MANITOK ENERGY INC.

Year Ended December 31, 2016

ANNUAL INFORMATION FORM

May 1, 2017

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DEFINITIONS

Definitions

In this Annual Information Form, certain terms are used but not defined herein. These terms are defined in NI 51-101 and CSA Staff Notice 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA Staff Notice 51-324. The capitalized terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act* (Alberta);

"**Annual Information Form**" means this Annual Information Form dated May 1, 2017;

"**Board**" means the board of directors of the Corporation;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook;

"**Crown**" means the Government of Alberta;

"**CSA Staff Notice 51-324**" means the Canadian Securities Administrators Staff Notice 51-324 *Glossary to NI 51-101*;

"**gross**" means: (a) in relation to the Corporation's interest in production or reserves, the Corporation's working interest (operating or non-operating) share before deduction of royalty obligations and without including any royalty interests; (b) in relation to wells, the total number of wells in which the Corporation has an interest; and (c) in relation to properties, the total area in which the Corporation has an interest;

"**GAAP**" means generally accepted accounting principles which is International Financial Reporting Standards, consistently applied;

"**Manitok**" or the "**Corporation**" means Manitok Energy Inc.;

"**Manitok Shares**" means common shares in the capital of the Corporation;

"**net**" means (a) in relation to the Corporation's interest in production or reserves, the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in such production or reserves; (b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of the Corporation's gross wells; and (c) in relation to properties, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation;

"**NI 51-101**" means National Instrument 51-101 *Standard of Disclosures for Oil and Gas Activities*;

"**P&NG**" means petroleum and natural gas;

"**reserves**" means estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates:

(a) probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves; and

(b) proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval;

"**Sproule**" means Sproule Associates Limited, independent qualified reserves evaluators and auditors of Calgary, Alberta;

"**2016 Sproule Evaluation**" means the Reserves Assessment and Economic Evaluation effective December 31, 2016 in respect of Manitok's oil and natural gas properties, which evaluation is contained in a report prepared by Sproule dated April 28, 2017;

"**2015 Sproule Evaluation**" means the Reserves Assessment and Economic Evaluation effective December 31, 2015 in respect of Manitok's oil and natural gas properties, which evaluation is contained in a report prepared by Sproule dated March 29, 2016;

"**Sproule Price Forecast**" means Sproule's December 31, 2016 forecast price assumptions set out in a table under "Reserves Data and Other Oil and Gas Information";

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations promulgated thereunder;

"**TSX**" means Toronto Stock Exchange;

"**TSX-V**" means TSX Venture Exchange;

"**WCSB**" means the vast sedimentary basin underlying western Canada that is the source of most of western Canada's current oil and natural gas production; and

"**working interest**" means a percentage of ownership in an oil and natural gas property, obligating the owner to share in the costs of exploration, development and operations and granting the owner the right to share in production revenues after royalties are paid.

ABBREVIATIONS, CONVERSIONS AND CONVENTIONS

Abbreviations

The abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	mcf	thousand cubic feet
bbls	barrels	Mmcf	million cubic feet
bbls/d	barrels per day	mcf/d	thousand cubic feet per day
Mbbls	thousand barrels	Mmcf/d	million cubic feet per day
NGLs	natural gas liquids	mcfe	thousand cubic feet equivalent
boe	barrels of oil equivalent	mcfe/d	thousand cubic feet equivalent per day
boe/d	barrels of oil equivalent per day	GJ	Gigajoule
Mboe	thousand barrels of oil equivalent	GJ/d	Gigajoules per day
		mmbtu	million British thermal units

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
M$	thousands of dollars

Conversions

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (metric units):

From	To	Multiply By
mcf	cubic metres	28.174
mcf	GJ	1.055
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
sections	acres	640
sections	hectares	256

Conventions

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in accordance with GAAP.

ADVISORIES

Non-GAAP Measures

This Annual Information Form contains references to measures used in the oil and natural gas industry such as "funds from operations" and "operating netback". These measures do not have any standardized meanings prescribed by GAAP and therefore should not be considered in isolation. These reported amounts and their underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of other companies where similar terminology is used. Where these measures are used they should be given careful consideration by the reader. These measures have been described and presented in this Annual Information Form in order to provide shareholders and potential investors with additional information regarding the Corporation's liquidity and its ability to generate funds to finance its operations.

Funds from operations should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net income (loss) as determined in accordance with GAAP, as an indicator of Manitok's performance or liquidity. Funds from operations is used by Manitok to evaluate operating results and Manitok's ability to generate cash flow to fund capital expenditures and repay indebtedness. Funds from operations denotes cash flow from operating activities as it appears on the Corporation's Statement of Cash Flows before decommissioning expenditures, acquisition-related expenses and changes in non-cash operating working capital. Funds from operations is also derived from net income (loss) plus acquisition-related expenses and non-cash items including deferred income tax expense (recovery), depletion and depreciation expense, impairment expense, stock-based compensation expense, accretion expense, unrealized gains or losses on financial instruments and gains or losses on asset divestitures.. Operating netback denotes P&NG revenue and realized gain or losses on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses calculated on a per boe basis.

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 using a 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 equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Forward Looking Information

This Annual Information Form 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" or "resources" contained, among other places, under "Reserves Data and Other Oil and Gas Information" is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves or resources exist in the quantities estimated and that it will be commercially viable to produce in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information. In particular, this Annual Information Form contains forward-looking information, including among other places, under the headings "Description of the Business", "Reserves Data and Other Oil and Gas Information" and "Risk Factors". This forward-looking information includes but is not limited to statements regarding: the Corporation's intention to drill and complete future wells; estimates of recoverable reserves and resource volumes; planned production increases; planned capital spending and sources of funding; expected results from the Corporation's portfolio of P&NG assets; the quantity and development of P&NG reserves and resources; future net cash flows and discounted cash flows; expected operating, services and environmental compliance costs; royalty rates and incentives; and treatment under tax laws. 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.

By their nature, forward-looking information involves a variety of assumptions, known and unknown risks and uncertainties, and other factors, which may cause actual results, levels of activity, and achievements to differ materially from those expressed or implied by such statements. The material factors and assumptions used to develop the forward-looking statements herein include, but are not limited to, the following; future commodity prices, currency exchange rates, inflation rates, well production rates, well drainage areas, success rates for future drilling, availability of labour and services, interest rates and future availability of debt and equity financing being at levels and costs that allow the Corporation to manage, operate and finance its business, develop its properties and meet its future obligations. With respect to estimates of reserves and resource volumes, a key assumption is the validity of the data used by Sproule in its independent reserves and resource evaluations. 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, intentions or expectations upon which it is based will occur. Although the Corporation believes that the expectations reflected in the forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ materially from those anticipated.

Forward-looking information necessarily involves both known and unknown risks associated with P&NG exploration, production, transportation and marketing, such as uncertainty of geological and technical data, imprecision of reserves and resources 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 and other risk factors that could affect operations or financial results are included under the heading "Risk Factors" in this 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 Annual Information Form 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.

CORPORATE STRUCTURE

Manitok was formed by the amalgamation of Desco Resources Inc. ("**Desco**") and Manitok Exploration Inc. ("**MEX**") under the ABCA on July 8, 2010 (the "**Amalgamation**").

Desco was incorporated under the ABCA on July 8, 2009. Prior to the Amalgamation, Desco was a reporting issuer in the provinces of British Columbia, Alberta, Manitoba and Ontario and was listed on the TSX-V under the trading symbol "DSR.P" as a "capital pool company".

MEX was incorporated under the ABCA on April 20, 2005 as a private company based in Calgary, Alberta. Prior to the Amalgamation, MEX was engaged in the acquisition, exploration, development and production of P&NG in the WCSB.

Desco and MEX agreed to amalgamate and form "Manitok Energy Inc." pursuant to the terms of an amalgamation agreement dated effective April 1, 2010. The Amalgamation was approved by the respective shareholders of Desco and MEX on June 25, 2010.

The Corporation's head office is located at Suite 700, 444 – 7th Avenue S.W., Calgary, Alberta, T2P 0X8, and its registered office is located at Suite 1600, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

The Corporation does have a wholly owned subsidiary, Raimount Oil and Gas Inc..

GENERAL DEVELOPMENT OF THE BUSINESS

Objectives

Manitok is a public P&NG exploration and development company focused on conventional P&NG in the WCSB. The stated business objectives of the Corporation consist of the following:

(a) find, develop and produce oil and natural gas on Manitok's current land holdings in order to maximize production, reserves and funds from operations; and

(b) acquire land, production and development and exploration opportunities in the WCSB, focusing on light oil in its core areas in southeast Alberta and west central Alberta.

Three Year History

2014

Effective February 10, 2014, The Corporation filed a Notice of Change of Auditors in connection with the appointment of KPMG LLP as the auditor of the Corporation. At the request of the Corporation, Kenway Mack Slusarchuk Stewart LLP resigned as the auditor of the Corporation.

On February 28, 2014, the Corporation closed a disposition of its entire working interest in its assets in the central Alberta foothills, with an effective date of January 1, 2014, for net cash proceeds of $21.8 million after post-closing adjustments ("**Foothills Asset Divestiture**"). The Foothills Asset Divestiture included approximately 777 boe/d (34% sweet natural gas, 60% sour natural gas and 6% liquids) of current production in the central Alberta foothills region and 36,000 net acres of undeveloped land. The net cash proceeds from the Foothills Asset Divestiture were used to partially fund the Corporation's ongoing capital expenditure program.

On March 11, 2014, the TSX-V authorized the Corporation's notice to make a normal course issuer bid ("**March 2014 NCIB**") to purchase for cancellation up to 6.8 million Manitok Shares on the open market during the period from March 17, 2014 to March 16, 2015.

On March 25, 2014, the Corporation announced the appointment of Timothy F. Jerhoff as the Vice President, Engineering. The Corporation also announced the departure of Yvonne McLeod as the Corporation's former Vice President, Drilling and Facilities.

On August 12, 2014, the Corporation announced the appointment of Dennis L. Nerland and R. Keith MacLeod to the board of directors. The Corporation also announced that Robert J. Dales did not seek re-election as a director of the Corporation at the June 2014 annual and special meeting of shareholders.

On October 30, 2014, Manitok received approval of the TSX-V to commence a new Normal Course Issuer Bid ("**November 2014 NCIB**") program to purchase for cancellation up to 6.3 million Manitok Shares on the open market during the period from November 3, 2014 and November 2, 2015.

On October 31, 2014, the Corporation completed an acquisition of approximately 290 boe/d (15% oil and liquids) in the Stolberg area of Alberta, with an effective date of October 1, 2014, for total cash consideration of $7.4 million after post-closing adjustments ("**Stolberg Acquisition**"). The Stolberg Acquisition was financed using the Corporation's credit facilities.

On December 30, 2014, the Corporation divested its interest in certain oil and gas infrastructure in the Carseland and Stolberg areas ("**December 2014 Facility Divestiture**") for net cash proceeds of $12.3 million after post-closing adjustments and closed a facilities financing agreement in the Stolberg area ("**December 2014 Facility Financing**") for net cash proceeds of $2.5 million with a third party for total net cash proceeds of $14.8 million after post-closing adjustments. The Corporation has entered into an agreement for the exclusive use of the oil and gas infrastructure, which include monthly facility fees of approximately $1.8 million per annum over eight years related to the December 2014 Facility Divestiture. Pursuant to the December 2014 Facility Financing, the Corporation is required to make monthly payments over 20 years at an effective interest rate of 13.5% over the life of the obligation and the obligation is secured by certain oil batteries in the Stolberg area. The net cash proceeds from the December 2014 Facility Divestiture and the December 2014 Facility Financing were used to reduce the Corporation's bank indebtedness.

2015

On May 1, 2015, the Corporation announced revised terms and additional lands to the Lease Issuance and Drilling Commitment Agreement with PrairieSky Royalty Ltd. ("**PSK**") ("**PrairieSky LIDCA**"). The major terms include:

- the acquisition of additional petroleum and natural gas leases covering about 180 net sections (115,200 acres) in southeast Alberta with access to proprietary 2D and 3D seismic data over the entire land base in exchange for a 4% gross overriding royalty on revenue with no deductions on its Stolberg lands ("**Stolberg GORR Divestiture**") of approximately 9,920 acres (5,555 net) from both the Cardium and Mannville formations effective as of January 1, 2015;
- the amendment of the freehold royalty rate in the majority of the land in Southeast Alberta to a flat rate of 17.5% retroactive to January 1, 2015, from the previous royalty calculation of a minimum of 10% and maximum of 30%;
- provisions to allow greater flexibility through capital deferment and reallocation of capital to additional lands in the area;
- the extension of the primary term of the PSK LIDCA for an additional 16 months from December 31, 2016 to April 30, 2018 with Manitok's option to extend for an additional period of four years for all or a portion of the land; and
- the decrease of the annual drilling and completion expenditure commitment; however, by extending the primary term 16 months, the aggregate drilling and completion expenditure commitment increased from $106.0 million to $126.0 million.

On June 12, 2015, the Corporation closed an asset acquisition in the Wayne area of southeast Alberta, including 1,800 boe/d of oil and natural gas production and a 25,000 bbls/d fluid processing facility, for total cash consideration of $61.1 million after post-closing adjustments ("**Wayne Acquisition**").

On June 12, 2015, the Corporation divested of a 5% gross overriding royalty on revenue with no deductions from the producing wells in the Wayne area ("**Wayne GORR Divestiture**") for net cash proceeds of $6.2 million after post-closing adjustments. The net cash proceeds from the Wayne GORR Divestiture were used to partially fund the Wayne Acquisition.

On June 12, 2015, Manitok entered into a production volume royalty agreement ("**PVR Divestiture**") with a royalty corporation for net cash proceeds of $24.4 million after post-closing adjustments. The PVR Divestiture royalty volume remains constant at 140 bbls/d of light crude oil for the first 8 years to May 31, 2023, and is then subject to a 10% decline per year thereafter. The royalty volumes are first allocated from the Corporation's Stolberg area, provided sufficient volumes are produced, and any short fall would be made up from oil production in the Wayne area and the Carseland area, if it exists at that point in the future. There is an associated capital commitment to spend a minimum of $10.0 million per year in 2016, 2017 and 2018 on drilling, completion, re-completion, workover, equipping and tie-in of wells targeting production from the Wayne and/or Carseland areas. This spending commitment will be satisfied with the PSK LIDCA spending and is not an additional commitment. Additionally, Manitok has agreed, but is not obligated to drill at least two gross wells per year in 2016, 2017 and 2018 in the Stolberg area. The net cash proceeds from the PVR Divestiture were used to partially fund the Wayne Acquisition.

