MANITOK ENERGY INC.

Year Ended December 31, 2011

ANNUAL INFORMATION FORM

April 18, 2012

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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 April 18, 2012;

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

"**COGEH**" 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;*

"**ERCB**" means the Energy Resources Conservation Board;

"**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;

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

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

"**Natural Gas Deep Drilling Program**" means the Government of Alberta, Department of Energy natural gas deep drilling program for royalty adjustments;

"**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 - Standards of Disclosure 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) **Possible Reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves;

(b) **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

(c) **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;

"**Sproule Evaluation**" means the Reserves Assessment and Economic Evaluation effective December 31, 2011 in respect of Manitok's oil and natural gas properties, which is contained in a report prepared by Sproule Associates Limited dated April 16, 2012;

"**Sproule Price Forecast**" means Sproule's December 31, 2011 forecast price assumptions set out in a table under "Reserves Data and Other Oil and Gas Information".

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

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

"**Uncertainty ranges**" means the low, best, and high estimates for reserves described in the Canadian Oil and Gas Evaluation Handbook as follows:

(a) **Best Estimate:** This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate;

(b) **High Estimate:** This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate; and

(c) **Low Estimate:** This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate;

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

"**Working interest**" means a percentage of ownership in an oil and 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	Bcf	billion cubic feet
Mboe	thousand barrels of oil equivalent	GJ	Gigajoule

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 International Financial Reporting Standards ("**IFRS**").

ADVISORIES

Non-GAAP Measures:

This Annual Information Form uses "cash flow" and "operating netback", which do not have standardized meanings prescribed by IFRS and therefore may not be comparable to measures by other companies where similar terminology is used.

Cash flow denotes cash flow from operating activities as it appears on the Corporation's Statement of Cash Flows before decommissioning expenditures and changes in non-cash working capital related to operating activities. Operating netback denotes petroleum and natural gas revenue less royalties, operating expenses and transportation and marketing expenses.

BOE Conversions:

*Barrels of oil equivalent (**"boe"**) amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 mcf) of natural gas to one barrel of oil (1 bbl). Boe amounts may be misleading, particularly if used in isolation. A 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.*

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 they 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 Information" and "Risk Factors". This forward-looking information includes but is not limited to statements regarding: the Corporations' intention to drill and complete future wells; estimates of recoverable reserves and resource volumes; planned production increases; planned 2012 capital spending and sources of funding; expected results from the Corporation's portfolio of oil and gas assets; the quantity and development of oil and gas reserves and resources; future net cash flows and discounted cash flows; expected operating, general administrative, services, environmental compliance costs and expenses; royalty rates and incentives; and treatment under tax laws.

The forward-looking information is based upon assumptions as to future commodity prices, currency exchange rates, inflation rates, well production rates, well drainage areas, success rates for future drilling and availability of labour and services. With respect to estimates of reserves and resource volumes, a key assumption is the validity of the data used by Sproule in their independent reserves and resource evaluations. With respect to estimates of numbers of 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 lands 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 they are based will occur. Although the Corporation believes that the expectations reflected in the forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ materially from those anticipated.

Forward-looking information necessarily involves both known and unknown risks associated with oil and gas exploration, production, transportation and marketing such as uncertainty of geological and technical data, imprecision of reserves estimates, operational risks, environmental risks, loss of market demand, general economic conditions affecting ability to access sufficient capital, changes in governmental 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 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.

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 petroleum and natural gas 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 2500, 639 – 5th Avenue S.W., Calgary, Alberta, T2P 0M9, and its registered office is located at Suite 1400, 700 – 2nd Street S.W., Calgary, Alberta, T2P 4V5.

The Corporation does not have any subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

Manitok is a public oil and gas exploration and development company focused on conventional oil and gas in the Canadian foothills. The stated business objectives and milestones of the Corporation consist of the following:

(a) to develop and exploit oil and natural gas production and drilling opportunities on Manitok's current land holdings in order to maximize production, reserves and cash flow; and

(b) to continue to acquire land, production, development and exploration opportunities in the WCSB, focusing in particular on the foothills.

Three Year History

Desco

On July 8, 2009, Desco completed a private placement of 3,200,000 common shares in the capital of Desco ("**Desco Shares**") at a price of $0.10 per Desco Share for aggregate gross proceeds of $320,000. On July 30, 2009, Desco completed an additional private placement of 1,800,000 Desco Shares at a price of $0.10 per Desco Share for additional aggregate gross proceeds of $180,000.

On October 29, 2009, Desco completed its initial public offering of 1,250,000 Desco Shares at a price of $0.20 per share for gross proceeds of $250,000, which offering closed on October 29, 2009. The Desco Shares commenced trading on the TSX-V on November 5, 2009 under the trading symbol "DSR.P".

MEX

With the world economy in difficulty and natural gas prices collapsing, MEX postponed capital spending until markets improved. MEX used the time to accumulate a land position in the southern Alberta foothills and from July 2009 to June 2010, it acquired a 100% working interest in approximately 67.8 undeveloped sections of land, primarily in the southern Alberta foothills, through Crown sales for approximately $2.1 million.

Manitok

2010

Immediately prior to completion of the Amalgamation, MEX completed a "best-efforts" private placement (the "**July 2010 Private Placement**") of 4,311,700 class "A" common shares in the capital of MEX ("**MEX Shares**") at a price of $1.15 per MEX Share and 3,846,000 MEX Shares issued on a "flow-through" basis under the *Income Tax Act* (Canada) ("**MEX Flow-through Shares**") at a price of $1.30 per MEX Flow-through Share (such share numbers being on a pre-Amalgamation basis), for aggregate gross proceeds of approximately $10.0 million.

Pursuant to the Amalgamation, the shareholders of MEX (including subscribers to the July 2010 Private Placement) exchanged each one of their MEX Shares for 0.75 of a Manitok Share and the shareholders of Desco exchanged each one of their Desco Shares for 0.375 of a Manitok Share.

On July 29, 2010, the Corporation received final approval from the TSX-V for the listing of the Manitok Shares and trading of the Manitok Shares on the TSX-V commenced under the symbol "MEI".

On August 4, 2010, Manitok completed a disposition of a non-core P&NG asset in the Garrington area of Alberta for approximately $1.8 million before post-closing adjustments and related expenses. The proceeds were used to partially fund the Corporation's capital program.

From July 2010 to December 2010, Manitok acquired approximately 48.0 (46.8 net) undeveloped sections of land, primarily in the southern Alberta foothills, through Crown sales for approximately $1.5 million. Manitok's undeveloped land position at December 31, 2010 was comprised of 84,620 (81,020 net) acres, which was a 59% increase on a net basis as compared to MEX's undeveloped land position of 53,920 (51,040 net) acres at June 30, 2010.

On December 22, 2010, the Corporation entered into an agency agreement with Integral Wealth Securities Limited and closed the first tranche of a reasonable "best-efforts" private placement (the "**December 2010 Private Placement**") of 10,031,500 Manitok Shares issued at a price of $1.00 per Manitok Share and 6,618,559 Manitok Shares issued on a "flow-through" basis under the *Income Tax* Act (Canada) ("**Manitok Flow-through Shares**") at a price of $1.15 per Manitok Flow-through Share, for aggregate gross proceeds of approximately $17.6 million. On December 30, 2010, the Corporation closed the second and final tranche of the December 2010 Private Placement with 325,400 Manitok Shares issued at a price of $1.00 per Manitok Share and 110,130 Manitok Flow-through Shares issued at a price of $1.15 per Manitok Flow-through Share, for aggregate gross proceeds of approximately $452,000. Under both tranches of the December 2010 Private Placement, the Corporation raised aggregate gross proceeds of approximately $18.1 million.

