000	$/boe	**$000**	**$/boe**	$000	$/boe
Realized gain on financial instruments	**924**	**1.64**	7,464	18.20	**20,639**	**12.25**	23,844	14.58
Unrealized gain (loss) on financial instruments	**(3,148)**	**(5.59)**	2,518	6.14	**(20,731)**	**(12.31)**	(910)	(0.56)

The Corporation monetized some derivative financial instruments in the first quarter of 2016 for a cash receipt of $12.3 million to reduce bank indebtedness.

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 consolidated financial statements. There are no physical sales contracts outstanding as at December 31, 2016.

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, 2016			Three months ended December 31, 2015	
	($000)	**Effective Royalty Rate[1]**	**Average ($/unit)**	($000)	Effective Royalty Rate[1]	Average ($/unit)
Light oil and NGLs (bbls)	**3,485**	**31.1%**	**15.72**	3,341	35.8%	16.49
Natural Gas (mcf)[2][3]	**921**	**13.9%**	**0.45**	65	1.9%	0.05
Total Royalties (boe)	**4,406**	**24.7%**	**7.82**	3,406	26.8%	8.30

		Twelve months ended December 31, 2016			Twelve months ended December 31, 2015	
	($000)	**Effective Royalty Rate[1]**	**Average ($/unit)**	($000)	Effective Royalty Rate[1]	Average ($/unit)
Light oil and NGLs (bbls)	**10,979**	**33.0%**	**14.76**	13,142	31.5%	16.28
Natural Gas (mcf)[2][3]	**2,041**	**14.5%**	**0.36**	1,444	10.0%	0.29
Total Royalties (boe)	**13,020**	**27.5%**	**7.73**	14,586	26.0%	8.92

(1) The effective royalty rate is calculated by dividing the royalties into the applicable P&NG sales category and into total sales for the period.
(2) Includes royalty expenses for sulphur, but sulphur production volumes are excluded.
(3) Includes natural gas cost allowance credits received from the government of Alberta.

Royalties for the three month Reporting Period were $4.4 million as compared to $3.4 million for the Comparable Prior Period. The increase in aggregate royalties is due mainly to the higher average realized commodity prices and additional revenue from the WG Acquisition. The decrease in the effective royalty rate is due mainly to the WG Acquisition assets.

Royalties for the twelve month Reporting Period were $13.0 million as compared to $14.6 million for the Comparable Prior Period. The decrease in aggregate royalties in the twelve month Reporting Period is due mainly to lower average realized commodity prices. The increase in the effective royalty rate in the Reporting Periods is due mainly to the production volume royalty which is based on a constant 140 bbls/d of production volumes and freehold royalties based on a fixed percentage of revenue, partially offset by the lower effective rate of the WG Acquisition assets.

In 2016, the Government of Alberta announced the key highlights of the Modernized Royalty Framework (**"MRF"**) that was effective on January 1, 2017. These highlights include the replacement of royalty credits and holidays on conventional wells through a Drilling and Completion Cost Allowance to emulate a revenue minus cost framework, a post-payout royalty rate based on commodity prices, and the reduction of royalty rates for mature wells, with the intent of delivering a neutral internal rate of return for any given play compared to the current royalty framework. No changes will be made to the royalty structure of wells drilled prior to January 2017 for a 10-year period from the royalty program's implementation date. Details of the MRF calibration formulas have been released and more specific information can be found on the Alberta government's website. Based on the details provided thus far, the Corporation believes that the MRF is generally consistent with the initial goal of incentivising the use of technology to improve productivity and rewards producers deploying the most competitive operating practices. As additional information continues to be provided, the Corporation will continue to monitor the overall impact in 2017.

Operating Expenses

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

	Three months ended December 31, 2016		Three months ended December 31, 2015		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Field operating expenses	**6,510**	**11.56**	5,208	12.70	25%	(9%)
Recoveries	**(107)**	**(0.19)**	(158)	(0.39)	(32%)	(51%)
Field operating expenses, net	**6,403**	**11.37**	5,050	12.31	27%	(8%)
Expensed workovers and other	**122**	**0.22**	149	0.36	(18%)	(39%)
Total operating expenses	**6,525**	**11.59**	5,199	12.67	26%	(9%)

	Twelve months ended December 31, 2016		Twelve months ended December 31, 2015		Variance	
	$000	**$/boe**	$000	$/boe	$	$/boe
Field operating expenses	**22,177**	**13.17**	21,261	13.00	4%	1%
Recoveries	**(392)**	**(0.23)**	(841)	(0.51)	(53%)	(55%)
Field operating expenses, net	**21,755**	**12.94**	20,420	12.49	7%	4%
Expensed workovers and other	**599**	**0.36**	333	0.20	80%	80%
Total operating expenses	**22,384**	**13.30**	20,753	12.69	8%	5%

Operating expenses for the three and twelve month Reporting Periods were $6.5 million ($11.59/boe) and $22.4 million ($13.30/boe) as compared to $5.2 million ($12.67/boe) and $20.8 million ($12.69/boe) for the Comparable Prior Periods. The higher aggregate costs in the Reporting Periods are due mainly to increased production volumes.

On a per boe basis, operating costs were $11.59 and $13.30 for the three and twelve month Reporting Periods, which is relatively consistent with prior periods.

Transportation and Marketing Expenses

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

	Three months ended December 31			**Twelve months ended December 31**		
	2016	2015	Variance	**2016**	2015	Variance
Total T&M expenses ($000)	**437**	703	(38%)	**2,233**	3,531	(37%)
Total T&M expenses ($/boe)	**0.78**	1.72	(55%)	**1.33**	2.16	(38%)

Total T&M expenses for the three and twelve month Reporting Periods were $0.4 million and $2.2 million as compared to $0.7 million and $3.5 million for the Comparable Prior Periods. On a per boe basis, T&M expenses decreased to $0.78/boe in the three month Reporting Period as compared to $1.72/boe in the Comparable Prior Period and T&M expenses decreased to $1.33/boe in the twelve month Period as compared to $2.16/boe in the Comparable Prior Period. The decrease is due mainly to a lower percentage of crude oil production relative to natural gas for the three and twelve month Reporting Periods. Natural gas transportation costs are lower on a per boe basis than crude oil transportation costs, and natural gas volumes represented 61% and 56% in the three and twelve month Reporting Periods, as compared to 51% in both of the Comparable Prior Periods.