On June 12, 2015, Manitok divested its interest in certain oil and gas infrastructure in the Wayne area ("**June 2015 Facility Divestiture**") for net cash proceeds of $7.1 million after post-closing adjustments and closed a facilities financing agreement in the Wayne area ("**June 2015 Facility Financing**") for net cash proceeds of $12.5 million with a third party for total net cash proceeds of $19.6 million after post-closing adjustments. The Corporation has entered into an agreement for the exclusive use of the oil and gas infrastructure, which include monthly facility fees of approximately $1.1 million per annum over eight years related to the June 2015 Facility Divestiture. Pursuant to the June 2015 Facility Financing, the Corporation is required to make monthly payments over 20 years at an effective interest rate of 14.5% over the life of the obligation and the obligation is secured by certain oil batteries in the Wayne area. The net cash proceeds from the June 2015 Facility Divestiture and the June 2015 Facility Financing were used to partially fund the Wayne Acquisition.

On June 12, 2015 and June 17, 2015, Manitok closed two tranches of a non-brokered private placement equity financing for the issuance of 12,587,600 Manitok Shares at a price of $0.80 per Manitok Share, 917,500 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 $0.85 per Manitok CDE Flow-through Share, and 6,305,077 Manitok Shares on a "flow-through" basis under the *Income Tax Act* (Canada) in respect of Canadian exploration expense ("**Manitok CEE Flow-through Shares**") at a price of $0.95 per Manitok CEE Flow-through Share for total net proceeds of $15.8 million ("**June 2015 Equity Financing**"). The net cash proceeds from the June 2015 Equity Financing of the Manitok Shares were used to partially fund the Wayne Acquisition and the net cash proceeds from the June 2015 Equity Financing of the Manitok CDE Flow-through Shares and the Manitok CEE Flow-through Shares were used to earn eligible Canadian development expenses and Canadian exploration expenses.

In June 2015 Manitok's credit facilities were reduced from $90.0 million to $80.0 million, which consists of a $45.0 million revolving operating demand loan facility ("**Conforming Credit Facility**") and a fully drawn $35.0 million non-revolving reducing demand loan facility ("**Non-Conforming Credit Facility**" and together with the Conforming Credit Facility, the "**Credit Facilities**"). The Corporation is required to repay the $35.0 million outstanding amount on the Non-Conforming Credit Facility as follows:

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

On June 25, 2015 Wilfred A. Gobert did not seek re-election as a director of the Corporation at the annual and special meeting of shareholders

In the fourth quarter of 2015, the Corporation entered into a farm-out agreement with a private oil and gas company (the "**Farmee**") whereby the Farmee has committed to spend up to $20.0 million from the fourth quarter of 2015 to the end of 2016 in the Rockyford area and depending on the level of success achieved with the drilling, may lead up to an additional $20.0 million of capital spending, with the Farmee having an option to drill the offset wells before the end of 2017 ("**Farm-out Agreement**"). Manitok has the option, but not the obligation to participate in each well and will be carried for a 5% working interest by the Farmee in each well it does not participate. The entire capital spend from the Farm-out Agreement will be fully allocated to Manitok's PSK LIDCA capital commitment.

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

2016

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

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

The Corporation is required to repay $0.4 million per month on the Non-Conforming Credit Facility beginning on February 1, 2016 and continuing every month thereafter until it is fully repaid.

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

In the first quarter of 2016, Manitok closed the final two tranches of the December 2015 Equity Financing for the issuance of 15,973,631 Manitok Shares at a price of $0.13 per Manitok Share and 1,170,000 Manitok CEE Flow-through Shares at a price of $0.15 per Manitok CEE Flow-through Share for net proceeds of $2.0 million along with an additional 70,414 Broker Warrants. The net cash proceeds from the final two tranches of the December 2015 Equity Financing of the Manitok Shares were used to reduce the Corporation's bank indebtedness and the net cash proceeds from the final two tranches of the December 2015 Equity Financing of the Manitok CEE Flow-through Shares will used to earn eligible Canadian exploration expenses. In connection with the December 2015 Equity Financing, Manitok has issued an aggregate of 1,241,127 Broker Warrants to the agents of the December 2015 Equity Financing, with each Broker Warrant entitling the holder thereof to acquire one Manitok Share at an exercise price of $0.13 per Manitok Share for a period of 18 months after the date of issuance of such Broker Warrants.

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

In February 2016, Manitok closed a non-cash asset exchange agreement from one partner in the Stolberg area, 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 with 122 boe/d (86% oil), along with an average 45% working interest in 10,500 acres of undeveloped land in the Stolberg area of Alberta (the "**Stolberg Asset Exchange**").

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 $2.9 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 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 (the "**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 "**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**") 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. The oil facility is pipeline connected to a terminal owned and operated by Pembina Pipeline Corporation and is only 70 kilometres east of Manitok's Stolberg assets. Total consideration for the acquisition was $14.9 million prior to transaction costs and customary closing adjustments ("**WG Acquisition**"), 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 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 gross proceeds of $5.1 million

Strategy

Manitok's corporate strategy is to build core areas focused around ownership in infrastructure and a solid development land base. The Corporation is focusing on lower Mannville oil in southeast Alberta and Cardium and Mannville plays in west central Alberta. Manitok has established a large land base, prospective for lower Mannville oil, in southeast Alberta through the PSK LIDCA and a number of targeted strategic acquisitions. Manitok plans to develop the Mannville oil primarily through horizontal drilling and multi-stage fracturing, which has been successful throughout North America. The Corporation has assembled a large undeveloped land base in west central, which is prospective for both Cardium oil and Mannville liquids rich gas. Manitok will create shareholder value through the development of its current assets and the strategic acquisition of additional assets within its core areas and in potentially new areas which complement our current core areas.

DESCRIPTION OF THE BUSINESS

General

The Corporation is a public oil and gas exploration and development company focused on Lithic Glauconitic ("**LG**") light oil in southeast Alberta and Cardium light oil in west central Alberta. The Corporation will utilize its experience, combined with the latest recovery techniques, to develop the remaining untapped oil and liquids-rich natural gas pools in its core areas of the WCSB.

Principal Properties

The following is a description of the Corporation's principal P&NG properties as at December 31, 2016. Unless otherwise noted, production stated is the average gross sales volumes for the period indicated in respect of the Corporation's working interest before the deduction of royalties and before royalty income volumes. Unless otherwise specified, gross and net acreage and well information is at December 31, 2016.

Carseland Area, southeast Alberta

The Carseland area is located approximately 70 kilometres east of Calgary, Alberta and is accessible year-round. In October 2013, Manitok leased the freehold mineral rights pursuant to the PSK LIDCA and gained access to the extensive 3D seismic covering all of the lands. Manitok began developing the LG and BQ formations with hydraulically fractured horizontal wells and as of December 31, 2016 Manitok had drilled 11 Mannville wells in Carseland. The area is highly prospective for extensive reserves of oil and solution gas. In February 2016 Manitok purchased a gas plant gas plant and sales line and plant modifications throughout 2016 have resulted in a highly economic liquids recovery plant with capacity of approximately 7,000 Mmcf/d.

Rockyford and Wayne Area, southeast Alberta

Rockyford is located approximately 91 kilometres east Calgary and the Wayne area is approximately 120 kilometres east of Calgary, Alberta and both areas are accessible year-round. In June 2015 Manitok closed the Wayne Acquisition which was comprised of the Wayne and Rockyford areas with access to 3D seismic which covers most of the acquired land. The Wayne and Rockyford areas are prospective for Mannville oil and natural gas and Manitok has identified a significant number of LG and BQ drilling opportunities on the lands. Manitok will develop the LG and BQ formations using horizontal wells with multi-stage fracturing. The infrastructure is well established and Manitok processes the Rockyford oil at Manitok’s facility in Wayne.

Manitok has also identified oil and natural gas potential in the Nisku, Pekisko and Upper Mannville formations, as well as natural gas potential in the Viking formation

The Wayne facility has the capacity to process 25,000 bbls/d of emulsion (oil/water mix), dispose 26,000 bbls/d of free water and process 15-18 Mmcf/d of natural gas. The plant can process sour/acid gas and has an acid gas injection well adjacent to the plant. The plant utilizes leading edge measurement and processing technology and is well suited to handle Manitok's processing requirements in southeast Alberta. Ownership of this facility allows Manitok to reduce its reliance on third-party processors as well as offer attractive third party processing options for other producers in the area.

Stolberg Area, west central Alberta

The Stolberg property is about 16 km north of the hamlet of Nordegg, Alberta and is accessible year-round. Over the last 30 years several major P&NG companies have explored and developed deep sour natural gas reserves in the area. Manitok has focused its capital on the Cardium Formation at Stolberg. In this area, the Cardium is a sweet oil bearing conventional reservoir, which has been deformed in complex geological structures. In some cases, the productive Cardium Formation has been deformed to depths as shallow as 800 metres. In these sandstone and conglomerate reservoirs, oil quality averages about 42° API. This very light oil is unusual in this part of the basin and demands a premium to the Alberta benchmark price. Manitok will develop this reservoir primarily with horizontal drilling. The Cardium in Stolberg is highly fractured naturally and typically does not require post-drilling stimulation, however the Corporation may elect to stimulate should the drill bit encounter lower permeable reservoirs. In addition, Manitok has been evaluating the potential to significantly increase the oil recovery through waterflood and gas injection. Simulation studies to date have indicated a positive response using this enhanced oil recovery technique, which will materially improve the oil recovery.

Manitok has also been developing Mannville gas in the Stolberg area. This reservoir is characterized by large reserves of sweet gas. Similar to the Cardium, the Mannville gas formations are complex, deformed geological structures where Manitok can apply its technical expertise. Development will consist of primarily short horizontal wells and the wells will not require post-drilling stimulation due to the natural occurring fractures in the reservoir, which is similar to Cardium oil development.

The area is prospective, particularly for large reserves of natural gas. The infrastructure is well established and Manitok has the technical expertise to successfully develop the area.

Willesden Green Area, west central Alberta

The Willesden Green Area is 185 kilometers north west of Calgary, Alberta and is accessible year-round. The property was acquired in the Willesden Green Acquisition in October 2016. The area is comprised of predominantly operated horizontal Cardium wells. Manitok owns an oil battery and compressor, which is pipeline connected to a sales oil terminal. Processing income is generated by third party treating at the battery. In addition to the 16 proven Cardium horizontal infill locations Manitok has identified, numerous liquids rich gas developments have been identified in the Mannville and Jurassic formations

Production

Production for the year ended December 31, 2016 averaged 4,602 boe/d (44% light oil and liquids), compared to average production of 4,480 boe/d (49% light oil and liquids) in the year ended December 31, 2015. Although aggregate production volumes remained consistent the Corporation has incurred natural production declines in Stolberg in 2016, which have been offset by an increase in production in the Carseland area and the closing of the WG Acquisition in October 2016 and the Wayne Acquisition in June 2015. For the year ended December 31, 2016, 30% of P&NG sales from the Corporation's properties before royalties was derived from natural gas and 70% was from crude oil and NGLs. Production is sold to marketers at delivery points in or close to the producing field.

Product Sales Revenues

The products produced and sold by the Corporation are light crude oil, conventional natural gas and NGLs. Most of these products are sold on a short-term basis at prices that are a function of current market prices. None of the Corporation's products are sold to non-arm's length parties.

The following table sets forth the aggregate sales of the products produced by the Corporation during the years ended December 31, 2016 and 2015:

Product	2016 Revenue (M$)	2015 Revenue (M$)
Natural Gas	14,033	14,503
Light Oil	30,096	39,953
NGLs	3,140	1,749
Total	47,269	56,205

Specialized Skill and Knowledge

The Corporation's business requires the application of extremely high levels of technical skill in the areas of geology, geophysics and reservoir engineering, well drilling and completions and well production operations. Manitok has assembled a team of skilled experts who provide the technical skills required to succeed in its business. See "*Risk Factors – Reliance on Key Personnel*".

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. The Corporation competes with numerous other participants in the search for and the acquisition of lands, P&NG projects and properties. The Corporation's competitors include companies which have greater technical and financial resources, as well as more staff and facilities, than the Corporation. Manitok believes that it has a competitive advantage in its focus areas based upon the facilities and land base it controls and the experience it has developed on the plays it pursues. See "*Risk Factors – Competition*".

Seasonal Factors

The exploration for and development of P&NG reserves in the Corporation's focus areas are dependent on access to areas where operational activities are to be conducted. Seasonal weather variations, including break-up, can delay such access. See *"Risk Factors – Seasonality*".

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on funds from operations and overall competitiveness. See "*Risk Factors – Environment and Regulatory Risks*" and "*Information Concerning the Oil and Natural Gas Industry – Environmental Regulation*".

Personnel

At December 31, 2016, the Corporation had: 27 full-time employees, eight part-time employees and six contract service providers in its head office and a total of 13 employees and 24 contract service providers in its various field locations. The Corporation hires skilled contractors to perform drilling operations, well completions and other field service operations. See "*Risk Factors – Reliance on Key Personnel*".

Environmental Policies

The Corporation has an active program to monitor and comply with health, safety and environmental laws, rules and regulations applicable to its operations. The Corporation's policies require operational activities to be conducted in a manner which meet or exceed regulatory requirements and industry standards to safeguard the environment and protect employees, contractors and the public at large. All employees receive pertinent health, safety and environmental training for their respective roles. The Corporation conducts regularly scheduled safety meetings, operational audits and assessments to identify risks and take steps to reduce or prevent accidents. See "*Risk Factors –Environmental and Regulatory Risks*".

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

- world market forces and more specifically, the North American market forces that shift the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
- political conditions, including the risk of hostilities throughout the world;
- increases or decreases in crude oil quality and market differentials;
- the impact of changes in the exchange rate between Canada and US dollars on prices received by the Corporation for its crude oil and natural gas;
- global and domestic economic and weather conditions;
- price and availability of alternative fuels; and
- the effect of energy conservation measures and government regulations.