2011

On April 14, 2011, Manitok closed an equity financing, completed by way of a short form prospectus, for the sale of 17,968,750 Manitok Shares issued at a price of $1.60 per Manitok Share for gross proceeds of approximately $28.8 million (the "**April 2011 Financing**"). Proceeds of this equity financing were used to fund the Corporation's drilling program and the asset acquisition as described immediately below.

On September 8, 2011, the Corporation announced the commencement of production of its liquids rich natural gas discovery well in the Stolberg area of Alberta. The Corporation has a 75% working interest in the well which had an unstimulated initial rate of 5.0 Mmcf/d and 11.0 bbl/Mmcf of wellhead condensate.

On October 31, 2011, the Corporation closed an acquisition of oil and natural gas assets in the central Alberta foothills area (the "**Asset Acquisition**"), with an effective date of July 1, 2011, for total cash consideration of approximately $41.8 million (before post-closing adjustments and acquisition-related expenses). The consideration paid by the Corporation for the assets was financed by existing cash balances and bank indebtedness. Concurrent with the closing of the Asset Acquisition, the borrowing base limit of the Corporation's revolving credit facility was increased from $5 million to $30 million. The Asset Acquisition included approximately 1,300 boe/d with about 94% being natural gas. .

On December 5, 2011, the Corporation closed a bought deal equity financing, completed by way of a short form prospectus, for the sale of 6,500,000 Manitok Shares issued at a price of $1.85 per Manitok Share and 3,635,000 Manitok Flow-through Shares at a price of $2.20 per Manitok Flow-through Share for gross proceeds of approximately $20.0 million (the "**December 2011 Financing**"). Proceeds of the equity issue were used to temporarily eliminate bank indebtedness incurred on the Asset Acquisition, which will be partially redrawn to fund the Corporation's exploration and development activities in 2012.

Recent Developments

On April 5, 2012, the Corporation entered into a purchase and sale agreement to dispose of its entire working interest in its heavy oil assets in the Swimming area of Alberta for total cash consideration of $14.0 million before post-closing adjustments and related expenses (the "**Swimming Asset Divestiture**"). The Swimming Asset Divestiture closed on the same day, April 5, 2012, with an effective date of April 1, 2012. The Swimming Asset Divestiture includes production of approximately 320 bbls/d of heavy oil, 13,794 net acres of land and seismic data. As a result of the Swimming Asset Divestiture, Manitok's aggregate limit on its revolving credit facility has been reduced from $30.0 million to $25.0 million. The net proceeds from the Swimming Asset Divestiture will be used to temporarily eliminate Manitok's current bank indebtedness, which will be partially redrawn and applied as needed to fund Manitok's ongoing capital expenditure program.

Strategy

Manitok's corporate strategy is that of being an "early mover" in the exploitation phase of the development life cycle of hydrocarbon reserves in the Canadian foothills. The Corporation has been created specifically to focus on and succeed in the foothills. Manitok's technical team has been assembled for its extensive geological and drilling experience to methodically and reliably exploit the bypassed shallower reservoirs in the foothills. At this time, there are few competitors due to the technical experience required to understand and execute drilling programs in the foothills, which has enabled the Corporation to assemble more than 74,000 net acres of undeveloped foothills land. Furthermore, the previous activities of the major oil and gas companies over the last 20 years in drilling deeper gas targets have resulted in available 2-D and 3-D seismic surveys, drill cuttings and well logs, roads, pipelines and processing plants with excess capacity, all of which will significantly reduce the costs of future development.

Significant Acquisitions in 2011

The Corporation completed the Asset Acquisition in 2011. The Corporation filed a Business Acquisition Report in Form 51-102F4 in respect of the Asset Acquisition on November 10, 2011. See "*General Development of the Business – Three Year History – Manitok – 2011*".

DESCRIPTION OF THE BUSINESS

General

The Corporation is in the business of exploring for, developing and producing oil and natural gas resources in the WCSB. The Corporation will utilize its experience and expertise to develop the untapped conventional sweet oil and liquids-rich natural gas pools in this large and under-exploited Canadian foothills area of the WCSB. The Corporation's business model envisages continuous growth through drilling and the acquisition of suitable properties via asset purchases, farm-ins and corporate acquisitions or mergers.

Principal Properties

The following is a description of the Corporation's principal oil and natural gas properties as at December 31, 2011. Unless otherwise stated, 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, 2011.

Cordel / Stolberg Area, Alberta

The Cordel property is about 16 km north of the Hamlet of Nordegg, Alberta. The area has been exploited for its deep sour gas by several major oil and companies over the last 30 years. However, the Corporation has focused on shallower liquids-rich gas and light sweet oil reservoirs. As at December 2011, the Corporation had 10 (2.1 net) producing wells, with 9 (1.3 net) from the Asset Acquisition and 1 (0.75 net) from the Corporation's discovery well. Of these wells, 6 (1.0 net) are light oil producers in the Cordel oil pool.

While there are many other liquids-rich gas targets in the area, due to very low natural gas prices, Manitok has refocused its capital in the shallower Cardium Formation at Cordel/Stolberg. In this area, the Cardium is a conventional reservoir, which has been deformed in complex fold structures over a large region. In some cases, the productive Cardium zone as been deformed to depths as shallow as 800 metres. In these sandstone and conglomerate reservoirs, oil quality ranges up to 54^0 API. The very light oil is unusual in the basin, and demands a premium to the benchmark price. The reservoir will be exploited primarily with horizontal drilling. While historically the Cardium has not required stimulation in this area, the Corporation may elect to stimulate should the drill bit encounter locally, lower permeability reservoirs.

Brown Creek Area, Alberta

Brown Creek is about 40 km north of the Hamlet of Nordegg, Alberta. Its structural position within the fold belt is very similar to the Cardium at Stolberg. As in most of the foothills, past operators have exploited the deep, sour dry gas reservoirs, but the Cardium in this area contains very light, sweet oil. Vertical wells may produce over 200 Mbbl of oil, and the Corporation expects to drill several horizontal wells in this area, subject to further technical review. The reservoir ranges from 1200 to 2200 metres in depth. Similar to Stolberg, abundant infrastructure built by previous operators will reduce the capital necessary to deliver P&NG to market. At present, there are 6 (1.4 net) wells producing a combination of sweet gas, oil and very minor sour gas.

Greater Hinton Area, Alberta

This area comprises a large area with a variety of shallow gas, oil, and liquids-rich gas prospects. Key properties include Banshee, Solomon, Lovett, and Antler in the Alberta foothills. There is a large inventory of liquids-rich gas opportunities in the area in several Cretaceous reservoirs, including the Cardium Formation. Manitok also owns extensive pipeline systems, compressors, and a 20% interest in a sweet gas plant in the Hanlan area of Alberta. These facilities significantly reduce operational costs, thus increase value of the drilling projects. Previous operators have focused on Devonian, Triassic, and to some extent Mississippian and Cretaceous reservoirs. The Devonian Leduc reservoirs, in particular, are prolific gas pools near the Gregg Lake area of Alberta; however, the sour gas is costly to process and the wells are presently shut-in. When natural gas prices improve, the natural gas from these deep reservoirs will flow through the Corporation's Gregg Lake Facility and ultimately the Semcams K3 gas plant.

