

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2014

Dated March 25, 2015

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DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this Annual Information Form. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook. Unless otherwise indicated, references in this Annual Information Form to "$" or "dollars" are to Canadian dollars.

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

"**AIF**" means this Annual Information Form;

"**Arrangement Agreement**" means the arrangement agreement dated December 20, 2012, among Charger, AvenEx and Pace with respect to the Arrangement;

"**AvenEx**" means AvenEx Energy Corp. an entity resulting from the plan of arrangement pursuant to Section 193 of the ABCA, completed on January 1, 2011, and pursuant to which, among other things, Avenir Diversified Income Trust, was dissolved;

"**Board of Directors**" or "**Board**" means the board of directors of Spyglass;

"**Charger**" means Charger Energy Corp., an entity resulting from the plan of arrangement under s.193 of the ABCA completed on March 6, 2012 involving Seaview Energy Inc., the shareholders of Seaview Energy Inc., Charger Energy Corp., the shareholders, optionholders and warrantholders of Charger Energy Corp., Silverback Energy Ltd., the shareholders of Silverback Energy Ltd., Sirius Energy Inc. and the shareholders of Sirius Energy Inc.;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the common shares of Spyglass;

"**Daylight**" means Daylight Energy Ltd.;

"**Daylight Arrangement**" means the plan of arrangement pursuant to the ABCA involving, *inter alia*, Pace, Daylight, Daylight Trust, Vintage Petroleum Canada Inc. and Midnight Oil & Gas Ltd. completed on November 30, 2004 pursuant to which certain assets of Midnight Oil & Gas Ltd. and Vintage Petroleum Canada Inc. were transferred to Pace;

"**Daylight Trust**" means Daylight Resources Trust and, where the context requires, includes its predecessor Daylight Energy Trust;

"**McDaniel**" means McDaniel & Associates Consultants Ltd.;

"**McDaniel Report**" means the independent engineering report dated February 25, 2015 and effective December 31, 2014 prepared by McDaniel evaluating the oil, NGL and natural gas reserves attributable to the properties of Pace;

"Midnight" means Midnight Oil Exploration Ltd.;

"**Midnight Shares**" means the common shares of Midnight;

"**Midnight/Provident Arrangement**" means the plan of arrangement pursuant to Section 193 of the ABCA involving Midnight, Provident, Provident Energy Ltd., PERI, the Provident Unitholders and holders of Midnight Shares completed on June 29, 2010;

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

"**Pace**" means Pace Oil & Gas Ltd., the resulting entity from the plan of arrangement pursuant to Section 193 of the ABCA involving Midnight Oil Exploration Ltd., Provident Energy Trust, Provident Energy Ltd., Provident Energy Resources Inc., the Provident Unitholders and holders of Midnight common shares completed on June 29, 2010;

"**PERI**" means Provident Energy Resources Inc.;

"**Provident**" means Provident Energy Trust;

"**Provident Unitholders**" means holders of trust units of Provident;

"**Spyglass**" or the "**Company**" means Spyglass Resources Corp.; and 1636527 Alberta Ltd., 1288916 Alberta Ltd., Pace Oil Resources Ltd., 1398850 Alberta Ltd., 1196823 Alberta Ltd., AvenEx Real Estate Acquisition Corp., Elbow River Marketing Corp., Seaview Energy Partnership, Pace Oil & Gas Partnership, Meota 2000 Partnership, AvenEx Energy Partnership, Elbow River Marketing Limited Partnership and 1583662 Alberta Ltd.

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

ABBREVIATIONS AND CONVERSION

In this AIF, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMBtu	million British Thermal Units
bbls/d	barrels per day	Bcf	billion cubic feet
NGLs	natural gas liquids	GJ	gigajoule
stb	standard tank barrels		

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 meters	28.174
Cubic meters	Cubic feet	35.494
Bbls	Cubic meters	0.159
Cubic meters	Bbls	6.293
Feet	Metres	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

Other

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas
boe/d	barrel of oil equivalent per day
m3	cubic meters
Mboe	1,000 barrels of oil equivalent
$000s	thousands of dollars
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NOTES ON RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of Spyglass' natural gas and petroleum reserves does not represent the fair market value of Spyglass' reserves.