RISK FACTORS

The Corporation's operations are exposed to a number of risks, some that impact the oil and gas industry as a whole and others that are unique to the Corporation. We have identified risks in four main categories: financial, operational, environmental and regulatory, and reputation. The impact of any risk or a combination of risks in these four categories may adversely affect the Corporation's business, reputation, financial condition, results of operations and funds from operations, which may materially affect the market price of the Corporation's securities. The holding of securities of the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision regarding the Corporation's securities.

Financial Risks

Access to Credit Markets

Due to the nature of the Corporation's business, it is necessary from time to time for the Corporation to access other sources of capital beyond its internally generated funds from operations in order to fund the development and acquisition of its long term asset base. As part of this strategy, the Corporation obtains a portion of this necessary capital by incurring debt and therefore the Corporation is dependent to a certain extent on continued availability of the credit markets. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing in the future to take advantage of business opportunities that may arise.

The continued availability of the credit markets for the Corporation is primarily dependent on the state of the economy and the health of the oil and natural gas and banking industries in Canada and the United States. There is risk that if the economy and banking industry experience unexpected and/or prolonged deterioration, the Corporation's access to credit markets may contract or disappear altogether. The Corporation tries to mitigate this risk by dealing with reputable lenders and tries to structure its lending agreements to give it the most flexibility possible should these situations arise. However, situations that give rise to credit market tightening or disappearing are largely beyond the Corporation's control.

The Corporation is also dependent, to a certain extent, on continued access to equity capital markets. The Corporation is listed on the TSX-V and maintains an active investor relations program. Continued access to capital is dependent on the Corporation's ability to continue to perform at a level that meets or exceeds market expectations.

Commodity Price Volatility

Manitok's liquidity and funds from operations is largely impacted by P&NG commodity prices. Oil and natural gas prices fluctuate in response to changes in the supply and demand for crude oil and natural gas, market uncertainty and a variety of additional factors that are largely beyond the Corporation's control.

Prices varied considerably throughout 2015 and 2016. There was a significant decline in prices during the last quarter of 2014 which continued to lead to depressed prices of crude oil and natural gas. Decreases in crude oil and natural gas prices typically result in a reduction of the Corporation's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Corporation's reserves. Any substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in the Corporation's net production revenue, funds from operations and profitability and have a material adverse effect on the Corporation's operations, financial condition and proved reserves and the level of expenditures for the development of its oil and natural gas reserves, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation will in part be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of the Corporation's bank indebtedness be repaid.

Crude oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, Organization of the Petroleum Exporting Countries ("**OPEC**") actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions, development and exploitation projects.

The Corporation has hedged a portion of its P&NG production at the date hereof and will continue to monitor the derivative market for opportunities to increase its hedged position. If there is a significant deterioration in the price it receives for P&NG, the Corporation will consider reducing its capital spending or accessing alternate sources of capital.

The Corporation enters into agreements to receive fixed prices for its P&NG production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, the Corporation may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose the Corporation to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedging arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts P&NG commodity prices.

Uncertainty of Reserves Estimates

There are a number of uncertainties inherent in estimating the quantities of reserves and resources, including many factors beyond the control of the Corporation. In general, estimates of economically recoverable P&NG reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, historical production from the properties, the assumed effects of regulation by government agencies and future operating costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable P&NG reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineer at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Corporation with respect to these reserves will vary from such estimates, and such variances could be material. Estimates with respect to proved plus probable reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. Consistent with the Canadian securities disclosure legislation and policies, the Corporation has used forecast prices and costs in calculating reserve quantities. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for P&NG, curtailments or increases in consumption by P&NG purchasers, changes in government regulations or taxation and the impact of inflation on costs. NI 51-101 requires the inclusion of the following statement in estimates of future net revenues based on reserves estimates; "estimates of future net revenues, whether discounted of not, does not represent fair market value".

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile in the near future as a result of global excess supply, recent actions taken by OPEC, and ongoing global credit and liquidity concerns. This volatility may affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Counterparty Credit Risk

The Corporation assumes customer credit risk associated with P&NG sales and joint venture participants. To mitigate this risk, the Corporation performs regular reviews of receivables to minimize default or non-payment and takes the majority of its production in kind.

Costs and Availability of Equipment and Services

Inflation is a risk common to all businesses in Canada. During times of high commodity prices for P&NG, there is a risk of substantially increased costs of operation, which impacts both the amount of capital required to perform operations and the netback the Corporation achieves from its production sales. Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. To the extent the Corporation is not the operator of its P&NG properties, the Corporation will be dependent on other operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators. Although the Corporation strives for continuous improvement in its planning, operations and procurement of materials, unexpected changes in the market for such equipment and services could negatively affect the Corporation's financial performance.

Volatility of Market Price of Manitok Shares

The trading price of Manitok Shares is subject to volatility as a result of factors both related and unrelated to the financial performance of the Corporation. The market price of the Manitok Shares may respond to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. The market price of the Manitok Shares may also respond to factors unrelated to the Corporation's performance such as commodity prices and the market perception of the attractiveness of the oil and gas industry.

Insurance

The Corporation obtains insurance in accordance with industry standards to address business risks, however such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, certain risks may not in all circumstances be insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on its financial position, results of operations or prospects.

Variations in Foreign Exchange Rates and Interest Rates

The Corporation is exposed to foreign currency fluctuations as its Canadian revenues are strongly linked to US dollar denominated benchmark prices. The Corporation has not hedged any of its foreign exchange risk at the date hereof.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Manitok Shares.

Joint Ownership

Many of the Corporation's material assets are jointly held and are governed by contractual arrangements. As a result, certain decisions regarding these assets require the approval of the Corporation's partners. While the

Corporation believes that it has prudent governance and contractual rights in place, there can be no assurance that the Corporation will not encounter disputes with partners that may impact operations or funds from operations.

Operations of the wells located on properties not operated by the Corporation are generally governed by operating agreements that typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of P&NG to the Corporation or to the operators, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of funds from operations available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

Income Taxes

The Corporation will file all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have a negative impact on current and future taxes payable and such impact may be material.

Borrowing

The Corporation's lenders have been provided with security over substantially all of the assets of the Corporation. If the Corporation becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell the Corporation's properties. The proceeds of any such sale would be applied to satisfy amounts owed to the Corporation's lenders and other creditors and only the remainder, if any, would be available to the Corporation.

Future Issuances of Manitok Shares

The Corporation may issue additional Manitok Shares in the future, which may dilute a shareholder's holdings in the Corporation. The Corporation's articles permit the issuance of an unlimited number of Manitok Shares and shareholders will have no pre-emptive rights in connection with such further issuances. The directors of the Corporation have the discretion to determine the terms of issue of further issuances of Manitok Shares. Also, additional Manitok Shares will be issued by the Corporation on the exercise of stock options under the Corporation's stock option plan and the exercise of Broker Warrants.

Dividends

The Corporation is not obligated to pay dividends on the Manitok Shares. The payment of dividends is at the sole discretion of the Corporation's Board and, as at the date hereof, the Corporation has not paid dividends. In addition, the Corporation's credit facilities may restrict its ability to pay dividends, and thus the Corporation's ability to pay dividends on the Manitok Shares will depend on, among other things, the Corporation's level of indebtedness at the time of the proposed dividend and whether it is in compliance with such credit facilities. Any reduction or elimination of dividends could cause the market price of the Manitok Shares to decline and could further cause the Manitok Shares to become less liquid, which may result in losses to shareholders.

Operational Risks

Exploration, Development and Production

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time and the production therefrom, will decline over time as such existing reserves are exploited.

Hydraulic fracturing involves the injection of fluid, sand and additives under pressure into rock formations to improve or encourage hydrocarbon production. The use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs. The Corporation anticipates that federal and provincial regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. The implementation of new regulations with respect to water usage of hydraulic fracturing generally could lead to operational delays, as well as increase the Corporation's costs of compliance, its operating costs, and may negatively impact the Corporation's prospects, any of which could have a material adverse effect on the Corporation's business, financial condition and results of operations. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves. The Corporation conducts its fracturing operations with reputable service providers, with due regard for the potential impact on the environment and closely monitors and complies with the regulatory regime.

The Corporation remains subject to the risk that the production rate of significant wells may decrease in an unpredictable and uncontrollable manner, which could result in a material decrease in the Corporation's overall production and associated funds from operations.

Availability of Processing and Pipeline Capacity

The Corporation is subject to deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and the possible inability to secure space on gathering systems that deliver production to processing facilities and on pipelines which deliver oil and natural gas to commercial markets. The majority of the Corporation's production is reliant on third party infrastructure prior to it being ready for transfer at designated commodity sales points. There is a risk that this infrastructure could fail and cause a significant portion of the Corporation's production to be shut-in and unable to be sold, which could have a material adverse effect on the Corporation's available funds from operations. The Corporation mitigates this risk by purchasing contingent business interruption insurance policies for its significant third party infrastructure.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of oil and gas properties in the ordinary course of business. Typically, once an opportunity is identified, a review of available information relating to the properties is conducted with most of the review effort being focused on the most significant properties. There is a risk that even a detailed review of records and properties may not necessarily reveal every existing or potential problem, nor will it permit the Corporation to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Corporation often assumes certain environmental and other risk liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of oil and gas reserves and actual future production rates and associated costs with respect to acquired properties, and actual results may vary substantially from those assumed in estimates. Management continually assesses the value of the Corporation’s assets and may dispose of non-core assets so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market, there is a risk that certain non-core assets could realize less than their carrying value in the Corporation’s financial statements. The Corporation manages the risk associated with acquisitions and disposition through a careful due diligence review of available information in order to make prudent business decisions.

Health, Safety and Environment Risks

Health, safety and environment risks influence the workforce, operating costs and the establishment of regulatory standards. These risks include, but are not limited to, encountering unexpected formations or pressures; premature declines of reservoirs; blow-outs; equipment failures; human error or wilful misconduct by field workers; other accidents such as, wellbore cratering, sour gas releases, uncontrollable flows of oil, natural gas or fluid spills; adverse weather conditions, pollution, fires and other environmental risks. The Corporation provides staff with the training and resources required to complete work safely and effectively; incorporates hazard assessment and risk management as an integral part of everyday operations; monitors performance to ensure its operations comply with legal obligations and internal standards; and identifies and manages environmental liabilities associated with its existing asset base. The Corporation has a site inspection program and a corrosion risk management program designed to ensure compliance with environmental laws and regulations. The Corporation carries insurance to cover a portion of property losses and liability to third parties and business interruption resulting from unusual events.

The Corporation is subject to the risk that the unexpected failure of its equipment used in drilling, completing or producing wells or in transporting production could result in release of fluid substances that pollute or contaminate lands at or near its facilities, which could result in significant liability to the Corporation for costs of clean up, remediation and reclamation of the contaminated lands. The Corporation conducts its operations with due regard for the potential impact on the environment. This includes hiring skilled personnel, providing adequate training to all staff involved with operations, and by retaining expert advice and assistance to deal with environmental remediation and reclamation work where such expertise is required.

Reserve Replacement

P&NG reserves naturally deplete as they are produced over time. The success of the Corporation's business is highly dependent on its ability to acquire or discover new reserves in a cost effective manner. Substantially all of the Corporation's funds from operations is derived from the sale of the P&NG reserves it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its funds from operations on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. In order to mitigate this risk, the Corporation employs a competent and experienced team of P&NG professionals and closely monitors the capital expenditures made for the purposes of increasing its P&NG reserves.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access and, as a result, reduced operations or a cessation of operations. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain P&NG producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in drilling and production activity.

Expiration of Licences and Leases

The Corporation’s properties are held in the form of licences and leases and working interests in licences or leases held by others. If the Corporation or the holder of the licence or lease fails to meet specific requirements of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of licences or leases may have a material adverse effect on results of operations and the business of the Corporation. To mitigate this risk, the Corporation carefully monitors its undeveloped land position and plans operations in order to keep key licences and leases from terminating or expiring.

Competition

The oil and natural gas industry is highly competitive particularly as it pertains to the exploration for and development of new sources of P&NG reserves. The industry also competes with other industries in supplying non-petroleum energy products. The Corporation actively competes for land, production and reserve acquisitions, exploration leases, licenses and concessions and skilled technical and operating personnel with a substantial number of other P&NG companies, many of which have greater financial resources than the Corporation.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's ownership claims, which could result in the Corporation losing all or a portion of its right title and interest in and to the properties to which the title defects relate.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. An inability of the Corporation to effectively deal with this growth could have a material adverse impact on its business, operations and business prospects. Management mitigates this risk by continually implementing appropriate procedures and policies for its size, upgrading its systems, training its employees and providing effective supervision and management of its staff.

Reliance on Key Personnel

The loss of the services of key personnel could have a material adverse effect on the Corporation. The Corporation does not have "key person" insurance in effect for management and the contributions of these individuals to the Corporation's immediate operations is of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Shareholders must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the Corporation's management.

Environment and Regulatory Risks

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of any such legislation may result in the imposition of fines or other penalties, as well as the responsibility to remedy environmental problems caused by the Corporation's operations. A serious breach could result in the Corporation being required to suspend operations or enter into an interim compliance measure which may restrict the Corporation's ability to conduct operations.

Political and economic events may significantly affect the scope and timing of climate change measures that are put in place. Some of the Corporation's facilities may be subject to future provincial or federal climate change regulations to manage emissions and there can be no assurance that the compliance costs will be immaterial. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the oil and natural gas industry generally could reduce demand for crude oil and natural gas and increase costs.

Litigation

In the normal course of the Corporation's operations, it may become involved in, be named as a party to or be the subject of various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes, among other matters. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceeding, the proceeding could be costly and time-consuming and may divert the attention of management and key personnel from the Corporation's business operations. Specific disclosure of current legal proceedings is disclosed under the heading "*Legal Proceedings and Regulatory Actions*" in this Annual Information Form.

Changes in Legislation

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on the Corporation. As a P&NG producer, the Corporation is subject to a broad range of regulatory requirements. Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, extraordinary environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment. In addition, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil and reduce its price. The Corporation hires and retains skilled personnel that are knowledgeable regarding changes to the regulatory regime under which it operates.