Swimming Area, Alberta

The Swimming property is located approximately 80 kilometres west of Lloydminster, Alberta. This property was acquired in 2005 as part of MEX's initial transaction with Provident Energy Trust ("**Provident**"). In the fourth quarter of 2011, the property was producing approximately 330 bbls/d of heavy (11°-13° API) oil from the Cummings, GP and Sparky formations. As indicated under ("*Description of the Business – Recent Developments – Swimming Asset Divestiture*" the Corporation has disposed of these heavy oil assets for total cash consideration of $14.0 million before post-closing adjustments and related expenses. The funds from the Swimming Asset Divestiture enable the Corporation to focus its efforts and resources on its Alberta foothills projects.

Production

The Corporation's 2011 exit production rate was about 2,325 boe/d, with 23% oil and liquids, which is an increase of 615% from its 2010 exit production rate of about 325 boe/d. Production for the year ended December 31, 2011 averaged 689 boe/d, compared to average production of 179 boe/d in the financial year ended December 31, 2010. The increase in production of 285% was due to a liquids-rich natural gas discovery well in the Stolberg area of Alberta which was brought on production in September 2011 and the Asset Acquisition. For the year ended December 31, 2011, 67% of the revenue from Manitok's properties before royalties was derived from natural gas and 33% was from crude oil and liquids. 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, heavy crude oil, 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 is sold to non-arm's length parties.

The following table sets forth the aggregate sales of those products produced by the Corporation during the six month financial year ended December 31, 2010 and the year ended December 31, 2011:

Product	**2011 Revenue**	**2010 Revenue**
Natural Gas	$3,460,055	$386,019
Heavy Oil	$5,184,632	$906,234
Light Oil	$260,685	$1,808
NGLs	$537,607	$9,475

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 technical 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, oil and natural gas projects and properties. The Corporation's competitors include companies which have more financial resources, staff and facilities than those of the Corporation. Manitok believes that it has a competitive advantage in its focus area based upon the facilities, 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 oil and natural gas reserves in the Corporation's focus area is dependent on access to areas where operational activities are to be conducted. Seasonal weather variations, including freeze-up and break-up can delay such access. See *"Risk Factors – Seasonality"*.

Environmental Regulation

The oil and 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 earnings and overall competitiveness. See "*Risk Factors – Regulatory Risks*".

Employees

At December 31, 2011, the Corporation had 18 full time, two part time employees and five contract service providers in its head office; two contract service providers in its field office in the Swimming area of Alberta; and two employees and four contract service providers in its field office in Hinton, Alberta. 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. Manitok's corporate policies require operational activities to be conducted in a manner which meets or exceeds 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 role. The Corporation conducts regularly scheduled operational audits and assessments to identify risks and take steps to reduce or prevent accidents. See "*Risk Factors – Health, Safety and Environmental 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, including the ability of OPEC to set and maintain production levels and prices for crude oil;
- political conditions, including the risk of hostilities in the Middle East and other regions 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;
- North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of 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

Commodity Price Risk

Manitok's liquidity and cash flow is largely impacted by P&NG commodity prices. The Corporation has hedged a portion of its crude oil production at the date hereof and will continue to monitor the hedge 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 access alternate sources of capital.

Foreign Currency Exchange Risk

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

Production Risks

The Corporation is subject to the risk that production rates of its most 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 cash flows.

The majority of the Corporation's production passes through third party infrastructure prior to it being ready for transfer at designated commodity sales points. There is a risk that should this infrastructure fail and cause a significant portion of the Corporation's production to be shut-in and be unable to be sold, which could have a material adverse effect on the Corporation's available cash flow.

Replacement of Reserves

Oil and natural gas reserves naturally deplete as they are produced over time. The success of the Corporation's business is highly dependent on its ability to acquire and/or discover new reserves in a cost efficient manner. All of the Corporation's cash flow is substantially derived from the sale of the petroleum and natural gas 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 cash flow 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 petroleum and natural gas professionals and closely monitors the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

Health, Safety and Environment Risks

Health, safety and environment risks influence the workforce, operating costs and the establishment of regulatory standards. The Corporation provides staff with the training and resources they need 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 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 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 needed.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on the Corporation. As an oil and natural gas producer, the Corporation is subject to a broad range of regulatory requirements. 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. There is a risk that, 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, 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/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.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (natural gas and oil) 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, provincial and state 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 increase the Corporation's costs of compliance, its operating costs, and may negatively impact the Corporation's prospects, any of which may have a material adverse effect on the Corporation's business, financial condition and results of operations. The Corporation conducts its fracturing operations with reputable service providers, with due regard for potential impact on the environment and closely monitors and complies with the regulatory regime.

Counterparty Risk

The Corporation assumes customer credit risk associated with oil and gas 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.

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 cash flow in order to fund the development and acquisition of its long term asset base. As part of this strategy, the Corporation obtains some of this necessary capital by incurring debt and therefore the Corporation is dependent to a certain extent on continued availability of the credit markets.

The continued availability of the credit markets for the Corporation is primarily dependent on the state of the economy and the health of the banking industry in North America and abroad. There is risk that if the economy and banking industry experienced 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, the situations that may give rise to credit markets tightening or disappearing are 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 market expectations.

Operating Hazards and Other Uncertainties

Acquiring, developing and exploring for oil and natural gas involves many risks, which even through a combination of experience, knowledge and careful evaluation, the Corporation may not be able to manage effectively. 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, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. Like other oil and natural gas companies, the Corporation attempts to conduct its business and financial affairs so as to protect against operational, political and economic risks applicable to operations in the relevant area, but there can be no assurance that the Corporation will be successful in this regard. The Corporation is also 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. Although prior to drilling, the Corporation obtains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such 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.

Seasonality

The level of activity in the Canadian oil and 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 oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consist of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity.

Reliance on Key Personnel

The Corporation's success depends, in large measure, on certain key personnel. The loss of the services of such key personnel could have a material adverse affect 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.

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 oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable oil and natural gas 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 that 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 securities disclosure legislation and policies of Canada, 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 oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental 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, do not represent fair market value.

Acquisition Risks

The Corporation seeks out opportunities for the acquisition of oil and natural gas properties. 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 proved plus probable 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.

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 a reduction of the revenue received by the Corporation.

Litigation

In the normal course of the Corporation's operations, it may become involved in, 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. 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. Specific disclosure of current legal proceedings is disclosed under the heading *"Legal Proceedings and Regulatory Actions"* in this Annual Information Form.

Costs and Availability of Equipment and Services

Inflation is a risk common to all businesses in Canada. During times of high commodity prices for oil and natural gas, 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 oil and gas properties, the Corporation will be dependent on other operators for the timing of activities related to such properties and will be largely be unable to direct or control the activities of the operators.

Additional Funding Requirements

The cash flow from the Corporation's reserves may not be sufficient to fund the Corporation's ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate the Corporation's operations. If the revenues from the Corporation's reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace the Corporation's reserves or to maintain the Corporation's production. If the Corporation's cash flow from operations is 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 available on terms acceptable to the Corporation.

Competition

The oil and natural gas industry is highly competitive particularly as it pertains to the exploration for and development of new sources of crude oil and natural gas 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 oil and natural gas companies, many of which have greater financial resources than the Corporation.

Climate Change Risks

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. As a signatory to the *United Nations Framework Convention on Climate Change* and as a participant in the Copenhagen Accord, the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas ("**GHG**") emissions from 2005 levels by 2020. However, these GHG emission reduction targets are not binding. The Corporation continues to monitor GHG legislative developments. Although it is not the case today, the Corporation expects that some of its significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. If the Corporation becomes subject to GHG legislation, there can be no assurances that the compliance costs will be immaterial.