Caution Respecting BOE

In this AIF, 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.

Definitions

Certain terms used in this AIF in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this AIF, but not defined or described, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

Reserves

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

"**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.

"**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.

"**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 (e.g., 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 as follows.

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

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

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a

significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

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

Interests in Reserves, Production, Wells and Properties

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

"**net**" means: (a) 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; (b) 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 (c) 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.

"**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: (a) 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; (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems.

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

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and 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: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploratory wells; and (e) costs of drilling exploratory type stratigraphic test wells.

"**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.

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 reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of 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.

Forecast prices and costs are future prices and costs that are:

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

The forecast summary table under "*Pricing Assumptions- Forecast Prices and Costs*" identifies benchmark reference pricing that applies to Spyglass.

Future income tax expenses estimate (generally, year by year):

- making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;
- without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
- taking into account estimated tax credits and allowances; and
- applying to the future pre-tax net cash flows relating to Spyglass' oil and gas activities the appropriate year end statutory rates, taking into account future tax rates already legislated.

Future net revenue is the estimated net amount to be received with respect to the development and production of reserves estimated using forecasted prices and costs. This net amount is computed by deducting from estimated future revenues: estimated amounts of future royalty obligations, costs related to the development and production of reserves, well abandonment costs and future income tax expenses.

Estimated future well abandonment costs have been taken into account by McDaniel in determining reserves that should be attributed to a property. In determining the aggregate future net revenue therefrom, the reasonable estimated future well abandonment costs were deducted. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities.
The forecast price and cost and assumptions assume the continuance of current laws and regulations.

The extent and character of all factual data supplied to McDaniel were accepted by McDaniel as represented**.** No field inspection was conducted.

Columns may not add due to rounding.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain information contained in this AIF constitutes forward-looking information as defined in applicable securities laws. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking information. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. Management of the Company believes the expectations reflected in forward-looking information are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking information included herein should not be unduly relied upon. This information is provided for the purpose of setting out management's current expectations and plans relating to the future business results of the Company. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions.

In particular, this AIF contains forward-looking information pertaining to the following:

- oil and natural gas production levels;
- drilling opportunities and prospects;
- capital expenditure programs;
- the future liquidity and financial capacity of the Company;
- future commodity risk;
- the quantity of the oil and natural gas reserves;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through exploration, development and acquisitions;
- the ability of the Company to integrate the assets acquired in connection with the Arrangement; and
- treatment under governmental regulatory regimes, including taxation.

Actual results could differ materially from those anticipated in the forward-looking information as a result of the risk factors set forth below and elsewhere in this AIF:

- volatility in market prices for oil and natural gas;
- changes or fluctuations in production levels;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates;
- stock market volatility and market valuations of the Company;
- limitations on insurance;
- failure to realize the anticipated benefits of acquisitions, including anticipated benefits of the Arrangement; and
- the other factors discussed under "*Risk Factors*" herein.

All forward-looking information in this AIF and in any documents incorporated by reference herein are based on assumptions and the Company's view of future events which reflect information available at the time the assumptions were made. With respect to forward-looking information contained in this AIF, the Company has made assumptions regarding, among other things:

- future natural gas, crude oil and NGL prices;
- the ability to obtain qualified staff and equipment in a timely and cost-efficient manner to meet demand;
- the regulatory framework regarding taxes and environmental matters in which the Company conducts its business;
- the impact of increasing competition;
- the Company's ability to obtain financing on acceptable terms;
- the general stability of the economic and political environment in which the Company operates;

- the timely receipt of any required regulatory approvals;
- the timing and costs of pipeline, storage and facility construction and expansion and the ability to secure adequate product transportation;
- currency, exchange and interest rates; and
- the ability of the Company to successfully market its products.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which may have been used in this AIF. The Company's actual results could differ materially from those anticipated as a result of the risk factors set forth above.

