Revised Annual Information Form
Financial Year Ended December 31, 2015

Dated March 30, 2016

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CONVENTIONS

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information with respect to Spartan Energy Corp. ("**Spartan**" or the "**Corporation**") has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. The information in this annual information form ("**Annual Information Form**") is stated as at December 31, 2015, unless otherwise indicated. For an explanation of the capitalized terms and expressions and certain defined terms, please refer to the section of this Annual Information Form titled "*Definitions*".

ABBREVIATIONS

	Oil and Natural Gas Liquids		**Natural Gas**
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	Mmcf	million cubic feet
BOPD	barrel of oil per day	Mcf/d	thousand cubic feet per day
Mbbls	thousand barrels	Mmcf/d	million cubic feet per day
Mmbbls	million barrels	MMBTU	million British Thermal Units
Mstb	1,000 stock tank barrels	Bcf	billion cubic feet
Bbls/d	barrels per day	GJ	gigajoule
NGLs	natural gas liquids		
STB	standard tank barrels		

Other

AECO	Alberta Energy Company's natural gas storage facility located at Suffield, Alberta.
API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/D	barrel of oil equivalent per day
m^3	cubic metres
EPEA	*Environmental Protection and Enhancement Act* (Alberta)
MBOE	1,000 barrels of oil equivalent
OOIP	original oil in place
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$000 or M$	thousands of dollars

CONVERSION

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.290
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

Wherever used in this Annual Information Form, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

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

"**Arrangement**" means the Plan of Arrangement completed effective as of March 31, 2014 among the Corporation, Renegade and the shareholders of Renegade pursuant to which the Corporation acquired Renegade;

"**Board of Directors**" means the board of directors of Spartan;

"**COGE Handbook**" means the "Canadian Oil and Gas Evaluation Handbook" maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;

"**Common Share**" or "**Common Shares**" means, respectively, one or more common shares in the capital of Spartan;

"**Consolidation**" means the share consolidation on the basis of one post-consolidation Common Share for every four pre-consolidation Common Shares, as approved at the special meeting of Shareholders held on February 18, 2014;

"**Corporation**" or "**Spartan**" means Spartan Energy Corp.;

"**NAFTA**" means the North American Free Trade Agreement;

"**NEB**" means the National Energy Board;

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

"**Options**" means the stock options granted by the Corporation to purchase Common Shares;

"**Renegade**" means Renegade Petroleum Ltd.;

"**Shareholders**" means the holders of Common Shares;

"**Sproule**" means Sproule Associates Limited;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c.1 (5th Supp.), as amended;

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

"**TSXV**" means the TSX Venture Exchange; and

"**U.S.**", "**US**" or "**United States**" means the United States of America.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form may constitute forward-looking statements. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Spartan believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Annual Information Form should not be unduly relied upon by investors. These statements speak only as of the date of this Annual Information Form and are expressly qualified, in their entirety, by this cautionary statement.

Forward-looking statements or information in this Annual Information Form include, but are not limited to, the characteristics of the Corporation's oil and natural gas interests, reserve quantities and the discounted present value of future net cash flows from such reserves, net revenue, future production levels, projection of market prices, capital expenditures, exploration plans, development plans, acquisition and disposition plans and the timing thereof, operating and other costs, world-wide supply and demand for petroleum products, royalty rates and treatment under governmental regulatory regimes. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources.

In particular, this Annual Information Form contains forward-looking statements pertaining to the following:

- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- oil and natural gas production levels;
- future development and growth prospects;
- ability to meet current and future obligations;
- future tax liabilities and future use of tax pools and losses;
- future decommissioning costs;
- treatment under governmental regulatory regimes and tax laws;
- the ability to obtain financing on acceptable terms or at all; and
- currency, exchange and interest rates.

With respect to forward-looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding, among other things:

- the legislative and regulatory environments of the jurisdictions where the Corporation carries on business or has operations;
- commodity prices and royalty regimes;
- the impact of increasing competition;
- availability of skilled labour;
- timing and amount of capital expenditures;

- the price of oil and natural gas;
- conditions in general economic and financial markets;
- royalty rates and future operating costs; and
- the Corporation's ability to obtain additional financing on satisfactory terms.

Spartan's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- general economic conditions in Canada and globally;
- the ability of management to execute its business plan;
- fluctuations in the price of oil and natural gas, interest and exchange rates;
- risks inherent in the oil and gas industry, such as operational risks and market demand;
- governmental regulation of the oil and gas industry, including environmental regulation;
- uncertainty in amounts and timing of royalty payments;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- geological, technical, drilling and processing problems;
- exploration and development activities are capital intensive and involve a high degree of risk;
- risks and uncertainties involving geology of oil and gas deposits;
- risks inherent in marketing operations, including credit risk;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Corporation's capital expenditures;
- unanticipated operating events which could reduce production or cause production to be shut-in or delayed;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- the ability to add production and reserves through development and exploration activities;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- the availability of capital on acceptable terms or at all;
- failure to realize the anticipated benefits of acquisitions and dispositions; and
- the other factors considered under "*Risk Factors*" below.

Statements relating to "reserves" are deemed to be forward-looking statements or information, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitable in the future. There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Corporation. The reserve data included herein represents estimates only. In general, estimates of economically recoverable oil and gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. 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 gas reserves attributable to any particular group of properties and 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 substantially. The actual production, revenues, taxes and development and operating expenditures of the Corporation with respect to these reserves will vary from such estimates, and such variances could be material.

Spartan has included the above summary of assumptions and risks related to forward-looking information provided herein in order to provide investors with a more complete perspective on the Corporation's current and future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained herein, and the documents incorporated by reference herein, are expressly qualified by this cautionary statement. Except as required by applicable securities laws, the Corporation does not undertake any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under the heading "*Risk Factors*" below.

The forward-looking statements or information contained herein are made as of the date hereof and the Corporation undertakes no obligation to update or revise any forward looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

Caution Respecting BOE

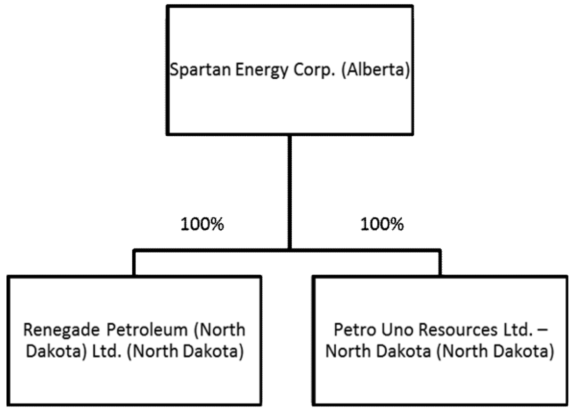
In this Annual Information Form, the abbreviation BOE means a barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency conversion ratio of 6 Mcf to 1 BOE, utilizing a conversion ratio of 6 Mcf to 1 BOE may be misleading as an indication of value.**

THE CORPORATION

The Corporation was incorporated pursuant to the provisions of the ABCA on December 12, 1988 as "394537 Alberta Ltd.". The Corporation changed its name to "Petro-Reef Resources Ltd." on February 23, 1989. On January 1, 2000, the Corporation amalgamated with twenty private Alberta numbered companies to form "Petro-Reef Resources Ltd.". The Corporation changed its name to "Alexander Energy Ltd." on September 9, 2012, and to "Spartan Energy Corp." on February 28, 2014. On March 31, 2014, Spartan completed the Arrangement with Renegade which included the amalgamation of Spartan and Renegade to form "Spartan Energy Corp.".

Spartan's head office is located at Suite 500, 850 – 2nd Street S.W., Calgary, Alberta, T2P 0R8, and the registered office is located at Suite 4000, 421 – 7th Avenue, S.W., Calgary, Alberta, T2P 4K9.

The following diagram describes the inter-corporate relationships among the Corporation and its subsidiaries as at the date hereof:



As of the date hereof, the Corporation is a reporting issuer in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario and New Brunswick. The Common Shares are listed on the TSX under the trading symbol "SPE".

GENERAL DEVELOPMENT OF THE BUSINESS

Financial Year Ended December 31, 2013

On September 13, 2013, the Corporation announced the completion of a private placement of Common Shares at a price of $0.15 per share for gross proceeds of $1.3 million.

On December 5, 2013, the Corporation entered into a reorganization and investment agreement (the "**Reorganization Agreement**") with Richard F. McHardy, Michelle Wiggins, Fotis Kalantzis, Ed Wong, Albert Stark and Thomas Boreen, which provided for: (i) a non-brokered private placement of up to an aggregate of approximately $26.5 million (the "**Recapitalization Transaction**"); (ii) the appointment of a new management team (the "**New Management Team**") and a new Board of Directors (the "**New Board**"); and (iii) a rights offering to current holders of Common Shares (the "**Rights Offering**"). The New Management Team was led by Richard F. McHardy as President & Chief Executive Officer, Michelle Wiggins as Vice President, Finance and Chief Financial Officer, Fotis Kalantzis as Vice President, Exploration, Ed Wong as Vice President, Engineering, Albert Stark as Vice President, Operations and Thomas Boreen as Vice President, Geology. The New Board was comprised of Richard F. McHardy, Michael Stark, Reginald Greenslade, Grant Greenslade and Don Archibald. Sanjib Gill was appointed Corporate Secretary.

On December 10, 2013, the New Management Team and New Board were appointed. The Corporation also issued a total of 119,735,183 units ("**Units**") at a price of $0.15 per Unit, for aggregate proceeds of approximately $18.0 million (the "**Initial Closing**"). The Units issued under the Initial Closing were issued to the New Management Team, the New Board and certain other individuals identified by the New Management Team and the New Board. Each Unit was comprised of one Common Share and one Common Share purchase warrant ("**Warrant**"), each Warrant entitling the holder thereof to purchase one Common Share at a price of $0.20 for a period of five years. On January 9, 2014, all of the vesting thresholds were met and the Warrants became fully vested and exercisable.

On December 17, 2013, the Corporation entered into a definitive purchase and sale agreement to acquire a crude oil producing asset (the "**Spartan Acquired Assets**") located in southeast Saskatchewan (the "**Asset Acquisition**") for $32.5 million, subject to normal closing adjustments. On February 3, 2014, the Corporation completed the Asset Acquisition.

On December 18, 2013, concurrent with the announcement of the Asset Acquisition, the Corporation commenced a private placement offering of special warrants ("**Special Warrants**") on a bought-deal basis (the "**Financing**"), which was subsequently upsized for aggregate gross proceeds of approximately $75.0 million. Each Special Warrant entitled the holder thereof, without additional consideration or action on the part of the holder, to one Common Share upon the occurrence of certain events.

On December 24, 2013, the Recapitalization Transaction was completed, with the Corporation issuing 15,151,668 Units at a price of $0.15 per unit and an aggregate of 41,779,816 Common Shares at a price of $0.15 per Common Share for aggregate proceeds of approximately $8.6 million. As a result of this closing and the Initial Closing, a total of 176,666,667 Common Shares and 134,886,851 Warrants were issued for total gross proceeds of approximately $26.5 million.

Financial Year Ended December 31, 2014

On January 13, 2014, the Corporation completed the Financing and issued 153,062,000 Special Warrants at a price of $0.49 per Special Warrant for aggregate proceeds of approximately $75.0 million, which Special Warrants converted into Common Shares on February 19, 2014 upon the filing of a final prospectus.

On January 13, 2014, the Corporation also closed a private placement offering of 5,100,000 Common Shares at a price of $0.49 per Common Share for gross proceeds of approximately $2.5 million.

On February 10, 2014, the Corporation entered into an arrangement agreement with Renegade whereby the Corporation agreed to acquire all of the issued and outstanding shares of Renegade in exchange for 2.25 Common Shares for each share of Renegade. Pursuant to the Arrangement, the Corporation would acquire approximately 5,200 Bbls per day (96.6% oil and liquids) of primarily southeast and west central Saskatchewan assets, including key producing infrastructure such as batteries, pipelines and waterflood facilities. These assets of Renegade included an average working interest of approximately 85% in 150,571 net acres of undeveloped land as at December 31, 2013.

On February 18, 2014, the Corporation held a special meeting of Shareholders where shareholders considered and approved changing the corporate name from "Alexander Energy Ltd." to "Spartan Energy Corp." and the Consolidation. On February 28, 2014, the name change and the Consolidation became effective and the Corporation's Common Shares began trading on the TSXV under the new name "Spartan Energy Corp." and stock symbol "SPE".