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 requires large industrial facility emitters of GHG to reduce GHG emissions intensities by 12% below a baseline derived from the average of 2003-2005 emissions. 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.*

Price Risk Management Activities

From time to time the Corporation may enter into agreements to receive fixed prices for its oil and natural gas 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 oil and natural gas prices.

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 16, 2012. The effective date of the reserves and future net revenues information provided is December 31, 2011, unless otherwise indicated. The information contained herein was prepared between December 31, 2011 and April 16, 2012.

Disclosure of Reserves Data

Sproule, independent qualified reserves evaluators and auditors of Calgary, Alberta prepared the Sproule Evaluation. Sproule has confirmed to the Reserve and Occupational Health and Safety Committee of Manitok's Board of Directors that the Sproule Evaluation has been prepared in accordance with the standards contained in the COGEH 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 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 Sproule's 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 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, NGL 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, 2011 may justify revision of assessed reserves, either upward or downward.

- The tables below are a summary of the oil, natural gas liquids and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Evaluation based on the Sproule Price Forecast. The tables summarize the data contained in the Sproule Evaluation.

- The 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.

All of the reserves held by Manitok as at December 31, 2011 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, 2011, using the Sproule Price Forecast.

SUMMARY OF OIL AND GAS RESERVES AT DECEMBER 31, 2011
(Forecast Prices and Costs)

	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		NATURAL GAS[1]		NATURAL GAS LIQUIDS		TOTAL	
RESERVE CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED										
Developed Producing	111.8	79.9	243.2	208.9	16,836	15,558	152.6	131.2	3,313.5	3,013.0
Developed Non-Producing	-	-	-	-	3,392	2,629	6.0	3.6	571.3	441.7
Undeveloped	59.9	47.0	141.9	125.7	2,561	1,997	26.3	18.5	654.9	524.0
TOTAL PROVED	**171.7**	**126.9**	**385.1**	**334.6**	**22,788**	**20,184**	**185.0**	**153.3**	**4,539.7**	**3,978.8**
PROBABLE	1,346.9	1,000.7	225.2	190.9	15,794	13,558	76.2	55.4	4,280.5	3,506.6
PROVED PLUS PROBABLE	**1,518.5**	**1,127.6**	**610.2**	**525.5**	**38,582**	**33,742**	**261.2**	**208.7**	**8,820.3**	**7,485.4**

(1) Estimates of reserves of natural gas include 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, 2011, using the Sproule Price Forecast, before and after deducting future income tax expense, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%. Future net revenue includes estimated future abandonment costs related to wells and production facilities required to produce the reserves.

NET PRESENT VALUE OF FUTURE NET REVENUE[1] AT DECEMBER 31, 2011
(Forecast Prices And Costs)

	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%
RESERVE 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	70,386	54,723	45,467	39,257	34,778	70,386	54,723	45,467	39,257	34,778	15.09
Developed Non-Producing	5,726	4,513	3,615	2,936	2,413	5,726	4,513	3,615	2,936	2,413	8.18
Undeveloped	7,462	4,702	2,946	1,757	916	6,904	4,363	2,735	1,623	829	5.62
TOTAL PROVED	**83,573**	**63,938**	**52,027**	**43,950**	**38,108**	**83,015**	**63,600**	**51,817**	**43,815**	**38,020**	**13.08**
PROBABLE	100,319	51,952	31,238	19,917	12,785	75,838	38,620	22,563	13,728	8,118	8.91
PROVED PLUS PROBABLE	**183,892**	**115,890**	**83,265**	**63,867**	**50,892**	**158,853**	**102,220**	**74,380**	**57,543**	**46,138**	**11.12**

(1) Estimates of future net revenues whether discounted or not do not represent fair market value.

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] AT DECEMBER 31, 2011
(Forecast Prices And Costs) (Undiscounted)

RESERVE CATEGORY	Future Net Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)[2]	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
TOTAL PROVED	186,509	29,488	58,544	13,094	1,809	**83,573**	558	**83,015**
PROVED PLUS PROBABLE	466,624	84,342	143,804	51,788	2,797	**183,892**	25,039	**158,853**

(1) Estimates of future net revenues whether discounted or not, do not represent fair market value.
(2) Does not include abandonment costs for facilities and reclamation costs for facilities and existing wells.

Future Net Revenue by Production Group

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

NET PRESENT VALUE OF PRE-TAX FUTURE NET REVENUE AT DECEMBER 31, 2011
(Forecast Prices And Costs) (10% discount rate)

	LIGHT AND MEDIUM CRUDE OIL[2]		HEAVY CRUDE OIL		NATURAL GAS[2]	
RESERVE CATEGORY	(M$)	($/boe)	(M$)	($/boe)	(M$)	($/boe)
TOTAL PROVED	**4,155**	**24.40**	**10,036**	**30.00**	**37,836**	**10.89**
PROVED PLUS PROBABLE	**21,014**	**13.63**	**14,642**	**27.86**	**47,609**	**8.79**

(1) Estimates of future net revenues whether discounted or not, do 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 revenues are after deduction of estimated costs of abandonment of existing and future wells and costs of reclamation of future wells only.

Pricing Assumptions

Forecast Prices Used in Estimates

The following table sets out the Sproule Price Forcast used for the 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 AT DECEMBER 31, 2011								
	CRUDE OIL			NATURAL GAS	NATURAL GAS LIQUIDS			
Year	WTI Cushing Oklahoma 40° API ($US/bbl)	Edmonton Par Price 40° API ($/bbl)	Hardisty Heavy 12° API ($/bbl)	Alberta AECO-C Spot ($/mmbtu)	Edmonton Propane ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Pentanes Plus ($/bbl)	Currency Exchange Rate ($US/$CAD)
2012	98.07	96.87	74.59	3.16	53.51	72.20	103.57	1.012
2013	94.90	93.75	72.19	3.78	52.29	69.87	100.23	1.012
2014	92.00	90.89	69.98	4.13	50.99	67.74	97.17	1.012
2015	97.42	96.23	74.10	5.53	54.77	71.73	102.89	1.012
2016	99.37	98.16	75.58	5.65	55.79	73.16	104.94	1.012
2017	101.35	100.12	77.09	5.77	56.83	74.63	107.04	1.012
2018	103.38	102.12	78.64	5.89	57.89	76.12	109.18	1.012
2019	105.45	104.17	80.21	6.01	58.97	77.64	111.37	1.012
2020	107.56	106.25	81.81	6.14	60.08	79.19	113.59	1.012
2021	109.71	108.38	83.45	6.27	61.20	80.78	115.87	1.012
thereafter	Escalate at 2.0% per annum							

The actual weighted average commodity prices received by Manitok in 2011 are as follows: (a) Light crude oil: $96.94 per bbl; (b) Heavy crude oil: $69.73 per bbl; (c) Natural Gas: $3.42 per mcf; and (d) Natural Gas Liquids: $91.38 per 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, 2011 as derived from the Sproule Evaluation against the Sproule evaluation of such reserves for the year ended December 31, 2010, using the Sproule price forecast provided in the Sproule evaluation for the year ended December 31, 2010.

