ANNUAL INFORMATION FORM

For the Year Ended December 31, 2013

Dated March 31, 2014

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ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the following abbreviations have the meanings set forth below.

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbl/d	barrel per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet

Other

AECO	a natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute.
API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28°API or higher is generally referred to as light crude oil.
boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.
boe/d	barrel of oil equivalent per day.
M$	thousands of dollars.
MM$	millions of dollars.
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.

Conversions

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

To convert from	To	Multiply by
Mcf	cubic metres	0.028
cubic metres of gas	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres of oil	bbl	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

DEFINITIONS

In this Annual Information Form, the following words and phrases have the meanings set forth below, unless otherwise indicated.

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time.

"**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

"**Board**" means the board of directors of the Company.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

"**Common Shares**" means the common shares in the capital of the Company.

"**Company**" or "**Strategic**" means Strategic Oil & Gas Ltd.

"**crude oil**" or "**oil**" as described in the COGE Handbook means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

Discovered Petroleum Initially In Place (DPIIP)*,* as defined in the Canadian Oil and Gas Evaluation Handbook ("COGEH") means that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable. "Contingent Resources" are defined in COGEH as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be economically recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The Contingent Resources estimates and the DPIIP estimates are estimates only and the actual results may be greater or less than the estimates provided herein. There is no certainty that it will be commercially viable to produce any portion of the resources except to the extent identified as proved or probable reserves. "Best estimate" is defined in COGEH with respect to entity-level estimates, as the value derived by an evaluator using deterministic methods that best represent the expected outcome with no optimism or conservatism. 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.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying and acquiring well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"**future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, CBM and other non-conventional reserves) estimated using forecast prices and costs.

"**gross**" means:

(a) in relation to the Company's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**McDaniel**" means McDaniel & Associates Consultants Limited, independent reserves engineers.

"**McDaniel Report**" means the independent engineering evaluation of the oil and natural gas interests of the Company prepared by McDaniel dated February 27, 2014 and effective December 31, 2013.

"**natural gas**" as described in the COGE Handbook means a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

"**natural gas liquids**" or "**NGLs**" as described in the COGE Handbook means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"**net**" means:

(a) in relation to the Company's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*.

"**non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

"**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**reservoir**" means a porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"**Shareholders**" means holders of Common Shares and "**Shareholder**" means any one of them.

"**solution gas**" means natural gas dissolved in crude oil.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**TSX-V**" means the TSX Venture Exchange.

"**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

"**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

RESERVES DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

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

"**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.

"**Developed Producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Non-Producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**Undeveloped**" reserves are those reserves expected to be recovered from know accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"**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.

"**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.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking information. This information relates to future events or future performance of Strategic. When used in this Annual Information Form, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "estimate", "predict", "seek", "propose", "expect", "potential", "continue", and similar expressions, are intended to identify forward-looking information. This information involves known and unknown risks, uncertainties, and other factors that may cause actual results of events to differ materially from those anticipated in such forward-looking information. This information reflects Strategic's current views with respect to certain events, and are subject to certain risks, uncertainties and assumptions. Many factors could cause Strategic's actual results, performance, or achievements to vary from those described in this Annual Information Form. Should one or more of these risks or uncertainties materialize, or should assumptions underlying the forward-looking information prove incorrect, actual results may differ materially from those described in this Annual Information Form as intended, planned, anticipated, believed, estimated, or expected. Specific forward-looking information in this Annual Information Form includes, among others, information pertaining to the following:

- factors upon which Strategic will decide whether or not to undertake a specific course of action;
- world wide supply and demand for petroleum products;
- expectations regarding Strategic's ability to raise capital;
- treatment under governmental regulatory regimes; and
- commodity prices and exchange rates.

With respect to forward-looking information in this Annual Information Form, Strategic has made assumptions, regarding, among other things:

- the impact of increasing competition;
- Strategic's ability to obtain additional financing on satisfactory terms;
- commodity prices and exchange rates; and

- Strategic's ability to attract and retain qualified personnel.

Strategic's actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth below and elsewhere in this Annual Information Form including, without limitation, the following:

- general economic conditions;
- volatility in global market prices for oil and natural gas;
- competition;
- liabilities and risks, including environmental liability and risks, inherent in oil and gas operations;
- the availability of capital;
- alternatives to and changing demand for petroleum products;
- changes in legislation and the regulatory environment; and
- the other factors discussed under the heading "*Risk Factors*".

Furthermore, information relating to "reserves" is deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions that reserves described can be recovered and profitable in the future. Statements relating to "reserves" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. See "*Risk Factors - Reserve Estimates*".

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Strategic's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through SEDAR at www.sedar.com. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Company assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

STRATEGIC OIL & GAS LTD.

Strategic Oil & Gas Ltd. was incorporated under the laws of the Province of British Columbia on December 30, 1987 as 338761 B.C. Ltd. pursuant to the *British Columbia Companies Act*, which was subsequently replaced by the British Columbia *Business Corporations Act*. In addition, the articles of the Company have been amended as follows:

- August 25, 1988 - name changed to Xpres Infosystems Inc.;
- November 15, 1988 - name changed to Xpres Communications Inc.;
- February 11, 2000 - name changed to Stratacom Technology Inc. and share capital consolidated on a four (4) for one (1) basis;
- February 22, 2005 - name changed to Strategic Oil & Gas Ltd.;

- July 23, 2009 - Notice of Articles filed under new *Business Corporations Act* (British Columbia);
- September 9, 2010 - Company continued as an Alberta corporation; and
- April 1, 2012 - Company amalgamated with two of its wholly owned subsidiaries, Steen River Oil & Gas Ltd. and ZinMac Inc.

On February 28, 2013, Strategic acquired all the outstanding common shares of Strategic Transmission Ltd., a Canada Business Corporations Act company, in conjunction with the acquisition of oil and gas assets in northwest Alberta and the Northwest Territories. Strategic Transmission Ltd. was registered under the Business Corporations Act of the Northwest Territories on January 6, 2014.

The Company, together with its two wholly-owned subsidiaries, is engaged in the exploration for and development of petroleum and natural gas reserves in Western Canada with minor operations in the Western United States. On March 29, 2006, Strategic incorporated a Nevada subsidiary, Strategic Oil & Gas, Inc. through which all oil and gas activities in the USA are conducted. On March 10, 2009 the Company acquired all the shares of ZinMac Inc., a private oil and gas consulting company. On December 22, 2010, the Company acquired all the shares of a private company, Steen River Oil & Gas Ltd., an Alberta oil and gas company with primary oil and gas assets in northwest Alberta.

The Company's principal office is located at 1100, 645-7th Avenue SW, Calgary, Alberta T2P 4G8 and its registered office is located at 3700, 400-3rd Avenue SW, Calgary, Alberta, T2P 4H2.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

2011

In 2011 the Company made significant progress increasing its production, due to the successful drilling program at the Steen River assets. The program was consistent with the Company's strategy to explore, exploit and acquire large hydrocarbon in-place reservoirs.

In early 2011, Strategic commissioned an independent reserves evaluator to conduct an independent resource evaluation of the Company's Maxhamish area effective December 31, 2010. This study assigned discovered petroleum initially-in-place ("DPIIP") to 13,874 gross acres (22 sections gross lease) of land. The DPIIP study was restricted to a 3 mile extension from the existing wells where proved and probable assignment of reserves were recognized and did not extend over the entire Maxhamish land base. The 13,874 acres evaluated represent 20% of Strategic's Maxhamish land base. In addition, Strategic management's internal estimate projected recovery factors of between 10% to 15% on primary recovery. Complete details of the resource evaluation are presented in a press release date March 16, 2011 which has been filed on www.sedar.com.

The Company's 2011 production was enhanced by the Steen River acquisition along with added production from a successful winter drilling program. The sales production averaged 956 boe/d (69% liquids) which represented a 216% increase over 2010 production results. The Company's 2011 financial results benefited from the increased production and the acquisition of Steen River combined with the strong oil price environment. The Company's revenue increased 289% over the 2010 financial results to $23.9 million and cash flow from operations increased to $0.8 million from negative cash flow from operations of $1.8 million in 2010. The Company realized an average price of $68.37 per boe, up 24% compared to $55.34 per boe in 2010.

A pipeline breach in late April 2011 shut down the Rainbow pipeline, which delivers the Company's Steen River crude oil to market. Strategic was forced to shut-in approximately 600 boe/d production at Steen River as a result. This had a significant impact on the Company's sales volumes in the second and third quarters. The resumption of normalized pipeline operations on the Rainbow pipeline allowed the Company to return to full production.

In the third quarter of 2011, Strategic purchased a horizontal oil treater. The treater was installed at the 9-17-122-20 Steen River gas plant as an enhancement to the existing oil handling facilities. The installation of the treater allowed for more efficient processing of existing crude production while increasing capacity in anticipation of a successful drilling program.

At Maxhamish, Strategic, with its operating partner Legacy Oil & Gas Inc., completed an all-weather road including well pads in early July 2011. Two wells were drilled and fracture stimulated. Liner difficulties in the first well resulted in only half the wellbore being effectively stimulated. The second well came on production in January 2012, but was rate constrained due to surface production equipment limitations.

In September 2011, the Company adopted a shareholders' rights plan which was approved by Shareholders on November 22, 2011. In December 2011, the Company issued 35,000,000 Common Shares at $0.90 per Share and 9,100,000 flow-through Common Shares at $1.10 per share for gross proceeds of $42.3 million.

2012

In March 2012, the Company made a significant light oil discovery in the Steen River region. The discovery well tested over a four day period and flowed on average 733 bbls of 36 API oil for 7 to 8 hours each day. The well discovery results reinforce the view that significant light oil potential exists in similar structures at Steen River.

On August 16, 2012, the Company announced that it was undertaking a normal course issuer bid in accordance with the policies of the TSX-V. Pursuant to the normal course issuer bid, Strategic purchased 958,800 Common Shares for cancellation during the 12 month period commencing August 20, 2012. The Common Shares were purchased at the market price on the purchase date through the facilities of the TSX-V.

In December 2012, the Company announced that it has entered into agreements to acquire certain assets in its core area at Steen River for cash consideration of $23.6 million. The Company acquired a 100% working interest in 340 boe/d (83% light oil) of production and over 26 sections of highly prospective land contiguous to its position at Steen River. The acquisition also includes significant pipelines, facilities and roads that are strategic to the Company and provides an immediate increase in efficiencies in current operations, coupled with a decrease in future infrastructure capital costs.

2013

In March 2013 the Company acquired the Cameron Hills and Bistcho assets from Paramount Resources Ltd. for total cash consideration of $9.6 million. These assets are located adjacent to the Company's Steen River core area. The Bistcho assets, located on the western edge of the Company's Steen River operations, have significant well control with opportunities for multi-zone subsurface upside. Cameron Hills is a high quality asset with significant oil and gas development potential. The Company believes that the acquisition represents the continued advancement of Strategic's business strategy to acquire and develop its northern assets.

In March 2013, the Company issued 23.2 million Common Shares at a price of $1.25 per share for net proceeds of $28.3 million after deducting related costs.

In September 2013 the Company issued 20,195,000 Common Shares at a price of $0.95 per common share for proceeds of $19.2 million further to a non-brokered private placement.

In October 2013 the Company completed a bought deal financing and issued 14,547,500 common shares at a price of $0.95 per Common Share and 15,454,545 common shares issued on a "flow-through" basis pursuant to the Income Tax Act (Canada) (the "Flow-Through Shares") at a price of $1.10 per Flow-Through Share, for aggregate gross proceeds of $30.8 million.

The net proceeds of approximately $48.4 million from both the Offering and private placement were used to pay down debt and to pay for the Company's increased 2013 drilling program and to partially fund the 2014 capital budget.

The Flow-Through Share proceeds were to be used to incur eligible Canadian exploration expenditures that will be renounced to subscribers effective on or before December 31, 2013.

Recent Developments

On March 12, 2014 the Company announced two private placements, one brokered and one non-brokered, of up to 100,000,000 Common Shares of the Company at a price of $0.50 per Common Share for gross proceeds of up to $50.0 million. These private placements closed by March 31, 2014 in the full amount of $50.0 million. The net proceeds will be used to reduce bank indebtedness incurred in successful execution the Company's winter capital program and for general corporate purposes.

DESCRIPTION OF THE BUSINESS

Corporate Summary

Strategic is an emerging junior oil and gas company primarily targeting upstream oil and gas exploitation and development in Western Canada. Management of Strategic believes that its sub-surface technical capabilities in geology, geophysics, engineering and petro physics analysis make it a unique operator within the junior natural resource marketplace.