This information is provided only as of the date hereof or at the date specified in the documents incorporated by reference into this AIF. Readers are cautioned not to place undue reliance on this forward-looking information. While the Company may choose to do so, it accepts no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by securities law.

Non-GAAP Measures

This AIF makes reference to certain non-GAAP financial measures to assist in assessing the Company's financial performance. Some of these non-GAAP measures include references to netbacks. Operating netback equals oil and natural gas sales net of royalties, realized gains and losses on financial derivative instruments, operating costs and transportation costs and is generally calculated on a per boe basis. As a non-GAAP measure, operating netback is an indicator of the financial performance of the Company. The Company uses such term as an indicator of financial performance as the term is commonly utilized by investors to evaluate companies in the energy sector. The Company believes that operating netback is a useful supplemental measure that provides investors with information on operating margins per barrel of oil equivalent for such periods.

SPYGLASS RESOURCES CORP.

Incorporation and Material Reorganizations

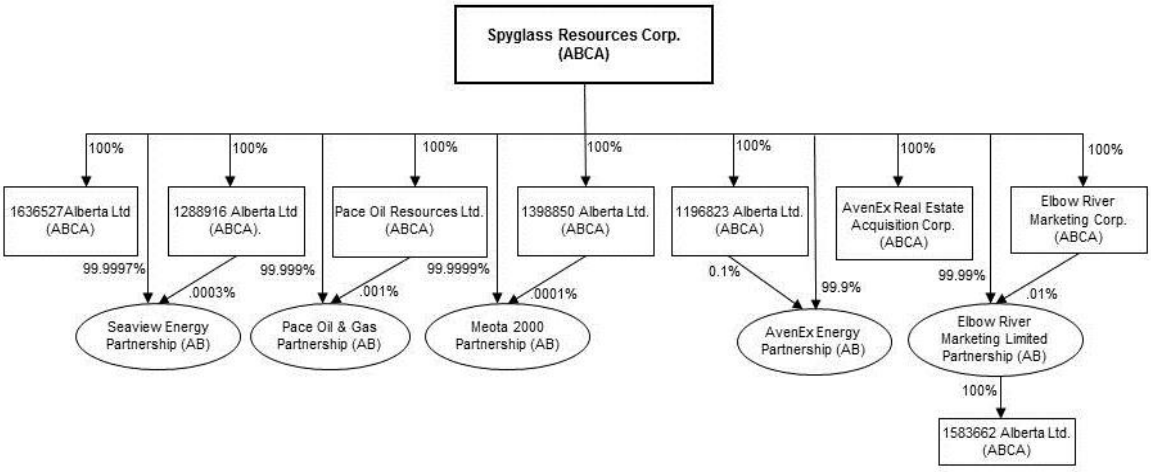
Spyglass was incorporated as Midnight Oil & Gas Ltd. on September 10, 2004 under the ABCA. On June 29, 2010, as part of the Midnight/Provident Plan of Arrangement, Midnight filed Articles of Amendment to reflect the consolidation of the Midnight Shares on the basis of one post-consolidation Common Share for each ten (10) pre-consolidation Midnight Shares. Also, on June 29, 2010, Midnight filed Articles of Amalgamation to effect an amalgamation of Midnight and PERI pursuant to the Midnight/Provident Plan of Arrangement and to change its name to "Pace Oil & Gas Ltd.". On March 28, 2013, Pace, Charger and AvenEx completed the Arrangement. In connection with the Arrangement, Pace, AvenEx and Charger were amalgamated and Pace changed its name to "Spyglass Resources Corp.". See *"Development of the Business - Pace/AvenEx/Charger Plan of Arrangement* below.