	Light and Medium Crude Oil			Heavy Crude Oil		
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, 2010	**-**	**-**	**-**	**395.5**	**133.4**	**528.9**
Extensions and Improved Recovery(1)	18.4	1,290.7	1,309.1	120.2	139.5	259.7
Technical Revisions	-	-	-	(56.9)	(47.8)	(104.7)
Discoveries(1)	-	-	-	-	-	-
Acquisitions(2)	156.0	56.1	212.1	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors(3)	-	-	-	0.7	-	0.7
Production(4)	(2.7)	-	(2.7)	(74.4)	-	(74.4)
December 31, 2011	**171.7**	**1,346.8**	**1,518.5**	**385.1**	**225.1**	**610.2**

	Natural Gas Liquids			Natural Gas		
Factors	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**	**Gross Proved (Mmcf)**	**Gross Probable (Mmcf)**	**Gross Proved Plus Probable (Mmcf)**
December 31, 2010	1.8	1.7	3.5	1,569	629	2,198
Extensions and Improved Recovery(1)	26.2	15.7	41.9	2,484	3,206	5,690
Technical Revisions	-	1.9	1.9	(290)	(180)	(470)
Discoveries(1)	37.7	25.4	63.1	3,256	7,515	10,771
Acquisitions(2)	125.1	31.5	156.6	17,008	4,629	21,637
Dispositions	-	-	-	-	-	-
Economic Factors(3)	-	-	-	(227)	(4)	(231)
Production(4)	(5.8)	-	(5.8)	(1,012)	-	(1,012)
December 31, 2011	**185.0**	**76.2**	**261.2**	**22,787**	**15,795**	**38,582**

	Total		
Factors	**Gross Proved (Mboe)**	**Gross Probable (Mboe)**	**Gross Proved Plus Probable (Mboe)**
December 31, 2010	658.8	239.8	898.6
Extensions and Improved Recovery(1)	578.8	1,980.3	2,559.1
Technical Revisions	(105.2)	(75.9)	(181.1)
Discoveries(1)	580.4	1,277.9	1,858.3
Acquisitions(2)	3,115.8	859.2	3.975.0
Dispositions	-	-	-
Economic Factors(3)	(37.2)	(0.6)	(37.8)
Production(4)	(251.6)	-	(251.6)
December 31, 2011	**4,539.7**	**4,280.5**	**8,820.3**

(1) The majority of reserve changes comprising "Extensions" and "Discoveries" was the result of drilling activity in the Stolberg area of Alberta. A well was drilled extending the play beyond lands to which reserves had previously been attributed. As a result of this successful well, reserves were attributed to future well locations proximal to this well.

(2) On October 31, 2011, the Corporation closed the Asset Acquisition. According to a different independent NI 51-101 reserve evaluator's reserve report dated March 31, 2011, the Corporation acquired total proved reserves of 4,998 Mboe (natural gas of 28,017 Mmcf, light oil of 167 Mbbls and NGLs of 162 Mbbls) and probable reserves of 1,813 Mboe (natural gas of 9,800 Mmcf, light oil of 140 Mbbls and NGLs of 40 Mbbls). Production from the acquired properties from April 1, 2011 to October 31, 2011 which are not included in the production numbers in the table were approximately 268 Mboe (natural gas of 1,488 Mmcf, light oil of 8 Mbbls and NGLs of 11 Mbbls). The difference between the reserve volumes at the time the acquisition was made, adjusted for production, and the December 31, 2011 reserves volume is attributable to economic cut-off being reached on certain reserves as a result of the significant reduction in natural gas prices between the dates of the two reports.

(3) "Economic Factors" result from natural gas prices forecast by Sproule that were significantly lower than the 2010 Sproule evaluation for the entire forecast period, and resulted in negative impacts on reserve volumes.

(4) Represents production for 2011.

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 Sproule Evaluation for each product type that were first attributed as reserves in each of the most recent three financial years and in the aggregate, before that time, based on the Sproule Price Forecast.

2011 UNDEVELOPED RESERVES								
	PROVED UNDEVELOPED RESERVES				**PROBABLE UNDEVELOPED RESERVES**			
Year	**Light and Medium Crude Oil (Mbbl)**	**Heavy Crude Oil (Mbbl)**	**Natural Gas (Mmcf)**	**NGLs (Mbbl)**	**Light and Medium Crude Oil (Mbbl)**	**Heavy Crude Oil (Mbbl)**	**Natural Gas (Mmcf)**	**NGLs (Mbbl)**
Dec, 2011	**60**	**142**	**2,561**	**26**	**1,312**	**149**	**9,674**	**29**
Dec, 2010	-	165	-	-	-	71	-	-
June, 2010	-	171	185	2	8	147	315	19
Prior Years	-	170	187	2	9	147	348	41

Manitok has a conservative list of low-risk development opportunities which have been recognized in the Sproule Evaluation. A total of 15.75 net locations comprise a mix of oil and natural gas locations within Manitok's drilling inventory. Undeveloped reserves make up 43% of proved and probable reserves in the Sproule Evaluation. The undeveloped reserves represent 28% of the estimated pre-tax future net revenue attributable to proved plus probable reserves using a discount rate of 10% in the Sproule Evaluation. Manitok's intent is to spud these wells within the next five years.

The undeveloped list of drilling opportunities is not exhaustive. Only three net gas locations were selected by the technical team as plausible within a low price gas environment. The highest value natural gas locations occur in Banshee where 0.75 net locations provide an estimated pre-tax future net revenue attributable to proved plus probable reserves using a discount rate of 10% of about $2.1MM, mainly due to the high liquids yield.

In Swimming, eight net undeveloped locations comprise 18% of the total proven and probable reserves. All locations were identified in propriety 3D seismic surveys and are within Manitok's subsequent two year drilling inventory.

In Cordel / Stolberg, 4.75 net locations are assigned to proved and probable undeveloped reserve categories. These are horizontal or vertical drill locations along existing Cardium reservoir trends in complex fold structures. The oil is very light (45°-54° API) and has associated liquids-rich sweet gas. About 18% of the Corporation's proven and probable undeveloped reserves occur within the light oil resource in this property and these reservoirs are a focus of the Corporation's 2012 capital program. The Cordel / Stolberg undeveloped drill locations have been supported by extensive deep, sour gas well intersections and a sparse 2D data set.

Manitok's plan relating to the development of its proved and probable undeveloped reserves and the timing of such reserve development may change based on commodity prices or any changes in geological, geophysical, or engineering data that become available to the Corporation and 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 oil and natural gas 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 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 oil and gas 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 by the Sproule Evaluation using the Sproule Price Forecast and calculated without discount.

FUTURE DEVELOPMENT COSTS (Forecast Prices and Costs)		
Calendar Year	**Total Proved (M$)**	**Proved Plus Probable (M$)**
2012	5,360	40,448
2013	3,277	3,298
2014	2,892	2,892
2015	1,515	1,515
2016	50	50
Thereafter	-	3,585
Total Undiscounted	**13,094**	**51,788**

The Corporation expects to be able to fund the development costs required in the future from working capital, internally generated cash flow, 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 Sproule Evaluation. Failure to develop those reserves would have a negative impact on future production and cash flow.

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*".

Producing and Non-Producing Wells

The following table shows Manitok's producing and non-producing oil and natural gas wells at December 31, 2011, all of which are in Alberta.

2011 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	20	13.5	12	9.1	64	21.3	32	11.1

Properties with No Attributed Reserves

At December 31, 2011 Manitok held 202,407 (149,993 net) acres of undeveloped land. Approximately 5% of the net acres for the rights to explore, develop and exploit are expected to expire prior to the end of 2012. It is expected that the Corporation will be able to continue approximately 60% 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 oil and natural gas from these properties in the future. If Manitok's cash flow from operations is 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 Manitok. 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 and Additional Funding Requirements*".