On March 19, 2014, the Corporation completed the Rights Offering with the issuance of 2,153,633 Common Shares, on a post-Consolidation basis, at a price of $0.60 per Common Share resulting in aggregate gross proceeds of approximately $1.3 million.

On March 31, 2014, Spartan closed the Arrangement for total consideration of approximately $495 million, comprised of 117,520,001 Common Shares, on a post-Consolidation basis, and assumed debt of approximately $168 million. Pursuant to the Arrangement, Thomas Budd, a former director of Renegade, was appointed as an independent director to the Board of Directors. In connection with the Arrangement, Spartan entered into a credit arrangement providing for a $250.0 million syndicated revolving demand credit facility ("**Credit Facility**") with six Canadian chartered banks.

On June 17, 2014, Spartan closed a bought-deal financing of 39,870,500 Common Shares, including the exercise in full of the over-allotment option of 5,200,500 Common Shares, at a price of $3.75 per Common Share for gross proceeds of approximately $149.5 million.

On July 7, 2014, Spartan completed the acquisition of southeast Saskatchewan light oil assets for gross consideration of $98.0 million. These assets consolidate Spartan's existing core area in southeast Saskatchewan and consist of approximately 1,000 BOE/d of operated, low decline crude oil production.

On July 7, 2014, Spartan also completed the acquisition of assets in southeast Saskatchewan for gross consideration of $17.25 million. These assets consist of approximately 150 BOE/d of low decline oil-weighted production and approximately 20 net sections of land prospective for the drilling of fracture stimulated horizontal wells in the Midale formation.

On July 9, 2014, the Common Shares commenced trading on the TSX under the symbol "SPE" and ceased trading on the TSXV.

On August 14, 2014, Spartan announced the completion of certain asset acquisitions in southeast Saskatchewan of approximately 130 BOE/d and 10 net sections of land for aggregate gross consideration of approximately $15.4 million.

Financial Year Ended December 31, 2015

On December 22, 2015, Spartan completed a non-brokered private placement of 735,294 Common Shares issued on a "flow-through" basis pursuant to the Tax Act for gross proceeds of approximately $2.0 million.

During the financial year ended December 31, 2015, Spartan averaged production of 8,866 BOE/d, comprised of 95% oil and liquids. Spartan drilled 66 (56.5 net) wells over the course of the year and brought 59 (50.5 net) wells on production.

Recent Developments

On March 16, 2016, Spartan completed a bought deal short form prospectus offering of 39,938,375 Common Shares (including 4,668,375 Common Shares issued pursuant to the exercise in full of the over-allotment option granted by the Corporation to the underwriters) at a price of $2.41 per Common Share for gross proceeds of approximately $96.3 million. The net proceeds were initially used to repay the Corporation's bank indebtedness under its Credit Facility.

NARRATIVE DESCRIPTION OF THE BUSINESS

General

Spartan is focussed on predominately light and medium oil opportunities in Saskatchewan and Alberta, growing through development drilling and the acquisition of long-life oil and gas assets. Spartan's extensive opportunity base and current oil weighted production base (95% oil and liquids) together with a well-capitalized corporate structure will allow for the exploitation of Spartan's current drilling inventory and expansion of Spartan's opportunity suite through internally generated prospects and strategic oil acquisitions.

As part of its continued growth strategy, Spartan intends to strategically investigate and search out oil properties that will result in meaningful reserve and production additions and will deploy capital to higher-quality, longer-life reservoirs in proven growth areas that offer existing infrastructure, low cost oil drilling opportunities, year round access and operational control. Spartan's existing core operating properties in Saskatchewan and Alberta are intended to be developed and expanded through a detailed technical analysis of information, including reservoir characteristics, original crude oil and natural gas in place, recovery factors and the application of exploitation drilling and enhanced recovery techniques, such as water flood schemes, multi-well fracturing programs and infill drilling programs.

In each of Spartan's core areas, Spartan's growth strategy is to:

1. acquire a land position or drilling opportunities to earn significant land positions;
2. build an inventory of low to medium risk drilling prospects drillable over a two to five year period;
3. efficiently control costs through facility ownership and operation of wells, where possible;
4. seek out opportunities where current leaseholders have time or resource constraints; and
5. manage risk through the geological and technical expertise Spartan has in each of these geographic areas.

It is the belief of management of Spartan that Spartan's officers and employees, who have significant technical and operational oil and gas experience, hold the necessary skill sets to successfully execute Spartan's business strategy in order to achieve its corporate objectives. In a relatively short period of time, Spartan's officers and employees have demonstrated the ability to profitably grow and expand Spartan's base of operations.

To execute the business strategy, Spartan requires: (i) access to land and additional opportunities; (ii) appropriate commercial terms; (iii) access to services and goods for operations; (iv) acquisition and operational success; and (v) timely financing for all those activities.

Spartan's geographically focused business expansion has positioned it to succeed in currently prevailing industry conditions. Since commencing active oil and gas operations upon completion of the Recapitalization Transaction, management of Spartan has established "critical mass", which includes a production base providing for a solid growth platform and a balanced production and prospect risk profile necessary to become a successful full-cycle exploration and development company. Spartan's inventory of drilling prospects generated internally as well as through the Asset Acquisition and the Arrangement, combined with the ability to execute strategic corporate and property acquisitions, is expected to continue to support and expand its existing asset base.

Personnel

As at December 31, 2015, Spartan had 51 full-time employees.

Industry Conditions

Canadian Government Regulation

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government and, with respect to pricing and taxation of oil and gas, by agreements among the governments of Canada, Saskatchewan, Alberta and Manitoba, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of the Corporation in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil

In Canada, producers of oil 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 type and quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires the approval of the Governor in Council.

On July 6, 2012, the federal government enacted the *Jobs, Growth and Long-term Prosperity Act* ("**Prosperity Act**") which made amendments to the National Energy Board Act ("**NEB Act**") that affect the NEB's export and import framework. As a result of these changes, the NEB issued the Interim Memorandum of Guidance Concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the NEB Act ("**Interim Oil and Gas MOG**"). The purpose of the Interim Oil and Gas MOG is to provide guidance to applicants until such time as the NEB has completed the review and update of the regulatory framework. As part of the review and update, the NEB is currently proposing amendments to the *National Energy Board Part VI (Oil and Gas) Regulations* and the *National Energy Board Export and Import Reporting Regulations*.

Pricing and Marketing - Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

In Canada, the price of natural gas sold in interprovincial and international trade 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 the export contracts 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 or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

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

Pipeline Capacity

Western Canada has seen significant growth in crude production volumes over recent years. This has resulted in pressure on the pipeline take-away capacity, leading to apportionment on the main lines and, in turn, backed-up local feeder pipelines. This has contributed to a widening of, and increased volatility in, the light oil pricing differential between WTI and Edmonton Par and the medium/heavy oil pricing differential between WTI and Cromer/WCS/Hardisty. Although pipeline expansions are ongoing and producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to affect the oil and gas industry and limit the ability to produce and to market production. In addition, the pro-rationing of capacity on the interprovincial systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

On January 1, 1994, NAFTA became effective among the governments of Canada, the United States and Mexico. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement.

In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian exports.

Trans-Pacific Partnership

On October 5, 2015, Canada and 11 other countries announced an agreement in respect of the Trans-Pacific Partnership ("**TPP**"). Canada and each participating country must ratify the TPP in their national legislatures. The TPP would lower tariffs on a wide range of Canadian products and benefit exporters across Canada in a number of sectors, including agriculture, wood and wood products, chemicals and plastics, and fish and seafood. An agreement would also bring enhanced and more predictable market access for Canada's services providers.

Extractive Sector Transparency Measures Act

The *Extractive Sector Transparency Measures Act* ("**ESTMA**"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state owned entities, including employees and public office holders, made Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Payments to aboriginal governments are exempt from reporting obligations until 2017. Failure to comply with the reporting obligations under ESTMA are punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $9,000,000 in total liability.

Competition

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

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids and sulphur production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Operations not on Crown lands and subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

From time to time the governments of the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and natural gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

Saskatchewan Royalties

With respect to production obtained from Crown lands in the Province of Saskatchewan, the amount payable as a royalty in respect of crude oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the price of the oil. For both Crown royalty and freehold production tax purposes, crude oil is categorized by oil type as either "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". Additionally, the oil in each category is subdivided according to the conventional royalty and production tax classifications as either "fourth tier oil", "third tier oil", "new oil", or "old oil" depending on the finished drilling date of a well. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after February 9, 1998 and before October 1, 2002, and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded water flood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for old oil, new oil and third tier oil, and 250 m^3 per month for fourth tier oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5 percent for all fourth tier oil, 10 percent for heavy oil that is third tier oil or new oil, 12.5 percent for southwest designated oil that is third tier oil or new oil, 15 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20 percent for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30 percent for all fourth tier oil, 25 percent for heavy oil that is third tier oil or new oil, 35 percent for southwest designated oil that is third tier oil or new oil, 35 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45 percent for old oil.

Similarly, the amount payable as a royalty in respect of natural gas in the Province of Saskatchewan depends on the vintage of the gas, the type of gas production, the quantity of gas produced in a month, and the price of the gas. For both Crown royalty and freehold production tax purposes, natural gas is categorized as either non-associated gas or associated gas, the former being produced from gas wells and the latter being produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as either “fourth tier gas”, “third tier gas”, “new gas”, or “old gas” depending on the finished drilling date of the respective well. The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government (effective February 1, 2012), the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties. Subject to certain restrictions, the operator may elect to use either a prescribed reference price determined monthly by SER, or a reference price based on the operator’s average gas price in a month. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on associated gas is less than on non-associated natural gas.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act*, *2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations*, *2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, *2012* which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3 per month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5 percent for all fourth tier gas, 15 percent for third tier or new gas, and 20 percent for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30 percent for all fourth tier gas, 35 percent for third tier and new gas, and 45 percent for old gas. The current regulatory scheme provides for certain differences with respect to the administration of fourth tier gas which is associated gas.

Approximately one-fifth of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the Crown. With respect to production from lands other than Crown lands, the tax levied in respect of freehold oil and gas production in the Province of Saskatchewan is determined by reducing the Crown royalty rate that would otherwise be payable if the lands were Crown lands by a fixed amount. Currently, this reduction ranges from 6.9% to 12.5% depending on the classification of the oil or gas.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards apply to all existing licensed wells and facilities as of July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 10 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Saskatchewan Incentives

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs.

The *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* provides reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate.

The *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* provides reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells.

The *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* provides reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate.

The *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* provides for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate.

The *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved water flood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations.

The *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* provides lower Crown royalty and freehold tax determinations based in part on the profitability of EOR Program projects during and subsequent to the payout of the EOR Program operations.

The *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* provides a Crown royalty of 1% of gross revenues on EOR Program projects pre-payout and 20% of EOR Program operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR Program projects.

The *Royalty/Tax Regime for High Water-Cut Oil Wells* is designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

Current Alberta Royalties

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

The current royalty regime was introduced by the Government of Alberta on October 25, 2007, and became effective January 1, 2009 and was subsequently modified in January of 2011 (the "**Royalty Framework**"). The Royalty Framework is structured separately for natural gas, conventional oil and oil sands. Natural gas royalties are calculated based on a sliding-scale formula that considers quantity of production and the price of natural gas; currently, royalty rates for natural gas range from 5% to 36%. Producers in Alberta can subtract allowable costs for gathering, compressing and processing the province's share of the natural gas from the gross royalty that would otherwise be payable. Further, there is a 5% maximum royalty rate on the first 12 production months, 50,000 barrels of oil production or 500 million cubic feet (MMcf) of gas production from a well, whichever is reached first.

For conventional oil, royalties are calculated on a sliding-scale formula that considers the quality of the oil, the quantity of production and the price of oil. Currently, royalty rates for conventional oil range from 0% to 40%.

The Royalty Framework also implemented a sliding rate formula based on both the commodity price of the gas and well production. The natural gas royalty formula also provides a reduction based on the measured depth of the well below 2,000 metres as well as the acid gas content of the produced gas. Subject to certain available incentives (discussed below), effective from the January 2011 production monthly royalty rates for natural gas production under the Royalty Framework range from a base rate of 5% to a cap of 36%. The royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral tax. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Crown. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is four percent of revenues reported from fee simple mineral title properties.