Operating Netback

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

	Three months ended December 31			Twelve months ended December 31		
($/boe)	**2016**	2015	Variance	**2016**	2015	Variance
Realized P&NG sales price	**31.67**	31.01	2%	**28.07**	34.38	(18%)
Processing revenue	**0.31**	1.16	(73%)	**0.49**	0.48	2%
Royalty expenses	**(7.82)**	(8.30)	(6%)	**(7.73)**	(8.92)	(13%)
Operating expenses, net of recoveries	**(11.59)**	(12.67)	(9%)	**(13.30)**	(12.59)	5%
Transportation and marketing expenses	**(0.78)**	(1.72)	(55%)	**(1.33)**	(2.16)	(38%)
Operating netback before realized gain (loss) on financial instruments	**11.79**	9.48	24%	**6.20**	11.09	(44%)
Realized gain (loss) on financial instruments	**1.64**	18.20	(91%)	**12.25**	14.58	(16%)
Operating netback	**13.43**	27.68	(51%)	**18.45**	25.67	(28%)

Manitok's operating netback was $13.43/boe in the fourth quarter of 2016, which is 51% lower than $27.68/boe in the Comparable Prior Period. The decrease in the three month operating netback was due to a lower realized gain on financial instruments, partially offset by lower royalties, operating and T&M expenses. In the first twelve months of 2016, the operating netback decreased 28% to $18.45/boe as compared to $25.67/boe in the Comparable Prior Period. The decrease in the twelve month operating netback was due primarily to lower realized P&NG prices and a lower realized gain on financial instruments, which included the monetization of crude oil derivative financial instruments for a cash receipt of $12.3 million in the first quarter of 2016 or $7.30/boe for the twelve month Reporting Period.

Administrative Expenses

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

	Three months ended December 31, 2016		Three months ended December 31, 2015		Variance
	$000	**%**	$000	%	$
Cash:					
Salaries and benefits(1)	**1,192**	**49**	1,067	53	12%
Other(2)	**1,256**	**51**	927	47	36%
	2,448	**100**	1,994	100	23%
Operating overhead recoveries	**(44)**	**(2)**	(57)	(3)	(23%)
Capitalized overhead recoveries(3)	**(497)**	**(20)**	(591)	(30)	(16%)
General and administrative expenses, net	**1,907**	**78**	1,346	67	42%
General and administrative expenses, net per boe	**3.39**		3.29		4%
Non-cash:					
Stock-based compensation	**280**	**100**	190	100	47%
Capitalized stock-based compensation(3)	**(102)**	**(36)**	(85)	(45)	20%
Stock-based compensation, net	**178**	**64**	105	55	70%
Stock-based compensation, net per boe	**0.32**		0.25		23%
Total administrative expenses, net	**2,085**	**76**	1,451	66	44%
Total administrative expenses, net per boe	**3.71**		3.54		5%

	Twelve months ended December 31, 2016		Twelve months ended December 31, 2015		Variance
	$000	**%**	$000	%	$
Cash:					
Salaries and benefits(1)	**4,579**	**51**	5,597	55	(18%)
Other(2)	**4,361**	**49**	4,520	45	(3%)
	8,940	**100**	10,117	100	(12%)
Operating overhead recoveries	**(199)**	**(2)**	(302)	(3)	(34%)
Capitalized overhead recoveries(3)	**(2,171)**	**(24)**	(3,181)	(31)	(32%)
General and administrative expenses, net	**6,570**	**74**	6,634	66	(1%)
General and administrative expenses, net per boe	**3.90**		4.06		(4%)
Non-cash:					
Stock-based compensation	**1,015**	**100**	1,269	100	(20%)
Capitalized stock-based compensation(3)	**(403)**	**(40)**	(631)	(50)	(36%)
Stock-based compensation, net	**612**	**60**	638	50	(4%)
Stock-based compensation, net per boe	**0.36**		0.39		(8%)
Total administrative expenses, net	**7,182**	**72**	7,272	64	(1%)
Total administrative expenses, net per boe	**4.26**		4.45		(4%)

(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 42% on an aggregate basis to $1.9 million in the three month Reporting Period as compared to $1.3 million in the Comparable Prior Period, mainly due to additional resources required for the WG Acquisition. The net G&A for the twelve month Reporting Period remained consistent with the Comparable Prior Period.

Stock-based compensation (non-cash)

Stock-based compensation remained consistent in the Reporting Periods as compared to the Comparable Prior Periods.

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

	Number	Weighted Average Exercise Price ($)
Outstanding, December 31, 2014	**5,308,606**	**1.97**
Granted	1,302,500	0.77
Expired	(667,340)	(1.10)
Forfeited	(716,333)	(1.89)
Outstanding, December 31, 2015	**5,227,433**	**1.79**
Granted	12,445,100	0.16
Expired	(608,333)	(1.31)
Forfeited	(614,100)	(0.62)
Outstanding, December 31, 2016	**16,450,100**	**0.62**

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

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, 2016		Three months ended December 31, 2015	
	$000	**$/boe**	$000	$/boe
Cash:				
Interest and fees	**1,693**	**3.01**	1,522	3.71
Effective interest on senior secured notes	**48**	**0.09**	-	-
Acquisition-related expenses(1)	**571**	**1.01**	(82)	(0.20)
	2,312	**4.11**	1,440	3.51
Non-cash:				
Accretion on discount of senior secured notes	**29**	**0.05**	-	-
Accretion on decommissioning obligations	**317**	**0.56**	140	0.34
Total finance expenses	**2,658**	**4.72**	1,580	3.85

	Twelve months ended December 31, 2016		Twelve months ended December 31, 2015	
	$000	**$/boe**	$000	$/boe
Cash:				
Interest and fees	**6,053**	**3.59**	4,933	3.02
Effective interest on senior secured notes	**48**	**0.03**	-	-
Acquisition-related expenses(1)	**952**	**0.57**	1,892	1.16
	7,053	**4.19**	6,825	4.18
Non-cash:				
Accretion on discount of senior secured notes	**29**	**0.02**	-	-
Accretion on decommissioning obligations	**755**	**0.45**	411	0.25
Total finance expenses	**7,837**	**4.66**	7,236	4.43

(1) Acquisition-related expenses are associated with the Raimount Arrangement and the WG Acquisition. See "Major Transactions Affecting Financial Results."