The significant economic factors that affect Manitok's development of its lands to which no reserves have been attributed are future commodity prices for crude oil and natural gas (and Manitok's outlook relating to such prices), the future costs of drilling, completing, tying in and operating wells at the time that such activities are considered in the future.

The significant uncertainties that affect Manitok's development of such lands are the future drilling and completion results Manitok achieves in its development activities, drilling and completion results achieved by others on lands in proximity to Manitok's lands, 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. On the other hand, 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

As of December 31, 2011, the Corporation had not entered into financial or physical hedges in respect of commodity prices, or foreign exchange contracts or other similar forward sale contracts. Subsequent to the December 31, 2011 year end the Corporation entered into an extendible swap on 300 bbls/d of its production from

March 1, 2012 to December 31, 2012 at a swap price of CAD$106.50/bbl WTI. The counterparty to the swap has the right on December 31, 2012 to extend the swap for all of 2013 at the same terms.

Additional Information Concerning Abandonment and Reclamation Costs

The Sproule Evaluation has included estimated well abandonment costs for only the wells with assigned reserves and future drilling locations identified in the Sproule Evaluation, but reclamation costs have not been included.

Manitok currently has 55.1 net wells that ultimately will need to be abandoned and/or reclaimed.

The following table sets forth the total amount of future costs in the Sproule Evaluation in connection with the abandonment of wells in the proved and probable category.

FUTURE ABANDONMENT AND RECLAMATION COSTS RELATING TO PROVED PLUS PROBABLE RESERVES
(Forecast Pricing and Costs)

	Undiscounted Amount (M$)	**Discounted Amount at 10% per year (M$)**
Total amount of the future abandonment costs	2,797	719
Anticipated to be paid in 2012[1]	2	2
Anticipated to be paid in 2013[1]	-	-
Anticipated to be paid in 2014[1]	35	26
Total anticipated costs in the next three years	37	28

(1) Excludes abandonment and reclamation costs for facility sites and pipelines.

Tax Horizon

The Corporation was not required to pay any cash income taxes for the year ended December 31, 2011. Manitok estimates that based on current expenditure plans and the current price environment no income taxes will become payable on Manitok's income during 2012. If Manitok continues to expend capital beyond its internally generated cash flow, it is likely that Manitok will not become taxable so long as such expenditures continue and commodity prices remain consistent with today's environment.

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, 2011.

2011 ACQUISITION, EXPLORATION AND DEVELOPMENT COSTS

Acquisition Costs Proved Properties (M$)	**Acquisition Costs Unproved Properties (M$)**	**Exploration Costs (M$)**	**Development Costs (M$)**	**Total (M$)**
39,679.7	13,360.1	14,856.7	6,410.0	**74,306.5**

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 will focus on the drilling and completion of light oil wells in the Stolberg area of Alberta.

The following table sets forth a summary of Manitok's exploration and development drilling activities for the year ended December 31, 2011.

2011 EXPLORATION AND DEVELOPMENT ACTIVITIES						
	EXPLORATION WELLS		**DEVELOPMENT WELLS**		**TOTAL**	
Type	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells	3.0	2.7	4.0	4.0	7.0	6.7
Natural Gas Wells	1.0	0.7	Nil	Nil	1.0	0.7
Service Wells	Nil	Nil	Nil	Nil	Nil	Nil
Stratigraphic Test Wells	Nil	Nil	Nil	Nil	Nil	Nil
Dry Holes	Nil	Nil	Nil	Nil	Nil	Nil
Total	**4.0**	**3.4**	**4.0**	**4.0**	**8.0**	**7.4**

Production Estimates

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 Sproule Evaluation for the 2012 financial year.

2012 PRODUCTION VOLUME ESTIMATES					
Reserve Category	**Light and Medium Crude Oil (Mbbl)**	**Heavy Crude Oil (Mbbl)**	**Natural Gas (Mmcf)**	**NGLs (Mbbl)**	**Total (Mboe)**
Gross Total Proved	23.3	136.3	3,351	29.9	748.0
Gross Probable	209.8	14.3	1,081	2.4	406.7

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, 2011 is set forth below:

2011 PRODUCTION VOLUMES FOR KEY FIELD		
Area Name	**2012 Sproule Forecast Production for determining Gross Total Proved Reserves (Mboe)**	**2012 Sproule Forecast Production for determining Gross Probable Reserves (Mboe)**
Cordel / Stolberg	189.5	275.0

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, 2011.

2011 QUARTERLY PRODUCTION HISTORY					
	Three months ended				**Year ended**
Product Type	**March 31, 2011**	**June 30, 2011**	**September 30, 2011**	**December 31, 2011**	**December 31, 2011**
Light and Medium Crude Oil (bbl/d)(1)	-	-	-	42.0	10.6
Heavy Crude Oil (bbl/d)	114.7	195.3	170.8	331.9	203.7
Natural Gas (mcfe/d)(2)	648.4	629.7	1,458.7	8,593.9	2,850.7
Total (boe/d)	**222.8**	**300.3**	**413.9**	**1,806.2**	**689.4**

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

Price Received, Royalties Paid, Production Costs and Operating Netbacks

The following tables set forth, by product type, Manitok's share of average daily production before deduction of royalties, the prices received, royalties paid, production costs incurred and the resulting operating netback on a per unit of volume basis, for each quarter of the year ended December 31, 2011.

LIGHT AND MEDIUM CRUDE OIL 2011 QUARTERLY PRICE, ROYALTY,PRODUCTION COST AND NETBACK HISTORY					
	Three months ended				**Year ended**
$/bbl	**March 31, 2011**	**June 30, 2011**	**September 30, 2011**	**December 31, 2011**	**December 31, 2011**
Price Received(1)	-	-	-	71.12	71.12
Royalties Paid	-	-	-	(23.55)	(23.55)
Production Costs	-	-	-	(13.51)	(13.51)
Transportation and Marketing	-	-	-	(0.20)	(0.20)
Operating Netback	-	-	-	33.86	33.86
Royalty Income	-	-	-	-	-
Operating Netback including Royalty Income	**-**	**-**	**-**	**33.86**	**33.86**

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

HEAVY CRUDE OIL 2011 QUARTERLY PRICE, ROYALTY, PRODUCTION COST AND NETBACK HISTORY					
	Three months ended				**Year ended**
$/bbl	**March 31, 2011**	**June 30, 2011**	**September 30, 2011**	**December 31, 2011**	**December 31, 2011**
Price Received(1)	59.88	74.61	63.31	73.52	69.73
Royalties Paid	(4.66)	(5.23)	(6.01)	(5.99)	(5.63)
Production Costs	(21.55)	(23.94)	(20.61)	(24.38)	(23.09)
Transportation and Marketing	(2.36)	(3.64)	(3.34)	(3.11)	(3.18)
Operating Netback	31.31	41.80	33.35	40.04	37.83
Royalty Income	-	-	-	-	-
Operating Netback including Royalty Income	**31.31**	**41.80**	**33.35**	**40.04**	**37.83**

(1) Does not include royalty income

NATURAL GAS 2011 QUARTERLY PRICE, ROYALTY, PRODUCTION COST AND NETBACK HISTORY					
	Three months ended				Year ended
$/mcfe	**March 31, 2011**	**June 30, 2011**	**September 30, 2011**	**December 31, 2011**	**December 31, 2011**
Price Received(1)	3.71	3.94	3.80	3.83	3.83
Royalties Paid	(0.27)	(0.11)	(0.28)	(0.57)	(0.49)
Production Costs	(2.33)	(3.40)	(1.04)	(1.59)	(1.66)
Transportation and Marketing	(0.17)	(0.20)	(0.19)	(0.12)	(0.13)
Operating Netback	0.94	0.23	2.29	1.55	1.55
Royalty Income	-	-	-	0.07	0.04
Operating Netback including Royalty Income	**0.94**	**0.23**	**2.29**	**1.62**	**1.59**

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

2011 Production History

The following table sets forth Manitok's annual production volumes for the year ended December 31, 2011 by product type, for the two fields each comprising more than 20% of Manitok's total production and in total.