All of the Corporation's properties are currently located within the province of Alberta. Although the Corporation believes it is making an economic investment at the time all of the upfront capital is invested in facilities or drilling, completing and equipping an oil or natural gas well, there is a risk that the Government of Alberta may at any point in the economic life of that project, expropriate without compensation a portion of the expected profit under a new royalty and/or tax regulation or regime with no grandfathering provisions. This may cause a particular project to become uneconomic once the new royalties or taxes take effect. This type of possible future government action is unpredictable and cannot be forecast by the Corporation.

Licensee Liability Rating Program

In Alberta, the Alberta Energy Regulator **("AER")** implements the *Licensee Liability Rating* **("AB LLR")** program which involves the assessment of the ratio of a licensee's deemed assets to its deemed liabilities. The AB LLR program requires a licensee whose deemed assets are less than its deemed liabilities (an AB LLR ratio of less than 1.0) to provide the AER with a security deposit. The AB LLR ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER. While Manitok's AB LLR ratio is currently well above 1.0, there is a risk that future acquisitions of oil and gas assets by Manitok, a decrease in the deemed asset value of Manitok or an increase in the amount of Manitok's deemed liabilities may lower such AB LLR ratio below 1.0. In the event that Manitok's AB LLR ratio drops below 1.0, Manitok will need to provide the AER with a security deposit, which may have an adverse effect on Manitok's operations.

Climate Change

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. If the Corporation becomes subject to Greenhouse Gas ("**GHG**") legislation, there can be no assurances that the compliance costs will be immaterial. In November 2015, Canada participated in the Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, the goal of which was to reach a new agreement for fighting global climate change. The Conference resulted in the adoption of the non-binding Paris Agreement which made several recommendations, including: a) holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial levels; b) increasing the ability to adapt to the adverse impacts of climate change and foster climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production; and c) making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development. The Paris Agreement is currently not in effect, but will enter into force upon fifty five parties that account for at least an estimated 55% of the total global greenhouse gas emissions depositing their instrument of ratification, approval or acceptance.

The Government of Alberta enacted the *Climate Change and Emissions Management Act* in response to concerns regarding GHG. The *Specified Gas Emitters Regulation* that accompanies the Act came into force in 2007 and currently requires large industrial facility emitters of GHG to reduce GHG emissions intensities by 15% below a baseline derived from the average of 2003-2005 emissions, which increases to 20% as of January 1, 2017. The Corporation is not considered a large industrial emitter under this legislation and, as such, the Corporation is not subject to the costs of complying with the *Specified Gas Emitters Regulation.*

In August 2015, the Alberta Government appointed a Climate Leadership Panel to provide advice to the government on the development of a comprehensive climate change strategy and policy measures to reduce GHG emissions in Alberta. On November 22, 2015, the government released the Climate Leadership Panel's Report to the Minister and the government announced that it would implement its recommendations on phasing out coal-fired power production, replacing two-thirds of that production with renewable energy and imposing a new economy-wide price on GHG emissions of $20.00 per tonne on January 1, 2017, rising to $30.00 per tonne on January 1, 2018. Emissions from flaring at oil and gas wells and facilities and from landfills will also be subject to a GHG emission levy starting at $20.00 per tonne in 2017 and increasing to $30.00 a tonne in 2018 and thereafter. Fuel gas consumed in operating oil and gas wells, pipelines and facilities will be subject to the $30.00 per tonne levy commencing January 1, 2023. The Panel also recommended that the $30.00 per tonne levy increase annually at a rate equal to the rate of inflation plus 2% per year so long as the levy in Alberta does not significantly exceed carbon prices in comparable jurisdictions or any future national carbon standard.

Methane emission reduction in the oil and gas industry is also part of the Climate Leadership Panel's Report, with a goal of reducing oil and gas methane emissions by 45% by 2025. The Panel has made two recommendations in this regard. First, to put in place new design specifications for oil and gas wells, pipelines and facilities as well as standards for key equipment and operational best practices. Fugitive emission standards will also be included in the regulatory requirements and will require raising current standards for performance, monitoring, measurement and reporting. Second, updating or retrofitting methane emitting equipment in existing facilities before the end of the equipment's useful life, which may include mandating the replacement of equipment at facilities that have not participated in the offset program before the end of the equipment's life, or the shut-in and abandonment of the well or facility which uses such equipment.

Potential Conflicts of Interest

Some of the directors of the Corporation are also directors of other P&NG companies, which may from time to time be in competition with the Corporation for working interest partners, property acquisitions, or other limited resources. Where required by law, appropriate disclosure of such conflicts will be made by the applicable directors. In particular, the Corporation follows the provisions of the ABCA, which state that in the event that a director has an interest in a contract or proposed contract or agreement, such director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise permitted by the ABCA.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of the Corporation's assets; however, if a claim arose and was successful, it could have an adverse effect on the Corporation and its operations.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

This statement of reserves data and other oil and gas information of Manitok is dated April 28, 2017. The effective date of the reserves and future net revenues information is December 31, 2016, unless otherwise indicated, and the preparation date is November 2016 to April 2017.

Disclosure of Reserves Data

Sproule, independent qualified reserves evaluators and auditors of Calgary, Alberta prepared the 2016 Sproule Evaluation. Sproule has confirmed to the Reserve and Occupational Health and Safety Committee of the Board that the 2016 Sproule Evaluation has been prepared in accordance with the standards contained in the COGE Handbook and NI 51-101.

In preparing its report, Sproule obtained basic information from Manitok, which included land data, well and accounting information, reservoir and geological studies, estimates of on-stream dates for certain properties, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluation, and upon which the 2016 Sproule Evaluation is based, were obtained from public records, other operators and from Sproule's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by Sproule.

For the purposes of properly understanding the reserves and future net revenue data presented from the 2016 Sproule Evaluation it is important to understand each of the following:

- Due to rounding, certain columns may not add exactly.
- The net present value of future net revenue attributable to the Corporation's reserves is based on the Sproule Price Forecast and is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, transportation and marketing costs, development costs, other income, future capital expenditures and well abandonment and reclamation costs for only those wells assigned reserves by Sproule.
- It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by Sproule represent the fair market value of those reserves.
- The recovery and reserve estimates of the Corporation's oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. Reservoir performance after December 31, 2016 may justify revision of assessed reserves, either upward or downward.
- The tables below are a summary of the oil, NGLs and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the 2016 Sproule Evaluation based on the Sproule Price Forecast and represent 100% of the Corporation's oil and natural gas assets.
- The 2016 Sproule Evaluation is based on certain factual data supplied by the Corporation and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to Manitok's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Manitok to Sproule and accepted without any further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.
- Estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.
- The monthly facility fees pursuant to the December 2014 Facility Divestiture of $1.8 million per annum for an undiscounted cumulative total of $10.9 million in facility fees for the remainder of the term of the

agreement which expires in December 2022 is not included in the 2016 Sproule Evaluation or the 2015 Sproule Evaluation.

- The monthly facility fees pursuant to the June 2015 Facility Divestiture of $1.1 million per annum for an undiscounted cumulative total of $7.3 million in facility fees for the remainder of the term of the agreement which expires in June 2023 is not included in the 2016 Sproule Evaluation or the 2015 Sproule Evaluation.
- The production volume royalty pursuant to the PVR Divestiture is not reflected in the 2016 Sproule Evaluation or the 2015 Sproule Evaluation.

All of the reserves held by Manitok as at December 31, 2016 are located in Canada and specifically, in the province of Alberta.

Reserves Data (Forecast Prices and Costs)

The following table summarizes Sproule's estimates of Manitok's oil and natural gas reserves at December 31, 2016, using the Sproule Price Forecast.

SUMMARY OF OIL AND GAS RESERVES AS AT DECEMBER 31, 2016
(Forecast Prices and Costs)

	LIGHT AND MEDIUM CRUDE OIL(1)		**CONVENTIONAL NATURAL GAS(2)**		**NATURAL GAS LIQUIDS**		**TOTAL**	
RESERVES CATEGORY	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED								
Developed Producing	2,733.5	2,165.0	34,437	29,418	1,197.7	878.9	9,670.7	7,946.9
Developed Non-Producing	488.0	426.4	6,791	5,807	381.4	288.4	2,001.2	1,682.6
Undeveloped	1,986.5	1,662.0	15,400	13,990	782.7	677.3	5,335.8	4,671.1
TOTAL PROVED	**5,207.9**	**4,253.4**	**56,627**	**49,216**	**2,361.9**	**1,844.6**	**17,007.7**	**14,300.6**
TOTAL PROBABLE	3,052.9	2,424.9	39,259	34,112	1,550.3	1,168.7	11,146.3	9,278.9
PROVED PLUS PROBABLE	**8,260.6**	**6,678.3**	**95,887**	**83,328**	**3,912.2**	**3,013.3**	**28,154.0**	**23,579.5**

(1) Estimates of reserves of light and medium crude oil include a minor amount of heavy crude oil.
(2) Estimates of reserves of natural gas include solution gas and both associated and non-associated gas.

The following table is a summary of the net present values of future net revenues associated with such reserves at December 31, 2016, using the Sproule Price Forecast, before and after deducting income taxes, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%. Future net revenue includes estimated future abandonment and reclamation costs related to wells and production facilities required to produce the reserves.

NET PRESENT VALUES OF FUTURE NET REVENUE[1] AS AT DECEMBER 31, 2016
(Forecast Prices and Costs)

	Before Income Taxes Discounted at (%/year)					**After Income Taxes Discounted at (%/year)**					**Before Income Tax Unit Value Discounted at 10%[2]**
RESERVES CATEGORY	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	($/boe)
PROVED											
Developed Producing	162,419	134,410	114,872	100,804	90,242	157,327	130,845	112,307	98,914	88,822	14.46
Developed Non-Producing	35,481	26,619	20,899	17,027	14,276	25,640	19,517	15,531	12,822	10,892	12.42
Undeveloped	100,890	70,698	52,549	40,832	32,731	74,389	50,834	36,670	27,602	21,395	11.25
TOTAL PROVED	**298,790**	**231,727**	**188,320**	**158,662**	**137,249**	**257,357**	**201,196**	**164,507**	**139,338**	**121,110**	**13.17**
TOTAL PROBABLE	224,823	153,514	111,459	84,601	66,328	164,084	110,708	79,168	59,067	45,436	12.01
PROVED PLUS PROBABLE	**523,613**	**385,241**	**299,780**	**243,264**	**203,577**	**421,441**	**311,904**	**243,675**	**198,404**	**166,545**	**12.71**

(1) Estimates of future net revenue, whether discounted or not, does not represent fair market value
(2) Unit values are based on net reserve volumes.

Components of Future Net Revenue

The following table sets out, in the aggregate, the various elements of the Corporation's future net revenue associated with the Corporation's reserves, calculated using the Sproule Price Forecast and without discount.

COMPONENTS OF FUTURE NET REVENUE[1] AS AT DECEMBER 31, 2016
(Forecast Prices And Costs) (Undiscounted)

RESERVES CATEGORY	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Development Costs (M$)**	**Abandonment and Reclamation Costs (M$)[2]**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
TOTAL PROVED	784,700	125,090	282,563	54,874	23,383	**298,790**	41,433	**257,357**
PROVED PLUS PROBABLE	1,310,120	217,170	431,169	109,370	28,797	**523,613**	102,173	**421,441**

(1) Estimates of future net revenues whether discounted or not, does not represent fair market value.
(2) Excludes abandonment and reclamation costs for wells with no assigned reserves in the 2016 Sproule Evaluation, pipelines and associated processing and transport facilities.

Future Net Revenue by Production Group

The following table provides additional information derived from the 2016 Sproule Evaluation, by production group, regarding the future net revenues associated with the Corporation's reserves, before deducting income taxes and calculated using a 10% discount rate.

NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAXES BY PRODUCTION GROUP AS AT DECEMBER 31, 2016 (Forecast Prices And Costs) (10% discount rate)						
	LIGHT AND MEDIUM CRUDE OIL(2)		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS(2)	
RESERVES CATEGORY	(M$)	($/boe)	(M$)	($/boe)	(M$)	($/boe)
TOTAL PROVED	**159,602**	**14.95**	**2,260**	**19.25**	**26,458**	**7.54**
PROVED PLUS PROBABLE	**260,566**	**14.88**	**2,800**	**18.94**	**36,414**	**6.15**

(1) Estimates of future net revenue, whether discounted or not, does not represent fair market value.
(2) Estimates of reserves include both associated and non-associated gas and by-products. The production groupings are determined based upon the primary product produced from each reserve entity. The values and volumes of associated gas and the by-products derived from such associated gas are included with oil. The values and volumes of the by-products derived from non-associated gas are included with natural gas.
(3) Unit amounts are derived using net reserves volumes.
(4) Future net revenue is after deduction of estimated costs of abandonment and reclamation of existing and future wells.

Pricing Assumptions

Forecast Prices Used in Estimates

The following table sets out the Sproule Price Forecast used for the 2016 Sproule Evaluation. The pricing and cost assumptions used were determined by Sproule using information available from numerous government agencies, industry publications, oil refineries, natural gas marketers and industry trends. These forecast price assumptions are subject to many uncertainties that exist in both the domestic and international petroleum industries.

SPROULE PRICE FORECAST AS AT DECEMBER 31, 2016							
	CRUDE OIL			NATURAL GAS	NGLs		
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Canadian Light Sweet 40° API ($/bbl)**	**Western Canadian Select 20.5° API ($/bbl)**	**Alberta AECO-C Spot ($/mmbtu)**	**Edmonton Butane ($/bbl)**	**Edmonton Pentanes Plus ($/bbl)**	**Exchange Rate ($US/$CAD)**
2017	55.00	65.58	53.12	3.44	47.60	67.95	0.780
2018	65.00	74.51	61.85	3.27	55.49	75.61	0.820
2019	70.00	78.24	64.94	3.22	57.65	78.82	0.850
2020	71.40	80.64	66.93	3.91	58.80	80.47	0.850
2021	72.83	82.25	68.27	4.00	59.98	82.15	0.850
2022	74.28	83.90	69.64	4.10	61.18	83.86	0.850
2023	75.77	85.58	71.03	4.19	62.40	85.61	0.850
2024	77.29	87.29	72.45	4.29	63.65	87.39	0.850
2025	78.83	89.03	73.90	4.40	64.92	89.21	0.850
2026	80.41	90.81	75.38	4.50	66.22	91.07	0.850
2027	82.02	92.63	76.88	4.61	67.54	92.96	0.850
thereafter	Escalate at 2.0% per annum						

The actual weighted average commodity prices received by Manitok in 2016 are as follows: (a) light crude oil: $48.11/bbl; (b) natural gas: $2.49/mcf; and (c) NGLs: $26.54/bbl.