The aggregate cash finance expenses in the twelve month Reporting Period included credit facility interest charges of $2.8 million (2015 - $3.1 million), credit facility commitment fees of $0.7 million (2015 - $0.4 million), interest on the long-term financial obligations of $2.2 million (2015 – $1.4 million) and interest on the Senior Secured Notes issued in October 2016 of $0.4 million (2015 – NIL).

The Corporation's average outstanding bank indebtedness was approximately $37.4 million and $42.9 million in the three and twelve month Reporting Periods as compared to $65.2 million and $67.7 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 6.4% and 6.5% in the three and twelve month Reporting Periods as compared to 5.9% and 4.6% in the Comparable Prior Periods.

The accretion charges are non-cash and are comprised of the accretion of decommissioning obligations that relates to the passage of time until the Corporation will incur to retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards and the accretion of the Corporations discount on its Senior Secured Notes. The increase in accretion of decommissioning obligations is due to the increase in assets from the WG Acquisition and the Wayne Acquisition.

The effective interest charge associated with the Corporation's Senior Secured Notes is based on the effective interest rate method in order to amortize the transaction costs related to the issue and to accrete the Senior Secured Notes to its face value of $21.2 million over the term of the debt.

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		
	2016	2015	Variance	**2016**	2015	Variance
Depletion and depreciation ($000)	**6,601**	5,026	31%	**19,957**	27,382	(27%)
Depletion and depreciation ($/boe)	**11.72**	12.25	(4%)	**11.85**	16.75	(29%)

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 2016 to $6.6 million ($11.72/boe) as compared to $5.0 million ($12.25/boe) for the Comparable Prior Period. For the twelve months of 2016, D&D expenses decreased to $20.0 million ($11.85/boe) as compared to $27.4 million ($16.75/boe) for the Comparable Prior Period. The per unit decrease in D&D expenses in the three month Reporting Period are due mainly to the WG Acquisition at lower acquisition metrics, and the per unit decrease in D&D in the twelve month reporting period are due to lower production volumes, a reduction in the net book value of the assets due to the asset divestitures and impairment charges in the second quarter of 2015 and the increase in proved plus probable reserves associated with the WG Acquisition.

Asset Impairment Assessment

The Corporation reviews its petroleum and natural gas assets for impairment in accordance with International Accounting Standard ("**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 CGUs, the Corporation took into consideration all available information including, but not limited to, the geographical proximity, geological similarities (i.e. reservoir characteristic, production profiles), degree of shared infrastructure, independent versus interdependent cash flows, operating structure, regulatory environment, management decision-making and overall business strategy.

The Corporation's CGUs are reviewed 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 the 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 with the agreements governing the Corporation's credit facilities; deterioration in the financial and operational performance of a CGU; net assets exceeding market capitalization; and significant downward revisions of estimated recoverable proved plus probable reserves of a CGU. If impairment indicators exist, an impairment test is performed by comparing a CGU's carrying value to its recoverable amount.

In the fourth quarter of 2016, Manitok performed an impairment assessment of its exploration and evaluation ("**E&E**") assets and developed and producing ("**D&P**") assets on a CGU basis and determined there was an impairment indicator identified in the Reporting Period in one CGU, as a result of negative technical reserve revisions. No indicators of impairment were identified in the Corporation's other CGUs. As a result of the impairment tests conducted in the one CGU, it was determined that the net book value of certain E&E and D&P assets exceeded the recoverable amount.

For the three and twelve month Reporting Periods, Manitok has recorded an impairment of its E&E assets of $9.7 million as compared to $5.3 million and $7.5 million in the Comparable Prior Periods. For the three and twelve month Reporting Periods, Manitok has recorded an impairment of its D&P assets of $8.8 million as compared to $7.4 million and $23.1 million in the Comparable Prior Periods.

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

(Gain) Loss on Divestiture or Acquisition of Assets

2016 Asset Divestitures

In February 2016, the Corporation closed a non-cash asset exchange agreement, in which Manitok divested of a 19.9% non-operated working interest in a gas plant in a non-core area, where it had no current throughput volumes or value in its reserve report, in exchange for a 17.5% average working interest in petroleum and natural gas assets, along with an average 45% working interest in associated undeveloped land in the Stolberg area of Alberta. The estimated fair value was determined to be $7.0 million, before post-closing adjustments and was based on the fair value of the acquired assets. The net book value of the divested non-core asset was $0.1 million and as a result Manitok recorded a gain of $6.8 million in the first quarter of 2016.

2016 Asset Acquisition

In October 2016, the Corporation closed the WG Acquisition for proceeds of $14.9 million before post-closing adjustments. The Corporation recorded a gain of $5.2 million, reflecting the lower purchase price required compared to the fair value of the assets and undeveloped lands in light of the significant decommissioning obligation acquired.

2015 Asset Divestitures

In May 2015, the Corporation closed the divesture of a gross over-riding royalty in the Stolberg area ("**Stolberg GORR**") in exchange for revised terms and additional undeveloped lands in a Lease Issuance and Drilling Commitment Agreement with PSK. The estimated fair market value was determined to be $7.1 million and was based on the fair value of the GORR assets. Manitok recorded a loss of $0.8 million ($0.6 million, net of tax) on the asset divestiture for the year ended December 31, 2015.