Current Alberta Incentives

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. This program encourages the injection of fluids such as hydrocarbons, carbon dioxide, nitrogen, chemicals and other approved substances for the recovery of additional oil.

The *Natural Gas Deep Drilling Regulation* 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 has been retained under the new Royalty Framework. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy determines which projects qualify for the IETP, as well as the level of support that will be provided. The deadline for the IETP's fifth round of applications was November 15, 2009.

On March 3, 2009, the Government of Alberta announced the New Well Royalty Reduction (the "**NWRR**") incentive program. The *New Well Royalty Reduction Regulation* provides that the NWRR will be available to qualifying wells that commence or recommence producing conventional oil or natural gas between April 1, 2009 and March 31, 2011. Pursuant to the *New Well Royalty Reduction Regulation*, the NWRR reduces royalties on production from qualifying wells 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 first 7949 cubic metres of eligible oil or oil equivalent is produced, the date the well becomes part of a Project under the *Oil Sands Royalty Regulation, 2009*, or March 31, 2012, whichever occurs 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 will become a permanent feature of Alberta's royalty regime. The NWRR is now referred to as the New Well Royalty Rate as it provides for a 5% royalty from the outset, as opposed to reducing an existing royalty to 5%. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.

In addition, on May 27, 2010, the Government of Alberta announced further initiatives to stimulate investment in emerging resources and technologies. The Shale Gas New Well Royalty Rate ("**SGNWRR**") reduced royalties on production from qualifying wells to a maximum royalty rate of 5% for 36 production months, with no limitation on volume. The Coalbed Methane New Well Royalty Rate ("**CMNWRR**") reduced royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 36 production months from date of first production or the date that the first 11,924 cubic metres of oil equivalent is produced. The Horizontal Gas New Well Royalty Rate ("**HGNWRR**") reduced 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 7949 cubic metres of oil equivalent is produced. Finally, the Horizontal Oil New Well

Royalty Rate ("**HONWRR**") reduced royalties on production from qualifying wells to a maximum royalty rate of 5% until the prescribed time or volume limit is met.

The NWRR applies to wells under the Royalty Framework. 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 run concurrently. In relation to natural gas wells eligible for both the NWRR and the Natural Gas Deep Drilling Program ("**NGDDP**") and any of the 5% royalty rates, including the NWRR, the HGNWRR, the CMNWRR or the SGNWRR, 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 reduces the royalty reduction that is available for wells under the EOR Program and the IETP.

The implementation of changes to royalties could have a negative impact on net earnings, funds from operations, cash flow from operating activities, operating netbacks, and reserve values, which could create uncertainty as to the recoverability of the carrying value of the Corporation's petroleum and natural gas assets.

New Alberta Royalty Regime

On January 29, 2016, the Alberta Government announced that it will adopt the recommendations of the Royalty Review Advisory Panel from the "Alberta at a Crossroads, Royalty Review Advisory Panel Report" (the "**Royalty Report**") to modernize Alberta's royalty framework.

The Royalty Report is extensive and recommends a new modernized royalty framework emulating a "revenue minus costs" approach. Further, the Royalty Report provides a harmonized royalty strategy across all hydrocarbons, aimed at rewarding innovation, efficiency and low-cost producers, while leaving oil sands royalties substantively as-is but with more transparency and financial reporting. The new modernized royalty framework ("**MRF**") requires a "Calibration Period" to finalize specific formulas and set up procedures for implementation. Those key formulaic and final inputs, including specific royalty rates, are scheduled to be released by the Calibration Period Committee on or before March 31, 2016.

The stated goal of the MRF is to create a simpler, more transparent and efficient royalty system that encourages investment, creates jobs, and enhances economic activity in Alberta. The MRF is divided by industry segments: conventional, unconventional, oil sands and value-added upgrading. First, all hydrocarbons (crude oil, liquids and natural gas) will be subject to a harmonized "revenue minus costs" approach with changes only applying to new wells spud in 2017 and thereafter (for wells drilled prior to December 31, 2016, existing royalties will remain in effect for 10 years). Second, Alberta's oil sands royalty framework will remain unchanged, subject only to new measures to increase transparency with respect to a project's allowable capital costs and financial reporting. Third, the Royalty Report recommends consideration of certain value-added partial upgrading investments.

The Province of Alberta will adopt the MRF in respect of crude oil, liquids and natural gas. The MRF will only apply to new wells spud after the implementation date of the framework (2017), provided, however, that a sunset provision will be established to transition exempt wells into the MRF 10 years from the implementation date of the MRF. The MRF will adopt a single royalty structure, with no differentiation between produced substances, under which royalty rates are calculated based on a total review of a blend of all hydrocarbon products, and all metrics are based in dollars.

A proxy "revenue minus costs" structure will be undertaken by the adoption of a Drilling and Completion Cost Allowance formula, based on vertical depth and horizontal length, under which average drilling costs for new wells will be estimated by proxy. A flat royalty of 5% will be instituted on early production revenue up to the point of payout (payout achieved when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance). Upon payout, elevated royalty rates will be paid on subsequent production. The existing production formula will be modified to provide that declining royalties based on production rates will be triggered only during the mature phase of a well's life cycle (i.e. once production drops below a set Maturity Threshold, as determined by a calibration team, royalty rates will be adjusted downward). Finally, an updated proxy cost formula will be implemented annually for the determination of the Drilling and Completion Cost Allowance.

Key attributes of the MRF include:

- A Capital Cost Index to track year-over-year inflationary or deflationary changes, and adjust the Drilling and Completion Cost Allowance annually based on the set Capital Cost Index will be established.

- The Index is to be set to 100 in 2017, and will "float" depending on changes in industry costs. In years following, the derivation and public announcement of the Alberta Capital Cost Index will be made by March 31 for application on April 1 of the same year.

- Carbon levies relating to capital cost expenditures will be captured within the Capital Cost Index, which will, by design, adapt over time.

- Following the annual update, the Capital Cost Index will apply to go-forward wells only (i.e. the Capital Cost will be fixed for each well).

As set out within the Royalty Report, the Government of Alberta intends to implement strategic programs to promote expanded production and programs aimed at enhanced hydrocarbon recovery and high risk experimental wells by March 31, 2016. The Government of Alberta has also indicated that it will extend the end date for the Natural Gas Deep Drilling Program and Emerging Research and Technology Initiative so as to cover wells drilled in 2016 and 2017.

It is not possible to predict what impact the implementation of the MRF and its resulting changes to royalties could have on the Corporation's net earnings, funds from operations, cash flow from operating activities, operating netbacks, and reserve values, which could create uncertainty as to the recoverability of the carrying value of the Corporation's petroleum and natural gas assets.

Manitoba Royalties

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

Producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated per production month. There is no freehold production tax payable on gas consumed as lease fuel.

Manitoba Incentives

The Government of Manitoba maintains a Drilling Incentive Program (the "**Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a holiday oil volume ("**HOV**") pursuant to which no Crown royalties or freehold production taxes are payable until the HOV has been produced. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area. On December 20, 2013, Manitoba announced that the Program had been revised and extended for the period from January 1, 2014 to December 31, 2018.

The *Vertical Well Incentive* provides licensees of a newly drilled, vertical development or exploratory well drilled less than 1.6 km from the nearest well cased for production from the same or a deeper zone, with a HOV of 500 m^3.

The *Exploration and Deep Well Incentive* provides licensees of a newly drilled exploratory well or deep development well with a HOV as follows: (i) non-deep exploratory well drilled more than 1.6 km from a well cased for production from the same or a deeper zone earns a HOV of 4,000 m^3; (ii) deep exploratory well drilled below the Birdbear Formation earns a HOV of 8,000 m^3, and (iii) deep development well completed for production in the Birdbear or deeper formation earns a HOV of 8,000 m^3.

The *Horizontal Well Incentive* provides licensees of horizontal wells drilled prior to January 1, 2018 with a HOV of 8,000 m^3.

The *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2018 with a HOV of 500 m^3, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 3 m^3 per operating day.

The *Pressure Maintenance Project Incentive* provides licensees with a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to injection of water or another substance in an approved new or modified pressure maintenance project. If a well is placed on injection before it has produced its HOV and within 5 years of the finished drilling date of the well, the exemption period is extended to 18 months.

The *Solution Gas Conservation Incentive* provides licensees with an exemption on Crown royalties and production taxes payable on gas captured from new solution gas conservation projects initiated and approved by the Direction after December 31, 2013. The exemption will apply from the project implementation date to December 31, 2018.

Under the Program, HOV accounts have been phased out as of January 1, 2015. Prior to that date, companies were able to assign a one-time maximum of 2,000 m^3 of HOV from their HOV account to vertical or horizontal wells drilled between January 1, 2014 and December 31, 2014. Effective January 1, 2014, companies were no longer able to assign HOV from a well to their HOV account or transfer HOV to another company.

The Program also implements a new minimum crown royalty rate of 3.0% and a minimum production tax rate of 1.0% payable during producing of HOV for wells drilled after December 31, 2013 and prior to January 1, 2019. The maximum Crown royalty and production tax rates apply during the production of HOV earned from the drilling of new wells and wells which have earned a marginal well major workover incentive during the period January 1, 2014 to December 31, 2018. The royalty payable is the lesser of the amount the well would have paid if a well was not producing holiday volume compared to the corresponding rates of 3% for a royalty or 1% for a freehold production tax.

Land Tenure

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

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80 percent of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Alberta also has a policy of “shallow rights reversion” which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. In 2013, Alberta Energy placed an indefinite hold on serving shallow rights reversion notices for leases and licences that were granted prior to January 1, 2009. Alberta Energy stated that it will provide the industry with notice if, in the future, a decision is made to serve shallow rights reversion notices.

Environmental Protection Requirements

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, or emissions of various substances produced in association with oil and natural gas operations, requirements with respect to oilfield waste handling and storage, habitat protection, and minimum setbacks of oil and gas activities from fresh water bodies. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Environmental laws may impose remediation obligations and costs on “persons responsible” with respect to contaminated property, including persons responsible for the substance causing the contamination, persons responsible for the release, past and present owners of the property, and occupiers of the property. 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, and in the suspension or revocation of necessary licences and approvals, as well as civil liability for damage caused by pollution. Certain environmental protection legislation may subject the Corporation to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge.

Federal

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

The Federal Government has signaled it will, inter alia, phase out subsidies for the oil and gas industry, which include allowing the use of the Canadian Exploration Expenses tax deduction only in cases of successful exploration activities, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change within 90 days of the United Nations 2015 Paris Climate Conference, which concluded on December 12, 2015 with the adoption of the Paris Agreement. These changes could affect earnings of companies operating in the oil and natural gas industry.

It is expected that any additional regulations eventually implemented by the Government of Canada will have an impact on the oil and gas industry as a whole, which could result in increased costs for the Corporation to comply with such legislation. In the meantime, the Corporation will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions, including any legislation or policies arising out of the Paris Agreement.

The U.S. Environmental Protection Agency ("**EPA**") is proceeding to regulate greenhouse gases under the Clean Air Act. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

Alberta

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* (the "**EPEA**") and the *Oil and Gas Conservation Act* ("**Alberta OGCA**"). The EPEA and the Alberta OGCA impose strict environmental standards with respect to releases of effluents and emissions, include reporting and monitoring obligations, and impose significant penalties for non-compliance. For example, regulations enacted under the EPEA target sulphur oxide and nitrous oxide emissions from oil and gas operations. On June 17, 2013, Alberta introduced the *Responsible Energy Development Act*, under which the Alberta Energy Regulator ("**AER**") superseded the Energy Resources Conservation Board ("**ERCB**") as the provincial energy regulator. On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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

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

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 percent of the province's oilsands resources and much of the Cold Lake oilsands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access.