Reconciliation of Changes in Reserves

The following tables set forth a reconciliation of the Corporation's gross reserves using the Sproule Price Forecast for the year ended December 31, 2016 as derived from the 2016 Sproule Evaluation against the 2015 Sproule Evaluation, using the Sproule price forecast provided in the 2015 Sproule Evaluation for the year ended December 31, 2015.

	Light and Medium Crude Oil[1]			NGLs		
Factors	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**
December 31, 2015	4,404.6	2,889.2	7,293.8	668.8	403.1	1,071.9
Extensions[2]	96.0	173.9	269.9	149.1	207.6	356.7
Infill drilling[3]	-	130.0	130.0	-	69.6	69.6
Improved recovery	-	-	-	-	-	-
Technical revisions[4]	(386.0)	(484.6)	(870.6)	242.1	357.6	599.7
Discoveries[5]	73.1	64.4	137.5	85.1	30.3	115.4
Acquisitions[6]	1,795.2	474.5	2,269.6	1,352.4	488.9	1,841.3
Dispositions	-	-	-	-	-	-
Economic Factors[7]	(149.4)	(194.6)	(344.0)	(17.5)	(6.8)	(24.3)
Production[8]	(625.6)	-	(625.6)	(118.1)	-	(118.1)
December 31, 2016	**5,207.9**	**3,052.8**	**8,260.6**	**2,361.9**	**1,550.3**	**3,912.2**

	Natural Gas			Total		
Factors	**Gross Proved (Mmcf)**	**Gross Probable (Mmcf)**	**Gross Proved Plus Probable (Mmcf)**	**Gross Proved (Mboe)**	**Gross Probable (Mboe)**	**Gross Proved Plus Probable (Mboe)**
December 31, 2015	29,190	26,369	55,559	9,938.4	7,687.2	17,625.6
Extensions[2]	1,848	3,197	5,045	553.0	914.4	1,467.4
Infill drilling[3]	-	1,157	1,157	-	392.4	392.4
Improved recovery	-	-	-	-	-	-
Technical revisions[4]	(1,175)	(3,086)	(4,262)	(339.7)	(641.4)	(981.1)
Discoveries[5]	1,602	560	2,162	425.2	188.0	613.2
Acquisitions[6]	31,413	11,571	42,984	8,383.1	2,891.8	11,274.9
Dispositions	-	-	-	-	-	-
Economic Factors[7]	(608)	(508)	(1,116)	(268.2)	(286.0)	(554.2)
Production[8]	(5,642)	-	(5,642)	(1,684.2)	-	(1,684.2)
December 31, 2016	**56,627**	**39,260**	**95,887**	**17,007.7**	**11,146.3**	**28,154.0**

(1) The light and medium crude oil category include a minor amount of heavy crude oil.

(2) The majority of reserve changes comprising "Extensions" were the result of drilling activities in the Carseland, Rockyford and Wayne areas. Wells were drilled extending the play in previously discovered reservoirs. As a result of these successful wells, reserves were attributed to future well locations proximal to these wells.

(3) The majority of reserve changes comprising "Infill drilling" were the result of drilling Lithic Glaucontic wells in Carseland which confirmed further drilling locations.

(4) "Technical Revisions" resulted mainly from operating costs and gas shrinkage increases as well as reservoir performance in the Wayne and Rockyford areas.

(5) The majority of reserve changes comprising "Discoveries" were the result of exploratory drilling activities in the Carseland, Rockyford and Wayne areas in the Lithic Glauconitic and Basal Quartz oil formations.

(6) "Acquisitions" were mainly the result of the WG Acquisition on October 27, 2016.

(7) "Economic Factors" result from oil and natural gas price forecasts used in the 2016 Sproule Evaluation that were lower than the oil and natural gas forecasts used in the 2015 Sproule Evaluation, resulting in negative impacts on some reserve volumes. In addition, the introduction of the Modernized Royalty Framework announced by the Government of Alberta in 2016 resulted in negative impacts on some reserve volumes.

(8) Represents production for 2016.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table sets forth the volumes of each of the gross proved undeveloped reserves and the gross probable undeveloped reserves from the 2016 Sproule Evaluation for each product type booked as reserves in each of the most recent four financial years.

Proved Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Natural Gas (Mmcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
Year(1)	**First Attributed(1)**	**Booked**	**First Attributed(1)**	**Booked**	**First Attributed(1)**	**Booked**	**First Attributed(1)**	**Booked**
Dec 31/13	833.1	1,623.9	849	3,616	2.4	44.0	977.0	2,270.6
Dec 31/14	789.8	905.6	1,691	2,791	24.5	27.8	1,096.1	1,398.6
Dec 31/15	410.0	1,407.9	1,551	4,762	88.5	105.5	757.0	2,307.1
Dec 31/16	966.5	1,986.5	12,518	15,400	684.4	782.7	3,737.2	5,335.9

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding financial year.

Probable Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Natural Gas (Mmcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
Year(1)	**First Attributed(1)**	**Booked**	**First Attributed(1)**	**Booked**	**First Attributed(1)**	**Booked**	**First Attributed(1)**	**Booked**
Dec 31/13	1,635.6	2.655.2	1,601	10,945	4.4	125.9	1,906.8	4,605.3
Dec 31/14	694.5	1,420.6	3,363	11,291	64.2	166.3	1,319.2	3,468.7
Dec 31/15	359.9	1,515.3	4,468	15,939	72.3	205.0	1,176.9	4,376.8
Dec 31/16	578.6	1,748.2	9,498	24,289	520.1	999.5	2,681.7	6,795.9

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding financial year.

The 2016 Sproule Evaluation has identified a conservative number of low-risk, undeveloped drilling opportunities. A total of 63 gross (54.9 net) locations have been identified in the 2016 Sproule Evaluation, comprising 43% of the total booked proved plus probable reserves, as compared to 39% in the 2015 Sproule Evaluation. Manitok has an inventory of over 250 gross locations for horizontal wells on current land holdings, suggesting a continued conservative approach to booking undeveloped locations. The majority of the undeveloped locations are in the Stolberg, Carseland, Wayne and Willesden Green areas. A total of 9 gross (4.2 net) locations have been identified in the Stolberg area, 15 gross (15 net) well locations in the Carseland area, 8 gross (8 net) well locations in the Wayne area and 16 gross (12 net) well locations in the Willesden Green area. The proved plus probable future development costs are approximately 4.0 times projected 2017 undiscounted proved plus probable before tax cash flow.

The highest value undeveloped reserves occur in the Carseland area. On a before tax net present value discounted at 10% ("**NPV10%**") basis, the proved plus probable undeveloped value in the Carseland area is 9.0% of the total proved plus probable reserve value before tax. The second highest value is in the Stolberg area which accounts for 4.9% of the NPV10% total proved plus probable reserve value before tax.

Manitok's plan relating to the development of its proved and probable undeveloped reserves and the timing of such reserves development may change based on commodity prices or any changes in geological, geophysical, or engineering data that become available to Manitok. Capital allocation also depends upon an array of other potential investments in its areas of interest and other areas.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting P&NG prices and costs change. The reserve estimates contained herein are based on Sproule's production forecasts, prices and economic conditions at the time of preparation of the 2016 Sproule Evaluation. The factors and assumptions that affect these reserve estimates include, among other things: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions are often required over time due to changes in well performance, prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end P&NG prices and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The following table sets forth the future development costs that have been deducted in the estimation of future net revenue attributable to the Corporation's reserves estimated in the 2016 Sproule Evaluation using the Sproule Price Forecast and calculated without discount.

FUTURE DEVELOPMENT COSTS (Forecast Prices and Costs)		
Calendar Year	**Total Proved (M$)**	**Proved Plus Probable (M$)**
2017	25,874	41,102
2018	11,474	25,740
2019	13,586	25,460
2020	3,939	9,530
2021	-	3,802
Thereafter	-	3,737
Total Undiscounted	**54,874**	**109,370**

The Corporation expects to be able to fund the development costs required in the future from internally generated funds from operations, existing credit facilities and access to equity markets. Interest and other costs of external funding are not included in the future net revenue estimates. The Corporation does not expect any inordinate costs to be associated with such funding sources.

There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the 2016 Sproule Evaluation. Failure to develop those reserves would have a negative impact on future production and funds from operations.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The Corporation's important properties and facilities are described under the heading "*Description of the Business – Principal Properties*".

Producing and Non-Producing Wells

The following table shows Manitok's producing and non-producing P&NG wells as at December 31, 2016, all of which are in Alberta.

2016 PRODUCING AND NON-PRODUCING WELLS								
	CRUDE OIL WELLS				**NATURAL GAS WELLS**			
	Producing		**Non-producing**		**Producing**		**Non-producing**	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	223	131.2	213	115.5	111	58.3	234	127.3

Properties with No Attributed Reserves

At December 31, 2016 Manitok held 237,830 (205,516 net) hectres of undeveloped land, all of which is in Alberta. Approximately 29.2% of the net hectres for the rights to explore, develop and exploit are expected to expire prior to the end of 2017. It is expected that the Corporation will be able to continue approximately 5% of this expiring acreage.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of Manitok's properties with no attributed reserves. Manitok will be required to make substantial capital expenditures in order to prove, exploit, develop and produce P&NG from these properties in the future. If Manitok's funds from operations are not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause Manitok to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of Manitok to access sufficient capital for its exploration and development activities could have a material adverse effect on Manitok's ability to execute its business strategy to develop these prospects. See "*Risk Factors – Access to Credit Markets*".

The significant economic factors that affect Manitok's development of its lands to which no reserves have been attributed are future commodity prices for P&NG and Manitok's outlook relating to such prices, and the future costs of drilling, completing, equipping, tie-in and operating the wells at the time that such activities are considered in the future.

The significant uncertainties that affect Manitok's development of such lands are: (i) the future drilling and completion results Manitok achieves in its development activities; (ii) drilling and completion results achieved by others on lands in proximity to Manitok's lands; and (iii) future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Alternatively, uncertainty as to the timing and nature of the evolution or development of better exploration drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such lands.

Forward Contracts and Marketing

With the exception of the following financial derivative contracts entered into pursuant to the Corporation's risk management program, as of December 31, 2016, the Corporation does not have any material commitments to buy or sell P&NG production.

As at December 31, 2016, the Corporation held the following derivative commodity contracts:

Product	**Notional Quantity**	**Term**	**Reference**	**Strike Price**	**Type of Contract**
Oil	250 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	$46.00	Option(1)
Oil	250 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	$41.00	Option(2)
Oil	250 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	$42.60	Option(3)
Oil	250 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	$42.00	Option(4)
Natural gas	4.000 GJs/d	January 1, 2017 to December 31, 2017	CAD$ AECO	$2.28	Option(5)
Natural gas	4,000 GJs/d	January 1, 2017 to December 31, 2017	CAD$ AECO	$2.52	Option(6)

(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	April 1, 2017 to December 31, 2017	CAD$ AECO	$2.20	Option(1)
Natural gas	2,000 GJs/d	April 1, 2017 to December 31, 2017	CAD$ AECO	$2.10	Option(2)

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

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

Tax Horizon

Based on after-tax economic forecasts in the 2016 Sproule Evaluation, income taxes begin to be payable by the Corporation in 2021, using proved developed producing reserves.

Costs Incurred

The following table sets forth Manitok's property acquisition costs for proved properties and unproved properties, exploration costs and development costs for the year ended December 31, 2016.

2016 ACQUISITION, EXPLORATION AND DEVELOPMENT COSTS				
Acquisition Costs Proved Properties (M$)	**Acquisition Costs Unproved Properties (M$)**	**Exploration Costs (M$)**	**Development Costs (M$)**	**Total (M$)**
32,141	2,110	11,677	8,085	**54,014**

Exploration and Development Activities

Manitok's planned exploration and development activities are described in "*Description of the Business*". Manitok's most important exploration and development activities focused on the drilling and completion of light oil wells in the Carseland, Rockyford and Wayne areas.

The following table sets forth a summary of Manitok's exploration and development drilling activities as defined in the *Income Tax Act* (Canada) for the year ended December 31, 2016.

2016 EXPLORATION AND DEVELOPMENT ACTIVITIES						
	EXPLORATION WELLS		**DEVELOPMENT WELLS**		**TOTAL**	
Type	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells	8	7.0	11	0.55	19	7.55
Natural Gas Wells	-	-	-	-	-	-
Service Wells	-	-	-	-	-	-
Stratigraphic Test Wells	-	-	-	-	-	-
Dry Holes	-	-	1	-(1)	1	-
Total	**8**	**7.0**	12	0.55	20	7.55

(1) Unsuccessful well relates to a well drilled pursuant to a farm-out agreement, in which Manitok's working interest costs with respect to the well were carried by the farmee.

The following table sets forth Sproule's forecast volumes of Manitok's production from gross proved reserves and gross probable reserves as estimated in the 2016 Sproule Evaluation for the 2017 financial year.

Reserves Category	Light and Medium Crude Oil(1) (Mbbls)	Natural Gas (Mmcf)	NGLs (Mbbls)	Total (Mboe)
Gross Total Proved	1,028.3	7,466	273.7	2,546.3
Gross Probable	144.1	1,214	41.7	388.1

(1) Estimates of light and medium crude oil production include a minor amount of heavy crude oil

The estimated production volumes for the area that accounts for more than 20% of Sproule's total forecast production for the year ended December 31, 2016 is set forth below:

2017 PRODUCTION VOLUMES FOR KEY FIELD		
Area Name	2017 Sproule Forecast Production for determining Gross Total Proved Reserves (Mboe)	2017 Sproule Forecast Production for determining Gross Probable Reserves (Mboe)
Stolberg	861.0	91

Production History

Average Daily Production by Product Type

The following table sets out, by product type, Manitok's average gross daily production volumes for each quarter of the year ended December 31, 2016.