Strategic is well positioned with the technical expertise and management team required to take advantage of the attractive balance of high impact, light oil resource plays it has available. Strategic's business strategy is to increase production, cash flow and shareholder value in a cost-effective manner by focused drilling, accretive acquisitions and operational efficiency.

Strategic is in a unique position for a junior/emerging oil and gas company:

- ongoing drilling program at Steen River with over 100 sections of undeveloped land;
- the ability to significantly increase production at Steen River utilizing recently upgraded and expanded infrastructure;
- large resource play at Maxhamish, with over 100 sections of land;
- drill ready targets in an emerging oil play at Amber and development opportunities at Cameron Hills and Bistcho; and
- access to drilling rigs through 2014.

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. Strategic competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Strategic's competitors include resource companies which have greater financial resources, staff and facilities than those of Strategic. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Strategic believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Steen River, in northwest Alberta, has all year access into certain areas of the property, while certain areas are restricted to winter access only.

Environmental Regulation

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

Employees

As of December 31, 2013, Strategic had 34 head office employees, 30 field employees, 30 contract field employees and 9 office consultants.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

A summary of the independent evaluation of the natural gas and crude oil reserves of Strategic as at December 31, 2013 as evaluated by McDaniel and expressed in the McDaniel Report follows.

OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, McDaniel prepared the McDaniel Report which evaluated, as at December 31, 2013, Strategic's crude oil, NGL and natural gas reserves in Canada and the United States. The McDaniel January 1, 2014 future price forecast was used to determine all estimates of future net revenue. The tables below are a summary of Strategic's crude oil, NGL and natural gas reserves and the net present value of future net revenue attributed to such reserves as evaluated in the McDaniel Report based on future price and cost assumptions. The tables summarize the data contained in the McDaniel Report and due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs, general and administrative costs and income taxes, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by McDaniel. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of Strategic's crude oil, NGL, and natural gas reserves provided herein are estimated only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimated provided herein.

The McDaniel Report is based on certain factual data supplied by the Company and McDaniel 's opinion of reasonable practice in the industry, including requirements under National Instrument 51-101. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to McDaniel and accepted without any further investigation. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

RESERVES SUMMARY

	Light and Medium Oil		**Heavy Oil**		**Natural Gas**		**Natural Gas Liquids**		**Total Oil Equivalent**	
Reserves Category	Company Gross Mbbl	Company Net Mbbl	Company Gross Mbbl	Company Net Mbbl	Company Gross MMcf	Company Net MMcf	Company Gross Mbbl	Company Net Mbbl	Company Gross Mbbl	Company Net Mbbl
PROVED										
Producing	2,991	2,186	104	99	10,118	9,388	63	46	4,845	3,895
Developed Non-Producing	112	98	0	0	3,360	3,173	0	0	672	627
Undeveloped	879	753	0	0	1,787	1,650	0	0	1,177	1,028
TOTAL PROVED	**3,982**	**3,036**	**104**	**99**	**15,265**	**14,211**	**63**	**46**	**6,694**	**5,550**
TOTAL PROBABLE	**3,935**	**2,990**	**39**	**37**	**11,979**	**10,742**	**50**	**36**	**6,021**	**4,853**
TOTAL PROVED PLUS PROBABLE	**7,918**	**6,026**	**143**	**135**	**27,244**	**24,953**	**113**	**82**	**12,715**	**10,403**

NET PRESENT VALUE SUMMARY

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)					**Unit Value Before Income Tax Discounted at 10%/year**	
	0%	**5%**	**10%**	**15%**	**20%**		
Reserves Category	M$	M$	M$	M$	M$	$/boe	$/Mcfe
PROVED							
Developed Producing	101,375	89,658	80,685	73,652	68,009	16.65	2.78
Developed Non-Producing	7,659	5,956	4,711	3,787	3,088	7.01	1.17
Undeveloped	21,486	15,718	11,442	8,200	5,690	9.72	1.62
TOTAL PROVED	**130,519**	**111,332**	**96,838**	**85,638**	**76,788**	**14.47**	**2.41**
TOTAL PROBABLE	**161,174**	**113,126**	**83,248**	**63,540**	**49,873**	**13.83**	**2.30**
TOTAL PROVED PLUS PROBABLE	**291,693**	**224,458**	**180,086**	**149,179**	**126,660**	**14.16**	**2.36**

	Net Present Values of Future Net Revenue After Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
Reserves Category	M$	M$	M$	M$	M$
PROVED					
Developed Producing	101,375	89,658	80,685	73,652	68,009
Developed Non-Producing	7,659	5,956	4,711	3,787	3,088
Undeveloped	21,486	15,718	11,442	8,200	5,690
TOTAL PROVED	**130,519**	**111,332**	**96,838**	**85,638**	**76,788**
TOTAL PROBABLE	**161,174**	**113,126**	**83,248**	**63,540**	**49,873**
TOTAL PROVED PLUS PROBABLE	**291,693**	**224,458**	**180,086**	**149,179**	**126,660**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Proved Producing	331,614	77,608	131,417	-	21,214	101,375	-	101,375
Proved Developed Nonproducing	27,157	2,112	11,927	4,601	659	7,659	-	7,659
Proved Undeveloped	88,952	12,086	19,854	35,078	449	21,486	-	21,486
Total Proved	**447,723**	**91,806**	**163,198**	**39,878**	**22,321**	**130,519**	**-**	**130,519**
Total Probable	**450,599**	**96,495**	**133,853**	**57,634**	**1,444**	**161,174**	**-**	**161,174**
Total Proved plus Probable	**898,322**	**188,301**	**297,050**	**97,513**	**23,765**	**291,693**	**-**	**291,693**

Notes and Definitions

In the tables set forth above and elsewhere in this annual information form, the following notes and other definitions are applicable.

Reserve Categories

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic estimation methods is required to properly use and apply reserves definitions.

Pricing Assumptions – Forecast Prices and Costs

McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of January 1, 2014 in estimating the Company's reserves data using forecast prices and costs.

	Natural Gas		Crude Oil		Natural Gas Liquids		
Year	U.S. Henry Hub ($US/MMBTU)	AECO Spot (C$/MMBTU)	WTI Crude Oil ($US/BBL)	Edmonton Light Crude Oil ($/BBL)	Propane ($/BBL)	Butane ($/BBL)	CDN/US Exchange Rate
2014	4.25	4.00	95.00	95.00	50.20	76.60	0.950
2015	4.50	4.25	95.00	96.50	50.50	77.80	0.950
2016	4.75	4.55	95.00	97.50	50.60	78.60	0.950
2017	5.00	4.75	95.00	98.00	51.30	79.00	0.950
2018	5.25	5.00	95.30	98.30	52.00	79.20	0.950
2019	5.50	5.25	96.60	99.60	53.20	80.30	0.950
2020	5.60	5.35	98.50	101.60	54.10	81.90	0.950
2021	5.70	5.45	100.50	103.60	55.20	83.50	0.950
2022	5.85	5.55	102.50	105.70	56.30	85.20	0.950
2023	5.95	5.65	104.60	107.90	57.40	87.00	0.950
2024	6.05	5.75	106.70	110.00	58.50	88.60	0.950
2025	6.20	5.90	108.80	112.20	59.80	90.40	0.950
2026	6.30	6.00	111.00	114.50	61.00	92.30	0.950
2027	6.45	6.15	113.20	116.70	62.20	94.00	0.950
2028	6.55	6.25	115.50	119.10	63.50	96.00	0.950
2029+	+2.0%/yr	+2.0%	+2.0%	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.950

All prices escalate at 2% per year after 2028.

The weighted average sales prices realized by Strategic for the year ended December 31, 2013 were $3.30/mcf for natural gas, and $85.77 bbl for crude oil and natural gas liquids.

Reconciliations of Changes in Reserves and Future Net Revenue

Reserves Reconciliation

The following table sets forth a reconciliation of Strategic's gross company interest reserves comprising total proved, total probable and total proved plus probable reserves as at December 31, 2013 against such reserves as at December 31, 2012 based on forecast price and cost assumptions.

RECONCILIATION OF COMPANY GROSS RESERVES
TOTAL CANADA & USA
BY PRINCIPAL PRODUCT TYPE

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2012	3,405	2,983	6,388	3,274	2,909	6,183	130	75	205	41	34	75
Discoveries & Extensions	108	2,115	2,712	598	2,115	2,712	0	0	0	0	0	0
Technical Revisions	899	(1,200)	(406)	801	(1,164)	(363)	(7)	(35)	(43)	11	23	34
Acquisitions & Dispositions	130	76	206	130	76	206	0	0	0	27	10	36
Economic Factors	0	0	0	0	0	0	0	0	0	0	(18)	(18)
Production	(839)	0	(839)	(818)	0	(818)	(21)	0	(21)	(15)	0	(15)
December 31, 2013	4,087	3,974	8,061	3,982	3,935	7,918	104	39	143	63	50	113

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2012	3,433	6,895	10,328	3,433	6,895	10,328	-	-	-	4,017	4,167	8,184
Discoveries & Extensions	1,218	5,115	6,332	1,218	5,115	6,332	-	-	-	800	2,967	3,768
Technical Revisions	3,747	(3,113)	633	3,747	(3,113)	633	-	-	-	1,429	(1,695)	(267)
Acquisitions & Dispositions	8,909	3,187	12,096	8,909	3,187	12,096	-	-	-	1,641	617	2,258
Economic Factors	0	(105)	(105)	0	(105)	(105)	-	-	-	0	(35)	(35)
Production	(2,040)	0	(2,040)	(2,040)	0	(2,040)	-	-	-	(1,194)	0	(1,194)
December 31, 2013	15,265	11,979	27,244	15,265	11,979	27,244	-	-	-	6,694	6,021	12,715

** The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions may be combined and reported as "Extensions and Improved Recovery".*

RECONCILIATION OF COMPANY GROSS RESERVES
CANADA - EVALUATED PROPERTIES
BY PRINCIPAL PRODUCT TYPE

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2012	3,404	2,984	6,388	3,274	2,909	6,183	130	75	205	41	34	75
Discoveries & Extensions	598	2,115	2,712	598	2,115	2,712	0	0	0	0	0	0
Technical Revisions	794	(1,200)	(406)	799	(1,165)	(366)	(4)	(36)	(40)	10	24	34
Acquisitions & Dispositions	130	76	206	130	76	206	0	0	0	27	10	36
Economic Factors	0	0	0	0	0	0	0	0	0	0	(18)	(18)
Production	(839)	0	(839)	(818)	0	(818)	(21)	0	(21)	(15)	0	(15)
December 31, 2013	4,087	3,974	8,061	3,982	3,935	7,918	104	39	143	63	50	113

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2012	3,357	6,874	10,231	3,357	6,874	10,231	-	-	-	4,005	4,164	8,168
Discoveries & Extensions	1,218	5,115	6,332	1,218	5,115	6,332	-	-	-	800	2,967	3,768
Technical Revisions	3,803	(3,092)	711	3,803	(3,092)	711	-	-	-	1,438	(1,692)	(254)
Acquisitions & Dispositions	8,909	3,187	12,096	8,909	3,187	12,096	-	-	-	1,641	617	2,258
Economic Factors	-	(105)	(105)	-	(105)	(105)	-	-	-	0	(35)	(35)
Production	(2,021)	-	(2,021)	(2,021)	-	(2,021)	-	-	-	(1,191)	0	(1,191)
December 31, 2013	15,265	11,979	27,244	15,265	11,979	27,244	-	-	-	6,694	6,021	12,715

** The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions may be combined and reported as "Extensions and Improved Recovery".*

RECONCILIATION OF COMPANY GROSS RESERVES
USA - EVALUATED PROPERTIES
BY PRINCIPAL PRODUCT TYPE

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2012	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries & Extensions	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions & Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2013	-	-	-	-	-	-	-	-	-	-	-	-

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2012	76	21	97	76	21	97	-	-	-	13	3	16
Discoveries & Extensions	-	-	-	-	-	-	-	-	-	0	0	0
Technical Revisions	(57)	(21)	(77)	(57)	(21)	(77)	-	-	-	(9)	(3)	(13)
Acquisitions & Dispositions	-	-	-	-	-	-	-	-	-	0	0	0
Economic Factors	-	-	-	-	-	-	-	-	-	0	0	0
Production	(18)	-	(18)	(18)	-	(18)	-	-	-	(3)	0	(3)
December 31, 2013	-	-	-	-	-	-	-	-	-	0	0	0

** The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions may be combined and reported as "Extensions and Improved Recovery".*

Undeveloped Reserves

The following discussion generally describes the basis on which the Company attributes Proved and Probable Undeveloped Reserves and its plans for developing those Undeveloped Reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the year or wells further away from the Company's gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two year timeframe.