Head Office and Registered Office

The head and registered office of Spyglass is located at Livingston Place, West Tower, 1700, 250 - 2nd Street S.W., Calgary, Alberta T2P OCI. The Common Shares are listed for trading on the TSX under the symbol "SGL". SGL is a reporting issuer in all provinces and territories of Canada

Intercorporate Relationships

The following table provides the name, the nature of the entity and the jurisdiction of incorporation or formation of each of Spyglass' material subsidiaries, all of which are wholly-owned.



DEVELOPMENT OF THE BUSINESS

Prior to the Arrangement

Midnight commenced operations on November 30, 2004, following the completion of the Daylight Arrangement, pursuant to which Midnight acquired an interest in petroleum and natural gas properties located in West Central Alberta and undeveloped land located in the West Central Alberta, Foothills and Peace River Arch areas. Midnight sold certain of the non-core assets in West Central Alberta acquired pursuant to the Daylight Arrangement to Daylight in October 2008 in exchange for trust units of Daylight Trust and cash.

On June 29, 2010, Pace completed the Midnight/Provident Arrangement, pursuant to which Midnight acquired Provident's upstream oil and natural gas production business. The consideration for the acquisition was $120,000,000 in cash which was paid directly to Provident with a receivable to Pace of approximately $4,800,000 for working capital adjustments and the issuance of 32,493,617 Common Shares (on a post-consolidation basis) to Provident Unitholders. Provident Unitholders received 0.12225 Common Shares (on a post-consolidation basis) for each Provident Unit held. As part of the Midnight/Provident Arrangement, the Midnight Shares were consolidated on the basis of one (1) post-consolidation Common Share for every ten (10) pre-consolidation Midnight Shares and Midnight and PERI amalgamated to form Pace. The Midnight/Provident Plan of Arrangement was viewed as a reverse takeover of Midnight by Provident's upstream oil and natural gas production business under Canadian generally accepted accounting principles.

Pace/AvenEx/Charger Arrangement

On December 20, 2012, Pace, Charger and AvenEx entered into the Arrangement Agreement, pursuant to which Pace, Charger and AvenEx agreed to combine their businesses and amalgamate pursuant to the Arrangement to form Spyglass Resources Corp. Under the terms of the Arrangement, Pace shareholders received 1.3 Common Shares for each pre-subdivided common share of Pace, AvenEx shareholders received 1.0 Common Share for each common share of AvenEx and Charger shareholders received 0.18 of a Common Share for each Class A share of Charger. In accordance with the Arrangement, immediately prior to the amalgamation of Pace, Charger and AvenEx, each Pace common share was subdivided on the basis of 1.3 post-subdivided Pace common shares for every 1.0 pre-subdivided Pace common share.

On February 25, 2013, Pace, AvenEx and Charger entered into an amending agreement (the "**Spyglass Amending Agreement**") to amend certain terms of the Arrangement Agreement to facilitate any alternative acquisition proposals for Pace, AvenEx or Charger from third parties. Further, pursuant to the Amending Agreement, changes were made to the proposed board of directors of Spyglass upon completion of the Arrangement.

On March 28, 2013, Pace, Charger and AvenEx completed the Arrangement. Upon closing of the Arrangement on

March 28, 2013, the former Pace management team was replaced with the former Charger management team, including Tom Buchanan as Chief Executive Officer, Dan O'Byrne as President and Mark Walker as Chief Financial Officer. In addition, as part of the Arrangement, the Board of Directors of Pace resigned and were replaced with a board of directors consisting of Randy Findlay as Chair, Dennis Balderston, Tom Buchanan, Gary Dundas, Peter Harrison, Mike Shaikh, Jeff Smith and John Wright.

Additional information relating to the Arrangement is included in the business acquisition report dated May 8, 2013 and joint information circular and proxy statement of Pace, Charger and AvenEx dated January 18, 2013, both available under the Spyglass issuer profile on the System for Electronic Document Analysis and Retrieval ("**SEDAR**") at www.sedar.com.

Post-Arrangement

On March 28, 2013, Spyglass entered into a $400 million revolving term credit facility with a syndicate of banks. The facility was most recently amended pursuant to the Fourth Amending Agreement dated December 18, 2014.