2016 QUARTERLY PRODUCTION HISTORY					
	Three months ended				Year ended
Product Type	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016	December 31, 2016
Light and Medium Crude Oil (boe/d)(1)	3,444	3,165	3,689	4,761	3.767
Natural Gas (mcfe/d)(2)	5,773	2,534	3,528	8,169	5,006
Total (boe/d)	**4,407**	**3,587**	**4,277**	**6,123**	**4,602**

(1) Includes solution gas and associated by-products.
(2) Includes associated by-products.

Realized Price, Royalty, Operating, Transportation and Marketing Expenses and Operating Netbacks

The following tables set forth, by product type, Manitok's prices received, royalties paid, operating and transportation and marketing costs incurred and the resulting operating netback on a per unit of volume basis, for each quarter of the year ended December 31, 2016.

LIGHT AND MEDIUM CRUDE OIL 2016 QUARTERLY PRICE, ROYALTY, OPERATING, TRANSPORTAION AND MARKIETING EXPENSES AND NETBACK HISTORY					
	Three months ended				Year ended
$/bbl	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016	December 31, 2016
Realized Price(1)(2)	25,42	29.51	31.31	34.53	30.62
Royalty expenses	(7.71)	(9.12)	(9.52)	(9.13)	(8.90)
Operating expenses, net of recoveries	(15.12)	(14.80)	(13.19)	(11.29)	(13.36)
Transportation and marketing expenses	(1.54)	(1.51)	(1.67)	(1.03)	(1.40)
Operating Netback	1.05	4.08	6.93	13.08	6.96
Royalty Income	-	-	-	0.02	0.01
Operating Netback including Royalty Income	**1.05**	**4.08**	**6.93**	**13.10**	**6.97**

(1) Does not include royalty income
(2) Includes solution gas and associated by-products

NATURAL GAS 2016 QUARTERLY PRICE, ROYALTY, OPERATING, TRANSPORATION AND MARKETING EXPENSES AND NETBACK HISTORY					
	Three months ended				Year ended
$/mcfe	**March 31, 2016**	**June 30, 2016**	**September 30, 2016**	**December 31, 2016**	**December 31, 2016**
Realized Price[(1)(2)]	2.10	1.51	2.73	3.61	2.76
Royalty Expenses	(0.16)	(0.74)	(0.26)	(0.54)	(0.41)
Operating expenses, net of recoveries	(1.77)	(2.35)	(0.87)	(1.87)	(1.72)
Transportation and marketing expenses	(0.25)	(0.08)	(0.50)	0.02	(0.16)
Operating Netback	(0.08)	(1.66)	1.10	1.22	0.47
Royalty Income	-	-	-	-	-
Operating Netback including Royalty Income	**(0.08)**	**(1.66)**	**1.10**	**1.22**	**0.47**

(1) Does not include royalty income.
(2) Includes associated by-products

2016 Production History

The following table sets forth Manitok's annual production volumes for the year ended December 31, 2016 by product type, for the fields comprising more than 20% of Manitok's total production and in total.

2016 PRODUCTION VOLUMES BY PRODUCT TYPE FOR MAJOR FIELDS				
Area name	**Light and Medium Crude Oil (Mbbls)**	**Natural Gas (Mmcf)**	**NGLs (Mbbls)**	**Total (Mboe)**
Stolberg	268.9	2,615.1	12.2	717.0
Wayne	182.4	800.6	40.2	356.0

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Companies operating in the oil and natural gas industry are subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry. It is not expected that any of such controls or regulations would affect the operations of the Corporation in a manner materially different than they would affect other companies of similar size in the oil and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in western Canada.

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada ("**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB.

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 40 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States ("**U.S.**") and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGLs, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

Occasionally, the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and funds from operations within the industry.

Alberta

Producers of P&NG from Crown lands in Alberta are required to make annual rental payments, currently at a rate of $3.50 per hectare, and monthly royalty payments in respect of P&NG produced.

On January 29, 2016, the Alberta Royalty Review Advisory Panel provided a report to the Alberta government recommending changes to Alberta’s royalty framework. The Alberta government has indicated that it will implement the Panel’s recommendations.

The changes recommended by Alberta Royalty Review Advisory Panel report include establishing a single royalty structure/rate for all hydrocarbons in calculating royalties, instead of the current system that distinguishes between oil, gas and natural gas liquids, and recommended eliminating multiple drilling incentive programs and replacing them with a permanent royalty formula. It also recommended that the revised royalty system should apply to all wells drilled after January 1, 2017, while the current royalty framework would continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, the older wells would become subject to the revised royalty system.

The revised royalty regime will apply to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the new royalty system will be determined on a “revenue-minus-costs” basis using a formula that will be based on industry average drilling and completion costs, as determined by the AER. Producers will pay a flat royalty rate of 5 percent of gross revenue from each well until cumulative revenues from the well equals the drilling and completion costs for that well, as set by the AER. After payout, producers will pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices, similar to the current system. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain a full royalty burden, the royalty rate for that well will be decreased.

Under the current royalty system, royalty rates for conventional oil range from 0% to 40%, with a rate cap of $120.00/bbl. Royalty rates for natural gas range from 5% to 36%, with a rate cap of $17.75/GJ.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, on March 3, 2009, an incentive program was announced that provided a drilling royalty credit, and a new well royalty incentive program, both of which applied to conventional oil or natural gas wells drilled after April 1, 2009. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010 (later extended to March 31, 2011), favouring smaller producers with lower activity levels. The drilling royalty credit regulation expires June 30, 2017. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 (later extended to March 31, 2011, and then later made a permanent part of the royalty framework) and provided for a maximum 5% royalty rate for the first 12 months of production to a maximum of 50,000 bbls of oil or 500 Mmcf of natural gas. The new well incentive program will expire June 30, 2018.

The Innovative Energy Technologies Program ("**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves. The IETP will expire on October 31, 2017.

The Emerging Resource and Technologies Initiative was announced on May 27, 2010, to accelerate technological development and facilitate the development of unconventional resources. This Initiative, which will expire on June 30, 2018, intended to achieve those goals by providing that:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 Mmcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 Mmcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

Land Tenure

Crude oil and natural gas located in the western Canadian provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce P&NG pursuant to leases, licences, and permits for varying terms from two years and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such P&NG are granted by lease on such terms and conditions as may be negotiated.

The province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and indicated that the decision would be revisited in the spring of 2012. This decision was to be revisited in spring 2012 and the formal response from Alberta Energy was communicated to industry in April 2013 when the issuance of shallow rights reversion notices was indefinitely suspended for agreements made prior to 2009. Leases issued after 2009 remain subject to the shallow rights reversion policy.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating ("**AB LLR**") program. The AB LLR program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Alberta Oil and Gas Conservation Act* ("**ABOGCA**") established an orphan fund ("**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR program through a levy administered by the AER. The AB LLR program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AB LLR program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase was implemented in May of 2014 and the final phase was implemented in May of 2015. The changes to the AB LLR program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced the inactive well compliance program ("**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment.

Environmental Regulation

The oil and natural 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.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the AER assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the ABOGCA. On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the Public Lands Act. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act and the Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* ("**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oilsands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The only other regional plan currently in effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres in Southern Alberta, and includes 45% of the provincial population, including the cities of Calgary, Lethbridge and Medicine Hat. The SSRP came into force on September 1, 2014. Other than the LARP and SSRP, the only other regional plan where development has started is the North Saskatchewan Region Plan ("**NSRP**"), which includes an area of 85,780 square kilometres across central Alberta and includes the city of Edmonton and Banff National Park. Phase 1 public consultations for the NSRP have been completed, but there is no current timetable for completion of the plan.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Climate Change Regulation

Federal

In November 2015, Canada participated in the Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, the goal of which was to reach a new agreement for fighting global climate change. The Conference resulted in the adoption of the non-binding Paris Agreement which made several recommendations, including: a) holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial levels; b) increasing the ability to adapt to the adverse impacts of climate change and foster climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production; and c) making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development. In order for the Paris Agreement to enter into force, fifty-five parties that account for at least an estimated 55% of the total global greenhouse gas emissions must deposit their instrument of ratification, approval or acceptance. On October 5, 2016, the threshold for entry into force was achieved and, on November 4, 2016, the Paris Agreement came into effect.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" ("**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 ("**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The Government of Canada indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second U.S./Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

The Canadian Prime Minister and the First Ministers of the provincial and territorial governments met to discuss a national climate change plan, and on March 3, 2016, jointly issued the Vancouver Declaration on Clean Growth and Climate Change. The Vancouver Declaration outlines the vision and principles that the governments will follow to create a climate change and economic growth framework for Canada. The governments agreed upon four immediate priorities: (a) clean technology, innovation, and jobs; (b) carbon pricing mechanisms adapted to each province's and territory's specific circumstances and in particular the realities of Canada's Indigenous peoples and Arctic and sub-Arctic regions; (c) specific mitigation opportunities; and (d) adaptation and climate resilience. Four federal-provincial-territorial working groups were established to work with Indigenous Peoples, to consult with the public, businesses and civil society, and to present options to act on climate change and enable clean growth. As a result of this process, the Pan-Canadian Framework on Clean Growth and Climate Change was developed and signed by the First Ministers of all provinces and territories except Saskatchewan and Manitoba.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* ("**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years, increasing to 15% of their baseline in 2016 and 20% of baseline in 2017. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are, for the year 2016, required to reduce their emissions intensity by 3% from baseline in the fourth year of commercial operation, 5% of their baseline in the fifth year, 8% of their baseline in the sixth year, 10% of their baseline in the seventh year and 13% of their baseline in the eighth year and 15% of their baseline in the ninth year. For the year 2017, New Facilities are required to reduce their emissions intensity by 3% from baseline in the fourth year of commercial operation, 7% of their baseline in the fifth year, 10% of their baseline in the sixth year, 13% of their baseline in the seventh year, 17% of their baseline in the eighth year and 20% of their baseline in the ninth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15.00 per tonne of carbon dioxide ("**CO_2**") equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for green energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed to invest $1.24 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

In August 2015, the Alberta Government appointed a Climate Leadership Panel to provide advice to the government on the development of a comprehensive climate change strategy and policy measures to reduce GHG emissions in Alberta. On November 22, 2015, the government released the Climate Leadership Panel's Report to the Minister and announced that it would implement the Report's recommendations on phasing out coal-fired power production, replacing two-thirds of that production with renewable energy and imposing a new economy-wide price on GHG emissions of $20.00 per tonne on January 1, 2017, rising to $30.00 per tonne on January 1, 2018.

The Climate Change Leadership Panel recommended that distributors of transportation and heating fuels would be required to either: (i) acquire and then retire emission performance credits or offset credits, or (ii) make payments to a technology fund at a rate of $30.00 per tonne of GHGs for transportation and heating fuels sold and distributed in the province. The distributors are expected to pass on the costs of compliance to their customers, which the Panel estimates will require customers to pay an additional $0.07 per litre for regular gasoline and $1.68 GJ for natural gas.

Emissions from flaring at oil and gas wells and facilities and from landfills will also be subject to a GHG emission levy starting at $20.00 per tonne in 2017 and increasing to $30.00 a tonne in 2018 and thereafter. Fuel gas consumed in operating oil and gas wells, pipelines and facilities will be subject to the $30.00 per tonne levy commencing January 1, 2023. It is proposed that the $30.00 per tonne levy should increase annually at a rate equal to the rate of inflation plus 2% per year, so long as the levy in Alberta does not significantly exceed carbon prices in comparable jurisdictions or any future national carbon standard. The Panel also recommended that new regulations require operators of facilities emitting more than 100,000 tonnes of GHGs per year to measure their facility's emissions intensity and then have AER reward the lowest 25% of emitters in each industry by providing them with free emission permits which they can then trade or bank for future use. The remaining 75% of the emitters in each industry will be required to do one or more of the following: (i) reduce their actual emission intensity to the level of the lowest quartile of emitters; (ii) acquire and retire emission performance credits, emission permits or offset credits in an amount that will bring their facility's emissions on a net basis within the lowest quartile of their industry; or (iii) make payments to a technology fund at a rate of $30.00 per tonne for each tonne that their facility exceeds the baseline established by the lowest 25% of emitters within their industry. The proposed regulations to implement the Panel's recommendations have not yet been released.

Methane emission reduction in the oil and gas industry is also a key to Alberta's new GHG emission plan with a goal of reducing oil and gas methane emissions by 45% by 2025. The Panel has made two recommendations in this regard. First, applying new design specifications to oil and gas wells, pipelines and facilities, as well as standards for key equipment and operational best practices. Fugitive emission standards will also be included in the regulatory requirements and will require raising current standards for performance, monitoring, measurement and reporting. Second, creating a joint initiative among regulators, the oil and gas industry, independent experts, environmental groups and Aboriginal groups to collaborate to develop and oversee a plan to address methane emissions from existing facilities by updating or retrofitting methane emitting equipment before the end of the equipment's useful life, which may include mandating the replacement of equipment at facilities before the end of the equipment's life, or the shut-in and abandonment of the well or facility which uses such equipment.

DIVIDEND AND DISTRIBUTION POLICY

The Corporation's Credit Facilities may restrict its ability to pay dividends, and thus the Corporation's ability to pay dividends on the Manitok Shares will depend on, among other things, the Corporation's level of indebtedness at the time of the proposed dividend and whether it is in compliance with such Credit Facilities. The Corporation has never paid any dividends on Manitok Shares or made distributions to shareholders and it is unlikely to pay any dividends on Manitok Shares or make distributions to shareholders in the foreseeable future.

CAPITAL STRUCTURE

The authorized capital of the Corporation consists of an unlimited number of Manitok Shares and an unlimited number of preferred shares ("**Preferred Shares**") issuable in series, each without par value. At May 1, 2017, there were 262,819,832 Manitok Shares outstanding and there were no Preferred Shares outstanding. The material characteristics of each class of authorized shares are set forth below.

Manitok Shares

Holders of Manitok Shares are entitled to: (a) receive notice of and attend and vote at all meetings of shareholders of the Corporation, except meetings at which only holders of a specified class of shares are entitled to vote; (b) receive any dividends declared by the Corporation on the Manitok Shares, provided that the Corporation is not entitled to declare dividends on the Preferred Shares, or on any of such classes of shares without being obliged to declare any dividends on the Manitok Shares; (c) subject to the rights, privileges, restrictions and conditions attaching to any other class of shares of the Corporation, to receive the remaining property of the Corporation upon dissolution in equal rank with the holders of all other Manitok Shares; and (d) the rights, privileges and restrictions normally attached to Manitok Shares.

Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each consisting of a number of Preferred Shares as determined by the Board, which also may fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. The holders of Preferred Shares are entitled to dividends, if, as and when declared by the Board. However, the Board may declare a dividend on any class of shares of the Corporation without being obligated to declare a dividend on the Preferred Shares. The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets in the event of voluntary or involuntary liquidation, dissolution or winding-up of the Corporation or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, rank on a parity with the Preferred Shares of every other series and shall be entitled to preference over Manitok Shares and the shares of any other class ranking junior to the Preferred Shares.

MARKET FOR SECURITIES

The Manitok Shares are listed for trading on TSX-V under the trading symbol "MEI". The following table sets forth the price ranges and volumes of Manitok Shares that were traded on TSX-V during the year ended December 31, 2016.

Month	High	Low	Monthly Trading Volume
January	0.165	0.115	2,401,265
February	0.175	0.115	3,730,699
March	0.280	0.160	3,837,018
April	0.270	0.205	2,084,628
May	0.210	0.140	2,804,222
June	0.210	0.105	3,445,477
July	0.155	0.135	1,183,781
August	0.160	0.120	1,883,984
September	0.140	0.100	12,938,937
October	0.165	0.120	10,633,463
November	0.140	0.120	8,831,360
December	0.205	0.140	19,463,042

ESCROWED SECURITIES

To the knowledge of the Corporation, there are no securities of the Corporation that are held in escrow as at the date hereof.

DIRECTORS AND OFFICERS

Directors

The directors of the Corporation are elected annually at the annual and special meeting of shareholders. The following table sets forth the name, province and country of residence, year first elected to the Board and principal occupation during the past five years or more:

Name, Province and Country of Residence	**Director Since**	**Present Occupations and Positions Held During the Past Five Years or More**
Bruno P. Geremia(1)(2)(3) *Alberta, Canada* Chairman of the Board	July 8, 2010	Mr. B. Geremia is chairman of the board of Manitok, chairman of the Audit Committee and a member of the Compensation Committee and the Reserves and Occupational Health and Safety Committee and is a Chartered Accountant. He has been the Vice-President and Chief Financial Officer of Birchcliff Energy Ltd., a TSX listed oil and gas company, from October 2004 to present. Mr. B. Geremia was chairman of the board of MEX from April 20, 2005 to July 8, 2010.
R. Keith MacLeod(2)(3) *Alberta, Canada* Independent Director	August 11, 2014	Mr. MacLeod is a director of Manitok and is chairman of the Reserves and Occupational Health and Safety Committee and a member of the Compensation Committee and is a professional engineer. Until his retirement on June 30, 2014, he was a director, partner and Chief Executive Officer of Sproule Associates Limited, a worldwide petroleum consulting firm. He holds the ICD.D designation from the Institute of Corporation Directors
Ken. B. Mullen(1)(2) *Alberta, Canada* Independent Director	August 19, 2016	Mr. Mullen is a director of Manitok and is a member of the Audit Committee and the Compensation Committee and is a Chartered Professional Accountant and Lawyer. Mr. Mullen is currently a dealing representative to NEC Canadian Fund LLP, a private investment fund co-founded by Mr. Mullen, and directed at investing in both private and public oilfield services businesses in Canada. He holds the ICD.D designation from the Institute of Corporation Directors.
Dennis L. Nerland(1)(2)(3) *Alberta, Canada* Independent Director	June 25, 2014	Mr. Nerland is a director of Manitok and is chairman of the Compensation Committee and a member of the Audit Committee and the Reserves and Occupational Health and Safety Committee. Mr. Nerland has been a partner with the law firm Shea Nerland LLP since 1990, practicing primarily in the areas of tax and trust law. He holds the ICD.D designation from the Institute of Corporation Directors and was awarded a Queen's Counsel status in 2014.
Gregory E. Peterson(1)(2) *Alberta, Canada* Independent Director and Corporate Secretary	July 8, 2010	Mr. Peterson is a director and Corporate Secretary of Manitok and is a member of the Audit Committee and Compensation Committee. He is a Partner with Gowling WLG (Canada) LLP, an international law firm and has been with the firm since 1990. Mr Peterson was a director and Corporate Secretary of MEX from April 20, 2005 to July 8, 2010.
Tom Spoletini(1)(3) *Alberta, Canada* Independent Director	July 8, 2010	Mr. Spoletini is a director of Manitok and is a member of the Audit Committee, Compensation Committee and Reserves and Occupational Health and Safety Committee. He was a founding partner and is the President of Spolumbo's Fine Foods & Deli, a private company based out of Calgary, Alberta since 1991. Mr. Spoletini was a director of MEX from April 20, 2005 to July 8, 2010.
Cameron G. Vouri(3) *Alberta, Canada* Director	July 8, 2010	Mr. Vouri is a director of Manitok and is a member of the Reserves and Occupational Health and Safety Committee and is a professional engineer. Mr. Vouri was the Vice President and Chief Operating Officer of Manitok from November 2013 to December 2016. Prior thereto, he had been an independent businessman from March 2011 to September 2013, Vice President, Operations and Chief Operating Officer of Renegade Petroleum Ltd., a TSX-V listed oil and gas company, from September 2010 to February 2011 and President, Canadian Oil and Gas Division of Provident Energy Trust, a TSX listed oil and gas company, from May 2000 to April 2010. Mr. Vouri was a director of MEX from February 1, 2007 to July 8, 2010.

Name, Province and Country of Residence	Director Since	Present Occupations and Positions Held During the Past Five Years or More
Massimo M. Geremia *Alberta, Canada* Director	July 8, 2010	See Mr. M. Geremia's biography under *"Executive Officers"*.

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Reserves and Occupational Health and Safety Committee.
(4) Each director's term expires at the close of the next annual and special meeting of the shareholders of the Corporation, unless re-elected.

The Board has an Audit Committee, a Compensation Committee and a Reserves and Occupational Health and Safety Committee. The Audit Committee is comprised of Messrs. Bruno P. Geremia (chair), Ken B. Mullen, Dennis L. Nerland, Gregory E. Peterson and Tom Spoletini. The Compensation Committee is comprised of Messrs. Dennis L. Nerland (chair), Bruno P. Geremia, R. Keith Macleod, Ken B. Mullen and Gregory E. Peterson. The Reserves and Occupational Health and Safety Committee is comprised of Messrs. R. Keith Macleod (chair), Bruno P. Geremia, Dennis L. Nerland, Tom Spoletini and Cameron G. Vouri. All of the members of such committees, and all of the members of the Board, are independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**"), other than Mr. M. Geremia, as an officer of the Corporation, and Mr. B. Geremia, as an immediate family member of an officer of the Corporation. Due to the small size of the Board, the Corporation does not have a separate corporate governance or executive committee.

Executive Officers

The following table sets forth the name, province and country of residence, position with the Corporation, and principal occupation during the past five years or more and educational background of each of the executive officers of the Corporation.

Name, Province and Country of Residence	Current Position with Manitok	Principal Occupations During the Past Five Years or More and Educational Qualifications
Massimo M. (Mass) Geremia *Alberta, Canada*	President and Chief Executive Officer	Mr. M. Geremia has been the President and Chief Executive Officer and a director of Manitok since July 8, 2010. He co-founded MEX on April 20, 2005 and served as the President, Chief Executive Officer and Chief Financial Officer from April 20, 2005 to July 8, 2010. Prior thereto, Mr. M. Geremia was employed at Birchcliff Energy Ltd., a TSX listed oil and gas company, Equatorial Energy Inc., a TSX listed oil and gas company and Boardwalk Equities Inc., a TSX listed real estate company.
Gregory A. (Greg) Vavra *Alberta, Canada*	Executive Vice President, Business Development	Mr. Vavra is Executive Vice-President, Business Development and is a lawyer. Mr. Vavra was formerly the President and CEO of Raimount Energy Inc. a TSX-V listed oil and gas company and was engaged in all aspects of operations, management and public reporting. Prior to his tenure with Raimount, Mr. Vavra was the Vice-President of Pacific Cassiar Limited.
Robert G. (Rob) Dion *Alberta, Canada*	Vice President, Finance and Chief Financial Officer	Mr. Dion is Vice-President, Finance and Chief Financial Officer and is a Chartered Accountant. He was Controller of MEX from April 16, 2010 until July 8, 2010. Prior thereto, Mr. Dion was Finance Manager at Compton Petroleum Corporation, a TSX listed oil and gas company from September 2003 to January 2010.

Name, Province and Country of Residence	**Current Position with Manitok**	**Principal Occupations During the Past Five Years or More and Educational Qualifications**
Timothy (Tim) F. Jerhoff *Alberta, Canada*	Vice President, Engineering	Mr. Jerhoff is Vice-President, Engineering and is a registered professional engineer in the Province of Alberta. Prior thereto, Mr. Jerhoff was a Group Lead for Encana Corporation, a TSX listed oil and gas company and from 2004 to 2010, he was Team Lead at Provident Energy Trust, a TSX listed oil and gas company. Prior to that, he was Vice President of Engineering at Terraquest Energy Corporation and Richland Petroleum Corp.
Donald (Don) R. Martin *Alberta, Canada*	Vice President, Exploration	Mr. Martin is Vice-President, Exploration and is a professional geologist. Prior thereto, he was Vice President, Exploration for Alston Energy Inc., a TSX-V listed oil and gas company, from June 2011 to September 2013 and a founding member of TriWestern Energy Corp, a private oil and gas company from October 2009 to June 2011.
Rodger D. Perry **Alberta, Canada**	Vice President, Land	Mr. Perry is Vice-President, Land and is a professional landman with over 36 years of extensive experience involving junior, intermediate and senior oil and gas companies in Alberta. Mr. Perry most recently held executive positions with South Bay Resources Canada and several other junior Oil & Gas companies.

Shareholdings of Directors and Executive Officers

As at December 31, 2016, the directors and executive officers of the Corporation, as a group, beneficially owned, or exercised control or direction over, directly or indirectly, 16,248,975 Manitok Shares, representing approximately 6.2% of the 262,819,832 Manitok Shares issued and outstanding at that date. The directors and executive officers, as a group, also held options to purchase 12,004,100 Manitok Shares and warrants to purchase 2,749,536 Manitok Shares at December 31, 2016.

The fully diluted holdings of directors and executive officers, as a group, were 31,002,611 Manitok Shares, or approximately 9.5% of the 325,592,540 Manitok Shares that were outstanding on a fully diluted basis, at December 31, 2016.

Orders

To the knowledge of management of the Corporation, other than as disclosed herein, no director or executive officer as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Corporation), that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Bankruptcies

To the knowledge of management of the Corporation, other than as disclosed herein, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control thereof, (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

On December 9, 2013, Alston Energy Inc. ("**Alston**"), a corporation of which Mr. Dennis Nerland was a director and Mr. Donald Martin was an executive who resigned in September 2013, filed for protection under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**"). To the knowledge of the Corporation, the CCAA order remains in effect as at the date hereof. On May 6, 2014, and May 8, 2014, the common shares of Alston were cease traded by the Alberta Securities Commission and the British Columbia Securities Commission, respectively, as a result of the failure by Alston to file audited annual financial statements and related management's discussion and analysis for the period ended December 31, 2013, together with the related certification of filings. On May 9, 2014, Alston announced that a receiver had been appointed by the Court of Queen's Bench of Alberta. All of the directors and officers of Alston, including Mr. Nerland, resigned on May 9, 2014.

Mr. Peterson was formerly a director of Great Prairie Energy Services Corp. ("**GPE**") (a public oilfield service company) which was placed in receivership on January 22, 2016. Mr. Peterson resigned as a director of GPE in connection with the appointment of the receiver on January 22, 2016.

Penalties and Sanctions

To the knowledge of management of the Corporation, no director or executive officer or shareholder holding a sufficient number of Manitok Shares to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or has been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and executive officers of the Corporation will be subject to in connection with the operations of the Corporation. In particular, certain of the directors and executive officers of the Corporation are involved in managerial or director positions with other P&NG companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation. The table below lists those directors of the Corporation that are also directors of other reporting issuers and sets forth certain details of those directorships.

Name	Name of Reporting Issuer	Exchange	Term
R. Keith Macleod	Trilogy Energy Inc.	TSX	May 9, 2014 - Present
Ken B. Mullen	Canyon Technical Services Inc.	TSX	March 2013 - Present
Dennis L. Nerland	Acceleware Ltd.	TSX-V	April 2011 - Present
	Arkadia Capital Corp.	TSX-V	July 2011 - Present
	Crew Energy Inc.	TSX	September 2003 - Present
	Critical Control Energy Services Corp.	TSX	May 2001 - Present
	Granite Oil Corp.	TSX	May 2015 - Present
	InPlay Oil Corp.	TSX	July 2013 - Present
	Liberty Biopharma Inc.	TSX-V	December 2016 - Present
	Olympia Financial Group Inc.	TSX	October 2015 - Present
	Strata-X Energy Ltd.	TSX-V	July 2014 - Present
	Westshire Capital II Corp.	TSX-V	May 2016 - Present

AUDIT COMMITTEE

Audit Committee

The Board has established the Audit Committee. The Audit Committee reviews, along with management and the external auditors, any significant financial reporting issues, the financial statements of the Corporation and any other matters of relevance to the parties. The Audit Committee meets quarterly to review and approve the interim financial statements and management's discussion and analysis ("**MD&A**") of the Corporation prior to their release, as well as annually to review the Corporation's annual audited financial statements and MD&A and to recommend their approval to the Board. The external auditors have unrestricted access to the Audit Committee.

The Corporation is relying upon the exemption in section 6.1 of NI 52-110 as the Corporation, as a venture issuer within the meaning ascribed thereto in NI 52-110, is exempt from the requirements of Part 3 (*Composition of the Audit Committee*) and Part 5 (*Reporting Obligations*) of NI 52-110. Part 3 (*Composition of the Audit Committee*) of NI 52-110 contains certain requirement for the composition of the audit committee of the board of directors of an issuer, including, independence and financial literacy requirements. Part 5 (*Reporting Obligations*) of NI 52-110 requires issuers to provide certain disclosure regarding the audit committee of the board of directors of an issuer, including additional disclosure in connection with composition, relevant education and experience and audit committee oversight.