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

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

In June 2015, Manitok closed a divestiture of its interest in certain oil and gas infrastructure in the Wayne area for net cash proceeds of $7.1 million after post-closing adjustments. The Corporation did not record a gain or loss on the divesture as the carrying value approximated the proceeds received, as the assets had just been acquired at fair value.

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	
	2016	2015	**2016**	2015
Deferred income tax expense (recovery) ($000)	**(5,056)**	(1,643)	**(7,646)**	(7,925)
Deferred income tax expense (recovery) ($/boe)	**(8.98)**	(4.00)	**(4.54)**	(4.85)

Manitok recorded a deferred income tax recovery of $5.1 million and $7.6 million for the three and twelve month Reporting Periods as compared to a recovery of $1.6 million and $7.9 million in the Comparable Prior Periods due to the net loss before taxes in the period.

Due to a continued low commodity price environment, Manitok has not recognized its deferred tax asset of $0.7 million.

The Corporation's estimated income tax pools were $154.9 million as at December 31, 2016. Management anticipates 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)	2016	2015
Cumulative Canadian Exploration Expense	**34,367**	33,087
Cumulative Canadian Development Expense	**21,976**	30,691
Cumulative Canadian Oil and Gas Property Expense	**61,327**	47,518
Undepreciated Capital Cost	**20,515**	20,350
Non-capital losses	**12,459**	459
Debt and Share issuance costs	**4,211**	2,398
	154,855	134,503

CAPITAL EXPENDITURES

Capital Expenditures

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

	Three months ended December 31		Twelve months ended December 31	
($000)	**2016**	2015	**2016**	2015
Land	**192**	15	**638**	948
Seismic	**106**	396	**573**	1,086
Workovers and recompletions	**840**	2,143	**1,186**	2,722
Drilling and completions	**9,438**	155	**11,317**	2,335
Well equipment and facilities	**1,499**	832	**4,379**	5,646
Capitalized overhead(1)	**497**	591	**2,171**	3,181
Total finding and development costs (F&D)	**12,572**	4,132	**20,264**	15,918
Acquisition(2)	**14,980**	(1,297)	**19,503**	61,549
Divestitures	**-**	6	**-**	(37,049)
Total finding, development and acquisition costs (FD&A)	**27,552**	2,841	**39,767**	40,418
Administrative and other assets	**17**	6	**26**	179
Total capital expenditures(3)	**27,569**	2,847	**39,793**	40,597

(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 Carseland Acquisition and the Willesden Green Acquisition.
(3) Excludes non-cash items such as capitalized stock-based compensation and decommissioning obligations.

In the twelve month Reporting Period, The Corporation drilled 5 (5 net) wells in the Carseland area and 1 (1 net) in the Wayne area. In addition, 13 (1.6 net) wells were drilled pursuant to a farm-out agreement in the Rockyford area of southeast Alberta for gross drilling and completion costs of approximately $19.4 million as at December 31, 2016. Manitok participated at 50% in two of the wells in the farm-out agreement for costs of approximately $1.4 million and it's working interest costs with respect to the 11 remaining wells were carried by the farmee. These costs are fully allocated to the Corporation's drilling commitments (see "Contractual Obligations").

Additionally, one gross well was spud pursuant to a seismic and farm-out option agreement in the Beiseker area of southeast Alberta for gross drilling costs of approximately $1.6 million. Manitok's working interest costs with respect to the well were carried by the farmee. This well was subsequently abandoned. These costs are fully allocated to the Corporation's drilling commitments (see "Contractual Obligations").

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

($000)	Three months ended December 31 2016	Three months ended December 31 2015	Twelve months ended December 31 2016	Twelve months ended December 31 2015
E&E assets	**11,013**	1,222	**15,547**	9,651
Property and equipment, net	**16,556**	1,625	**24,246**	30,946
Total capital expenditures[(1)]	**27,569**	2,847	**39,793**	40,597

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

Decommissioning Liability

At December 31, 2016, Manitok has recorded decommissioning obligations of $87.0 million (December 2015 - $27.7 million) for the future abandonment and reclamation of Manitok's properties. The estimated decommissioning liability includes assumptions in respect of actual costs to abandon wells or reclaim the property, the time frame in which such costs will be incurred as well as annual inflation factors in order to calculate the undiscounted total future liability. The future liability has been discounted at the risk free rate of 2.3% (December 2015 – 2.2%). Abandonment cost estimates are derived from both third party and government sources and operational knowledge of the properties. The estimates are reviewed quarterly and adjusted as new information regarding the liability is determined. The increase in the obligation from December 31, 2015 is due mainly to the WG Acquisition in the fourth quarter of 2016.

Accretion expense is the increase in the decommissioning obligations resulting from the passage of time. The Corporation's Liability Management Rating ("**LMR**") with the Alberta Energy Regulator ("**AER**") was 3.05 at December 31, 2016 (2015 – 7.86). The reduction from the prior period is due mainly to the WG Acquisition. The LMR reflects the results of a comparison of the Corporation's deemed assets to its deemed liabilities and is updated monthly. An LMR rating of less than 1.0 would require the Corporation to pay a deposit to the AER.

CAPITAL RESOURCES AND LIQUIDITY

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, 2016**	December 31, 2015
Working capital deficit	**46,354**	40,675
Current portion of the Credit Facilities	**(33,083)**	(62,398)
Current portion of provisions for building lease obligations	**(1,321)**	-
Current portion of the deferred premium on financial instruments	**-**	(1,400)
Current portion of the fair value of financial instruments	**(2,876)**	14,172
Adjusted working capital (surplus) deficit	**9,074**	(8,951)

The Corporation's adjusted working capital changed from a surplus of $8.9 million at December 31, 2015 to a deficit of $9.1 million as at December 31, 2016. The adjusted working capital surplus at December 31, 2015 was largely comprised of the net proceeds of $7.5 million from an equity financing in December 2015, which were received in January 2016. The Corporation initiated a 6 well drill program in the fourth quarter of 2016, which increased the working capital deficit as at December 31, 2016.