The South Saskatchewan Regional Plan ("**SSRP**") was approved by the Government of Alberta on July 23, 2014 and became effective on September 1, 2014. The SSRP is the second regional plan developed under the ALUF and covers approximately 83,764 square kilometres and includes 44 percent of the province's population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, oil and gas companies must nonetheless minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. Freehold mineral rights will not be subject to this restriction. With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Saskatchewan

The Corporation has operations in Saskatchewan and, as such, is also subject to the Saskatchewan *Environmental Management and Protection Act, 2002* (the "**EMPA**") and *Oil and Gas Conservation Act* (the "**Saskatchewan OGCA**"). The EMPA and the Saskatchewan OGCA regulate and control harmful or potentially harmful activities and substances, any release of such substances to the air, water, or land, and remediation obligations in Saskatchewan. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require a screening or an environmental impact assessment under the provincial *Environmental Assessment Act*. With implementation anticipated shortly, Saskatchewan is currently working towards a new legal framework, the Saskatchewan Environmental Code, which aims to address specific activities and standards under current environmental legislation as well as introduce new regulations for the management of greenhouse gases.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards will apply to existing licensed wells and facilities on July 1, 2015

Manitoba

The Corporation owns oil and natural gas properties and related assets in Manitoba and, as such, is subject to the *Oil and Gas Act* which incorporates provisions related to the environment from *The Environment Act* and *The Surface Rights Act*. This legislation imposes obligations to protect, preserve and, where required, rehabilitate the environment and provides penalties in the event of non-compliance.

North Dakota

Spartan, through its wholly-owned subsidiaries, owns oil and natural gas properties and related assets in North Dakota in the United States. In North Dakota, the North Dakota Department of Health regulates practices in oil and gas exploration and production and enforces applicable laws to ensure protection of human health, safety and environmental health. The Environmental Health Division governs public health, air quality, waste management and water quality (surface and groundwater). The North Dakota Department of Health, Water Diversions regulates water injection.

Compliance with Environmental Legislation

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 Spartan to incur costs to remedy any such discharge not covered by Spartan's insurance. Although Spartan maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. Further, Spartan expects incremental future compliance costs in light of increasingly more complex environmental protection requirements, some of which may require the installation of emissions monitoring and measuring devices and the verification of emissions data.

Spartan believes it is in material compliance with environmental legislation at this time. Spartan 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. 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, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects.

Spartan is obligated to abandon, retire and reclaim wells, well sites and facilities in compliance with applicable environmental laws and regulations. As of December 31, 2015, Spartan has recorded in its financial statements decommissioning liabilities of $110.9 million. The decommissioning liability is anticipated to be funded by future cash flow as required. No abandonment expenses were incurred in 2015.

Other than decommissioning liabilities, ordinary course operational expenditures necessary to ensure environmental compliance and the employment cost of health, safety and environmental personnel and programs. Spartan is not aware of any environmental protection requirement that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its areas of operation.

Liability Management Rating Programs

Alberta

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

On May 1, 2013, the AER began to implement a three year program of changes to the LLR Program. Some of the important changes which were implemented through this three year process include:

- a 25 percent increase to the prescribed average reclamation cost for each individual well or facility (which increased a licensee's deemed liabilities);
- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which increased a licensee's deemed liabilities);
- a decrease in the industry average netback from a five-year to a three-year average (which affected the calculation of a licensee's deemed assets, as the reduction from five to three years resulted in the average being more sensitive to price changes); and
- a change to the present value and salvage factor, which increased to 1.0 for all active facilities from 0.75 for active wells and 0.50 for active facilities (which increased a licensee's deemed liabilities).

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

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

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**"). The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Social or Environmental Policies

The health and safety of employees, contractors and the public, as well as the protection of the environment, is of utmost importance to Spartan. To this end, the Corporation has instituted a comprehensive environmental policy to which it and its employees and contractors are required to adhere. Spartan 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, particularly relating to the environment, health and safety;
- operating consistent with industry codes, practices and guidelines;
- ensuring prompt, effective response and repair to emergency situations and environmental incidents;
- providing training to employees and contractors to ensure compliance with corporate safety and environmental rules and procedures; and
- communicating openly with members of the public regarding its activities.

Spartan believes that all employees have a vital role in achieving excellence in environmental, health and safety performance, which is best achieved through careful planning and the support and active participation of everyone involved. To further ensure that the Corporation achieves excellence in health and safety performance, an emergency response plan and a corporate safety policy have been implemented. Furthermore, the Corporation aligns itself with the best industry practices to ensure positive results.

RISK FACTORS

Spartan's business consists of the exploration and production of crude oil and natural gas projects, with properties in Saskatchewan, Alberta and Manitoba in Canada and in North Dakota in the United States. There are a number of inherent risks associated with the exploration and production of oil and gas reserves. Many of these risks are beyond the control of the Corporation. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Commodity Price Volatility

Spartan's results of operations and financial condition are dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices have fluctuated widely in the recent past and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond Spartan's control. Crude oil and natural gas prices are impacted by a number of factors including, but not limited to: the global supply of and demand for crude oil and natural gas; global economic conditions; the actions of the Organization of Petroleum Exporting Countries ("**OPEC**"); government regulation;

political stability; the ability to transport crude to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. In addition, significant growth in crude production volumes in western Canada and the northern United States has resulted in pressure on transportation and pipeline capacity, contributing to the widening of the light oil pricing differential between WTI and Cromer/WCS/Hardisty, resulting in fluctuations in the price of oil and natural gas. All of these factors are beyond Spartan's control and can result in a high degree of price volatility.

Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. Spartan's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between the Corporation's light/medium oil and heavy oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions; refining demand; the availability and cost of diluent used to blend and transport product; and the quality of the oil produced, all of which are beyond Spartan's control. See also "*Variations in Foreign Exchange Rates and Interest Rates*".

Fluctuations in the price of commodities and associated price differentials may impact the value of Spartan's assets, the Corporation's ability to maintain its business and to fund growth projects. Prolonged periods of commodity price depression and volatility may also negatively impact Spartan's ability to meet guidance targets and meet all of its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves, including delay or cancellation of existing or future drilling or development programs or curtailment in production.

Any material or sustained decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. Spartan might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities.

Crude oil and natural gas 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 world economies and OPEC actions. 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, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Spartan conducts regular assessments of the carrying value of its assets in accordance with International Financial Reporting Standards. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of the Corporation's assets may be subject to impairment.

Capital Lending Markets

As a result of recent economic uncertainties in the oil and gas industry and, in particular, the lack of risk capital available to the junior resource sector, the Corporation, along with other junior resource entities, may have reduced access to bank debt and to equity. As future capital expenditures will be financed out of funds generated from operations, bank borrowings, if available, and possible issuances of debt or equity securities, the Corporation’s ability to fund future capital expenditures is dependent on, among other factors, the overall state of lending and capital markets and investor and lender appetite for investments in the energy industry, generally, and the Corporation’s securities in particular.

To the extent that external sources of capital become limited, unavailable or available only on onerous terms, the Corporation’s ability to invest and to maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Markets and Marketing

The marketability and price of crude oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. Spartan’s ability to market its crude oil and natural gas may depend upon its ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets. Spartan may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting 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 gas business.

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 Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation’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 Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation 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 Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances 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. 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 personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation 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 Corporation could incur significant costs. 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 may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Credit Facility Risks

The Corporation currently has the Credit Facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility may impose operating and financial restrictions on the Corporation that could include restrictions on the repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facility. This could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

Substantial Capital Requirements

Spartan anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the current commodity price environment exposes the Corporation to additional access to capital risk. 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 Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Additional Funding Requirements

Spartan's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation 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 Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of depressed oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Future Sales of Common Shares

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

Finding, Developing and Acquiring Petroleum and Natural Gas Reserves on an Economic Basis

Petroleum and natural gas reserves naturally deplete as they are produced over time. The success of the Corporation's business is highly dependent on its ability to acquire and/or discover new reserves in a cost efficient manner. Substantially all of the Corporation's cash flow is derived from the sale of the petroleum and natural gas reserves it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. The Corporation mitigates this risk by employing a qualified and experienced team of petroleum and natural gas professionals, operating in geological areas in which prospects are well understood by management and by closely monitoring the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation'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.

Project Risks

Spartan manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

Spartan's ability to execute projects and market oil and natural gas depends upon numerous factors beyond Spartan's control, including:

- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of processing capacity;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and gas industry by various levels of government and governmental agencies.

Because of these factors, Spartan could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. Spartan competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Spartan's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Spartan's ability to increase its 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 other 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 and storage. Competition may also be presented by alternate fuel sources.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be materially adversely affected. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

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, which may be amended from time to time. See "*Industry Conditions*" above. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Fiscal and Royalty Regime

In addition to federal regulation, each province has legislation and regulations which govern land tenure, drilling and construction permits, royalties, production rates, environmental protection and other matters. See "*Industry Conditions*" above. 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 well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

Alberta announced a new royalty regime in January 2016 and such regime changes are expected to come into effect in 2017. See "*Industry Conditions*" above. The royalty regime in Alberta, Saskatchewan and any other jurisdictions in which the Corporation's oil and natural gas assets are located may be subject to further review and changes which could adversely impact the Corporation's financial condition and operations.

Environmental

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The 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 of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. 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 governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Although Spartan maintains insurance consistent with prudent industry practice, it 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, Spartan'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 Spartan.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". In December 2011, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. On December 12, 2011, Canada formally withdrew from the Kyoto Protocol. The impact of Canada's withdrawal from the Kyoto Protocol on prior GHG emission reduction initiatives is uncertain.

Spartan's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. Spartan may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions – Environmental Protection Requirements*" above.

In December 2015, at the United Nations Paris Climate Conference, Canada became a signatory to an agreement which has set broad goals to, among other things, limit global climate change to not more than 2 degrees Celsius (or less), preparing, maintaining and publishing national greenhouse gas reduction targets and creating a "carbon-neutral" world by 2050. The Federal Government has committed to establishing a pan-Canadian framework for combating climate change within 90 days of the Paris Climate Conference, which concluded on December 12, 2015. It is not possible to predict what this framework will be, or the impact it will have on the Corporation and its operations and financial conditions.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/U.S. dollar exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators. To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract. Furthermore, an increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation 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

Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Corporation 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 Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to U.S. dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the U.S. dollar; however, if the Canadian dollar declines in value compared to the U.S. dollar, the Corporation will not benefit from the fluctuating exchange rate. See *"Other Oil and Gas Information - Forward Contracts and Marketing*" for additional information.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves.

The reserve and associated cash flow information set forth herein are 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, production rates, ultimate reserve 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 materially from actual results. 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 associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Spartan'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. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

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.

Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. 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.

There are numerous uncertainties inherent in estimating quantities of resources, including many factors beyond the Corporation's control. No assurance can be given that the indicated level of resources will be realized. In general, estimates of recoverable resources are based upon a number of factors and assumptions made as of the date on which the resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable natural gas and the classification of such resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

Geological risking of prospective resources addresses the probability of success for the discovery of petroleum; this risk analysis is conducted independently of probabilistic estimates of petroleum volumes and without regard to the chance of development. Principal risk elements of the petroleum system include: (i) trap and seal characteristics; (ii) reservoir presence and quality; (iii) source rock capacity, quality and maturity; and (iv) timing, migration and preservation of petroleum in relation to trap and seal formation. Geological risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows 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.

Reserve Replacement

Spartan's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Spartan successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Spartan may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Spartan's reserves will depend not only on Spartan's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Spartan's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Insurance

Spartan's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation 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 any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Spartan will not have insurance to protect against the risk from terrorism.

Management of Growth

Spartan may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

Spartan's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation 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 Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Western Canada. Spartan 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 Corporation's business, financial condition, results of operations and prospects.

Dividends

Spartan has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the Board of Directors considers relevant.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of this Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

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 enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas 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 the Corporation.

Third Party Credit Risk

Spartan may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation’s business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner’s willingness to participate in the Corporation’s ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Reliance on Key Personnel

Spartan’s success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation’s business, financial condition, results of operations and prospects. Spartan does not have any key person insurance. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in Western Canada. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

United States

Spartan, through its wholly-owned subsidiaries, owns oil and natural gas properties and related assets in North Dakota in the United States. Spartan's oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Spartan's operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Spartan cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation’s business, financial condition, results of operations and cash flows.

Forward-Looking Information May Prove to be Inaccurate

Investors are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions and uncertainties are found in this Annual Information Form under the heading “*Forward-Looking Statements*” above.