In 2013 Spyglass sold, in aggregate, $22.7 million in non-core properties and seismic which exceeded the Company's previously announced $10 million to $15 million target. These transactions involved the sale of approximately 410 boe/d of non-core Saskatchewan oil and associated natural gas production, representing aggregate transaction metrics of approximately $55,400 per boe/d.

In 2013 Spyglass drilled 10 horizontal and 2 vertical light oil wells in Southern and Central Alberta. Spyglass has also participated in 2 (0.67 net) oil wells in the Glauconite channel play at Enchant with positive results and also participated in another 2 non operated (0.2 net) properties in Brazeau and Herronton.

2014

In 2014, Spyglass drilled and completed 21 gross (17.3 net) wells including 10 (10.0 net) in the Viking oil program at Halkirk Provost, 7 (6.2 net) Pekisko/Banff and Glauconite wells at Matziwin and Enchant, and 1 (1.0 net) Cadomin gas well at Noel.

During 2014, the Company disposed of $166.4 million of assets located in Alberta and southern Saskatchewan. In total, these transactions involved the disposition of approximately 2,700 boe/d (66 percent oil and liquids), total proved reserves of 14.4 MMboe, total proved plus probable reserves of 23.2 MMboe and undeveloped land of approximately 71,000 net acres (The proceeds of the asset sales were primarily used to reduce bank indebtedness).

Recent Activity

On February 11, 2015, as a result of the sustained decline in commodity prices, the Company revised its 2015 capital budget to $8 million from the previously announced $26 million. The reduced program is based on an average 2015 WTI price of approximately US$50 per barrel and will focus primarily on maintenance capital initiatives with the majority of the Company's drilling projects deferred until commodity prices improve. Furthermore, the Company revised its average production guidance to 9,000 boe/d compared to 10,000 boe/d as previously announced, as a result of the reduced capital program and the shut-in of certain uneconomic properties.

DESCRIPTION OF THE BUSINESS

Corporate Strategy

Spyglass is an intermediate oil and gas company headquartered in Calgary, Alberta, with a balanced commodity profile underpinned by stable, low decline oil and gas production. Spyglass currently operates oil and natural gas properties in Alberta, Saskatchewan and British Columbia. Spyglass is committed to improving the quality of its asset base and cash flow. The Company continues to focus on netback improvement through a combination of ongoing operating cost initiatives and increasing the weighting of oil and liquids production through drilling. Average production for 2014 was 13,798boe/d. Spyglass management and the Board regularly review the Company's strategic objectives and opportunities in an effort to maximize shareholder value.

The Board has approved a base capital budget of $8 million for 2015, with a focus primarily on maintenance activities with development deferred until commodity prices improve.

Competition

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

Seasonal Factors

The level of activity in the Canadian oil and natural 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 natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company. Furthermore, while the Company's business is generally not cyclical, its revenue from the sale of natural gas is highly seasonal, with demand for natural gas rising during cold winter months and hot summer months.

Personnel

As at December 31, 2014, Spyglass had 94 head office employees and 101 field employees and consultants.

ENVIRONMENTAL MATTERS

Environmental Regulation

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, and municipal laws and regulations. Environmental legislation governs all aspects and phases of oil and gas development, from planning and construction, through operations and onto final abandonment and reclamation. All jurisdictions have restrictions and prohibitions for spills, releases, discharges, or emissions of various substances produced or used in association with oil and natural gas operations, as well as requirements for oilfield waste handling and storage, habitat protection, and setbacks of oil and natural gas activities from fresh water bodies, buildings and urban centers.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* and the *Oil and Gas Conservation Act*. This legislation enables numerous regulations, guidelines and codes of practice, which impose strict environmental standards relating to the release of substances and the protection of species, habitat and land capability in the province and include monitoring and reporting obligations that carry significant penalties for non-compliance.