	L&M Oil (Mbbl)		**Heavy Oil (Mbbl)**		**Conventional Natural Gas (MMcf)**		**Natural Gas Liquids (Mbbl)**		**BOE (Mbbl)**	
Year	First Attributed[1]	Current Total	First Attributed[1]	Current Total	First Attributed[1]	Current Total	First Attributed[1]	Current Total	First Attributed[1]	Current Total
Prior to 2011	247	247	0	0	1,224	1,224	26	26	480	480
2011	871	913	0	0	169	240	1	19	900	972
2012	193	193	0	0	20	20	0	0	196	196
2013	686	879	0	0	1,767	1,787	0	0	980	1,177

[1] Attributed refers to the incremental reserves booked in the current year.

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and land contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

	L&M Oil (Mbbl)		**Heavy Oil (Mbbl)**		**Conventional Natural Gas (MMcf)**		**Natural Gas Liquids (Mbbl)**		**BOE (Mbbl)**	
Year	First Attributed[1]	Current Total	First Attributed[1]	Current Total	First Attributed[1]	Current Total	First Attributed[1]	Current Total	First Attributed[1]	Current Total
Prior to 2011	987	987	24	24	933	933	90	90	1,257	1,257
2011	1,756	1,868	0	24	455	857	0	30	1,832	2,065
2012	1,732	1,809	0	24	4,377	4,671	0	19	2,462	2,631
2013	784	2,593	-	-	1,477	6,148	8	27	1.038	3,645

[1] Attributed refers to the incremental reserves booked in the current year.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves and resources 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 becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions. The Company's reserves are evaluated by McDaniel.

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 the new information. Revisions are often required 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 will affect 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 table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves, using forecast prices and costs.

Company Annual Capital Expenditures ($M)			
	Proved Producing	**Total Proved**	**Total Proved +Probable**
2014	-	20,502	22,462
2015	-	17,687	73,361
2016	-	-	-
2017	-	-	-
2018	-	-	-
2019	-	1,690	1,690
2020	-	-	-
2021	-	-	-
2022	-	-	-
2023	-	-	-
2024	-	-	-
Total	-	39,879	97,513

The Company estimates that its internally generated cash flow and cash on hand will be sufficient to fund the future development costs disclosed above. The Company typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing and new equity. The Company plans to utilize all three sources to meet its future development cost needs.

OIL AND GAS PROPERTIES

The following is a description of the oil and natural gas properties in which the Company has an interest and that are material to its operations and activities. The production numbers stated refer to the Company's working interest share before deduction of Crown and freehold royalties. Reserve amounts are stated before deduction of royalties based on escalated cost and price assumptions as evaluated in the McDaniel Report as at December 31, 2013.

Canada

Amber Area, Alberta

The Amber area is located in Twp 113 -114 and Rge 6 – 8 W6M. The Company owns a 100% working interest in 38,880 acres (60.75 sections) of undeveloped land in Amber as of December, 2013. The land is prospective for Sulphur Point and emerging unconventional resource oil in the Jean Marie and Muskwa. No reserves have been assigned to Strategic in Amber in 2013.

Bistcho, Alberta

Bistcho is located 60 km west of the Company's Steen River asset in northern Alberta. Strategic acquired these assets on February 28th, 2013. The Company holds an average 62% working interest and operates a mature sour gas facility at Bistcho. The Company has interests in 55,360 (32,816 net) acres of developed land, 43,840 (28,470 net) acres of undeveloped land for a total of 99,200 (61,286 net) acres of land at December, 2013. There are 12 gross (6.5 net) producing wells in the pool. The field currently produces natural gas at a total rate of approximately 300 mcfd from the Sulphur Point and Slave Point Formations. The geological settings of broad widespread carbonate shelves has resulted in reservoir development found in limestones with grainstone shoal development. Trapping is a combination of stratigraphic pinchout of the porosity, enhanced by structural closure created by deep structures. Production attributed to the Company for the full year 2013 from Bistcho was 22,099 boes or 60 boe/d. McDaniel has attributed 226,100 boes of proved reserves and 321,100 boes of proved plus probable reserves to this property.

Cameron Hills, Northwest Territories

Cameron Hills is located 50 km north of Strategic's Steen River asset in northern Alberta. Strategic acquired these assets on February 28th, 2013. The oil battery is pipeline connected to Strategic's Bistcho asset where the gas is processed and oil is shipped via pipeline to sales. Strategic holds a 86% working interest in 17,732 (15,504 net) acres of developed and 68,490 (48,703) acres of undeveloped land for a total position of 86,223 (74,207 net) acres. The field currently produces light oil and gas from the Sulphur Point and Keg River Formations, and gas from the Slave Point Formation at a total rate of approximately 750 barrels of oil equivalent per day from 6 (5.64 net) wells. The geological setting for the various reservoirs is complex. Formerly scattered grainstone shoals on broad widespread carbonate shelves have been diagenetically altered by faulting and karst development into hydrocarbon reservoirs. Keg River reservoirs are biostromal reefs built upon underlying structures. Production attributed to the Company for the full year 2013 from Cameron Hills was 236,325 boes or 647 boe/d. McDaniel has attributed 1,484,700 boes of proved reserves and 2,015,400 boes of proved plus probable reserves to this property.

Conrad, Alberta

Conrad is located 35 km southwest of Taber, Alberta. Strategic holds a 94% working interest and operates a mature medium gravity oil property at Conrad. There are 16 gross (13.9 net) oil wells and a production facility. The field currently produces 23 degree API oil from the Ellis Member of the Sawtooth Formation (1,000 m in depth) at a total rate of approximately 60 barrels of oil per day. The geological setting for the Sawtooth Formation at Conrad is a series of sands lapping a Mississippian high. Production attributed to the Company for the full year 2013 from Conrad was 22,099 boes or 60 boe/d. McDaniel has attributed 105,400 boes of proved reserves and 145,200 boes of proved plus probable reserves to this property.

Maxhamish, Northeast British Columbia

Maxhamish is located 125 km north of Fort Nelson and is operated by Legacy Oil & Gas. In 2011 Strategic participated in two horizontal wells which were drilled and multi-stage fractured stimulated. Both wells were placed on production late 2011. The property now has 7 producing oil wells (2.7 net to the Company). Strategic has a 38.16% working interest in 6,055 (2,331 net) acres of developed and 63,398 (24,169) acres of undeveloped land for a total position of 69,453 (26,500 net) acres. The Company in 2013 produced 18,224 boes from this property. McDaniel has attributed 63,500 boes of proved reserves and 143,400 boes of proved plus probable reserves to this property.

In early 2011, Strategic commissioned McDaniel to conduct an independent resource evaluation of the Company's Maxhamish area effective December 31, 2010. This study has assigned discovered petroleum initially-in-place ("DPIIP") to 13,874 gross acres (22 sections gross lease) of land for a best estimate of 123 MMbbl of oil (48 MMbbl net to Strategic). This represents 6 MMbbl of oil per section gross lease. This assignment is consistent with Strategic's internal estimate for DPIIP resources for the study area. The DPIIP study is restricted to a 3 mile extension from the existing wells where proven and probable assignment of reserves has been recognized and does not extend over the entire Maxhamish land base. The 13,874 acres represents 20% of Strategic's Maxhamish land base. There is no certainty that any portion of the estimated DPIIP will be discovered. Further, if discovered, there is no certainty that it will be commercially viable to produce any portion of the estimated PIIP. Additional drilling analysis is required to develop a resource on the property. There has been no development activity in this area and as a result, the resource evaluation was not reviewed in 2012

The Company's internal estimate for PIIP is over 500 MMbbl (192 MMbbl net) of 42 deg API oil on Strategic's lands. Strategic management's internal estimate has projected recovery factors of between 13% to 15% on primary recovery. At 4 wells per section this would yield recoverable volumes of between 150 and 225 Mbbl per well. The same qualifications as to DPIIP as above apply to PIIP.

Historically, Strategic entered into a purchase and sale agreement ("the Agreement") with its partner to acquire from Encana Company the remaining 35% working interest in Maxhamish, for a total purchase price of $13.0 million ($5.0 million net to Strategic), in October 2010.

Terms of the Agreement:

1. The acquisition included 21,500 net acres (> 30 sections) of undeveloped land, 7 oil wells (representing 50 boe/d of production net to Strategic), related facilities, an oil pipeline, and a road that connects the area to the year round Liard Highway.

2. The acquisition included rights to extensive 2-D seismic coverage over the area.

3. The acquisition included rights to the Dunvegan zone, providing access to a source of water.

As a result, the farmout agreement with Encana was eliminated providing Strategic with an undivided 38.5% working interest.

Steen River / Lessard Area, Alberta

The Steen River area assets are located in northwestern Alberta, approximately 60 mile north of the town of High Level, Alberta. Strategic is operator with a 93.5% working interest in 39,680 (39,580 net) acres of developed and 375,840 (349,024 net) acres of undeveloped land for a total position of 415,520 (388,604 net) acres. At year end 2013 the Company had 41 oil wells and 3 gas well producing. Further, the Company operates two major gas and oil production facilities. The field currently produces 34 degree API oil from the Sulphur Point, Muskeg Stack and Keg River and gas from the Slave Point, Sulphur Point, Muskeg Stack and Keg River. In 2013 the Company drilled 12 wells. All wells were cased and 9 were tied in for production with IP's ranging from 50 to 350 boe/d. In 2013, the Company purchased 44,600 net acres of land in Steen River, shot 19.97 km2 of 3D seismic, 177 km of 2D seismic, upgraded the production facility and built all weather road access to all major producing wells.

Production attributed to the Company in Steen River for 2013 was 776,760 boes or 2,128 boe/d. McDaniel has attributed 4,357,700 boes of proved reserves and 9,200,000 boes of proved plus probable reserves to this property.

Historically, the Company acquired a 5% working interest in December 2007. On December 22, 2010, Strategic purchased Steen River Oil & Gas Ltd. and increased its average producing working interest to 100%. In December 2012, the Company acquired the assets of a private company operating within the Steen River area for a total cost of $23.6 million. This acquisition brought in 340 boe/d of current and behind pipe production as well as key infrastructure to support further development with this area.

Production from the Steen River area assets at year end 2012 was weighted 93 percent to oil with the balance being natural gas. All production is pipelined to Company-owned processing facilities that include a sour service natural gas plant rated to 40 mmcf/d and fluid handling and treating facilities for the oil. A portion of the oil sales are then trucked to Rainbow whereas the gas sales are directly tied into the Nova pipeline system at the plant gate. In December 2012, the company began moving up to 1500 bopd via rail from the CN facilities at High Level. Produced water and acid gas are both disposed of into a water disposal well and an acid gas injection well respectively.

The Lessard asset is located to the East of Steen River, located across the Haywood River and currently is non-producing due to access restrictions. There are numerous oil and gas wells in this area which require a gathering system scheduled for tie-in 2013. McDaniel has attributed no proven reserves to Lessard and 180,033 boes of proved plus probable reserves.

The 2014 development program is proceeding on schedule:

(i) In Q1 and Q2 drill up to 6 wells with infrastructure and all weather roads, where possible, to major producing wells,

(ii) Connect the Steen River area oil sales infrastructure directly to pipe via the acquired Bistcho Oil sales pipeline.

(iii) In Q3 and Q4 drill an additional 6 plus wells with infrastructure and all weather roads, where possible, to major producing wells.

Larne Area, Alberta

The Larne area assets are located in north western Alberta and to the east of the Zama Keg River basin. Strategic is operator with a primarily 87.9% working interest in 12,800 (11,840 net) acres of developed and 5,760 (4,480 net) acres of undeveloped land for a total position of 18,560 (16,320 net) acres. The Larne assets include the Larne natural gas field plus several single well pools which produce from the Sulphur Point and Slave Point formations. The Larne assets are 100% weighted toward natural gas with minor associated natural gas liquids. In the Larne area the Company owns an interest in 10 gross (9.5 net) producing gas wells.

Production from the Larne assets are treated through the Strategic operated Bistcho Gas Plant that was acquired in February, 2013. That facility includes fluid handling, gas processing and compression with a sales gas connection to the Nova pipeline.

Production attributed to the Company in Larne for 2013 was 48,320 boes. McDaniel has attributed 324,900 boes of proved reserves and 438,900 boes of proved plus probable reserves to this property.