2011 PRODUCTION VOLUMES BY PRODUCT TYPE FOR MAJOR FIELDS					
Area name	**Light and Medium Crude Oil (Mbbls)**	**Heavy Crude Oil (Mbbls)**	**Natural Gas (Mmcf)**	**NGLs (Mbbls)**	**Total (Mboe)**
Cordel / Stolberg	2.4	-	384.8	2.8	69.3
Swimming	-	74.4	-	-	74.4

DIVIDEND AND DISTRIBUTION POLICY

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 issuable in series, each without par value. At April 18, 2012, there were 61,800,531 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 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 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, 2011.

Month	High	Low	Monthly Trading Volume
January	1.95	1.22	465,511
February	2.14	1.60	1,366,531
March	2.50	1.60	819,450
April	2.05	1.65	1,300,779
May	1.90	1.63	1,008,344
June	1.85	1.51	1,161,471
July	1.75	1.55	1,342,845
August	1.65	1.20	1,303,744
September	1.74	1.25	3,135,488
October	2.12	1.50	2,690,086
November	2.00	1.56	2,805,006
December	1.70	1.35	739,332

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.

Pricing and Marketing

Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with a competitive open market setting the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board (the "**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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

In Canada, the price of natural gas results from transactions between buyers and sellers in an open, transparent market environment. 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 export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the government of Canada. As is the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB licence and Governor in Council approval. The price received by the Corporation depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply and demand balance and other contractual terms.

The governments of Alberta and British Columbia also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as availability of reserves, transportation arrangements and market considerations.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the U.S. and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed provided that the restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade then only if the export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36-month period); (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, to minimize disruption of contractual arrangements and to avoid undue influence with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

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 cash flow within the industry.

Alberta

Producers of oil and natural gas 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 oil and natural gas produced.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure, which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF range from 0% to 50%, an increase from the previous maximum rates of 30% to 35% depending on the vintage of the oil, and rate caps are set at $120/bbl. Effective January 1, 2011, the maximum royalty payable under the NRF were reduced to 40%.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which were subsequently implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system that were intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors. As a result of this announcement, the maximum royalty rates for conventional oil and natural gas production were decreased as of the January 2011 production month and certain temporary incentive programs were made permanent.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5% to 50%, an increase from the previous maximum rates of 5% to 35%, and rate caps are set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF were reduced to 36%.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of oil: rates are 1% when the market price of oil is less than or equal to $55/bbl and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120/bbl or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% to 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55/bbl up to 40% when oil is priced at $120/bbl or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves. As at the date hereof, 37 such projects have been approved and announced.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. 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, favouring smaller producers with lower activity levels. 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 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 bbls of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

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 oil and natural gas 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 oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan 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. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

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 will revisit the decision in spring 2012.

Environmental Regulation

Companies operating in the oil and natural gas industry are subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines or the issuance of clean-up orders. Under the Environmental Protection and Enhancement Act (Alberta), changes in these regulations have had an incremental effect on the cost of conducting operations in Alberta.

In December 2008, the Government of Alberta released a new land policy for surface land in Alberta, the Alberta Land Use Framework (the "**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 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.

The Alberta Land Stewardship Act (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be 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, leases, licenses, 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 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature, as a result of the increasingly stringent laws relating to the protection of the environment. The Corporation's internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding. The

Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

Climate Change Regulation

International

In December 2002, the Government of Canada ratified the Kyoto Protocol (the "**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and Canada formally withdrew from the Kyoto Protocol on December 12, 2011.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark in December 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020, in line with the reduction commitment made by the United States. The Copenhagen Accord and the Kyoto Protocol remain in place subsequent to Conference of the Parties 16, held in Cancun, Mexico in 2010.

Federal

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**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 (the "**Updated Action Plan").** The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010, followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity or (ii) involve significant changes to the processes of the facility. New Facilities will be given a three-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of carbon dioxide equivalents ("**CO_{2e}**") per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_{2e} per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above-mentioned targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_{2e} for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

(b) The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or to non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

(c) Under the Updated Action Plan, regulated entities are able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol, which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such emissions reduction credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations. However, with Canada's recent withdrawal from the Kyoto Protocol, this mechanism may be of little use in the future.

(d) A one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, 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. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012 and, with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the Climate Change and Emissions Management Act (the "**CCEMA**") on July l, 2007, amending it 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 similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs per year must comply with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated Specified Gas Emitters Regulation make a distinction 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 to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 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 Specified Gus Emitters Regulation. New Facilities are required to reduce their emissions intensity by 2% of baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms similar those in the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_{2e}. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can 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.

On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010, which 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.

ESCROWED SECURITIES

To the knowledge of the Corporation, there are no securities of the Corporation that are held in escrow as at April 18, 2012.

DIRECTORS AND OFFICERS

Directors

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

Name, Province and Country of Residence	Director Since	Present Position, Principal Occupations During the Past Five Years or More, Educational Qualifications and Other Directorships
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 and is a member of the Audit Committee, Compensation Committee and Reserves and Occupational Health and Safety Committee. 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.
Robert J. (Bob) Dales(1)(3) *Alberta, Canada* Independent Director	July 8, 2010	Mr. Dales is a director of Manitok and is a member of the Audit Committee and Reserves and Occupational Health and Safety Committee. He has been President of Valhalla Ventures Inc., a private investment corporation, since January 1999 and President, Chief Executive Officer and a director of Drako Capital Ltd. Mr. Dales is also a director of Celtic Exploration Ltd. a TSX listed oil and gas company and Arcan Resources Ltd. a TSX-V listed oil and gas company.
Wilfred A. (Wilf) Gobert(1)(2) *Alberta, Canada* Independent Director	July 8, 2010	Mr. Gobert is a director of Manitok and is a member of the Audit Committee and Compensation Committee. He has been an independent businessman since May 2006 and prior thereto, he was Managing Director, Research of Peters & Co. Limited, an investment dealer, from August 1979 to September 2002. Mr Gobert was a director of MEX from February 28, 2007 to July 8, 2010.
Gregory E. (Greg) Peterson(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 Compensation Committee. He has been a Partner with Gowling Lafleur Henderson LLP, a national Canadian law firm, since 1990. Mr Peterson was a director and Corporate Secretary of MEX from April 20, 2005 to July 8, 2010.
Tom Spoletini(1)(2) *Alberta, Canada* Independent Director	July 8, 2010	Mr. Spoletini is a director of Manitok and is a member of the Audit Committee and Compensation Committee. He is a founding partner of Spolumbo's Deli, a private deli company based out of Calgary, Alberta. Mr. Spoletini was a director of MEX from April 20, 2005 to July 8, 2010.
Cameron G. (Cam) Vouri(3) *Alberta, Canada* Independent Director	July 8, 2010	Mr. Vouri is a director of Manitok and is a member of the Reserves and Occupational Health and Safety Committee. He has been an independent businessman since March 1, 2011. Prior thereto, he was Vice President, Operations and Chief Operating Officer of Renegade Petroleum Ltd. and President, Canadian Oil and Gas Division of Provident Energy Trust. Mr. Vouri was a director of MEX from February 1, 2007 to July 8, 2010.
Massimo M. Geremia(1))(3) *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 meeting of the shareholders of the Corporation, unless re-elected.