At December 31, 2016, the major component of Manitok's current assets was the revenue to be received from its marketers in respect of December 2016 production ($8.1 million) with the majority received in January 2017 and accounts receivable from joint venture partners related to joint capital and operating activities in which Manitok is the operator ($1.1 million). Manitok routinely assesses the financial strength of its marketers and joint venture partners and at this time, Manitok expects that such counterparties will be able to meet their financial obligations. Current liabilities excluding the amount drawn on the credit facilities and the fair value on financial instruments largely consist of trade and accrued liabilities ($10.1 million) related to the Corporation's capital program and trade and joint venture payables and accrued liabilities ($8.5 million) related to the Corporation's operations.

The Corporation manages its working capital using a combination of its funds from operations and advances under its credit facilities and if applicable funds from debt and equity issuances and asset divestitures.

Bank Indebtedness

As at December 31, 2016, the Corporation's credit facilities consisted of a $30.0 million revolving operating demand loan facility ("**Conforming Credit Facility**") and a $13.3 million non-revolving reducing demand loan facility ("**Non-Conforming Credit Facility**" and together with the Conforming Credit Facility, the "**Credit Facilities**"), for total Credit Facilities of $43.3 million. In December 2016, the $30.0 million Conforming Credit Facility and the $13.3 million Non-Conforming Credit Facility was maintained, and the Corporation is required to repay $0.5 million per month on the Non-Conforming Credit Facility until it is fully repaid.

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

As at	**December 31, 2016**	December 31, 2015
Maximum borrowing base limit		
Conforming Credit Facility(1)	**30,000**	45,000
Non-Conforming Credit Facility(1)	**13,300**	30,000
	43,300	75,000
Principle amount utilized		
Drawn Conforming Credit Facility	**(19,783)**	(32,398)
Drawn Non-Conforming Credit Facility	**(13,300)**	(30,000)
Outstanding letters of credit(2)	**(230)**	(290)
	(33,313)	(62,688)
Undrawn Credit Facilities	**9,987**	12,312

(1) The Corporation's lender requires quarterly compliance that the working capital ratio (current assets excluding the fair value of financial instruments plus any undrawn portion of the Conforming Credit Facility divided by current liabilities excluding any current portion of an amount drawn on the Credit Facilities, the fair value of financial instruments, the deferred premium on financial instruments and current provisions) is not less than 1 to 1. As at December 31, 2016 the Corporation's working capital ratio was 1.04 to 1.

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

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, well performance, reserve additions and commodity prices. The Credit Facilities are demand in nature and the lender may reduce the borrowing base at its sole discretion at any time. Based on the Corporation's budgeted cash flow from operating activities at current forward strip crude oil and natural gas prices, and available Credit Facilities, which are demand facilities and a portion of which is non-conforming and requires repayment, the Corporation is unable to meet its commitments (see "Contractual Obligations"). The Corporation is subject to a working capital covenant of 1 to 1 pursuant to its Credit Facilities. As at December 31, 2016 the working capital covenant was 1 to 1. There is minimal cushion on this covenant as at December 31, 2016 and uncertainty surrounding future compliance. As a result, Manitok is in the process of identifying and pursuing alternative debt arrangements, joint venture arrangements, property acquisitions or divestitures, corporate mergers and acquisitions and other recapitalization opportunities to satisfy its obligations, but there is no assurance that the Corporation will be able to access the various financing alternatives. Should the Corporation fail to meet its commitments, the outstanding capital commitment shortfall amount and all debt obligations may become due and payable to the counterparties immediately and/or loss of lands. There can be no assurance that the Corporation will be successful in its efforts to renew the Credit Facilities at acceptable levels, or to arrange additional financing, if required, or complete other transactions on terms satisfactory to the Corporation or at all. Manitok has not received an indication if its lender will demand repayment in the next twelve months, however, the demand nature including the Non-Conforming Facility does create uncertainty. The next review dates for the Credit Facilities have been set for May 31, 2017.

Management recognizes the current economic environment relating to the oil and gas industry has made access to both debt and equity capital challenging for many companies, and as such have made cost reduction and capital management initiatives to manage spending and indebtedness. The Corporation continually monitors its capital structure and capital program in response to changes in business conditions, including changes in economic conditions, forecasted commodity prices and resulting funds from operations, indebtedness and the risk and timing of capital investments.

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, 2016:

($000)	2017	2018	2019 - 2021	Thereafter
Accounts payable and accrued liabilities	19,768	-	-	-
Drawn on Credit Facilities	33,083	-	-	-
Senior Secured Notes(1)	2,229	2,227	27,609	-
Long-term financial obligations(2)	2,235	2,235	6,705	29,899
Minimum drilling and completion expenditures(3)(4)(5)	35,750	20,250	-	-
Firm transportation agreement(6)	629	348	212	-
Facility fees(7)	2,937	2,937	8,811	3,443
Office leases(8)	1,225	817	3,163	5,323
Total estimated contractual obligations(9)	**97,856**	**28,814**	**46,500**	**38,665**

(1) In accordance with the $21.2 million of 10.5% Senior Secured Notes, which matures on November 15, 2021, interest of $0.6 million is payable quarterly to the holders of record immediately preceding February 1, May 1, August 1 and November 1.

(2) In conjunction with facility financing agreements incurred in December 2014 and June 2015, Manitok is committed to pay monthly facility payments of $0.2 million to June 2035, which relates primarily to interest charges.