Taber, Alberta

Strategic holds a 75% working interest in 440 (340 net) acres of developed and 2,246 (2,108 net) acres undeveloped land at December 31, 2013. The Company operates a mature medium gravity oil property at Taber, in Southern Alberta. There are 9 (6.8 net) producing oil wells and a production facility. The field currently produces 23 degree API oil from the Glauconite Formation (1,000 m in depth) at a total rate of approximately 26 barrels of oil per day net to Strategic. The Glauconite reservoir is consistently clean and highly porous and permeable, with permeabilities greater than 1,000 mD. Typical net oil pays range from 2.0-5.0 metres. Strategic's wells at Taber have a long reserve life and have been producing medium gravity oil at a steady rate for several decades. Production attributed to the Company from Taber for 2013 was 9,446 boes or 26 boe/d. McDaniel has attributed 10,200 boes of proved reserves and 32,600 boes of proved plus probable reserves to this property. The additional probable reserves at Taber may be obtained through infill drilling and through a comprehensive plan to optimize the water flood currently in place

Non-Operated, Alberta

The Company has minor working interests in several non-operated assets located in central Alberta. The Company has interests in 5,135 (1,100.3 net) acres of developed land and 800 (118.4 net) acres of undeveloped land at December 31, 2013. In 2013, The Company produced 31,163 boes or 85 boe/d from these properties and McDaniel has attributed 112,500 boes of proved reserves and 238,300 boes proved plus probable reserves to these properties. There were 6 gross (1.4 net) wells on production for the year 2013.

United States

Pinedale, Wyoming

The Company purchased a 22.5% working interest in 640 (144 net) acres of land located in the Greater Green River Basin in southwest Wyoming in 2008. The target zone of interest is in the Lance formation which has producing zones in the offset Jonah/Pinedale fields. The Company has 135 net acres of undeveloped land on this prospect (640 gross acres). The Company's share of production from this area for the year 2013 was 2,661 boes or 7 boe/d.

Oil and gas wells

The following table summarizes Strategic's interest as at December 31, 2013 in wells that were producing and non-producing at that time.

	Producing wells				Non-producing wells					
	Oil		Gas		Standing		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada	80	68.8	31	22.7	81	71.2	43	39.7	78	65.9
USA	-	-	2	.5	-	-	-	-	-	-
Total	80	68.8	33	23.2	81	71.2	43	39.7	78	65.9

Notes:
1. "Gross" refers to all wells in which Strategic has a working interest.
2. "Net" refers to the aggregate of the percentage working interests of Strategic in the gross wells before deduction for royalties.

Forward Contracts

A summary of Strategic's commodity price risk management contracts as at December 31, 2013 is as follows:

Financial WTI Crude Oil Contracts

Term		Contract Type	Volume (bbl/d)	Fixed Price (CAD$/bbl)	Index
01-Jan-2014	31-Dec-2014	Swap	500	92.00	WTI - NYMEX
01-Jan-2014	31-Dec-2014	Swap	1,000	92.00	WTI - NYMEX
01-Jan-2015	30-Jun-2015	Swap	750	90.15	WTI - NYMEX
01-Jan-2015	31-Dec-2015	Option (1)	600	90.00	WTI - NYMEX
01-Jul-2015	31-Dec-2015	Option (1)	250	90.00	WTI - NYMEX

(1) Counterparty has an option to convert into a swap at the fixed price indicated. The 600 bbl/d option expires on the last business day before the term begins, while the 250 bbl/d option expires monthly during the contract term.

Financial AECO Gas Contracts

Term		Contract Type	Volume (GJ/d)	Fixed Price (CAD$/GJ)	Index
01-Jan-2014	31-Dec-2014	Swap	1,500	3.50	AECO

Properties with No Attributed Reserves

	Gross acres	Net acres	Net acres expiring within one year
Canada	743,936	616,481	9,127
USA	640	144	0
Total	**744,576**	**616,625**	**9,127**

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

The Company estimates well abandonment costs area by area. Such costs are included in the McDaniel Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the McDaniel Report (forecast pricing) is $23,765,400 of which $4,030,300 is estimated to be incurred in the next three financial years. It should be noted that the McDaniel forecasts of abandonment represent downhole abandonment cost net of wellbore salvage only. They do not include estimates for lease reclamations or facility abandonment.

Tax Horizon

The Company was not required to pay income taxes during the year ended December 31, 2013. Taxes payable beyond 2013 will become a function of commodity prices, production volumes, capital expenditures and current tax pools available to offset taxable income. Based on a strategy of re-investing internally generated cash flow in an exploration and development program and based on commodity prices used in the McDaniel Report, combined with its current tax pools, the Company estimates that it will not be required to pay income taxes in the next 5 years.

COSTS INCURRED

The following table summarizes the Company's property acquisition costs, exploration costs and development costs for the year ended December 31, 2013.

	Property acquisition costs $000			
	Proven properties	**Unproven properties**	**Exploration costs**	**Development costs**
Canada	10,011	1,238	17,198	100,715
USA	-	-	-	-
Total	10,011	1,238	17,198	100,715

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes Strategic's exploration and development wells completed in the year ending December 31, 2013.

	Gross Wells	Net wells	Net Oil wells	Net gas wells	Net dry
Exploratory wells completed					
Canada	3	3	3	-	-
USA	-	-	-	-	
Development wells completed					
Canada	9	9	9	-	-
USA	-	-	-	-	-

Most of Strategic's exploration and development activity in the next year will be focused on its properties located in Canada as well as new opportunities.

PRODUCTION ESTIMATES

The following table discloses for each product type the total volume of production estimated by McDaniel for 2013 in the estimates of future net revenue from proved reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue".

	2014 Average Daily Production										Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent		Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
Entity Description	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross Mbbl	Company Net Mbbl	Company Gross Mbbl	Company Net Mbbl	Company Gross MMcf	Company Net MMcf	Company Gross Mbbl	Company Net Mbbl	Company Gross Mbbl	Company Net Mbbl
Proved Producing																				
Steen River	1,739	1,173	0	0	1,211	1,091	-	-	1,941	1,355	2,658	1,867	0	0	1,667	1,478	-	-	2,936	2,114
Other Properties	252	241	49	47	4,791	4,463	34	25	1,133	1,056	332	317	105	100	8,451	7,911	63	46	1,909	1,782
Total: Proved Producing	**1,991**	**1,414**	**49**	**47**	**6,003**	**5,554**	**34**	**25**	**3,075**	**2,411**	**2,990**	**2,184**	**105**	**100**	**10,118**	**9,388**	**63**	**46**	**4,845**	**3,895**
Proved Developed Nonproducing																				
Steen River	81	76	0	0	386	330	-	-	145	131	112	98	0	0	796	712	-	-	245	217
Other Properties	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,564	2,461	-	-	427	410
Total: Proved Developed Nonproducing	**81**	**76**	**-**	**-**	**386**	**330**	**-**	**-**	**145**	**131**	**112**	**98**	**-**	**-**	**3,360**	**3,173**	**-**	**-**	**672**	**627**
Proved Undeveloped																				
Steen River	302	286	0	0	305	294	-	-	353	335	879	753	0	0	1,787	1,650	-	-	1,177	1,028
Other Properties	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total: Proved Undeveloped	**302**	**286**	**-**	**-**	**305**	**294**	**-**	**-**	**353**	**335**	**879**	**753**	**-**	**-**	**1,787**	**1,650**	**-**	**-**	**1,177**	**1,028**
Total Proved																				
Steen River	2,123	1,535	-	-	1,903	1,716	-	-	2,440	1,821	3,649	2,718	-	-	4,251	3,839	-	-	4,358	3,358
Other Properties	252	241	49	47	4,791	4,463	34	25	1,133	1,056	332	317	105	100	11,015	10,372	63	46	2,336	2,192
Total: Total Proved	**2,375**	**1,776**	**49**	**47**	**6,694**	**6,179**	**34**	**25**	**3,573**	**2,878**	**3,981**	**3,035**	**105**	**100**	**15,265**	**14,211**	**63**	**46**	**6,694**	**5,550**
Total Probable																				
Steen River	258	200	-	-	285	249	-	-	305	241	3,685	2,768	-	-	6,942	6,064	-	-	4,842	3,779
Other Properties	19	18	1	1	198	183	5	4	59	54	250	221	40	37	5,037	4,678	50	36	1,179	1,075
Total: Total Probable	**277**	**218**	**1**	**1**	**482**	**431**	**5**	**4**	**364**	**295**	**3,935**	**2,989**	**40**	**37**	**11,979**	**10,742**	**50**	**36**	**6,021**	**4,853**
Total Proved Plus Probable																				
Steen River	2,381	1,735	0	0	2,187	1,964	-	-	2,745	2,063	7,334	5,486	0	0	11,193	9,904	-	-	9,200	7,137
Other Properties	271	259	51	48	4,989	4,646	39	29	1,192	1,110	582	538	145	137	16,051	15,050	113	82	3,515	3,266
Total: Total Proved Plus Probable	**2,652**	**1,994**	**51**	**48**	**7,176**	**6,610**	**39**	**29**	**3,937**	**3,173**	**7,916**	**6,024**	**145**	**137**	**27,244**	**24,953**	**113**	**82**	**12,715**	**10,403**

PRODUCTION HISTORY

The following tables disclose, on a quarterly basis for the year ended December 31, 2013, the Company's share of average daily production volumes, prior to royalties, prices received, royalties paid, production costs incurred and net backs on a per boe basis.

Average Daily Production

	Average daily production for the three months ended			
	March 31 2013	**June 30 2013**	**September 30 2013**	**December 31 2013**
Canada				
Oil (Bbls/d)	2,289	2,718	2,349	1,843
Natural gas (Mcf/d)	2,824	6,888	6,699	5,695
NGLs (Bbls/d)	29	50	38	45
United States				
Oil (Bbls/d)	-	-	-	-
Natural gas (Mcf/d)	50	48	44	58
NGLs (Bbls/d)	-	-	-	-
Total (boe/d)	2,797	3,924	3,510	2,847

Average Prices Received, Royalties Paid, Production Costs and Net Back

	Three months ended			
	March 31 2013	**June 30 2013**	**September 30 2013**	**December 31 2013**
Canada				
Prices $				
Oil - per Bbl	82.73	86.15	96.78	80.17
Natural gas - per Mcf	3.26	3.70	2.67	3.79
NGLs - per Bbl	29.47	15.89	28.23	25.79
Per Boe $	71.22	66.66	70.19	61.25
Royalties paid per Boe $	16.60	13.48	16.18	12.23
Production costs per Boe $	29.84	24.17	23.91	40.23
Net back per Boe $	24.78	29.01	30.09	8.79
United States				
Prices $				
Oil - per Bbl	-	-	-	-
Natural gas - per Mcf	2.81	3.20	2.30	3.51
NGLs - per Bbl	-	-	-	-
Per Boe $	16.86	19.20	13.80	21.06
Royalties paid per Boe $	2.84	2.96	3.23	2.45
Production costs per Boe $	12.46	12.98	14.16	10.74
Net back per Boe $	2.84	2.96	3.23	2.45

Production Volume by Field

The following table discloses for each important field, and in total, the Company's production volumes for the financial year ended December 31, 2013 for each product type.

	Light and Medium Crude (bbl)	Natural Gas (Mcf)	Natural Gas Liquids (bbl)
Sundre/Sylvan Lake	1,503	43,335	11,639
Conrad	21,379	-	-
Cheddarville/Pembina	237	44,590	3,130
Maxhamish	18,224	-	-
Steen River	710,750	396,061	-
Larne	1,493	280,961	-
Bistcho	752	288,685	-
Cameron Hills	75,019	967,832	-
Taber	9,446	-	-
Other - US	130	18,102	-
Total	838,933	2,039,566	14,769

DEVELOPMENTS SINCE DECEMBER 31, 2013

Strategic's Board of Directors has approved a capital spending budget of $80 million for 2014 with a focus on Muskeg Stack horizontal wells at Marlowe and related infrastructure. Strategic plans to drill up to 13 wells in 2014.

Capital spending will be allocated as follows

- Drill, complete, equip & tie-ins: $54 million
- Workovers/recompletions: $4 million
- Land, seismic, facility expenditures & plant turnarounds: $8 million
- Bistcho oil pipeline: $14 million

DESCRIPTION OF CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares ("**Preferred Shares**"). As of December 31, 2013, there were 260,600,647 Common Shares and no Preferred Shares issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares of the Company. This summary does not purport to be complete and is subject to, and qualified by, reference to the articles of the Company.

Common Shares

The holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors of the Company, to one vote per share at meetings of the holders of Common Shares of the Company and, upon liquidation, dissolution or winding-up of the Company, to receive pro-rata the remaining property and assets of the Company, subject to the rights of shares having priority over the Common Shares.