Hydraulic Fracturing

The proliferation of the use of hydraulic fracturing as a recovery technique employed in oil and natural gas drilling has given rise to increased public scrutiny of its environmental aspects, particularly with respect to its potential impact on local aquifers. Spartan utilizes hydraulic fracturing in a portion of the light oil wells it drills and completes. Negative public perception of hydraulic fracturing may place pressure on governments in the jurisdictions where Spartan operates to implement additional regulatory requirements or limitations on the utilization of hydraulic fracturing, which in turn could restrict Spartan's operations and increase its costs.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data and Other Information for the Financial Year Ended December 31, 2015

The reserves data herein is based upon a report prepared by Sproule, dated February 18, 2016, with an effective date of December 31, 2015 (the "**Spartan Reserve Report**") evaluating the crude oil, natural gas liquids and natural gas reserves of Spartan as at December 31, 2015. The reserves data set forth below is based upon an evaluation of the Spartan Reserve Report. The Spartan Reserve Report summarizes the crude oil, natural gas liquids and natural gas reserves of Spartan and the net present values of future net revenue for these reserves using forecast prices and costs. The Spartan Reserve Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The following tables provide summary information presented in the Spartan Reserve Report effective December 31, 2015 and based on the Sproule December 31, 2015 price forecast.

As of the date hereof, Spartan's reserves are located in the provinces of Alberta, Saskatchewan and Manitoba in Canada and in North Dakota in the United States.

The Report on Reserves Data by Sproule and the Report of Management and Directors on Oil and Gas Disclosure are attached as Appendix A and Appendix B, respectively, to this Annual Information Form.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the Corporation's reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Spartan's crude oil, natural gas liquids and conventional natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, conventional natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

		Light and Medium Crude Oil		Conventional Natural Gas (associated & non-associated)		Natural Gas Liquids		Barrels of Oil Equivalent	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
		(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)
Proved									
	Developed Producing	13,498	11,960	3,907	3,490	456	411	14,605	12,952
	Developed Non-Producing	248	209	271	230	17	14	310	262
	Undeveloped	9,246	8,407	713	642	113	103	9,478	8,617
Total Proved		**22,992**	**20,576**	**4,891**	**4,362**	**586**	**528**	**24,394**	**21,831**
Probable		16,814	15,048	2,845	2,533	355	320	17,642	15,790
Total Proved plus Probable		**39,806**	**35,624**	**7,736**	**6,896**	**941**	**848**	**42,036**	**37,621**

Notes:
(1) Columns may not add due to rounding.
(2) Conventional natural gas volumes include solution gas volumes associated with Spartan's light and medium crude oil reserves.
(3) Conventional natural gas is converted to a BOE at a ratio of six thousand standard cubic feet to one barrel of oil.

	Net Present Value of Future Net Revenue										
	Before Income Tax Discounted at Various Rates					After Income Tax Discounted at Various Rates					BT Unit Value
Entity Description	0% M$	5% M$	10% M$	15% M$	20% M$	0% M$	5% M$	10% M$	15% M$	20% M$	
Proved											
Producing	463,684	380,340	318,878	273,458	239,152	463,684	380,340	318,878	273,458	239,152	24.62
Developed Nonproducing	8,798	6,022	4,349	3,289	2,584	8,798	6,022	4,349	3,289	2,584	16.61
Undeveloped	187,314	187,314	136,021	100,273	74,775	247,527	178,695	130,644	96,830	72,519	15.79
Total Proved	**734,225**	**573,677**	**459,248**	**377,020**	**316,510**	**720,008**	**565,058**	**453,870**	**373,577**	**314,254**	**21.04**
Total Probable	749,968	515,671	377,176	289,551	230,553	556,019	382,444	280,969	217,397	174,835	23.89
Total Proved plus Probable	**1,484,193**	**1,089,348**	**836,425**	**666,571**	**547,063**	**1,276,027**	**947,501**	**734,840**	**590,974**	**489,090**	**22.23**

Notes:
(1) Utilizes Sproule's price forecast as of December 31, 2015 as detailed below.
(2) Values are net of abandonment liabilities.
(3) Columns may not add due to rounding.
(4) BT Unit Value is the unit value before income tax discounted at 10% per year.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	CAPITAL DEVELOPMENT COSTS (M$)	ABANDONMENT/ OTHER COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAX (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved	1,908,524	232,288	658,974	209,897	73,140	734,225	14,217	720,008
Proved Plus Probable	3,448,932	419,085	1,112,663	341,659	91,331	1,484,193	208,166	1,276,027

FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX[(2)] (discounted at 10%/year ($/BOE)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	458,608	21.11
	Conventional Natural Gas (including associated by-products)	641	5.83
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	835,306	22.29
	Conventional Natural Gas (including associated by-products)	1,119	7.49

Notes:
(1) Columns may not add due to rounding.
(2) Unit values are based on net reserve volumes.

Reserve Categories

Reserves are estimated remaining quantities of crude oil and conventional natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) 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.

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

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

   (i) 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.

   (ii) 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.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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) 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 subdivide 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.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Interests in Reserves, Production, Wells and Properties

An issuer's interest in reserves, production, wells and properties can be reported in a number of ways:

(a) "**gross**" means: (i) in relation to an issuer'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 issuer; (ii) in relation to wells, the total number of wells in which an issuer has an interest; and (iii) in relation to properties, the total area of properties in which an issuer has an interest.

(b) "**net**" means: (i) in relation to an issuer'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; (ii) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (iii) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer.

(c) "**working interest**" means the percentage of undivided interest held by an issuer in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the issuer the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Description of Exploration and Development Wells and Costs

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural 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: (i) gain access to and prepare well locations for drilling, including surveying 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; (ii) 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 wellhead assembly; (iii) 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 (iv) 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 natural 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: (i) 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"); (ii) 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; (iii) dry hole contributions and bottom hole contributions; (iv) costs of drilling and equipping exploratory wells; and (v) costs of drilling exploratory type stratigraphic test wells.

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

"**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.

Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Spartan Reserve Report were Sproule's forecasts, as at December 31, 2015, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma 40° API ($US/bbl)	Canadian Light Sweet 40° API ($Cdn/bbl)	Cromer LSB 35° API ($Cdn/bbl)	Natural Gas AECO ($Cdn/MMbtu)	Edmonton Pentanes Plus ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Operating Cost Inflation Rate %/year	Capital Cost Inflation Rate %/year	Exchange Rate ($US/$CDN)
2016	45.00	55.20	54.20	2.25	59.10	39.09	0	0	0.75
2017	60.00	69.00	68.00	2.95	73.88	51.43	0	4.0	0.80
2018	70.00	78.43	77.43	3.42	83.98	58.46	1.5	4.0	0.83
2019	80.00	89.41	88.41	3.91	95.73	66.64	1.5	4.0	0.85
2020	81.20	91.71	90.71	4.20	98.19	68.35	1.5	1.5	0.85
2021	82.42	93.08	92.08	4.28	99.66	69.38	1.5	1.5	0.85
2022	83.65	94.48	93.48	4.35	101.16	70.42	1.5	1.5	0.85
2023	84.91	95.90	94.90	4.43	102.68	71.48	1.5	1.5	0.85
2024	86.18	97.34	96.34	4.51	104.22	72.55	1.5	1.5	0.85
2025	87.48	98.80	97.80	4.59	105.78	73.64	1.5	1.5	0.85
2026	88.79	100.28	99.28	4.67	107.37	74.74	1.5	1.5	0.85
Thereafter	Escalation Rate of 1.5%								

Weighted average historical prices realized for the year ended December 31, 2015, after hedging, was $50.71/Bbl for crude oil, $16.89/Bbl for NGLs and $2.49/Mcf for natural gas.

Estimated future abandonment and reclamation costs related to a working interest have been taken into account by Sproule for all entities assigned reserves within a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment and reclamation costs. No allowance was made, however, for the reclamation or the abandonment of any major facilities. The forecast price and cost assumptions assume the continuance of current laws and regulations.

Reconciliations of Changes in Reserves and Future Gross Revenue

The following sets out the reconciliation of Spartan's gross reserves based on forecast prices and costs by principal product type:

RECONCILIATION OF
COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil			Heavy Crude Oil			Natural Gas Liquids		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)
December 31, 2014	24,212	13,263	37,474	-	-	-	461	243	703
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	1,161	2,428	3,589	-	-	-	5	7	12
Infill Drilling	2,230	1,938	4,168	-	-	-	23	14	37
Technical Revisions	(1,195)	(1,138)	(2,333)	-	-	-	201	94	295
Acquisitions	48	70	117	-	-	-	1	1	1
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(495)	166	(328)	-	-	-	(10)	(4)	(14)
Production	(2,968)	-	(2,968)	-	-	-	(94)	-	(94)
December 31, 2015	22,992	16,814	39,806	-	-	-	586	355	941

	Associated and Non-Associated Conventional Natural Gas			Natural Gas Solution		
Factors	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved + Probable (Mmcf)	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved + Probable (Mmcf)
December 31, 2014	592	209	801	4,944	2,724	7,668
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	25	38	63
Infill Drilling	-	-	-	108	74	182
Technical Revisions	77	(29)	48	324	(102)	222
Acquisitions	-	-	-	6	3	9
Dispositions	-	-	-	-	-	-
Economic Factors	(32)	(11)	(43)	(113)	(61)	(174)
Production	(144)	-	(144)	(896)	-	(896)
December 31, 2015	493	169	662	4,398	2,676	7,074

Reserves Data

Undeveloped Reserves

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to Spartan's assets for the years ended December 31, 2014 and 2015 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross
Prior to December 31, 2014	194	348	-	-	209	532	1	2
December 31, 2014	4,593	9,258	-	-	368	721	57	93
December 31, 2015	2,216	9,246	-	-	77	713	16	113

Probable Undeveloped Reserves

	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross
Prior to December 31, 2014	83	205	-	-	82	381	-	1
December 31, 2014	4,094	7,598	-	-	413	849	61	91
December 31, 2015	3,939	10,938	-	-	86	870	16	129

In general, once proved and/or probable undeveloped reserves are identified, they are scheduled into Spartan's development plans. Spartan plans to develop its proved and probable undeveloped reserves within three years. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (including production anomalies, such as water breakthrough, accelerated depletion);
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- availability and allocation of capital based on other opportunities available to Spartan in any given year;
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties

The process of evaluating reserves is inherently 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 reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates 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 government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Spartan does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Spartan's future net revenue attributable to the reserve categories noted below:

	Forecast Prices and Costs (M$)	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2016	$46,799	$66,267
2017	$43,764	$69,596
2018	$61,836	$93,794
2019	$30,106	$61,460
2020	$26,916	$50,065
Thereafter	$475	$475
Total Undiscounted	$209,897	$341,659
Total Discounted at 10%	$170,500	$274,230

The future development costs are capital expenditures required in the future for Spartan to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $209.9 million for proved reserves and $341.7 million for proved plus probable reserves (in each case based on forecast prices and costs).

On an ongoing basis, Spartan will use internally generated cash flow from operations, debt and new equity issues, if available on favourable terms, to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for Spartan.

Other Oil and Gas Information

Principal Properties

Southeast Saskatchewan

The southeast Saskatchewan properties consist of approximately 153,313 net acres of land focused primarily on conventional open-hole horizontal wells drilled on Mississippian oil plays, including the Frobisher, Alida, Souris Valley, Tilston and Midale formations. Of this acreage, approximately 16,600 is prospective for drilling fracture stimulated horizontal wells in the Midale formation. 53 gross (44.5 net) horizontal wells were drilled by Spartan in Southeast Saskatchewan in 2015, including 5 gross (4.9 net) fracture stimulated Midale wells. Spartan owns producing infrastructure across its southeast Saskatchewan asset base, including gathering lines, multi-well batteries, water disposal and an interest in the Nottingham gas processing plant. The Corporation anticipates that its 2016 capital program will be primarily focused on the development of its southeast Saskatchewan assets.

West Central Saskatchewan

The west central Saskatchewan property includes approximately 11,343 net acres of land targeting the Viking formation. In 2015, Spartan drilled 13 gross (12.0 net) horizontal wells with a 100% success rate. At December 31, 2015, Spartan had completed 6 gross (6.0 net) of these Viking wells and put them on production. Spartan completed the remaining 7 gross (6.0 net) wells in the first quarter of 2016. As of the date hereof, Spartan does not intend to drill any additional wells in west central Saskatchewan in 2016.

Alberta

The Alexander property is located northwest of Edmonton in Townships 55-56, Ranges 26-27, W4M. The Corporation holds approximately 31,960 net acres of land in Alberta. Since 2011, the Corporation has drilled, cased completed and tied-in six successful oil wells in the Detrital zone on the lands. The Corporation did not drill any wells in Alberta in 2015 and does not plan to drill additional wells in 2016. Spartan also owns and operates a gas processing plant and oil battery in the area complete with an amine plant and salt water disposal facilities.