Disclosure of the Audit Committee practices is set forth below.

Audit Committee Charter

In response to NI 52-110, the Corporation has established an Audit Committee charter to address certain matters, which include but are not limited to the following: (a) the procedure to nominate the external auditor and the recommendation of its compensation; (b) the overview of the external auditor's work; (c) pre-approval of non-audit services; (d) the review of financial statements, MD&A and financial sections of other public reports requiring board approval; (e) the procedure to respond to complaints respecting accounting, internal accounting controls or auditing matters and the procedure for confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters; and (f) the review of the Corporation's hiring policies towards present or former employees or partners of the Corporation's present or former external auditor.

The full text of the Audit Committee charter is attached hereto as Schedule "A".

Composition of the Audit Committee

The Audit Committee is comprised of Mr. Bruno P. Geremia (Chair), Mr. Ken B. Mullen, Mr. Dennis L. Nerland, Mr. Gregory E. Peterson and Mr. Tom Spoletini. Each member of the Audit Committee is independent within the meaning of section 1.4 of NI 52-110, other than Mr. Bruno P. Geremia, as an immediate family member of an officer of the Corporation. In addition, each member of the Audit Committee is financially literate within the meaning of section 1.6 of NI 52-110.

Relevant Education and Experience

Mr. Bruno P. Geremia is a Chartered Accountant and Chief Financial Officer of Birchcliff Energy Ltd., a TSX listed oil and gas company and the other four members of the Audit Committee have had long and successful business careers, having been the chief executive officer or chief operating officer of a substantial business enterprise or have been directors and members of the Audit Committee for several oil and natural gas exploration and production companies in the past. As a result, they are all "financially literate" in that they have an ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that can reasonably be expected to be raised by the Corporation's financial statements. Details of the relevant experience of each of the members of the Audit Committee are set forth under the heading "*Directors and Officers – Directors*".

Audit Committee Oversight

No recommendation of the Audit Committee to nominate or compensate an external auditor was not adopted by the Board since the beginning of the Corporation's most recently completed financial year.

Reliance on Certain Exemptions

Since the commencement of the Corporation's most recently completed financial year, the Corporation has not relied on the exemptions contained in section 2.4 (*De Minimis Non-audit Services*), section 3.2 (*Initial Public Offerings*), section 3.4 (*Events Outside Control of Member*), Section 3.5 (*Death, Disability or Resignation of Audit Committee Member*) or an exemption granted under NI 52-110, in whole or in part, granted under Part 8 (*Exemptions*) of NI 52-110.

Pre-Approval Policies and Procedures

The Audit Committee has adopted policies and procedures for the engagement of non-audit services. The Audit Committee has delegated to its members the authority to pre-approve non-audit services, provided, however, that such pre-approval of non-audit services shall be presented to the Audit Committee at its first scheduled meeting following any such pre-approval.

External Auditor Service Fees

The table below summarizes the fees billed by the Corporation's external auditors KPMG LLP ("**KPMG**"), during the years ended December 31, 2016 and December 31, 2015.

Nature of fees	2016	2015
Audit fees	$385,000(1)	$205,000(3)
Audit-related fees	52,500(2)	-
Tax fees	-	-
All other fees	-	-
Total	**$437,500**	**$205,000**

(1) Fees paid to KPMG for the audit of annual financial statements for December 31, 2015 and the review of interim financial statements for March 31, 2016, June 30, 2016 and September 30, 2016 and other financial transactions which occurred during 2016.

(2) Fees paid to KPMG for the French translation of the December 31, 2015 and June 30, 2016 financials statements and management discussion and analysis.

(3) Fees paid to KPMG for the audit of annual financial statements for December 31, 2014 and the review of interim financial statements for March 31, 2015, June 30, 2015 and September 30, 2015 and for the interim audit of annual financial statements for December 31, 2015.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

To the knowledge of the management of the Corporation, there are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated.

Regulatory Actions

To the knowledge of management of the Corporation, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the directors or executive officers of the Corporation, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of outstanding voting securities of the Corporation, nor any associate or affiliate of the foregoing persons had any material interest, direct or indirect, in any transaction during the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for Manitok Shares is Computershare Trust Company of Canada at its principal office located in Toronto, Ontario.

MATERIAL CONTRACTS

Other than the asset purchase agreement dated effective September 29, 2016 in connection with the WG Acquisition, the warrant indenture dated as of October 27, 2016 and the trust indenture dated as of October 27, 2016 in connection with the Offering and an underwriting agreement dated effective November 22, 2016 in connection with the November 2016 Equity Offering, the Corporation did not enter into any material contracts outside the ordinary course of business within the most recently completed financial year or prior thereto that are still in effect. See "*General Development of the Business – Three Year History*".

INTERESTS OF EXPERTS

The 2016 Sproule Evaluation was prepared by Sproule, an independently qualified reserves evaluator and auditor of Calgary, Alberta. As of the date hereof, the partners, employees and consultants of Sproule who participated in or who were in a position to directly influence the preparation of the 2016 Sproule Evaluation own no securities of the Corporation.

KPMG LLP have confirmed that they are independent of the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

ADDITIONAL INFORMATION

Additional information about the Corporation can be found on SEDAR at www.sedar.com and on the Corporation's website at www.manitokenergy.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Manitok Shares, and securities authorized for issuance under equity compensation plans, is contained in the Information Circular of the Corporation dated May 24, 2016. Additional financial information relating to the Corporation is provided in the Corporation's annual audited financial statements and MD&A for the year ended December 31, 2016.

SCHEDULE "A"
AUDIT COMMITTEE CHARTER

(Adopted by the Board of Directors on July 15, 2010)

A. PURPOSE

The overall purpose of the Audit Committee ("**Committee**") of the Board of Directors ("**Board**") is to assist the Board in fulfilling its oversight responsibilities and to carry out the functions associated with an audit committee of an issuer of the size and nature of Manitok Energy Inc. ("**Corporation**"). The purpose of the Committee is to ensure that the Corporation's management has designed and implemented an effective system to review and report on the integrity of the financial statements of the Corporation. As part of this mandate, the Committee shall take all necessary steps so as to ensure compliance by the Corporation with all laws and regulatory policies, rules, regulations and instruments pertaining to audit and financial reporting that are applicable to the Corporation from time to time.

B. COMPOSITION, PROCEDURES AND ORGANIZATION

1. The Committee shall consist of not less than three members of the Board, each of whom:

   (a) must be "independent" ("independent" means that the audit committee has no direct or indirect material relationship with the Corporation, being a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a member's independent judgment (and certain individuals are deemed by Multilateral Instrument 52-110 to have a material relationship)); and

   (b) must be "financially literate" ("financially literate" means a member has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements);

   except as may be allowed under any applicable exemptions provided for under applicable laws or any exemption orders obtained from applicable regulatory authorities.

2. The Board, at its organizational meeting held in conjunction with each annual general meeting of the holders of shares of the Corporation, shall appoint the members of the Committee for the ensuing year. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

3. Unless the Board shall have appointed a chair of the Committee ("**Chairman**"), the members of the Committee shall elect a chair from amongst their number. If the chair of the Committee is absent from any meeting, the Committee shall select one of the other members of the Committee to preside at that meeting.

4. The Secretary of the Corporation shall be the secretary of the Committee, unless otherwise determined by the Committee. Minutes of meetings of the Committee shall be recorded and maintained by the Secretary of the Committee. Copies of the minutes shall be provided to the Board.

5. The quorum for meetings shall be a majority of the members ("**Members**") of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

6. The Committee shall have access to such officers and employees of the Corporation and of the other consolidated subsidiaries of the Corporation (if any), and to the Corporation's external auditors and to such information respecting the Corporation, as the Committee considers to be necessary or advisable in order to perform its duties and responsibilities.

7. Meetings of the Committee shall be conducted as follows:

   (a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the Chairman, and the Corporation's external auditors or any member of the Committee may request a meeting of the Committee;

   (b) the Corporation's external auditors shall receive notice of and have the right and shall be encouraged to attend all meetings of the Committee; and

   (c) the Chief Executive Officer and the Chief Financial Officer of the Corporation shall be invited to attend all meetings of the Committee, except executive sessions and private sessions with the external auditors, and other management representatives of the Corporation shall be invited to attend as necessary.

8. The internal auditors of the Corporation (if any) and the external auditors of the Corporation shall have a direct line of communication to the Committee through the Chairman. The Corporation shall require the external auditors of the Corporation to report directly to the Committee.

C. DUTIES AND RESPONSIBILITIES

1. The overall duties and responsibilities of the Committee shall be as follows:

   (a) assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and approve the Corporation's annual and quarterly financial statements;

   (b) assess the qualifications of the external auditors;

   (c) establish and maintain a direct line of communication with the Corporation's internal (if any) and external auditors and assess their performance;

   (d) identify principal business risks;

   (e) ensure that the management of the Corporation has designed, implemented and is maintaining an effective system of disclosure controls and internal controls for the Corporation by requiring that management report at least quarterly on the measures in place, the testing done to ensure effectiveness, any areas where improvement is needed and whether there are any issues relating to the signing of the certifications required under Multilateral Instrument 52-109;

   (f) report regularly to the Board on the fulfilment of the duties and responsibilities of the Committee;

   (g) confirm that the Corporation's Disclosure Policy is adequate to ensure the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements is appropriate and periodically test the adequacy of the procedures mandated by such policy;

   (h) assess the effectiveness of the Disclosure Committee established under the Disclosure Policy;

   (i) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management and recommend changes to the Board;

   (j) review compliance with the Code of Business Conduct and Ethics and periodically review this policy and recommend to the Board changes which the Committee may deem appropriate; and

(k) review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation.

2. The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

(a) recommend to the Board a firm of external auditors to be engaged by the Corporation;

(b) review and approve the fee, scope and timing of the audit and other related services rendered by the external auditors;

(c) oversee the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management of the Corporation and the external auditor regarding financial reporting;

(d) review the audit plan of the external auditors prior to the commencement of the audit;

(e) review with the external auditors, upon completion of their audit, the:

(i) contents of their report;

(ii) scope and quality of the audit work performed;

(iii) adequacy of the Corporation's financial and auditing personnel;

(iv) co-operation received from the Corporation's personnel during the audit;

(v) internal resources used;

(vi) significant transactions outside of the normal business of the Corporation;

(vii) the major points contained in the auditor's management letter resulting from control evaluation and testing (if any); and

(viii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems (if any);

(f) pre-approve all non-audit services to be provided to the Corporation by the external auditor in accordance with applicable laws;

(g) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal audit staff or by the external auditors have been implemented; and

(h) meet in camera (i.e. without the presence of management of the Corporation) with the external auditors at least once a year prior the approval of the audited annual financial statements of the Corporation and at such other times as determined necessary or appropriate by the Committee.

3. The duties and responsibilities of the Committee as they relate to the Corporation's internal auditors (if any) shall be as follows:

(a) periodically review the internal audit function with respect to the organization, staffing and effectiveness of the internal audit department;

(b) review and approve the internal audit plan; and

(c) review significant internal audit findings and recommendations, and management's responses thereto.

4. The Committee is also charged with the responsibility to:

(a) review and approve the Corporation's financial statements (annual and interim) and management's discussion and analysis (annual and interim) as well as the financial sections of prospectuses and other public reports requiring approval by the Board before such documents are publicly disclosed by the Corporation;

(b) review regulatory filings and decisions as they relate to the Corporation's financial statements;

(c) review the minutes of any audit committee meeting of associated companies, partnerships or trusts (if any);

(d) review the Corporation's accounting policies and discuss the impact of proposed changes in accounting standards;

(e) review with management, the external auditors and if necessary with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the financial statements;

(f) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters;

(g) establish procedures for the confidential, anonymous submission by employees of the Corporation or any other consolidated subsidiary (if any) of the Corporation of concerns regarding questionable accounting or auditing matters;

(h) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation;

(i) develop a calendar of activities to be undertaken by the Committee for each ensuing year and to submit the calendar in the appropriate format to the Board following each annual general meeting of shareholders; and

(j) on an annual basis, review and assess the adequacy of the Charter and the performance of the Committee in connection therewith.

5. The Committee has the authority to:

(a) engage independent counsel and other advisors as it determines necessary to carry out its duties; and

(b) set and pay the compensation for any advisors employed by the Committee.

SCHEDULE "B"

FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Manitok Energy Inc. ("**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time ("**COGE Handbook**"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the reserves data of the Corporation evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule Associates Limited	December 31, 2016	Canada	**Nil**	**299,780**	**Nil**	**299,780**

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed, but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Manitok Energy Inc. (As of December 31, 2016)".

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada
April 28, 2017

(signed) *"Paul B. Jung"*

Paul B. Jung, P. Eng.
Manager, Engineering

(signed) *"Tanja M. Hale"*

Tanja M. Hale, P. Eng.
Senior Petroleum Engineer

(signed) *"Miles P. Hughes"*

Miles P. Hughes, P. Eng.
Manager, Strategic Advisory

(signed) *"Elizabeth (Betty) M. Swift"*

Elizabeth (Betty) M. Swift, C.E.T.
Technologist

(signed) *"Alec Kovaltchouk"*

Alec Kovaltchouk, P. Geo.
Vice President, Geoscience

(signed) *"Cameron P. Six"*

Cameron P. Six, P. Eng.
President, CEO and Director

SCHEDULE "C"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which meanings are ascribed in NI 51-101 have the same meanings herein.

Management of Manitok Energy Inc. ("**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator or auditor is presented above.

The Reserves and Occupational Health and Safety Committee of the Board of Directors of the Corporation has:

1. reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

2. met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

3. reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves and Occupational Health and Safety Committee has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has on recommendation of the Reserves and Occupational Health and Safety Committee approved:

4. the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

5. the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

6. the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "*Massimo M. Geremia*"	(signed) " *Tim F. Jerhoff* "
Massimo M. Geremia President and Chief Executive Officer	Tim F. Jerhoff Vice President, Engineering
(signed) "*R. Keith Macleod*"	(signed) "*Cameron G. Vouri*"
R. Keith Macleod Chairman of Reserve and Occupational Health & Safety Committee & Director	Cameron G. Vouri Director

May 1, 2017