The board of directors of the Corporation (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. B. Geremia (chair), Dales, Gobert, Spoletini and M. Geremia. The Compensation Committee is comprised of Messrs. Gobert (chair) B. Geremia, Peterson and Spoletini. The Reserves and Occupational Health and Safety Committee is comprised of Messrs. Vouri (chair) Dales, B. Geremia and M. Geremia. 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. Massimo M. Geremia, as an officer of the Corporation and Mr. Bruno P. 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 separate corporate governance or executive committees.

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. Geremia *Alberta, Canada*	President and Chief Executive Officer	Mr. M. Geremia is the President and Chief Executive Officer and a director of Manitok. He co-founded MEX on Apirl 20, 2005 and served as the President, Chief Executive Officer and Chief Financial Officer of MEX from April 20, 2005 to July 8, 2010. Prior thereto, Mr. Geremia was a manager of Birchcliff Energy Ltd., a TSX listed oil and gas company, from April 2005 to May 2008.
Tim A. de Freitas *Alberta, Canada*	Vice-President, Exploration and Chief Operating Officer	Mr. de Freitas is Vice-President, Exploration and Chief Operating Officer and is a professional geologist. Prior thereto, he co-founded MEX and served as Vice President, Exploration and Chief Operating Officer of MEX from September 2008 until July 8, 2010. From September 2006 to September 2008, Mr. de Freitas was a consultant with British Gas International and from April 1999 to September 2006, he was in various technical and managerial capacities in foothills exploration and development teams with Talisman Energy Inc.
Robert G. 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 from September 2003 to January 2010.
Dorothy Else *Alberta, Canada*	Vice-President, Land	Ms. Else is Vice-President, Land. She was Vice President, Land of MEX from April 16, 2010 until July 8, 2010 and an independent consultant for MEX since 2005.

Shareholdings of Directors and Executive Officers

At December 31, 2011, the directors and executive officers of the Corporation, as a group, beneficially owned, or exercised control or direction over, directly or indirectly, 4,075,074 Manitok Shares representing approximately 6.6% of the 61,800,531 Manitok Shares issued and outstanding at that date. The directors and executive officers, as a group, also held options to purchase 1,738,000 Manitok Shares.

The fully diluted holdings of directors and executive officers, as a group, were 5,813,074 Manitok Shares or approximately 8.9% of the 61,800,531 Manitok Shares that were outstanding on a fully diluted basis at December 31, 2011.

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.

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 be likely to 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 officers of the Corporation will be subject to in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial or director positions with other oil and natural gas 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 oil and natural gas companies and sets forth certain details of those directorships.

Name	Name of Reporting Issuer	Exchange	Term
Robert J. Dales	Arcan Resources Inc. (formerly Desco Energy Ltd.)	TSX-V	January 2007 – Present
	Celtic Exploration Ltd.	TSX	April 2002 – Present
	Drako Capital Corp.	TSX-V	January 2010 – Present
Wilfred A. Gobert	Canadian Natural Resources Limited	TSX and New York Stock Exchange	November 2010 – Present
	Aston Hill Energy Inc.	TSX	December 2008 – Present
	Catapult 2008 Inc.	TSX	August 2008 – Present
	Gluskin Sheff + Associates	TSX	May 2006 – Present
	Trilogy Energy Inc.	TSX	November 2006 – 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.

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. Robert J. Dales, Mr. Wilfred A. Gobert, Mr. Tom Spoletini and Mr. Massimo M. Geremia. Each member of the Audit Committee is independent within the meaning of section 1.4 of NI 52-110, other than Mr. Massimo M. Geremia, as an officer of the Corporation and 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

Each of the members of the Audit Committee has been involved in the financing, administration and operation of managing public companies or significant operations of private companies and has been either directly involved in the preparation of the financial statements, filing of the quarterly and annual financial statements, dealing with the auditors or as a member of the Audit Committee. All members have the ability to read, analyze and understand the complexities surrounding the issuance of financial statements.

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*) or 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 Kenway Mack Slusarchuk Stewart LLP, the Corporation's external auditors, during the year ended December 31, 2011 and December 31, 2010.

Nature of fees	2010	2011
Audit fees	$35,000	$49,500
Audit-related fees	$6,000(1)	$40,000(3)
Tax fees	-	-
All other fees	$1,000(2)	$26,000(4)
Total	**$42,000**	**$115,500**

(1) Fees for the review of September 30, 2010 interim financial statements.
(2) Fees for the due diligence procedures for the December 22, 2010 equity issuance.
(3) Fees for the review of interim financial statements for March 31, 2011, June 30, 2011 and September 30, 2011 which includes the transition to International Financial Reporting Standards.
(4) Fees for the due diligence procedures for the April 2011 Financing and the December 2011 Financing.

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 Valiant Trust Company at its principal office located in Calgary, Alberta.

MATERIAL CONTRACTS

Other than the asset purchase and sale agreement dated September 20, 2011 between Manitok Energy Inc. and Petrus Resources Ltd. regarding the Asset Acquisition, underwriting agreement dated effective as of November 15, 2011 in connection with the December 2011 Financing and the agency agreement dated effective March 24, 2011 in connection with the April 2011 Financing, 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 Business – Relevant Three Year History*".

INTERESTS OF EXPERTS

The 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 Sproule Evaluation own no securities of the Corporation.

Kenway Mack Slusarchuk Stewart LLP has confirmed that it is independent of the Corporation in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

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 6, 2011. Additional financial information relating to the Corporation is provided in the Corporation's annual audited financial statements and management's discussion and analysis for the year ended December 31, 2011.

SCHEDULE "A"
AUDIT COMMITTEE CHARTER

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

A. PURPOSE

The overall purpose of the Audit Committee (the "**Committee**") of the Board of Directors (the "**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. (the "**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 (the "**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 affect 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

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

1. We have evaluated the Corporation's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated 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 by us as of December 31, 2011, 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	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Sproule Associates Limited	Evaluation of the P&NG Reserves of Manitok Energy Inc., as at December 31, 2011, prepared January to March 2012	Canada	-	$83,265	-	$83,265

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented 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.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. 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 16, 2012

(signed) *"Paul B. Jung"*

Paul B. Jung, P. Eng.
Supervisor, Engineering and Partner

(signed) *"James A. Chisholm"*

James A. Chisholm, P. Eng.
Petroleum Engineer and Partner

(signed) *"Alec Kovaltchouk"*

Alec Kovaltchouk, P. Geol.
Manager, Geoscience and Partner

(signed) *"Harry J. Helwerda"*

Harry J. Helwerda, P. Eng., FEC
Executive Vice-President 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. (the "**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, 2011, 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 is presented in the Statement of Reserves Data and Other Oil and Gas Information of the Corporation effective as at December 31, 2011.

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 and auditor 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 approved:

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

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

3. 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*"
Massimo M. Geremia
President and Chief Executive Officer

(signed) "*Robert G. Dion*"
Robert G. Dion
Vice President, Finance and Chief Financial Officer

(signed) "*Cameron G. Vouri*"
Cameron G. Vouri
Chairman of the Reserve and Occupational Health and Safety Committee and Director

(signed) "*Bruno P. Geremia*"
Bruno P. Geremia
Director

Dated: April 18, 2012