Manitoba

The Manitoba property includes approximately 2,266 net acres of land in the Waskada area of southwest Manitoba targeting the Spearfish/Amaranth formation. The Corporation did not drill any wells in Waskada in 2015 and does not plan to drill additional wells in 2016.

North Dakota

The North Dakota property includes 6,064 net acres of land in Renville County, North Dakota. In late 2010, Renegade drilled a horizontal well targeting the Bakken formation. The horizontal well encountered hydrocarbons in the Bakken formation proving a new pool, however, there has not been further development of this acreage since 2010. The Corporation did not drill any wells in North Dakota in 2015 and does not plan to drill additional wells in 2016.

Oil and Gas Wells

The following table sets forth the number and status of wells in which Spartan had a working interest as at December 31, 2015.

	Producing				Non-Producing (3)			
	Oil		Gas		Oil		Gas	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Alberta	20	18.3	12	6.8	43	37.3	42	25.9
Saskatchewan	1,418	1,091.3	-	-	909	656.7	2	1.2
Manitoba	4	3.0	-	-	2	1.8	-	-
Total	1,442	1,112.6	12	6.8	954	695.8	44	27.1

Notes:
(1) "Gross" means total number of wells in which we hold an interest.
(2) "Net" means the aggregate of the percentage working interests of Spartan in the gross wells.
(3) "Non-Producing" means wells that may or may not have been previously on production and the date production will be obtained from these wells is uncertain.

Properties with No Attributable Reserves

The following table summarizes Spartan's undeveloped land holdings (in acres) as at December 31, 2015.

	Unproved Properties		
	Gross(1)	Net(2)	Net Acres Expiring Within One Year
Canada	118,912	106,781	14,744
United States	9,213	4,929	3,858
Total	**128,125**	**111,710**	**18,602**

Notes:
(1) "Gross" means the total number of acres in which we hold an interest.
(2) "Net" means the aggregate of the percentage working interests of Spartan in the gross acres.

Forward Contracts and Marketing

Spartan markets the majority of its production on month to month contracts on spot market terms and as at the date hereof has no forward commodity contracts in place.

Additional Information Concerning Abandonment and Reclamation Costs

Spartan estimates well abandonment and reclamation costs on an area by area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

Estimated abandonment and reclamation costs for wells that have been assigned reserves were included in the Spartan Reserve Report as a deduction in determining future net revenue. The total estimated abandonment and reclamation costs in respect of proved reserves using forecast prices with respect to 905 net wells is $73.1 million undiscounted ($13.2 million using a 10% discount rate). All of such amounts were deducted as abandonment and reclamation costs in estimating future net revenue of Spartan in respect of proved reserves as disclosed above. No allowance for salvage value was included in these costs. The total proved plus probable abandonment and reclamation costs are $91.3 million (undiscounted) and $11.0 million (discounted at 10%) for 1,070 net wells. The following tables set forth the timing of abandonment and reclamation costs deducted in the estimation of Spartan's future net revenue:

Forecast Prices and Costs (Total Proved) ($000)

Year	Abandonment Costs (Undiscounted)
2016	-
2017	-
2018	-
Thereafter	73,140
Total Undiscounted	73,140
Total Discounted at 10%	13,237

Forecast Prices and Costs (Total Proved & Probable) ($000)

Year	Abandonment Costs (Undiscounted)
2016	-
2017	-
2018	-
Thereafter	91,331
Total Undiscounted	91,331
Total Discounted at 10%	10,995

Expected reclamation costs for surface leases, reclamation and remediation costs for facilities and abandonment costs for wells not assigned reserves are not included in the Spartan Reserve Report as deductions in arriving at future net revenue. Spartan has estimated expected total costs related to these of $63.2 million undiscounted ($26.5 million discounted at 10%) as of December 31, 2015. Decommissioning liabilities as recorded in the December 31, 2015 annual financial statements will not equal the aggregate of the amounts described above as such liabilities are calculated using a different discount rate.

Tax Horizon

Depending on levels of production, commodity prices, acquisitions and capital expenditures, Spartan will not pay current income taxes until at least 2021.

Costs Incurred

The following tables summarize by Spartan's property acquisition costs, exploration costs and development costs for the year ended December 31, 2015:

	Canada ($M)
Property Acquisition Costs	
Proved Properties	1,647
Unproved Properties	-
Exploration Costs	-
Development Costs	66,623
Total:	68,270

Capital Expenditures

The following table summarizes capital expenditures related to Spartan's activities for the year ended December 31, 2015:

	($000)
Land/Seismic	1,553
Drilling and Completion	41,993
Equipment and Facilities	21,437
Capitalized G&A Expenses/Other	1,640
Plus: Acquisitions	1,647
Net Expenditures	68,270

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Spartan participated during the year ended December 31, 2015:

Canada	**Exploration**		**Development**	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Crude Oil	-	-	65	55.5
Conventional Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test Wells	-	-	-	-
Dry	-	-	1	1.0
Total:	-	-	66	56.5

See "*Principal Properties*" above for a description of Spartan's exploration and development plans.

Production Estimates

The following table sets forth the volume of Spartan's gross working interest production estimated for the year ending December 31, 2016, as evaluated by Sproule which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Information*".

	Light and Medium Crude Oil (Including C5+) *(Bbls/d)*	**Heavy Crude Oil** *(Bbls/d)*	**Conventional Natural Gas** *(Mcf/d)*	**Natural Gas Liquids** *(Bbls/d)*	**BOE** *(BOE/D)*
Proved					
Alberta	226	-	449	22	323
Saskatchewan					
Southeast	6,292	-	1,803	236	6,828
West Central	1,290	-	1	-	1,291
Manitoba	10	-	-	-	10
Total Proved	7,818	-	2,253	258	8,452
Probable					
Alberta	12	-	24	1	17
Saskatchewan		-			
Southeast	1,803	-	333	47	1,905
West Central	119	-	1	-	120
Manitoba	6	-	-	-	6
Total Probable	1,940	-	358	48	2,048
Total Proved plus Probable	9,759	-	2,612	306	10,500

Production History

The following tables summarize certain information in respect of Spartan's production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2015 Quarter Ended			
	Q4 Dec. 31	**Q3 Sept. 30**	**Q2[1] June 30**	**Q1 March 31**
Average Daily Production[1]				
Oil (Bbls/d)	8,411	7,382	8,015	8,732
Liquids (Bbls/d)	413	296	136	186
Gas (Mcf/d)	2,968	2,182	3,353	2,903
Combined (BOE/D)	9,319	8,042	8,710	9,402
Average Price Received				
Oil ($/Bbl)	46.38	50.24	60.16	46.60
Liquids ($/Bbl)	14.62	15.22	20.63	21.99
Gas ($/mcf)	2.49	2.65	2.27	2.60
Combined ($/BOE)	43.30	47.40	56.56	44.52
Royalties Paid				
Oil ($/Bbl)	6.23	6.75	8.18	6.19
Liquids ($/Bbl)	1.15	0.82	1.87	2.08
Gas ($/mcf)	0.24	0.21	0.21	0.25
Combined ($/BOE)	6.44	7.67	8.77	6.83
Operating & Transportation Expenses				
Oil ($/Bbl)	14.87	16.01	14.84	17.48
Liquids ($/Bbl)	0.73	0.64	0.25	0.37
Gas ($/mcf)	0.87	0.79	1.03	0.97
Combined ($/BOE)	16.48	17.44	16.13	18.82
Netback Received[2]				
Oil ($/Bbl)	25.28	27.48	37.14	22.93
Liquids ($/Bbl)	12.74	13.61	18.51	19.54
Gas ($/mcf)	1.43	1.72	0.93	1.28
Combined ($/BOE)	20.38	22.29	31.66	18.87

Notes:

(1) Before deduction of royalties.

(2) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

The following table indicates Spartan's average daily production from its material properties for the year ended December 31, 2015:

	Oil (Bbls/d)	**Liquids (Bbls/d)**	**Gas (Mcf/d)**	**BOE (BOE/D)**
Saskatchewan				
Southeast	6,390	254	2,197	7,010
West Central	1,432	-	10	1,434
Alberta	310	5	642	422

Spartan's average production for the year ended December 31, 2015 was 95% liquids. For the year ended December 31, 2015, 98% of Spartan's gross revenue was derived from liquids production.

DIVIDEND POLICY

Spartan has not declared or paid any dividends on the Common Shares since incorporation. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Spartan's earnings, financial requirements and other conditions existing at such future time.

DESCRIPTION OF SHARE CAPITAL

Spartan is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series (the "**Preferred Shares**").

As of December 31, 2015, an aggregate of approximately 265.1 million Common Shares were issued and outstanding. As at the date hereof, there are approximately 305.0 million Common Shares issued and outstanding. In addition, Spartan has approximately 31.2 million Warrants and approximately 12.0 million Options to acquire Common Shares outstanding as of the date hereof. There are no Preferred Shares issued or outstanding.

The holders of Common Shares are entitled to notice of and to vote at all meetings of shareholders (except meetings at which only holders of a specified class or series of shares are entitled to vote) and are entitled to one vote per Common Share. Holders of Common Shares are entitled to receive, if, as and when declared by the Board of Directors, such dividends as may be declared thereon by the Board of Directors from time to time. In the event of the liquidation, dissolution or winding-up of the Corporation, or any other distribution of assets among its shareholders for the purpose of winding-up its affairs, holders of Common Shares, are entitled to share equally, share for share, in the remaining property.

The Preferred Shares are issuable in series and each series of the Preferred Shares will have such rights, restrictions, conditions and limitations as the Board of Directors may from time to time determine. Holders of Preferred Shares are entitled, in priority to the holders of Common Shares, to receive, if, as and when declared by the Board of Directors, such dividends as may be declared thereon by the Board of Directors from time to time, to be paid ratably with the other holders of the Preferred Shares. In the event of the liquidation, dissolution or winding-up of the Corporation, or any other distribution of assets among its shareholders for the purpose of winding-up its affairs, holders of Preferred Shares are entitled, in priority to the holders of Common Shares, to share equally, share for share, in the property of the Corporation.

MARKET FOR SECURITIES

The Common Shares are listed on the TSX under the symbol "SPE". The following table sets the price range and trading volume of these securities before giving effect to the Consolidation for the period from January 1, 2015 to December 31, 2015, as reported by the TSX:

	Common Shares		
Month	**High**	**Low**	**Volume**
January	$2.83	$2.20	46,334,245
February	$3.04	$2.60	52,569,122
March	$3.09	$2.54	64,515,811
April	$3.52	$2.86	54,514,955
May	$3.52	$3.12	37,369,881
June	$3.33	$2.92	20,576,229
July	$3.13	$2.30	48,476,841
August	$2.65	$1.80	36,261,494
September	$2.60	$2.12	20,860,069
October	$2.91	$2.19	40,489,947
November	$2.70	$2.25	21,182,111
December	$2.52	$1.97	18,733,888

PRIOR SALES

The following table sets forth, for each class of securities of the Corporation that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the financial year ended December 31, 2015 and the number of securities of the class issued at that price and the date on which the securities were issued:

Date of Issuance	Class of Securities	Number of Securities Issued	Issue or Exercise Price
March 20, 2015	Grant of Stock Options	3,210,000 Options	$2.69[(1)]
June 15, 2015	Grant of Stock Options	170,000 Options	$3.10[(1)]
August 21, 2015	Grant of Stock Options	185,000 Options	$2.25[(1)]
September 22, 2015	Issued pursuant to property acquisition[(2)]	89,271 Common Shares	$2.42
December 22, 2015	Private Placement of Flow-Through Shares[(3)]	735,294 Common Shares issued on a "flow-through" basis pursuant to the Tax Act	$2.72

Notes:

(1) Represents the exercise price of the Options granted.

(2) On September 22, 2015, the Corporation completed the acquisition of certain minor working interests from arm's length vendors for aggregate consideration of $1.2 million, which included the issuance of 89,271 Common Shares at a deemed issue price of $2.42 per Common Share.

(3) On December 22, 2015, the Corporation completed a private placement of 735,294 Common Shares issued on a "flow through" basis pursuant to the Tax Act at a subscription price of $2.72 per Common Share for aggregate gross proceeds of approximately $2.0 million.

DIRECTORS AND OFFICERS

The name, municipality of residence, shareholdings and principal occupation for the past 5 years of each of Spartan's directors and senior officers are as follows. The term of office for each director named below will expire at the next annual meeting of shareholders of Spartan.