(3) Pursuant to a Lease Issuance and Drilling Commitment Agreement with PrairieSky Royalty Ltd. ("**PSK LIDCA**"), Manitok has agreed to an annual work program including minimum annual drilling and completion expenditures until April 30, 2018. In an effort to reduce the Corporation's PSK LIDCA commitment in 2016 and potentially 2017, the Corporation entered into a farm-out agreement with a private oil and gas company ("**Farmee**") in 2015, whereby the Farmee has committed to spend a minimum of $20.0 million from the fourth quarter of 2015 to the end of 2016 in the Rockyford area of Alberta and depending on the level of success achieved with the drilling, may lead to additional capital spending in 2017, with the Farmee having an option to drill additional earning wells before the end of 2017 ("**Farm-out Agreement**"). The entire capital spend from the Farm-out Agreement will be fully allocated to Manitok's PSK LIDCA capital commitment.

(4) Pursuant to a production volume royalty divestiture in 2015, Manitok is committed to incur a minimum capital commitment of $10.0 million per year in 2017 and 2018 on drilling, completion, re-completion, workover, equipping and tie-in for the production of wells targeting the Carseland and/or Wayne areas of Alberta. This commitment is concurrent with the PSK LIDCA commitment and is not an additional spending commitment. Additionally, Manitok has agreed, but is not obligated to drill at least two gross wells per year in 2016, 2017 and 2018 in the Stolberg area of Alberta. In the event Manitok does not meet this commitment, the royalty corporation may either grant an extension to Manitok, drill the wells itself or elect to do nothing. Due to commodity prices Manitok did not drill two gross wells in Stolberg in 2016.

(5) The remaining flow-through share exploration spending commitments of $4.7 million on or before December 31, 2017 are anticipated to be met with the PSK LIDCA commitment as there are exploration opportunities within the undeveloped land acreage in the PSK LIDCA.

(6) The Corporation is committed to transport natural gas from various gas processing facilities to the NOVA pipeline system.

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

(8) Manitok has committed to a new operating lease relating to new office space commencing November 2016 and expiring on November 30, 2025, which includes a rent free period to December 31, 2017 and various other rent reduction allowances. Pursuant to the Raimount Arrangement, Manitok is committed to office space with lease payments commencing July 1, 2017 to June 30, 2025 for a total commitment of about $0.9 million. The Corporation is in the process of mitigating this obligation by subleasing the space to a third party. Manitok also remains committed to two other operating leases relating to its previous office premises expiring on February 28, 2017 and November 30, 2017. The Corporation has subleased approximately 82% of its previous office space to arm's length parties for the remainder of the lease terms. The recovery of rental costs from the subleases are not included in the table.

(9) Contractual commitments that are routine in nature and form part of the normal course of operations for Manitok are not included in the above table. The Corporation's decommissioning obligations are excluded from the table as these obligations arise from a regulatory requirement rather than from a contractual arrangement. Manitok estimates the total inflation adjusted undiscounted cash flow to settle its decommissioning obligations as at December 31, 2016 to be approximately $140.4 million and will be incurred as follows: 2017 - $3.1 million, 2018 - $1.2 million, 2019 to 2021 - $25.0 million and $111.1 million thereafter. The estimate for undiscounted decommissioning obligations requires significant assumptions on both the abandonment cost and timing of the decommissioning and therefore the actual obligations may differ materially.

OFF-BALANCE SHEET TRANSACTIONS

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

RELATED PARTY TRANSACTIONS

Other than the payment of compensation to key management personnel, the Corporation has not entered into any related party transactions in the Reporting Periods.

OUTSTANDING SHARE DATA

At December 31, 2016, the Manitok Shares are the only class of shares issued and outstanding. Manitok Shares began trading on the TSX-V on July 29, 2010 under the symbol "**MEI**". The following table summarizes the Manitok Shares issued and outstanding:

	Manitok Shares
Outstanding, December 31, 2014	**65,279,607**
Issue of Manitok Shares in June 2015(1)	19,810,177
Issue of Manitok Shares in December 2015(2)	58,846,331
Outstanding, December 31, 2015	**143,936,115**
Issue of Manitok Shares in January and February 2016(1)	17,143,631
Issue of Manitok Shares in May 2016(2)	16,430,925
Issue of Manitok Shares in August 2016(3)	8,333,334
Issue of Manitok Shares in August 2016(4)	41,207,196
Issue of Manitok Shares in November 2016(5)	35,768,631
Outstanding, December 31, 2016	**262,819,832**

(1) In the first quarter of 2016, Manitok closed the final tranches of a private equity financing for the issuance of 15,973,631 Manitok Shares at a price of $0.13 per Manitok Share and 1,170,000 Manitok CEE Flow-through Shares at a price of $0.15 per Manitok CEE Flow-through Share for gross proceeds of $2.3 million (net proceeds - $2.0 million).

(2) In the second quarter of 2016, Manitok closed a private equity financing for the issuance of 8,435,945 Manitok Shares at a price of $0.18 per Manitok Share and 7,994,980 Manitok CEE Flow-through Shares at a price of $0.21 per Manitok CEE Flow-through Share for gross proceeds of $3.2 million (net proceeds - $2.8 million).

(3) In the third quarter of 2016, Manitok closed a non-brokered private placement offering of 8,333,334 Subscription Receipts at a price of $0.18 per Subscription Receipt for gross proceeds of $1.5 million (net proceeds - $1.3 million). The Subscription Receipts were exchanged for Manitok Shares on a 1 to 1 basis.

(4) In the third quarter of 2016, Manitok completed the Raimount Arrangement, in which each Raimount shareholder received six (6) Manitok Shares and one and one-half (1.5) Raimount Arrangement Warrants in exchange for each Raimount common share held. As a result, Manitok issued 41,207,196 Manitok Shares and 10,301,837 Raimount Arrangement Warrants, which have an exercise price of $0.30 per Manitok Share for a term of two years (see "Major Transactions Affecting Financial Results").