Preferred Shares

The Preferred Shares are issuable in series and each class of Preferred Shares will have such rights, restrictions, conditions and limitations as the Board may from time to time determine. The holders of Preferred Shares are entitled, in priority to holders of Common Shares, to be paid rateably with holders of each other series of Preferred Shares the amount of accumulated dividends, if any, specified to be payable preferentially to the holders of such series, and upon liquidation, dissolution or winding-up of the Company, to be paid rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series.

DIVIDENDS

Strategic has not declared or paid any dividends on the Common Shares since incorporation. The payment of dividends in the future will be at the discretion of the Board and will be dependent on the future earnings and financial condition of the Company and such other factors as the Board considers appropriate.

PRIOR SALES

The following set out the securities of the Company that are outstanding but not listed or quoted on a marketplace, that were issued during the financial year ended December 31, 2013 and up to the date hereof.

Date of Issuance	Description of Transaction	Number of Securities Granted	Exercise Price
April-01-13	Stock Option Grant[(1)]	10,000	$ 1.14
April-07-13	Stock Option Grant[(1)]	20,000	$ 1.18
April-11-13	Stock Option Grant[(1)]	75,000	$ 1.24
April-19-13	Stock Option Grant[(1)]	335,000	$ 1.18
May-01-13	Stock Option Grant[(1)]	10,000	$ 1.10
May-15-13	Stock Option Grant[(1)]	10,000	$ 1.13
May-25-13	Stock Option Grant[(1)]	10,000	$ 1.19
July-09-13	Stock Option Grant[(1)]	175,000	$ 1.13
August-06-13	Stock Option Grant[(1)]	10,000	$ 1.06
August-13-13	Stock Option Grant[(1)]	15,000	$ 1.03
September-24-13	Stock Option Grant[(1)]	100,000	$ 0.97
October-08-13	Stock Option Grant[(1)]	10,000	$ 0.94
October-10-13	Stock Option Grant[(1)]	10,000	$ 0.93
October-15-13	Stock Option Grant[(1)]	10,000	$ 0.86
November-06-13	Stock Option Grant[(1)]	10,000	$ 1.00
November-18-13	Stock Option Grant[(1)]	225,000	$ 0.87
December-18-13	Stock Option Grant[(1)]	10,000	$ 0.72
January-01-14	Stock Option Grant[(1)]	10,000	$ 0.75
January-16-14	Stock Option Grant[(1)]	10,000	$ 0.75
January-23-14	Stock Option Grant[(1)]	10,000	$ 0.49

Date of Issuance	Description of Transaction	Number of Securities Granted	Exercise Price
January-29-14	Stock Option Grant[1]	10,000	$ 0.47
January-30-14	Stock Option Grant[1]	10,000	$ 0.44
February-05-14	Stock Option Grant[1]	10,000	$ 0.54
March-16-14	Stock Option Grant[1]	25,000	$ 0.52

Notes:

(1) Each common share option entitles the holder to acquire one (1) common share at the stated exercise price per share expiring five (5) years from the date of grant, generally with one third vesting immediately and the remaining two thirds over the next 2 anniversary dates.

MARKET FOR SECURITIES

The outstanding Common Shares are traded on the TSXV under the trading symbol "SOG". The following table sets forth the high and low trading prices and aggregate trading volume of the Common Shares as reported by the TSXV for the periods indicated.

	High	Low	Volume
April	$1.36	$1.00	15,620,809
May	$1.21	$0.84	19,034,712
June	$1.21	$0.82	14,246,254
July	$1.21	$1.01	13,235,057
August	$1.11	$0.94	11,121,116
September	$1.10	$0.94	11,761,578
October	$1.07	$0.84	11,464,721
November	$1.03	$0.74	6,779,963
December	$0.80	$0.65	4,632,629
2014			
January	$0.82	$0.41	19,389,969
February	$0.64	$0.50	5,847,119
March (1 - 28)	$0.62	$0.47	6,498,000

DIRECTORS AND OFFICERS

Directors and Officers

The following table sets forth the names, province or state and country of residence, present positions with Strategic and principal occupations during the past five years of the executive officers and directors of Strategic as at the date hereof.

Name and Residence	Position(s) with Strategic	Director Since	Number of Shares Owned or Controlled	Principal Occupation(s) Over Past 5 Years
John Harkins(1)(2)(3) Texas, USA	Director	2008	Nil	CEO of Greenfields Petroleum Corporation from July 2008 to date.
Rodger G. Hawkins(1)(3)	Director	2013	Nil	Business consultant since 2007, Prior thereto, Mr. Hawkins was a partner of BDO Canada LLP in the Calgary office.
Thomas E. Claugus(2)(3)) Atlanta, Georgia, USA	Director	2011	169,144,000 (46.9%)	Fund Manager.
D. Richard Skeith(1)(3) Calgary, Alberta	Director	2005	434,683 (0.12%)	Partner at Norton Rose Fulbright Canada LLP.
James H.T. Riddell(2) Calgary, Alberta	Director	2013	7,200,000(5) (2.0%)	President and Chief Operating Officer of Paramount Resources Ltd. since 2002.
Gurpreet Sawhney(4) Calgary, Alberta	President and Chief Executive Officer	2013	1,702,010 (0.47%)	VP Business Development in 2009. Became President in 2011 and CEO in 2012.
Sean Hayes Calgary, Alberta	Executive VP Geoscience	N/A	666,696 (0.18%)	Chief Operating Officer from 2009, now Executive VP Geoscience.
Aaron Thompson(4) Calgary, Alberta	Chief Financial Officer	N/A	65,265 (0.02%)	Chief Financial Officer of Strategic since January 2013. Prior to that controller for Perpetual Energy Inc. from 2005 until 2013.
Mahrookh Driver Vancouver, British Columbia	Chief Administration Officer and Corporate Secretary	N/A	697,327 (0.19%)	Corporate Secretary of Strategic and Chief Administration Officer since 2005.
Cody Smith Calgary, Alberta	COO	N/A	56,582 (0.02%)	Chief Operating Officer from January, 2014, Vice President, Operations from November of 2012 to December 2013. Prior thereto,employed by Encana since 1986.
Shelina Hirji Calgary, Alberta	Vice President, Finance	N/A	15,265 (0.00%)	Vice President, Finance and interim CFO since January 2011. Previously controller of Steen River Oil and Gas since 2010.
Barbara Joy Calgary, Alberta	Vice President, Land	N/A	114,738 (0.03%)	Vice President, Land for Strategic since February 2012. Prior thereto, landman at Encana.
Douglas M. Wright Okotoks, Alberta	Vice President, Engineering and Corporate Development	N/A	291,897 (0.08%)	Vice President, Business Development from July 2012. Prior to that General Manager of Reservoir Engineering and Prospect Inventory for Perpetual Energy Inc.
Michael A. Zuk Calgary, Alberta	Vice President, Business Development	N/A	500,000 (0.14%)	VP Business Development since December 2013. Prior thereto, Research Analyst at Stifel Nicolaus. Prior thereto, an Associate Analyst at TD Newcrest, and Raymond James.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Environmental, Health & Safety and Reserves Committee.
(3) Member of the Compensation Committee

(4) Member of the Disclosure Committee
(5) Held by Paramount Resources Ltd., of which James H.T. Riddell is president and CEO.

Each of the directors has been elected or appointed to serve as such until the next annual meeting of the Shareholders or until his successor is duly elected or appointed, unless his office is earlier vacated in accordance with the articles or by-laws of the Company.

As of the date hereof, the directors and executive officers of Strategic, as a group, beneficially own, directly or indirectly, or exercise control or direction over 180,888,463 Common Shares representing 50.15 percent of the issued and outstanding Common Shares. In addition, the directors and executive officers of Strategic, as a group, hold Options to purchase 8,258,334 Common Shares.

Corporate Cease Trade Orders or Bankruptcies

Other than as set forth below, to the knowledge of management of the Company, no director or executive officer of Strategic is, or has been in the last 10 years, a director, chief executive officer or chief financial officer of an issuer that, (i) while that person was acting in that capacity was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, for a period of more than 30 consecutive days, (ii) was subject to an event that occurred while that person was acting in the capacity of director, chief executive officer or chief financial officer, which resulted, after that person ceased to be a director, chief executive officer or chief financial officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, or (iii) while that person was acting in the 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.

Subsequent to Mr. Skeith's resignation as the corporate secretary of Cheyenne Energy Inc., in January, 2008, a receiver was appointed by Cheyenne's bank and its assets sold to pay its bank debts. Mr. Skeith was the corporate secretary of MegaWest Energy Corp. when it was subject to a cease trade order from September 7, 2010 until October 22, 2010 for failure to file required financial statements. Mr. Skeith was the corporate secretary of Canaf Group Inc. and was subject to a management cease trade order on March 5, 2008, when that company failed to file required financial statements. Such statements were subsequently filed and the MCTO was revoked on June 20, 2008.

Mr. Riddell was a director of Jurassic Oil and Gas Ltd, a private oil and gas company, within one year of such company becoming bankrupt.

Shelina Hirji, Vice-President, Finance of the Company, was the Vice-President, Finance of Launch Resources Inc. when that company went bankrupt in 2005.

Penalties or Sanctions or Personal Bankruptcy

To the knowledge of management of the Company, no director, executive officer or Shareholder holding a sufficient number of Common Shares to affect materially the control of the Company: (i) has been subject to, (a) 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 (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision; or (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver, receiver manager or trustee appointed to hold his or its assets.

Conflicts of Interest

Circumstances may arise where members of the Board or officers of the Company are directors or officers of companies which are in competition to the interests of the Company. No assurances can be given that opportunities identified by such board members or officers will be provided to the Company. In accordance with the ABCA, a director or officer who is a party to a material contract or proposed material contract with the Company or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Company shall disclose to the Company the nature and extent of the director's or officer's interest. In addition, a director shall not vote on any resolution to approve a contract of the nature described except in limited circumstances. Management of the Company is not aware of any existing or potential material conflicts of interest between the Company or a subsidiary of the Company and a director or officer of the Company or any other subsidiary of the Company other than those disclosed in the notes to the financial statements of the company available on Sedar.

AUDIT COMMITTEE

Composition of the Audit Committee

The Audit Committee of the Board operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this Annual Information Form as Appendix "A". The Audit Committee is comprised of three directors: D. Richard Skeith, John W. Harkins and Rodger G. Hawkins. Messrs. Harkins and Hawkins are considered to be independent, Mr. Skeith is not independent as he is a partner in a law firm that provides legal services to the Company. All of the members of Audit Committee are financially literate (as determined under Multilateral Instrument 52-110 *Audit Committees*).

As a company listed on the TSX Venture Exchange, the Company is exempt from the requirements of Parts 3 (*Composition of the Audit Committee*) and 5 (*Reporting Obligations*) of Multilateral Instrument 52-110 *Audit Committees*, and is relying on the exception contained in section 6.1 of that instrument.

In considering criteria for the determination of financial literacy, the Board looked at the ability to read and understand a statement of financial position, a statement of comprehensive income and a statement of cash flows of a public company as well as the director's past experience in reviewing or overseeing the preparation of financial statements. The following sets out the education and experience of each director relevant to the performance of his duties as a member of the Audit Committee.

John W. Harkins

Mr. Harkins is a chemical engineer and an independent businessman with over 30 years of diverse international energy experience. Mr. Harkins is currently the President and Chief Executive Officer of Greenfields Petroleum Corporation (TSXV: GNFS), an independent exploration and production company with assets in Azerbaijan. Previously, Mr. Harkins acted as head of business development in Asia for Anadarko from 2001 to 2008, in which capacity Mr. Harkins was able to expand Anadarko’s exploration positions in Asia. As a senior executive for TransCanada Pipelines Ltd. in the mid 1990’s, Mr. Harkins established a significant and successful midstream business in Latin America. He played a prominent role in the establishment of some of the first private gas pipelines and a power project in Mexico, a liquids extraction facility in Venezuela and major oil and gas pipelines in Colombia. Mr. Harkins has been involved in successfully closing structured financing for energy projects with banks, multilaterals and other financial institutions.

D. Richard Skeith

Mr. Skeith is a partner with a large international law firm, and has degrees in economics and law from the University of Alberta. He has served on other audit committees as well as being a director or officer of public companies in various industry sectors.

Rodger G. Hawkins

Mr. Hawkins is a chartered accountant and has been a business consultant since 2007, Prior thereto, Mr. Hawkins was a partner of BDO Canada LLP in the Calgary office. He is chair of the audit committees of CanElson Drilling Inc., (TSX) and Matrrix Energy Technologies Inc. (TSXV).