Name	Positions Presently Held	Director Since	Principal Occupation for Previous Five Years
Richard F. McHardy *Calgary, Alberta*	Director, President and Chief Executive Officer	December 10, 2013	President and Chief Executive Officer of the Corporation since December 10, 2013. Prior to that, President and Chief Executive Officer of Spartan Oil Corp. from March 2011 to January 2013. Prior to that, President and Chief Executive Officer of Spartan Exploration Ltd., a public oil and gas exploration company, from January 2008 to June 2011.
Adam MacDonald *Calgary, Alberta*	Chief Financial Officer		Chief Financial Officer of the Corporation since February 24, 2016. Prior to that Interim Chief Financial Officer of the Corporation since August 14, 2014 and Controller of the Corporation since April 1, 2014. Prior to that, Controller of Renegade Petroleum Ltd. from October 2013 to April 2014 and Manager, Financial Reporting of Renegade Petroleum Ltd. from February 2011 to October 2013.

Name	Positions Presently Held	Director Since	Principal Occupation for Previous Five Years
Fotis Kalantzis *Calgary, Alberta*	Senior Vice President, Exploration		Vice President, Operations of the Corporation since December 10, 2013. Prior to that, Vice President, Operations of Spartan Oil Corp. from June 2011 to January 2013. Prior to that, Vice President, Operations of Spartan Exploration Ltd. from September 2010 to June 2011. Prior to that Vice President, Engineering and Operations of Spartan Exploration Ltd. from January 2008 to September 2010.
Ed Wong *Calgary, Alberta*	Senior Vice President, Engineering		Vice President, Engineering of the Corporation since December 10, 2013. Prior to that, Vice President, Engineering of Spartan Oil Corp. from June 2011 to January 2013. Prior to that Vice President, Engineering of Spartan Exploration Ltd. from September 2010 to June 2011. Prior to that Engineering Manager with Spartan Exploration Ltd. from September 2008 to September 2010.
Albert Stark *Calgary, Alberta*	Senior Vice President, Operations		Vice President, Operations of the Corporation since December 10, 2013. Prior to that, Vice President, Operations of Spartan Oil Corp. from June 2011 to January 2013. Prior to that Vice President, Operations of Spartan Exploration Ltd. from September 2010 to June 2011. Prior to that Vice President, Engineering and Operations of Spartan Exploration Ltd. from January 2008 to September 2010.
Thomas Boreen *Calgary, Alberta*	Vice President, Geology		Vice President, Geology of the Corporation since December 10, 2013. Prior to that, Chief Geologist at Spartan Oil Corp. from June 2011 to January 2013. Prior to that held positions with Suncor, Apache Canada, Shell Canada and Home Oil.
Randy Berg *Calgary, Alberta*	Vice President, Land		Vice President, Land of the Corporation since March 10, 2016. Prior to that Land Manager of the Corporation since April 1, 2014. Prior to that Vice President, Land and Business Development at Renegade Petroleum Ltd. from July 2012 to April 2014. Prior to that Conventional Business Unit Manager at Petrobakken Energy Ltd. from November 2010 to July 2012.
Michael J. Stark[1][2] *Calgary, Alberta*	Chairman	December 10, 2013	Independent Businessman since 2006. Chairman of Spartan Oil Corp. from June 2011 to January 2013.

Name	Positions Presently Held	Director Since	Principal Occupation for Previous Five Years
Reginald J. Greenslade(2)(3)(4) *Calgary, Alberta*	Director	December 10, 2013	Independent Businessman since February 2013. Director of Spartan Oil Corp. from June 2011 to January 2013. President and Director of Tuscany International Drilling Inc., an oilfield services company, from April 2010 to February 2013. Independent Businessman from March 2006 to April 2010.
Grant W. Greenslade(3)(4) *Shaunavon, Saskatchewan*	Director	December 10, 2013	Independent Businessman. Director of Spartan Oil Corp. from June 2011 to January 2013. President of Greenslade Consulting Ltd., a private oil and gas consulting company.
Donald Archibald(1)(2)(3) *Calgary, Alberta*	Director	December 10, 2013	President of Cypress Energy Corp., a private investment company, since March 2008. Director of Spartan Oil Corp. from June 2011 to January 2013.
Thomas Budd(1)(4) *Calgary, Alberta*	Director	March 31, 2014	Independent businessman since July 2008. Director of Whitehall Energy Inc., Waldron Energy Corporation and Toscana Energy Income Corporation.
Sanjib Gill *Calgary, Alberta*	Corporate Secretary		Partner at the law firm of McCarthy Tétrault LLP since January 2008, practicing primarily in the areas of corporate finance, mergers and acquisitions.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Corporate Governance Committee.
(4) Member of the Reserves and Environment Committee.

The directors and officers of Spartan as a group, beneficially own, or exercise control or direction over, an aggregate of approximately 30.5 million Common Shares representing approximately 10.0% of the issued and outstanding Common Shares.

The information as to Common Shares beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to Spartan by each of the individuals listed above.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as set forth below, to the knowledge of management of Spartan:

(a) no director or executive officer is, or within the ten years prior to the date hereof has been, a director, chief executive officer or chief financial officer of any other issuer that, while that person was acting in that capacity: (i) was the subject of a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or (ii) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemptions under securities legislation that was issued after the director or officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

(b) no director, executive officer or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person: (i) is, or within the ten years prior to the date hereof has been, a director or executive officer that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years preceding the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual; and

(c) no director, executive officer or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within the last 10 years, has: (i) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or (ii) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Sanjib Gill was the Corporate Secretary of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Gill resigned as the Corporate Secretary immediately thereafter.

Mr. Reginald Greenslade was a director of JMG Exploration, Inc. ("**JMG**"). On June 4, 2008, the Alberta Securities Commission issued a cease trade order in respect of JMG for failure to file audited annual financial statements for the year ended December 31, 2007 and interim financial statements for the period ended March 31, 2008. JMG filed audited annual financial statements for the years ended December 31, 2007 and December 31, 2008 on July 27, 2009. Mr. Greenslade resigned from the board of JMG in November 2009.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Spartan will be subject in connection with the operations of Spartan. In particular, certain of the directors and officers of Spartan are involved in managerial or director positions with other oil and gas companies, whose operations may, from time to time, be in direct competition with those of Spartan. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that, in the event that a director has an interest in a contract or a proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA. As at the date of this Annual Information Form, Spartan is not aware of any existing or potential material conflicts of interest between Spartan and any director or officer of Spartan.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings or regulatory actions material to the Corporation to which the Corporation is a party, or was a party to in 2015, or of which any of its properties is the subject matter, or was the subject matter of in 2015, nor are there any such proceedings known to the

Corporation to be contemplated. There have been no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority and the Corporation has not entered to any settlement agreements with a court or securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Sanjib Gill, the Corporate Secretary of the Corporation, is a partner of the national law firm McCarthy Tétrault LLP, which law firm rendered legal services to the Corporation.

Other than as set out above, there are no material interests, direct or indirect, of directors or executive officers of Spartan, or any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or any other Informed Person (as defined in National Instrument 51-102 *Continuous Disclosure Obligations* of the Canadian Securities Administrators) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect Spartan or any of its subsidiaries.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The auditor of the Corporation is PricewaterhouseCoopers LLP, Chartered Accountants at its office located at 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3.

The transfer agent and registrar for the Common Shares is Alliance Trust Company at its office located at 1010, 407 - 2nd Street S.W., Calgary, Alberta, T2P 2Y3.

MATERIAL CONTRACTS

Spartan has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by Spartan during, or related to, Spartan's most recently completed financial year other than Sproule, the independent reserve evaluators, and PricewaterhouseCoopers LLP, Spartan's auditors.

None of the principals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of Spartan or of Spartan's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

PricewaterhouseCoopers LLP is independent of Spartan in accordance with the rules of professional conduct of the Institute of Chartered Accountants of Alberta.

Certain legal matters relating to the business of Spartan will be passed upon on Spartan's behalf by McCarthy Tétrault LLP. As at the date hereof, the partners and associates of McCarthy Tétrault LLP as a group beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

AUDIT COMMITTEE

The purpose of Spartan's Audit Committee is to provide assistance to the Board of Directors in fulfilling its legal fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. It is the objective of the Audit Committee to maintain a free and open means of communications among the Board of Directors, the independent auditors and the financial and senior management of the Corporation.

The full text of the Audit Committee's Charter is included as Appendix "C" to this Annual Information Form.

Composition of the Audit Committee

As of the date hereof, the Audit Committee is comprised of:

Name of Director	Independent (Yes/No)(1)	Financially Literate (Yes/No)
Donald Archibald	Yes	Yes
Michael J. Stark	Yes	Yes
Thomas Budd	Yes	Yes

Notes:
(1) As defined in NI 52-110.

Relevant Education and Experience

Collectively, the Audit Committee has the education and experience to fulfill the responsibilities outlined in the Audit Committee Charter. Mr. Archibald has held senior executive positions in oil and gas issuers and has participated as a member of audit committees in the past. Mr. Stark is a certified financial planner and previously served as the Chairman of the audit committee of Titan Exploration Ltd., Spartan Exploration Ltd. and Spartan Oil Corp. Mr. Budd is a Certified Management Accountant (non-active) with the Society of Management Accountants of Alberta, holds a Masters of Business Administration from the University of Toronto and has many years of experience providing mergers and acquisitions and financial advice on a significant number of oil and gas transactions in Canada.

Each member of the Audit Committee has: (i) an understanding of the accounting principles used by the Corporation to prepare its financial statements; (ii) the ability to assess the general application of those principles in connection with the estimates, accruals and reserves; (iii) experience in preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising individuals engaged in such activities; and (iv) an understanding of internal controls and procedures for financial reporting.

Reliance on Certain Exemptions

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on an exemption from NI 52-110, in whole or in part, granted under Part 8 of NI 52-110 (securities regulatory authority exemption).

Audit Committee Oversight

Since the commencement of Spartan's most recently completed financial year, there has not been a recommendation of the Audit Committee to nominate or compensate an external auditor which was not adopted by the Board of Directors.

Pre-Approval Policies and Procedures

The Audit Committee is authorized by the Board of Directors to review the performance of the Corporation's external auditors, and approve in advance the provision of services other than audit services and to consider the independence of the external auditors, including reviewing the range of services provided in the context of all consulting services bought by the Corporation. The Audit Committee is authorized to approve any non-audit services or additional work, which the Chairman of the Audit Committee deems as necessary.

External Auditor Service Fees

The fees paid to the Corporation's external auditor for audit services are as follows:

Financial Year Ending	Audit Fees (1)	Audit-Related Fees (2)	Tax Fees (3)	All Other Fees(4)
December 31, 2015	$190,000	$45,000	$Nil	$Nil

Notes:
(1) The aggregate fees billed by the Corporation's auditor for audit fees.
(2) The aggregate fees billed for assurance and related services by the Corporation's auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not disclosed in the "Audit fees" column.
(3) The aggregate fees billed for professional services rendered by the Corporation's auditor for tax compliance, tax advice, and tax planning.
(4) The aggregate fees billed for professional services rendered by the Corporation's auditor for acquisitions.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's management information circular dated May 6, 2015.

Additional financial information is provided for in Spartan's financial statements and management's discussion and analysis for the year ended December 31, 2015. Documents affecting the rights of securityholders, along with other information relating to the Corporation, may be found on SEDAR at www.sedar.com. Additional copies of this Annual Information Form and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Corporation at its offices at Suite 500, 850 – 2nd Street S.W., Calgary, Alberta, T2P 0R8, by phone at (403) 355-8920 or fax at (403) 355-2779.

APPENDIX A

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

To the board of directors of Spartan Energy Corp. (the "Corporation"):

1. We have evaluated of the Corporation's Reserves Data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management and Board of Directors.

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	Evaluation of the P&NG Reserves of Spartan Energy Corp. As of December 31, 2015, dated February 18, 2016	Canada	**Nil**	**836,425**	**Nil**	**836,425**
Total			**Nil**	**836,425**	**Nil**	**836,425**

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

7. We have no responsibility to update the report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Spartan Energy Corp. (As of December 31, 2015)".