(5) In the fourth quarter of 2016, Manitok closed an equity financing by way of a short form base shelf prospectus as supplemented by the Corporation's prospectus supplement for the issuance of 7,562,923 Manitok Shares at a price of $0.13 per Manitok Share, 4,599,829 Manitok CDE Flow-through Shares at a price of $0.14 per Manitok CDE Flow-through Share and 23,605,879 Manitok CEE Flow-through Shares at a price of $0.145 per Manitok CEE Flow-through Share for gross proceeds of $5.0 million (net proceeds - $4.5 million).

At May 1, 2017, there are 262,819,832 Manitok Shares outstanding, 21,399,100 stock options and a total of 46,322,608 warrants to purchase an equivalent number of Manitok Shares.

SUMMARY OF QUARTERLY INFORMATION

	2016				2015			
Quarters Ended	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
OPERATING								
Average daily production								
Light oil (bbls/d)	**1,864**	1,642	1,519	1,812	2,002	2,176	1,864	2,269
Natural gas (mcf/d)	**22,281**	14,017	11,004	14,305	13,540	12,412	15,435	13,049
NGLs (bbls/d)	**545**	298	235	211	200	190	84	61
Total (boe/d)	**6,123**	4,276	3,587	4,407	4,459	4,434	4,521	4,504
Average realized sales price (CAD$)								
Light oil ($/bbl)	**56.43**	50.17	49.42	36.48	47.83	51.85	63.71	48.77
Natural gas ($/mcf)	**3.23**	2.54	1.49	2.03	2.73	3.20	2.89	2.89
NGLs ($/bbl)	**30.63**	23.82	24.86	21.58	27.88	29.50	55.98	52.85
Total ($/boe)	**31.67**	29.25	27.11	22.63	31.01	35.65	37.18	33.66
OPERATING NETBACK ($ per boe)(1)								
Petroleum and natural gas sales	**31.67**	29.25	27.11	22.63	31.01	35.65	37.18	33.66
Processing revenue	**0.31**	0.42	0.49	0.58	0.64	0.41	0.24	0.22
Realized gain (loss) on financial instruments	**1.64**	4.86	5.74	39.72	18.20	15.75	10.86	13.54
Royalty expenses	**(7.82)**	(8.42)	(8.57)	(6.24)	(8.30)	(10.13)	(8.78)	(8.47)
Operating expenses, net	**(11.59)**	(12.49)	(15.19)	(14.70)	(12.15)	(16.13)	(11.52)	(10.60)
Transportation and marketing expenses	**(0.78)**	(1.86)	(1.39)	(1.53)	(1.72)	(1.71)	(2.35)	(2.87)
Operating netback(1)	**13.43**	11.76	8.19	40.46	27.68	23.84	25.63	25.48
FINANCIAL								
Petroleum and natural gas revenue ($000)	**17,848**	11,509	8,849	9,074	12,720	14,548	15,297	13,645
Processing income ($000)	**175**	169	159	230	266	165	100	91
Royalty expenses ($000)	**(4,406)**	(3,315)	(2,798)	(2,501)	(3,406)	(4,134)	(3,613)	(3,433)
Realized gain on financial instruments ($000)	**924**	1,912	1,874	15,929	7,464	6,426	4,466	5,488
Unrealized gain (loss) on financial instruments ($000)	**(3,148)**	(2,009)	(5,356)	(10,218)	2,518	11,014	(10,328)	(4,114)
Total revenue, net ($000)	**11,393**	8,266	2,728	12,514	19,562	28,019	5,922	11,677
Funds from operations ($000)(1)	**4,038**	1,711	(244)	13,035	8,488	6,643	7,341	7,918
Per share – basic and diluted ($)(1)	**0.02**	0.01	-	0.08	0.10	0.08	0.11	0.12
Net income (loss) ($000)	**(16,421)**	(4,521)	(7,354)	3,602	(5,258)	8,316	(26,852)	(3,401)
Per share - diluted ($)(2)	**(0.07)**	(0.02)	(0.04)	0.02	(0.06)	0.10	(0.39)	(0.05)
Capital expenditures, net of divestitures ($000)	**27,569**	2,798	3,260	6,166	2,847	3,890	28,959	4,901
Book value of total assets ($000)	**252,865**	187,146	190,401	194,014	204,705	206,644	199,995	196,945
Adjusted working capital (surplus) deficit ($000)(1)	**9,074**	1,153	1,853	141	(8,951)	598	(1,575)	(2,313)
Drawn on Credit Facilities ($000)	**33,083**	40,031	43,693	44,529	62,398	65,371	69,949	75,379
Net bank debt ($000)(1)	**42,157**	41,184	45,546	44,670	53,447	65,969	68,374	73,066
Senior Secured Notes ($000)	**18,138**	-	-	-	-	-	-	-
Long-term financial obligations ($000)	**14,856**	14,879	14,902	14,925	14,948	14,966	14,984	2,494
Net debt ($000)(1)	**75,151**	56,063	60,448	59,595	68,395	80,935	83,358	75,560
Shareholders' equity ($000)	**74,237**	85,348	82,034	86,398	80,540	78,586	69,965	81,348
Common shares outstanding (000s)								
End of period - basic	**262,820**	227,051	177,511	161,080	143,936	85,090	85,090	65,280
End of period - diluted	**325,593**	255,197	193,889	177,453	150,334	90,553	91,565	71,720
Weighted average for the period – basic and diluted	**239,616**	200,164	169,037	156,340	85,729	85,090	68,751	65,280