Auditors' Fees

Deloitte LLP, became the Company's auditor on July 9, 2012. Prior thereto, the auditor of the Company was MNP LLP since June 10, 2004. The audit committee pre-authorized $69,500 for non-audit services from the Company's auditors for 2013.

	Year Ended December 31, 2013				Year Ended December 31, 2012			
	Audit Fees	**Audit Related Fees[(1)]**	**Tax Fees[(2)]**	**All Other Fees[(3)]**	**Audit Fees**	**Audit Related Fees**	**Tax Fees**	**All Other Fees**
MNP LLP	-	-	$20,626	-	-	$122,684	$16,480	$19,394
Deloitte LLP	$95,000	$57,000	-	$130,000	$97,500	$36,200	-	-
Total	$95,000	$57,000	$20,626	$130,000	$97,500	$158,884	$16,480	$19,394

Note:
(1) Quarterly reviews, non year-end audit activities.
(2) Year end tax filing fees and amalgamation fees.
(3) IFRS updates and other related filing procedures.

RISK FACTORS

The following are certain risk factors relating to Strategic's business which prospective investors should carefully consider before deciding whether to purchase Common Shares.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions.

Other companies operate some of the assets in which the Company has an interest. As a result, the Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others therefore depends upon a number of factors that may be outside of the Company's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with standard industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition. The Company carries insurance to mitigate the cost of remediating damage from environmental incidents, but there can be no assurance that the insurance will cover all types of incidents or that remediation costs will not exceed the limit of the insurance carried. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company will be affected by numerous factors beyond its control. The Company's ability to market its natural gas and oil may depend upon its ability to acquire space on pipelines that deliver natural gas and oil to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The Company's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas which are volatile and subject to fluctuations. The Company's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Fluctuations in the price of oil and gas could have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and funds flows from operations.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the global economy, OPEC actions, instability in the Middle East and the impact of emerging countries such as China and India on the demand for crude oil and natural gas.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, financial resources available to the Company are in part determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt to be repaid.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and cash flows to be derived therefrom, including many factors beyond the Company's control. The reserve and associated cash flow information set forth in this Annual Information Form represents estimates only. 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, future commodity prices, production rates, ultimate reserves recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those 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 engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

McDaniel has used forecast price and cost estimates in calculating reserve quantities included herein. Actual future net revenue 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 regulation or taxation and the impact of inflation on costs.

Actual production and revenues derived therefrom will vary from the estimates contained in the McDaniel Report and such variations could be material. The McDaniel Report is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the report will be reduced to the extent that such activities do not achieve the level of success assumed therein.

Royalty Rates

The potential for additional future changes and corresponding changes in the royalty regimes applicable in the provinces of Alberta,British Columbia and the Northwest Territories have created uncertainty surrounding the ability to accurately estimate future royalties, resulting in additional volatility and uncertainty in the oil and gas market. Increases to royalty rates in jurisdictions in which the Company operates may negatively impact the Company's results from operations and its ability to economically develop existing reserves or add new reserves. See "*Industry Conditions* - *Royalties*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/United States dollar exchange rates, which will fluctuate over time. Material increases in the value of the Canadian dollar negatively impact the Company's production revenues although the rise in the Canadian dollar may be offset by increases in oil and natural gas prices which have been significant factors in the increase in the Canadian dollar. Future Canadian/United States dollar exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in an increase in the amount the Company pays to service debt, which could negatively impact the market price of the Common Shares.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time, See "*Industry Conditions*". The Company's operations may require licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects and the obtaining of such licences and permits may delay operations of the Company. Changes to the regulation of the oil and gas industry in jurisdictions in which the Company operates may adversely impact the Company's ability to economically develop existing reserves and add new reserves.

Environmental

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that Strategic may be in non-compliance with an environmental law, regulation, permit, licence, or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose Strategic to fines or penalties, suspension or revocation of regulatory permits, third party liabilities or to the requirement to remediate, which could be material. The operational hazards associated with possible blowouts, accidents, oil spills, gas leaks, fires, or other damage to a well, pipeline or facility may require Strategic to incur costs and delays to undertake corrective actions, and could result in environmental damage or contamination for which Strategic could be liable. Oil and gas operations are also subject to specific operational risks which may have a material operational and financial impact on Strategic should they occur, such as drilling into unexpected formations or unexpected pressures, premature decline of reservoirs and water invasion into producing formations.

Strategic may also be subject to associated liabilities, resulting from lawsuits alleging property damage or personal injury brought by private litigants related to the operation of Strategic's facilities or the land on which such facilities are located, regardless of whether Strategic leases or owns the facility, and regardless of whether such environmental conditions were created by Strategic or by a prior owner or tenant, or by a third party or a neighbouring facility whose operations may have affected Strategic's facility or land. Such liabilities could have a material adverse effect on Strategic's business, financial position, operations, assets or future prospects.

Strategic also faces uncertainties related to future environmental laws and regulations affecting its business and operations. Existing environmental laws and regulations may be revised or interpreted more strictly, and new laws or regulations may be adopted or become applicable to Strategic, which may result in increased compliance costs or additional operating restrictions, each of which could reduce Strategic's earnings and adversely affect Strategic's business, financial position, operations, assets or future prospects. See "*Industry Conditions – Environmental Regulation*".

Compliance with environmental laws and regulations could materially increase costs. Strategic may incur substantial capital and operating costs to comply with increasingly complex laws covering the protection of the environment and human health and safety. In particular, the Company may be required to incur significant costs to comply with future federal Green House Gas ("GHG") emissions reduction requirements or other GHG emissions regulations compliance costs, if enacted. Although the Company records a provision in its consolidated financial statements relating to its estimated future abandonment and reclamation obligations, Strategic cannot guarantee that it will be able to satisfy its actual future abandonment and reclamation obligations.

Although the Company maintains insurance consistent with prudent industry practice, Strategic is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms.

Accordingly, Strategic's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to Strategic. Any site reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of the Company's reclamation fund and, if required, out of cash flow and, therefore, will reduce the amounts available for other corporate purposes. Should Strategic be unable to fully fund the cost of remedying an environmental problem, it might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

Potential Risks Associated with Hydraulic Fracturing

Some of Strategic's operations use hydraulic fracturing, which involves the high pressure injection of fluids and sand down a well to fracture the reservoir and thereby stimulate the increased flow of oil or gas into the well bore. Hydraulic fracturing has recently been the subject of greater regulatory scrutiny and regulation in certain jurisdictions of the world, including some of the areas in which Strategic operates. In a limited number of areas, hydraulic fracturing has been banned pending public review or is subject to moratoria while regulators study the practice. Strategic may be required to expend additional costs to comply with future regulatory requirements with respect to hydraulic fracturing or, in the future, be unable to carry out hydraulic fracturing operations, thereby lessening the volume of oil and gas it could otherwise produce and this could have a material operational and financial impact on Strategic and adversely affect the market price of the Common Shares.

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. In the event the Company's revenues or reserves decline, the Company may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's financial condition, results of operations or prospects.

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Company may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Company's cash flows from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing to meet these requirements will be available at all or on terms acceptable to the Company.

Competition

Oil and gas exploration is intensely competitive in all its phases and involves a high degree of risk. The Company competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. The Company's ability to increase reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Competition may also be presented by alternate fuel sources.

Availability of Drilling, Completion Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling, completion 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 Company and may delay exploration and development activities. To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

It is the practice of the Company when acquiring significant oil and gas leases or interests in oil and gas leases to examine the title to the interest under the lease. In the case of minor acquisitions the Company may rely upon the judgment of oil and gas lease brokers or landmen who perform the field work in examining records in the appropriate governmental office before attempting to place under lease a specific interest. The Company believes that this practice is widely followed in the oil and gas industry. Nevertheless, there may be title defects which affect lands comprising a portion of the Company's properties which may adversely affect the Company.

Hedging

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company would not benefit from the fluctuating exchange rate for the fixed price agreement amount.

Issuance of Debt

From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Depending on future exploration and development plans, the Company may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time, could impair the Company's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Credit Risk

The majority of the Company's accounts receivable are due from joint venture partners in the oil and gas industry and from purchasers of the Company's petroleum and natural gas production and are subject to the same industry factors such as commodity price fluctuations and escalating costs. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of Strategic. The integration of an acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Seasonal Impact on Industry

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural 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 consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of Strategic.

Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of the Company will be subject in connection with the operations of the Company. Some of the directors and officers are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Company.

Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Company, to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Reliance on Key Personnel

The Company'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 Company. The Company does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Company are likely to be 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 Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Expiration of Licences and Leases

The Company's properties are held in the form of licences and leases and working interests in licences and leases. If the Company or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Company's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Company's results of operations and business.

Management of Growth

The Company may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expend, train and manage its employee base. The inability of the Company to deal with this growth could have a material adverse impact on its business, operations and prospects.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Company is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although prior to drilling the Company will obtain 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 Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Company's financial position, results of operations or prospects.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive laws and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by various levels of governments and with respect to pricing and taxation of oil and natural gas by agreements among the Governments of Canada, Alberta and British Columbia, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these laws or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current laws and regulations are a matter of public record and the Company is unable to predict what additional laws and regulations or amendments may be enacted. Outlined below are some of the principal aspects of the legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

In Canada, oil producers negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, and the value of refined products. Oil exports may be made under export contracts having terms not exceeding one year in the case of light oil, and not exceeding two years in the case of heavy oil, provided that an order approving any such export has been approved by the National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Government of Canada.

In Canada, the price of natural gas sold is determined by negotiation between buyers and sellers. 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. 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 Government of Canada approval.

The provincial governments of Alberta and British Columbia also regulate the removal of gas from their jurisdictions for consumption elsewhere based upon such factors as reserve availability, transportation arrangements and market considerations.

Royalties

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions where Strategic operates, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the governments of Canada, Alberta and British Columbia have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. Such programs are generally introduced when commodity prices are low, and are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. These programs reduce the amount of Crown royalties otherwise payable.

<u>Alberta</u>

In terms of oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. On February 16, 2007, the Government of Alberta announced a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, natural gas and oil sands to be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process was to ensure that Albertans were receiving a fair share from energy development through royalties, taxes and fees.

On October 25, 2007, the Government of Alberta unveiled a new royalty regime for determining Crown royalty rates in Alberta (the "Royalty Framework"), effective January 1, 2009. The Royalty Framework introduced new royalties applicable to all conventional oil and natural gas wells and bitumen production, with the exception of those subject to the transitional royalty rate discussed below.

The Royalty Framework eliminated the previous tier system for conventional oil, which was based on the vintage or discovery date of the oil, and implemented a sliding rate formula based on both the commodity price of oil and well production. Subject to certain available incentives, effective from the January 2011 production month royalty rates for conventional oil production under the Royalty Framework range from a base rate of 0% to a cap of 40%. This represents an increase from the previous rate cap of 35% under the tier system, but a decrease from the rate cap of 50% under the Royalty Framework prior to January 2011. Actual royalty rates are determined on a monthly basis.

The Royalty Framework also eliminated the previous tier system for natural gas, which was also based on the vintage or discovery date of the gas, and implemented a sliding rate formula based on both the commodity price of the gas and well production. This eliminated the option to use a corporate average reference price. The natural gas royalty formula also provides for a reduction based on the measured depth of the well below 2,000 metres (the "Depth Factor Adjustment"), as well as the acid gas content of the produced gas (the "Acid Gas Adjustment"). Subject to certain available incentives, effective from the January 2011 production month royalty rates for natural gas production under the Royalty Framework range from a base rate of 5% to a cap of 36%. This represents an increase from the previous rate cap of 35% under the tier system, but a decrease from the rate cap of 50% under the Royalty Framework prior to January 2011.

Under the Royalty Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

Transitional Incentive

In late November 2008, the Alberta government announced details of an optional five-year transitional royalty program (the "Transitional Program") applicable to conventional oil and natural gas wells drilled to measured depths from 1,000 to 3,500 metres, with a spud date on or after November 19, 2008. For each eligible well, the producer could make a one-time election to produce the well under the Transitional Program royalty rates or the Royalty Framework rates. The Transitional Program royalty rates would only apply to production from January 1, 2009 until December 31, 2013. As of January 1, 2014, all production subject to the Transitional Program will revert to the Royalty Framework regime. Operators electing the Transitional Program rates are not eligible for the Depth Factor Adjustment or the Acid Gas Adjustment, which are specific to the Royalty Framework, but are otherwise not excluded from available incentive programs, subject to eligibility as discussed below. On March 11, 2010, the Government of Alberta announced that the Transitional Program would continue until its originally announced expiration, however, effective January 1, 2011, no new wells would be eligible for the selection of the Transitional Program royalty rates. Wells which had already opted for the Transitional Program royalty rates prior to January 1, 2011 had the option to continue under the Transitional Program royalty rates until the expiry of the Transitional Program, or to opt out of the Transitional Program by February 15, 2011 in favour of the Royalty Framework rates.