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

Executed as to our report referred to above:

Sproule Associated Limited
Calgary, Alberta
February 18, 2016

(signed) "*Richard A. Brekke*"

Richard A. Brekke, P. Eng.
Manager, Engineering and Partner

(signed) "*Brian G. Trieber*"

Brian G. Trieber, P.L. (Geol.)
Senior Geological Technologist and Partner

(signed) "*Victor Verkhogliad"*

Victor Verkhogliad, P.Geol.
Supervisor, Geoscience and Partner

(signed) "*Nora T. Stewart"*

Nora T. Stewart, P. Eng.
Vice-President, Reserve Certification and Director

APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of Spartan Energy Corp. (the “Corporation”) are responsible for the preparation and disclosure, or arranging for the preparation and disclosure of information with respect to the Corporation’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data

Independent qualified reserves evaluators have evaluated and reviewed the Corporation’s reserves data. The report of the independent qualified reserves evaluators is presented in the Annual Information Form of the Corporation for the year ended December 31, 2015.

The Reserves Committee of the Board of Directors of the Corporation has:

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

(b) met with the independent qualified reserves evaluator 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 Corporation’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of From 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 evaluator 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.

(signed) “*Richard F. McHardy*”
Richard F. McHardy
President, Chief Executive Officer and a Director

(signed) “*Adam MacDonald*”
Adam MacDonald
Chief Financial Officer

(signed) “*Reginald J. Greenslade*”
Reginald J. Greenslade
Director

(signed) “*Michael J. Stark*”
Michael J. Stark
Director

Dated March 30, 2016

APPENDIX C

SPARTAN ENERGY CORP.
AUDIT COMMITTEE
TERMS OF REFERENCE

I. The Board of Directors' Mandate for the Audit Committee

A. The Board of Directors ("**Board**") has responsibility for the stewardship of Spartan Energy Corp. (the "**Corporation**"). To discharge that responsibility, the Board is obligated by the Business Corporations Act (Alberta) to supervise the management of the business and affairs of the Corporation. The Board's supervisory function involves Board oversight or monitoring of all significant aspects of the management of the Corporation's business and affairs.

Public financial reporting and disclosure by the Corporation are fundamental to the Corporation's business and affairs. The objective of the Board's monitoring of the Corporation's financial reporting and disclosure is to gain reasonable assurance of the following:

1) that the Corporation complies with all applicable laws, regulations, rules, policies and other requirement of governments, regulatory agencies and stock exchanges, if applicable, relating to financial reporting and disclosure;

2) that the accounting principles, significant judgements and disclosures which underlie or are incorporated in the Corporation's financial statements are appropriate in the prevailing circumstances;

3) that the Corporation's quarterly and annual financial statements are accurate within a reasonable level of materiality and present fairly the Corporation's financial position and performance in accordance with generally accepted accounting principles; and

4) that appropriate information concerning the financial position and performance of the Corporation is disseminated to the public, to the extent required by applicable securities laws, in a timely manner in accordance with corporate and securities law and with stock exchange regulations, if applicable.

The Board is of the view that monitoring of the Corporation's financial reporting and disclosure policies and procedures cannot be reliably met unless the following activities (the "Fundamental Activities") are, in all material respects, conducted effectively:

1) the Corporation's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Corporation's financial transactions and consistent with internal financial controls implemented by companies of similar size and peer group as the Corporation;

2) the internal financial controls are regularly assessed for effectiveness and efficiency consistent with assessments performed by companies of similar size and peer group as the Corporation;

3) the Corporation's quarterly and annual financial statements are properly prepared by management to comply with International Financial Reporting Standards ("IFRS");

4) the Corporation's quarterly and annual financial statements are reported on by an external auditor appointed by the shareholders of the Corporation.

To assist the Board in its monitoring of the Corporation's financial reporting and disclosure and to conform to applicable corporate and securities law, the Board has established the Audit Committee (the "Committee") of the Board.

B. Composition of Committee

1) The Committee shall be appointed annually by the Board and consist of at least three members from among the directors of the Corporation, each of whom shall be an independent director (as determined under applicable laws). Officers of the Corporation, who are also directors, may not serve as members of the Committee;

2) The Board shall designate the Chairman of the Committee; and

3) In the event of a vacancy arising in the Committee or a loss of independence of any member, the Committee will fill the vacancy within six months or by the following annual shareholders' meeting if sooner.

C. Reliance on Experts

In contributing to the Committee's discharging of its duties under this mandate, each member of the Committee shall be entitled to rely in good faith upon:

1) financial statements of the Corporation represented to him by an officer of the Corporation or in a written report of the external auditors to present fairly the financial position of the Corporation in accordance with generally accepted accounting principles; and

2) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

D. Limitations on Committee's Duties

In contributing to the Committee's discharging of its duties under Terms of Reference, each member of the Corporation shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in these Terms of Reference is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to endeavor to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the objectives of the Corporation's financial reporting are being met and to enable the Committee to report thereon to the Board.

II. Audit Committee Terms of Reference

The Committee's Terms of Reference outlines how the Committee will satisfy the requirements set forth by the Board in its mandate. Terms of Reference reflect the following:

- Operating Principles;
- Operating Procedures;
- Specific Responsibilities and Duties.

A. Operating Principles

The Committee shall fulfill its responsibilities within the context of the following principles:

1) Committee Values

The Committee expects the management of the Corporation to operate in compliance with corporate policies; reflecting laws and regulations governing the Corporation; and to maintain strong financial reporting and control processes.

2) Communications

The Committee and members of the Committee expect to have direct, open and frank communications throughout the year with management, other Committee Chairmen, the external auditors, and other key Committee advisors or Corporation staff members as applicable.

3) Financial Literacy

All Committee Members should be sufficiently versed in financial matters to read and understand the Corporation's financial statements and also to understand the Corporation's accounting practices and policies and the major judgements involved in preparing the financial statements.

4) Annual Audit Committee Work Plan

The Committee, in consultation with management and the external auditors, shall develop an annual Committee work plan responsive to the Committee's responsibilities as set out in these Terms of Reference. In addition, the Committee, in consultation with management and the external auditors, shall participate in a process for review of important financial topics that have the potential to impact the Corporation's financial disclosure.

The work plan will be focused primarily on the annual and interim financial statements of the Corporation; however, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the Committee's Terms of Reference.

5) Meeting Agenda

Committee meeting agendas shall be the responsibility of the Chairman of the Committee in consultation with Committee members, senior management and the external auditors.

6) Committee Expectations and Information Needs

The Committee shall communicate its expectations to management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at a reasonable time in advance of meeting dates.

7) External Resources

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditors, at the expense of the Corporation, retain one or more persons having special expertise, including independent counsel.

8) In Camera Meetings

At the discretion of the Committee, the members of the Committee shall meet in private session with the external auditors. In addition, at the discretion of the Committee, the members of the Committee shall meet in private with the management of the Corporation, without the auditors being present at such meeting.

9) Reporting to the Board

The Committee, through its Chairman, shall report after each Committee meeting to the Board at the Board's next regular meeting.

10) Committee Self Assessment

The Committee shall annually review, discuss and assess its own performance. In addition, the Committee shall periodically review its role and responsibilities.

11) The External Auditors

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditors shall report directly to and be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues, either specific to the Corporation or to the financial reporting environment in general, to the Committee.

B. Operating Procedures

1) The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chairman, upon the request of two members of the Committee or at the request of the external auditors.

2) A quorum shall be a majority of the members.

3) Unless the Committee otherwise specifies, the Secretary (or his or her deputy) of the Corporation shall act as Secretary of all meetings of the Committee.

4) In the absence of the Chairman of the Committee, the members shall appoint an acting Chairman.

5) A copy of the minutes of each meeting of the Committee shall be provided to each member of the Committee and to each director of the Corporation in a timely fashion.

C. Specific Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

1) Financial Reporting

(a) Review, prior to public release, the Corporation's annual and quarterly financial statements with management and the external auditors with a view to gaining reasonable assurance that the statements (i) are accurate within reasonable levels of materiality, (ii) complete, (iii) represent fairly the Corporation's financial position and performance in accordance with IFRS. The Committee shall report thereon to the Board before such financial statements are approved by the Board;

(b) Receive from the external auditors reports of their review of the annual and quarterly financial statements and any management letters issued to the management of the Corporation;

(c) Receive from management a copy of the representation letter provided to the external auditors and receive from management any additional representations required by the Committee;

(d) Review, prior to public release, to the extent required pursuant to applicable securities laws, and, if appropriate, recommend approval to the Board, of news releases, to the extent required pursuant to applicable securities laws, and reports to shareholders issued by the Corporation with respect to the Corporation's annual and quarterly financial statements;

(e) Review and, if appropriate, recommend approval to the Board of prospectuses, material change disclosures of a financial nature, management discussion and analysis, annual information forms and similar disclosure documents that may be issued by the Corporation; and

(f) Review and validate procedures for the receipt, retention and resolution of complaints received by the Corporation from any party regarding accounting, auditing or internal controls. For greater certainty, the Committee's responsibilities in this area will not include complaints about minor operational issues. (Examples of minor operational issues include late payment of invoices, minor disputes over accounts owing or receivable, revenue and expense allocations and other similar items characteristic of the normal daily operations of the accounting department of an oil and gas company.)

2) Accounting Policies

(a) Review with management and the external auditors the appropriateness of the Corporation's accounting policies, disclosures, reserves, key estimates and judgements, including changes or variations thereto.

(b) Obtain reasonable assurance that they are in compliance with IFRS from management and external auditors and report thereon to the Board.

(c) Review with management and the external auditors the apparent degree of conservatism of the Corporation's underlying accounting policies, key estimates and judgements and provisions along with quality of financial reporting.

(d) Participate, if requested, in the resolution of disagreements, between management and the external auditors.

(e) Review with management the categorization of flow through expenditures and the qualification of such expenditures to satisfy the Corporation's existing obligations.

3) Risk and Uncertainty

(a) Acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Corporation, determine the Corporation's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:

(i) reviewing with management the Corporation's tolerance for financial risks;

(ii) reviewing with management its assessment of the significant financial risks facing the Corporation;

(iii) reviewing with management the Corporation's policies and any proposed changes thereto for managing those significant financial risks;

(iv) reviewing with management its plans, processes and programs to manage and control such risks;

(b) Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

(c) Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

(d) Review the adequacy of insurance coverages maintained by the Corporation;

(e) Review regularly with management, the external auditors and the Corporation's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these matters have been disclosed in the financial statements.

4) Financial Controls and Control Deviations

(a) Review the plans of the external auditors to gain reasonable assurance that the evaluation and testing of applicable internal financial controls is comprehensive, coordinated and cost effective;

(b) Receive regular reports from management and the external auditors on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto;

(c) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Chairman of the Committee, under conditions of confidentiality, concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgement, through existing reporting structures in the Corporation;

(d) Review, and periodically assess the adequacy of controls over financial information disclosed to the public, which is extracted or derived from the Corporation's financial statements.

5) Compliance with Laws and Regulations

(a) Review regular reports from management and others (e.g. external auditors) with respect to the Corporation's compliance with laws and regulations having a material impact on the financial statements including:

(i) tax and financial reporting laws and regulations;

(ii) legal withholding requirements;

(iii) other laws and regulations which expose directors to liability;

(b) Review the filing status of the Corporation's tax returns, flow through share renunciation filings and those of its subsidiaries.

6) Relationship with External Auditors

(a) Recommend to the Board the nomination of the external auditors;

(b) Approve the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter;

(c) Review the performance of the external auditors annually or more frequently as required;

(d) Receive annually from the external auditors an acknowledgement in writing that the shareholders, as represented by the Board and the Committee, are their primary client;

(e) Receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non audit services by the Corporation;

(f) Review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ;

(g) Meet with the external auditors in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee;

(h) Establish effective communication processes with management and the Corporation's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee; and

(i) Establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgement of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee as to disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

7) Other Responsibilities

(a) Approve annually the reasonableness of the expenses of the Chairman of the Board and the Chief Executive Officer;

(b) After consultation with the Chief Financial Officer and the external auditors, consider at least annually the quality and sufficiency of the Corporation's accounting and financial personnel and other resources;

(c) Approve in advance non-audit services, including tax advisory and compliance services, provided by the external auditors. However, the Committee can establish a threshold amount for fees for non-audit services to be provided by the external auditors without advance approval of the Committee. In such case, the nature of such services and the associated cost will be provided to the Committee at the next following meeting;

(d) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

(e) Perform such other functions as may from time to time be assigned to the Committee by the Board;

(f) Review and update the Terms of Reference on a regular basis for approval by the Board; and

(g) The Committee will review disclosures regarding the organization and duties of the Committee to be included in any public document, including quarterly and annual reports to shareholders, information circulars and annual information forms.