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

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

Discussion of Quarterly Results

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

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

- Net loss for the second quarter of 2015 was $26.9 million, compared to a net loss of $3.4 million in the first quarter of 2015. The increase was primarily the result of an impairment charge of $17.9 million, an increased unrealized loss on financial instruments and losses on the PVR Divestiture and the Stolberg GORR Divestiture.
- In the second quarter of 2015, Manitok closed the Wayne Acquisition for cash consideration of $61.1 million after post-closing adjustments.
- The Corporation closed the June 2015 Equity Financing for net proceeds of $15.8 million.
- The Corporation completed the Wayne GORR Divestiture, the PVR Divestiture, the June 2015 Facility Divestiture in the second quarter of 2015 for net cash proceeds of $37.7 million along with the June 2015 Facility Financing for additional net cash proceeds of $12.5 million.
- Net income for the third quarter of 2015 was $8.4 million, compared to a net loss of $26.9 million in the second quarter of 2015. The increase was primarily the result of an increased unrealized gain on financial instruments in the third quarter of 2015, a loss on the PVR Divestiture and the Stolberg GORR Divestiture of $3.6 million and an impairment charge of $17.9 million in the second quarter of 2015.
- The Corporation closed an equity financing in December 2015 for net proceeds of $7.5 million.
- Adjusted working capital changed to a surplus of $9.0 million at December 31, 2015, compared to a deficit as at September 30, 2015 due mainly to the net proceeds of $7.5 million from the December 2015 Equity Financing being received in January 2016.
- Net loss for the fourth quarter of 2015 was $5.3 million, compared to net income of $8.3 million in the third quarter of 2015. The net loss was due mainly to an impairment charge of $12.7 million in the fourth quarter of 2015.
- The Corporation closed the Q1 2016 Equity Financing for net proceeds of $2.0 million.
- In the first quarter of 2016, the Corporation monetized crude oil derivative financial instruments for a cash receipt of $12.3 million or $30.67/boe to reduce bank indebtedness, which was recorded in the realized gain on financial instruments.
- Funds from operations increased by $4.5 million in the first quarter of 2016 from the fourth quarter of 2015 mainly attributable to the monetization of crude oil derivative financial instruments for $12.3 million and an aggregate decrease to royalty expenses partially offset by a decrease in petroleum and natural gas revenue due to the sharp decline in commodity prices and increases in operating and interest expenses.
- The net income in the first quarter of 2016 was $3.6 million compared to a net loss of $5.3 million in the fourth quarter of 2015. The increase in net income was due mainly to increased funds from operations and a $6.9 million gain on an asset divestiture in the first quarter of 2016 and an impairment charge of $12.7 million in the fourth quarter of 2015, partially offset by an increase in the unrealized loss on financial instruments.
- The Corporation closed the May 2016 Equity Financing for net proceeds of $2.8 million.
- In the second quarter of 2016, average daily production decreased 820 boe/d from the first quarter of 2016 due mainly to gas plant turnarounds in both southeast Alberta and the foothills which decreased production by 640 boe/d. Subsequent to the plant turnarounds, Manitok continued to shut-in the majority of its natural gas wells due to low natural gas prices, which decreased production by an additional 316 boe/d.
- Funds from operations decreased by $13.3 million in the second quarter of 2016 from the previous quarter, which was mainly attributable to the monetization of crude oil derivative financial instruments for $12.3 million in the first quarter of 2016.
- The net loss in the second quarter of 2016 was $7.4 million compared to a net income of $3.6 million in the first quarter of 2016. The increase in net loss was due mainly to decreased funds from operations and a $6.9 million gain on an asset divestiture in the first quarter of 2016.
- The Corporation closed the Subscription Receipts Offering in August 2016 for net proceeds of $1.3 million.
- The Corporation completed the Raimount Arrangement, which included assets of approximately $5.0 million of cash, no indebtedness and 65 boe/d (95% gas) of production.
- In October 2016, the Corporation completed the WG Acquisition which included approximately 1,750 boe/d of production (34% oil and liquids). Total consideration for the acquisition was $13.5 million prior to

transaction costs and customary closing adjustments, which included $9.0 million of cash and $4.5 million of CEL Notes.

- In October 2016, the Corporation issued the Senior Secured Notes and used a portion of the net proceeds of the Offering for the WG Acquisition and the remaining net proceeds of the Offering were used to reduce the amount drawn on its credit facilities.
- The Corporation closed the November 2016 Equity Offering for net proceeds of $4.5 million.
- Net loss for the fourth quarter of 2016 was $20.0 million, compared to a net loss of $4.5 million in the third quarter of 2016. The increase in net loss was due mainly to an impairment charge of $18.5 million in the fourth quarter of 2016, partially offset by a gain on the WG Acquisition of $5.2 million.

POTENTIAL TRANSACTIONS

Within its focus area, the Corporation is always reviewing potential property acquisitions and corporate mergers and acquisitions for the purposes of determining whether any such potential transaction is of interest to the Corporation, as well as the terms on which such a potential transaction would be available. As a result, the Corporation may from time to time be involved in discussions or negotiations with other parties or their agents in respect of potential property acquisitions and corporate merger and acquisition opportunities. The Corporation is not committed to any such potential transaction and cannot be reasonably confident that it can complete any such potential transaction until appropriate legal documentation has been signed by the relevant parties.

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

CRITICAL ACCOUNTING ESTIMATES

The Corporation's financial and operating results incorporate certain estimates including:

- estimated revenues, royalties and operating expenses on production as at a specific reporting date but for which actual revenues and expenses have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated DD&A that are based on estimates of oil and gas reserves that the Corporation expects to recover in the future, commodity prices, estimated future salvage values and estimated future capital costs;
- estimated value of decommissioning obligations that are dependent upon estimates of future costs, timing of expenditures and the risk-free rate;
- estimated income and other tax liabilities requiring interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time;
- estimated share-based compensation expense using the Black-Scholes option pricing model; and
- estimated recoverable amounts are based on estimated proved plus probable reserves, production rates, oil and gas prices, future costs, discount rates and other relevant assumptions.

The Corporation has hired individuals and consultants who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

FUTURE ACCOUNTING PRONOUNCEMENTS

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers*, which replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts*, and related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by the Corporation on January 1, 2018. 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.

In July 2014, the IASB completed the final elements of IFRS 9 *Financial Instruments*. The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. 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.

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces IAS 17 *Leases*. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 *Revenue from Contracts with Customers*. The standard is required to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by Manitok on January 1, 2019 and the Corporation is currently evaluating the impact of the standard on Manitok's financial statements.

RISK FACTORS & RISK MANAGEMENT

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

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