Incentive Programs

The Royalty Framework also eliminated some previously available incentives, and introduced certain revised or updated incentive programs.

With respect to conventional oil, the Royalty Framework eliminated the Third Tier Exploratory Well Royalty Exemption, the Re-activated Well Royalty Reduction, the Low Productivity Well Royalty Reduction, the Horizontal Re-entry Well Royalty Program, and the Experimental Project Petroleum Royalty.

With respect to natural gas, the Royalty Framework eliminated the Deep Gas Royalty Holiday and the Royalty Adjustment Program for Deep Marginal Gas Wells.

Pursuant to the Royalty Framework, the Deep Oil Exploratory Well Program, the Enhanced Recovery of Oil Royalty Reduction Program ("EOR Program"), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the "IETP") were either created or retained.

The Deep Oil Exploratory Well Regulation provides a limited royalty exemption for qualifying exploratory oil wells spudded or deepened between January 1, 2009 and December 31, 2013 that are deeper than 2,000 metres and have a producing interval below 2,000 metres. Existing oil wells approved under the discontinued Third Tier Exploratory Well Royalty Exemption and qualifying for the Deep Oil Exploratory Well Program were transitioned into the new program on January 1, 2009.

With respect to the EOR Program, the Enhanced Recovery of Oil Royalty Reduction Regulation provides that Alberta Energy may approve royalty reductions for qualifying enhanced oil recovery projects.

The Natural Gas Deep Drilling Regulation, 2010 provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened on or after May 1, 2010, with producing intervals that are deeper than 2,000 metres.

The IETP was originally intended to promote producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. This program had been retained under the Royalty Framework. The IETP provides royalty reductions to successful applicants. Alberta Energy determines which projects qualify for the IETP, as well as the level of support that will be provided.

On March 3, 2009, the Government of Alberta announced an additional incentive program, the Drilling Royalty Credit (the "DRC"), in respect of conventional oil and gas wells drilled on Alberta Crown lands. On June 25, 2009, the Government of Alberta announced the extension of the DRC for one additional year, expiring on April 1, 2011. The Drilling Royalty Credit Regulation provided that for qualifying wells drilled for the purpose of extracting conventional oil or natural gas and with a spud date and finish drill date between April 1, 2009 and April 1, 2011, the operator would receive a royalty credit of $200 per metre drilled, up to a prescribed maximum percentage of the operator's royalties. The maximum percentage was determined on a sliding scale ranging from 10% to 50%, based on the operator's production, with a higher maximum percentage available to lower producing operators. The DRC was only available to companies that would be recognized as having royalty payment obligations pursuant to applicable regulation. Any DRC royalty credits not used prior to March 31, 2011 were forfeited.

On March 3, 2009, the Government of Alberta also announced the New Well Royalty Reduction (the "NWRR") incentive program. The New Well Royalty Reduction Regulation provided that the NWRR would be available to qualifying wells that commence or recommence producing conventional oil or natural gas between April 1, 2009 and April 30, 2010. Pursuant to the New Well Royalty Reduction Regulation, royalties on production from qualifying wells were reduced to a maximum royalty rate of 5% until the earlier of either 12 production months from the date of first production, the date that the production cap was met (for natural gas wells, 7,949 m^3 of oil equivalent (500 MMcf of gas) and for conventional oil 7,949 m^3 of oil or oil equivalent), the date the well becomes part of a Project under the Oil Sands Royalty Regulation, 2009, or March 31, 2012, whichever occurred first. On March 11, 2010, as part of a larger modification of royalty rates under the Royalty Framework, the Government of Alberta announced that the NWRR was to become a permanent feature of Alberta's royalty regime, and the New Well Royalty Regulation was enacted. Pursuant to the New Well Royalty Regulation, production from a qualifying well is calculated at royalty of 5% until either the end of the eligible production month cap of the well, the date that the volume cap is reached for that well or the date the well becomes part of a Project under the Oil Sands Royalty Regulation, 2009, whichever occurs first.

In addition, on May 27, 2010 the Government of Alberta announced further initiatives to stimulate investment in emerging resources and technologies. In particular, the Horizontal Gas New Well Royalty

Rate ("HGNWRR") reduces royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 18 production months from date of first production or the date that the first 7,949 m^3 of oil equivalent is produced. Finally, the Horizontal Oil New Well Royalty Rate ("HONWRR") reduces royalties on production from qualifying wells to a maximum royalty rate of 5% until the prescribed time or volume limit is met. The time and volume limits increase with the depth of metres drilled, from a minimum of 7,949 m^3 of oil equivalent and 18 months for wells drilled to measured depths from 0 to 2,499 metres, to a maximum of 15,899 m^3 of oil equivalent and 48 months for wells drilled to measured depths in excess of 4,500 metres. The NWRR applies retroactively to production produced on or after May 1, 2010. The HGNWRR and HONWRR apply retroactively to spud dates on or after May 1, 2010.

Both the DRC and NWRR apply to wells under the Royalty Framework as well as those wells electing the Transitional Program rates. In relation to conventional oil wells eligible for both the NWRR and the Deep Oil Exploratory Well Program, the date constraints and volume limits under each program will run concurrently. In relation to natural gas wells eligible for both the NWRR and the NGDDP and any of the 5% royalty rates, including the HGNWRR, the Coal Bed Methane NWRR or the Shale Gas NWRR, the 5% royalty rate will be applied first, with the NGDDP benefits applied after the expiration of the 5% rate. However, the 60 calendar month benefit under the NGDDP begins on the well's finished drilling date, not with the expiry of the 5% royalty rate. In addition, the NWRR will reduce the royalty reduction that is available for wells under the EOR Program and the IETP.

British Columbia

Producers of crude oil and natural gas in the Province of British Columbia are required to pay annual rental payments in respect of Crown leases, and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively.

The Crown royalty payable in respect of natural gas depends on the vintage of the gas, the type of gas produced, the quantity of gas produced in a month, and the price of the gas. Natural gas is categorized as either "conservation gas" (being gas produced from oil wells) and "non-conservation gas (being gas produced from gas wells). Additionally, gas is divided into vintage categories, dependent on when the well was drilled ("base 15 gas", "base 12 gas" and "base 9 gas"). The royalty is also dependent upon the quantity of gas produced from a well in a month. Finally the royalty is adjusted based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price.

The Crown royalty payable in respect of crude oil depends on the vintage of the oil, the type of oil produced, the quantity of oil produced in a month, and the price of the oil. Crude oil is categorized as either "old oil", "new oil", "third-tier oil", or "heavy oil". The Crown royalty payable on third-tier oil and heavy oil is adjusted based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price.

The royalties payable on oil and natural gas may also be reduced pursuant to various incentive programs, including royalty credits for deep gas exploration, summer drilling, and infrastructure development and special royalty rates for marginal and ultra-marginal gas. Eligibility for such incentive programs is subject to the satisfaction of specified criteria and conditions provided in legislation, regulation and guidelines.

Northwest Territories

Before payout the interest holder pays a royalty of 1% of gross revenues for the 1st to the 18th production month, 2% of gross revenues from 19th to the 36th production month, 3% of gross revenues from 37th to the 54th production month, 4% of gross revenues from 55th to the 72th production month and 5% of gross revenues from 73th to the last production month before payout. At payout and after payout the interest holder pays a royalty of the greater of 30% of net revenues or 5% of the gross revenues.

The royalty formula is as above plus withdrawals from the deferred royalty abandonment trust in that month and minus the royalty deferred due to contributions to the abandonment trust. The royalty payable is reduced by the lesser of the royalty deferral and the investment royalty credit balance.

Royalties are payable to the government on petroleum from the project lands unless consumed, lost or wasted.

Exemptions to royalties

No royalties payable on:

(a) consumed petroleum on drilling and testing

(b) injected petroleum for conservation

(c) consumed petroleum in operation of the facility

- (i) as in processing, transportation

- (ii) not already included in gas processing or transportation allowance

(d) flared petroleum

Royalty exemptions do not apply to 'petroleum wasted' as defined in the *Canada Oil Gas Operations Act*.

Environmental Regulation

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, territorial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced or used in association with oil and gas operations, as well requirements with respect to oilfield waste handling, storage and disposal, land reclamation, habitat protection, and minimum setbacks of oil and gas activities from surface water bodies.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* and the *Oil and Gas Conservation Act*, which impose strict environmental standards with respect to releases of effluents and emissions, including monitoring and reporting obligations, and impose significant penalties for non-compliance. For example, regulations enacted thereunder target sulphur dioxide and nitrous oxide emissions from oil and gas operations. Environmental legislation in the Province of British Columbia is, for the most part, set out in the *Environmental Management Act* ("EMA") and the *Oil and Gas Activities Act*, which regulate the storage, discharge and disposal of air contaminants, effluent and hazardous waste into the environment. The EMA provides for the imposition of significant penalties in the event of non-compliance and for the remediation of contaminated sites. New oil and gas projects, or modifications to existing projects, may be subject to a review under the *Environmental Assessment Act*. Environmental legislation in the Northwest Territories is, for the most part, set out in the Environmental Protection Act, the Northwest Territories Waters Act, the Canada Oil and Gas Operations Act, and associated regulations. These acts and regulations stipulate environmental conditions of operating approvals and the environmental standards to which monitoring and reporting obligations, in addition to emissions and waste discharge criteria, adhere to.

Environmental legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, or in the suspension or revocation of necessary licences and approvals. Strategic may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject Strategic to statutory strict liability in the event of an accidental spill or discharge from a facility, meaning that fault on the part of Strategic need not be established if such a spill or discharge is found to have occurred.

As at December 31, 2012, Strategic owned approximately 210 gross (174.8 net) wells, for which abandonment and reclamation costs are expected to be incurred. Strategic estimates abandonment and reclamation costs by taking into consideration the costs associated with decommissioning, abandonment, remediation, and reclamation, all adjusted according to its working interest and discounted in accordance with NI 51-101. Decommissioning liability cost estimates are based on information published by the Alberta Energy Regulator ("AER").

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas, or other pollutants into the air, soil or water may give rise to liabilities to third parties and may require Strategic to incur costs to remedy such a discharge in an event not covered by Strategic's insurance, which insurance is in line with industry practice. Furthermore, Strategic expects incremental future costs associated with compliance with increasingly complex environmental protection requirements with respect to GHG emissions or otherwise, some of which may require the installation of emissions monitoring and measuring devices, the verification and reporting of emissions data and additional financial expenditures to comply with GHG emissions reduction requirements.

Greenhouse Gas (GHG) Emissions

In Alberta, GHG emissions are regulated under the Specified Gas Emitters Regulation pursuant to the *Climate Change and Emissions Management Act*. These regulations require Alberta facilities that emit more than 100,000 tonnes of GHG per year to reduce emissions intensity by 12% below an average baseline taken from a facility's 2003 - 2005 emissions. Companies may meet requirements through improvements to their operations; by purchasing Alberta based emission reduction credits; or by contributing to the provincial Climate Change and Emissions Management Fund. The Province of Alberta also published a climate change action plan in January of 2008 wherein it set an objective to deliver a 50% reduction in GHG emissions from business as usual by 2050 by employing: (a) mandatory carbon capture and storage ("CCS") for certain facilities; (b) energy efficiency and conservation; and (c) research and investment in clean energy technologies, including carbon separation technologies to assist CCS.

In British Columbia, GHG emissions are regulated under the Reporting Regulation enacted pursuant to the Greenhouse *Gas Reduction (Cap and Trade) Act*. Starting January 1, 2010, these regulations impose GHG emissions reporting requirements upon B.C. facilities emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year. In addition, facilities reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party.

Strategic's facilities and other operations emit GHG emissions, making it possible that Strategic will be subject to federal and provincial GHG emissions controls or reduction requirements if its facilities or operations are above applicable thresholds, particularly in B.C. where a cap and trade regime is pending. In the near term, Strategic does not expect to have any facilities subject to reporting based on these preliminary regulations.

In December 2002, the Government of Canada ratified the Kyoto Protocol, which requires a reduction in GHG emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol. However, the Canadian federal government has indicated an intention to regulate the emissions of GHGs from a range of industries in its framework and has outlined a number of policies to reduce GHGs intensity of regulated facilities (the "Federal Plan"). New facilities (which are defined as those facilities whose first year of operation is 2004 or later) would face intensity reduction requirements beginning in their fourth year of commercial production, of 2% per year from their "baseline" emissions intensity (which baseline is the emissions intensity for such facility's third year of commercial production) until at least 2020. Compliance options for new facilities under the Federal Plan include making emissions intensity improvements; making investments in certified carbon capture and storage projects; buying offsets or emissions performance credits; and for a portion of each entity's emissions reduction obligations, making payments of $15 per tonne until 2012, $20 per tonne in 2013 and an escalating annual rate per tonne thereafter; to the federal technology fund.

The Federal Plan also includes proposed requirements to be implemented by the Canadian federal government which would govern the emission of industrial air pollutants. Certain of the proposed requirements include fixed emissions caps, an emissions credit trading system, and several options from which companies can choose to meet their GHG emission reduction targets. At present, the status of its proposals is unclear. The Canadian federal government has repeatedly stated that it intends to align Canada's GHG emission reduction policies with those of the United States, and it is willing to wait until the United States has developed its framework before implementing any policies in Canada. As such, it is unclear when, or in what form, the Federal Plan will be implemented.

Several of the provinces and territories are working together with various American states to develop a cap and trade system. It remains to be seen whether the Canadian federal government would adopt such an approach, but given its statements regarding aligning policy with the United States, this will likely depend on whether the United States adopts a cap and trade system. No assurance can be given that either a modified Federal Plan or a North American cap and trade system will or will not be implemented, or what kinds of obligations may be imposed under such a system.

At the July 2009 G8 Summit in Italy, Canada and the other G8 members agreed to work together toward achieving at least a 50% reduction of global GHG emissions by 2050. Canada reiterated its commitment to this goal at the June 2010 G8 Summit in Huntsville, Ontario.

In December 2009, Canada participated in the Fifteenth session of the Conference of the Parties to the United Nations Framework Convention on Climate Change ("COP 15") in Denmark, the goal of which was to reach a new agreement for fighting global climate change. COP 15 resulted in the non-binding Copenhagen Accord, whereby Canada and the other participating countries committed to implementing quantified economy-wide emissions targets by 2020. Canada submitted its GHG emission reduction targets on January 30, 2010, noting that: (a) its target is a 17% reduction from a baseline of 2005 emission levels (which target is aligned with the final economy-wide emissions target and base year of the United States); and (b) its submission is dependent on the other parties to the Copenhagen Accord submitting emissions targets and mitigation actions in accordance with such Accord.

There remains ongoing uncertainty regarding Canada's short-term and long-term emissions reduction targets and whether such targets will be absolute or intensity based. Facility owners across Canada await further information regarding Canada's approach to regulating GHG emissions. Although the timing and nature of federal GHG regulations are unknown at this time, Strategic anticipates that, based on current production levels, Government of Canada GHG regulations will apply to its operations in the future and as a result additional costs will be incurred to comply with reduction requirements and to perform necessary monitoring, measurement, verification, and reporting of GHG emissions.

Strategic anticipates changes in environmental legislation may require reductions in emissions from its operations and result in increased capital expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liability and increased capital expenditures and operating costs, which could have a material adverse effect on Strategic's financial condition and results of operations.

Health, Safety and Environment

The health and safety of employees, contractors, visitors and the public, as well as the protection of the environment, is of utmost importance to Strategic. Strategic endeavours to conduct its operations in a manner that will minimize both adverse effects and consequences of emergency situations by:

- Complying with government regulations and standards;

- Conducting operations consistent with industry codes, practices and guidelines;
- Ensuring prompt, effective response and repair to emergency situations and environmental incidents;
- Promoting the aspects of careful planning, good judgment, implementation of the Company's procedures, and monitoring Company activities;
- Communicating openly with members of the public regarding Strategic's activities; and
- Amending the Company's policies and procedures as may be required from time to time.

Strategic believes that it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. Strategic's practice is to do all that it reasonably can to ensure that it remains in material compliance with applicable environmental protection legislation. Strategic also believes that it is reasonably likely that the trend towards stricter standards in environmental regulation will continue. Strategic is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. Strategic anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given however that environmental laws will not result in a curtailment of production or a material increase in the costs of production, the development or exploration activities, or otherwise adversely affect Strategic's financial condition, capital expenditures, results of operations, competitive position or prospects.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter provincial pipeline systems also continues to affect the ability to export oil and natural gas.

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 restrict exports to the U.S. or Mexico provided that such export restrictions do not: (i) reduce the proportion of the energy resource exported relative to the total supply of that energy resource in Canada as compared to 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 except in exceptional circumstances.

NAFTA also requires the parties thereto to ensure that their respective energy regulators implement any energy regulatory measures in an orderly and equitable manner and in a manner which avoids disrupting contractual relationships to the maximum extent possible.

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, licenses and permits for varying periods 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.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments may at times restrict the movement of drilling rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural 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 consists of swampy terrain. See "*Risk Factors – Seasonal Impact on Industry*" in this Annual Information Form.

LEGAL AND REGULATORY PROCEEDINGS

Strategic is not a party to any regulatory actions or legal proceedings nor was it a party to, nor is or was any of its property the subject of any legal proceeding, during the financial year ended December 31, 2013, nor is Strategic aware of any such contemplated regulatory actions or legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10 percent of the current assets of Strategic.

During the year ended December 31, 2013, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed in this Annual Information Form, no director, officer or principal Shareholder, nor any affiliate or associate of such a person, has or has had any material interest in any transaction or any proposed transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Strategic.

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company, at its principal offices in Calgary, Alberta, is the transfer agent and registrar for the Common Shares.

INTERESTS OF EXPERTS

Reserve estimates contained in this Annual Information Form have been prepared by McDaniel & Associates Consultants Ltd. ("McDaniel"). As at December 31, 2013, the effective date of those estimates, and as of the date hereof, the principals, directors, officers and associates of McDaniel, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares of the Company.

The auditors of the Company, Deloitte LLP, are independent with respect to the Company, in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Proxy Statement and Information Circular of the Company prepared in connection with the most recent annual meeting of Shareholders that involved the election of directors. Additional financial information is provided in the Company's financial statements and management discussion and analysis for the year ended December 31, 2013.

Copies of this Annual Information Form, any interim financial statements of the Company, the Company's Information Circular and other additional information relating to the Company are available on SEDAR at www.sedar.com and on the Company's website at www.sogoil.com.

APPENDIX "A"
AUDIT COMMITTEE CHARTER

Mandate

The primary function of the audit committee (the "Committee") is to assist the Board of Directors in fulfilling its financial oversight responsibilities by reviewing the financial reports and other financial information provided by the Company to regulatory authorities and shareholders, the Company's systems of internal controls regarding finance and accounting and the Company's auditing, accounting and financial reporting processes. The Committee's primary duties and responsibilities are to:

- serve as an independent and objective party to monitor the Company's financial reporting and internal control system and review the Company's financial statements;
- review and appraise the performance of the Company's external auditor;
- provide an open avenue of communication among the Company's auditor, financial and senior management and the Board of Directors; and
- report regularly to the Board of Directors the results of its activities.

Composition

The Committee shall be comprised of a minimum three directors as determined by the Board of Directors. If the Company ceases to be a "venture issuer" (as that term is defined in Multilateral Instrument 52-110 entitled "Audit Committees"), then all of the members of the Committee shall be free from any material relationship with the Company that, in the opinion of the Board of Directors, would interfere with the exercise of their independent judgment as a member of the Committee.

If the Company ceases to be a venture issuer then all members of the Committee shall also have accounting or related financial management expertise. All members of the Audit Committee should have 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 Company's financial statements.

The members of the Committee shall be elected by the Board of Directors at its first meeting following the annual shareholders' meeting or until their successors are duly elected. Unless a Chair is elected by the full Board of Directors, the members of the Committee may designate a Chair by a majority vote of the full Committee membership.

Meetings

The Committee shall meet a least once quarterly, or more frequently as circumstances dictate or as may be prescribed by securities regulatory requirements. As part of its job to foster open communication, the Committee will meet at least annually with the Chief Financial Officer and the external auditor in separate sessions.

Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall conduct a review of/with:

1. Documents/Reports

   (a) review and update this Audit Committee Charter annually;

(b) review the Company's financial statements, MD&A and any annual and interim earnings press releases before the Company publicly discloses this information and any reports or other financial information (including quarterly financial statements), which are submitted to any governmental body, or to the public, including any certification, report, opinion, or review rendered by the external auditor; and

(c) review regular summary reports of directors and officers expense account claims at least annually.

(d) Establish and review approval policies for expense reports and, as required, request audits of expense claims and policies for expense approval and reimbursements. The Chairman of the Audit Committee or of the Compensation Committee will approve expense reports of the President and the CEO and the CEO will approve those of the directors and officers.

2. External Auditor

(a) review annually, the performance of the external auditor who shall be ultimately accountable to the Board of Directors and the Committee as representatives of the shareholders of the Company;

(b) obtain annually, a formal written statement of external auditor setting forth all relationships between the external auditor and the Company;

(c) review and discuss with the external auditor any disclosed relationships or services that may impact the objectivity and independence of the external auditor;

(d) take, or recommend that the Board of Directors take, appropriate action to oversee the independence of the external auditor, including the resolution of disagreements between management and the external auditor regarding financial reporting;

(e) recommend to the Board of Directors the selection and, where applicable, the replacement of the external auditor nominated annually for shareholder approval;

(f) recommend to the Board of Directors the compensation to be paid to the external auditor;

(g) at each meeting, where desired, consult with the external auditor, without the presence of management, about the quality of the Company's accounting principles, internal controls and the completeness and accuracy of the Company's financial statements;

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

(i) review with management and the external auditor the audit plan for the year-end financial statements;

(j) recommend fees to be paid to the external auditors, and any advisors retained by the committee for such services as part of the annual audit plan; any subsequent additional audit related fees shall be subject to approval by the chair of the audit committee;

(k) review and pre-approve all non-audit services, provided by the Company's external auditor. The pre-approval requirement is waived with respect to the provision of non-audit services if:

(i) the aggregate amount of all such non-audit services provided to the Company constitutes not more than five percent of the total amount of revenues paid by the Company to its external auditor during the fiscal year in which the non-audit services are provided,

(ii) such services were not recognized by the Company at the time of the engagement to be non-audit services, and

(iii) such services are promptly brought to the attention of the Committee by the Company and approved prior to the completion of the non-audit services by the Committee or by one or more members of the Committee who are members of the Board of Directors to whom authority to grant such approvals has been delegated by the Committee.

Provided the pre-approval of the non-audit services is presented to the Committee's first scheduled meeting following such approval, such authority may be delegated by the Committee to one or more independent members of the Committee.

3. Financial Reporting Processes

(a) in consultation with the external auditor, review with management the integrity of the Company's financial reporting process, both internal and external;

(b) consider the external auditor's judgments about the quality and appropriateness of the Company's accounting principles as applied in its financial reporting;

(c) consider and approve, if appropriate, changes to the Company's auditing and accounting principles and practices as suggested by the external auditor and management;

(d) review significant judgments made by management in the preparation of the financial statements and the view of the external auditor as to appropriateness of such judgments;

(e) following completion of the annual audit, review separately with management and the external auditor any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information;

(f) review any significant disagreement among management and the external auditor in connection with the preparation of the financial statements;

(g) review with the external auditor and management the extent to which changes and improvements in financial or accounting practices have been implemented;

(h) review any complaints or concerns about any questionable accounting, internal accounting controls or auditing matters;

(i) review certification process;

(j) establish a procedure for the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matters;

(k) establish a procedure for the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters; and

(l) on at least an annual basis, review with the Corporation's counsel, any legal matters that could have a significant impact on the Corporation's financial statements, the

Corporation's compliance with applicable laws and regulations, and inquiries received from regulators or government agencies.

4. Authority

The Audit Committee will have the authority to:

(a) review any related-party transactions;

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

(c) to set and pay compensation for any independent counsel and other advisors employed by the Committee;

(d) communicate directly with the auditors; and

(e) conduct and authorize investigations into any matters within the Committee's scope of responsibilities. The Committee shall be empowered to retain independent counsel and other professionals to assist in the conduct of any investigation.

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

APPENDIX "C"
REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Strategic Oil & Gas Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company'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, 2013, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) 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.

"Gurpreet Sawhney"

Gurpreet Sawhney
President and Chief Executive Officer

"Aaron Thompson"

Aaron Thompson
Chief Financial Officer

"John Harkins"

John Harkins
Director and Chair of Reserves Committee

"D. Richard Skeith"

D. Richard Skeith
Director

March 31, 2014