Environmental legislation in the Province of British Columbia is, for the most part, set out in the *Environmental Management Act* (the "**EMA**") and the *Petroleum and Natural Gas Act,* which regulate the storage, discharge and disposal of air contaminants, effluent and hazardous waste into the environment. Specifically, the *Oil and Gas Waste Regulation* under the EMA regulates hydrogen sulphide and nitrogen oxide emissions from oil and natural gas facilities. The EMA provides for the imposition of significant penalties in the event of non-compliance with regulations and standards and sets the criteria for the remediation of contaminated sites. New oil and natural gas projects, or modifications to existing projects, may be subject to a review under the Environmental Assessment Act.

The Province of Saskatchewan's environmental legislation is mostly set out in the *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. A new *Environmental Management and Protection Act, 2011* has been passed by the Saskatchewan Legislature but not yet proclaimed. The new Act will include authority for the *Saskatchewan Environmental Code,* which adopts a new results-based regulatory framework for managing and protecting the environment. The Act and the Code will be proclaimed into force on June 1, 2015.

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

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 in order 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. The South Saskatchewan Regional Plan was approved on July 23, 2014 and will be further developed and implemented from 2014 to 2024. Also, the planning process is well underway for the Lower Athabasca Region (which contains the majority of oil sands development). While the impact of the regional plans developed and implemented under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Policies and Procedures, Personnel and Facilities

Spyglass undertakes continuing efforts to ensure compliance with all applicable environmental laws and regulations and to ensure the safety of its employees, consultants and contractors and the general public in all areas where it conducts operations. These efforts include the development and implementation of environmental, health and safety policies, procedures and manuals and the conduct of regular meetings and exercises.

Spyglass employs a manager of health, safety and environment whose full time and attention is dedicated to these matters. The Operations, Reserves and Environmental, Health and Safety Committee (the "**Reserves Committee**") of the Board of Directors of Spyglass reviews and monitors the environmental policies and activities of Spyglass and the activities of Spyglass as they relate to health and safety.

Emergency Response Plans

Spyglass has adopted emergency response plans for the areas in which it operates.

Decommissioning Liabilities

Spyglass is obligated to abandon, retire and reclaim wells, well sites and facilities in compliance with applicable environmental laws and regulations. Spyglass has recorded decommissioning liabilities in its financial statements for the year ended December 31, 2014. Other than decommissioning liabilities, ordinary course operational expenditures necessary to ensure environmental compliance and the employment cost of health, safety and environmental personnel, Spyglass 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. See *"Other Oil and Gas Information - Additional Information Concerning Abandonment and Reclamation Costs"*.

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. Spyglass utilizes hydraulic fracturing in a significant portion of the light oil wells it drills and completes. Spyglass believes that the hydraulic fracturing that it conducts, given the depth and location of the wells and its consistent utilization of good oilfield practices, is environmentally sound and would not give rise to similar concerns respecting local aquifers.

Spyglass anticipates that there will be a trend towards increased regulatory requirements concerning hydraulic fracturing in the future. The Canadian Association of Petroleum Producers has announced hydraulic fracturing operating practices designed to improve water management and water and fluids reporting for shale gas and tight gas development across Canada. On December 20, 2012 the Alberta Energy Regulator issued a directive implementing new requirements for: (i) electronically reporting fracture fluid data, including service provider, fracture scenario, carrier fluid type, proppant type and additives for wells that have been fractured; (ii) electronically reporting water source data, including source location, source type, diversion permit information and volume for all water used in hydraulic fracturing operations with water quality information required for groundwater sources; and (iii) reporting fluid and water source data in daily reports of operations.

Trends

Spyglass believes that there is a general trend towards stricter standards in environmental legislation and regulation. Spyglass is committed to meeting its responsibilities to protect the environment in all areas where it conducts operations 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, the development or exploration activities, or otherwise adversely affect Spyglass' financial condition, capital expenditures, results of operations, competitive position or prospects. See *"Industry Conditions – Climate Change Regulations"* and *"Risk Factors – Environmental Concerns".*

Risks

Breaches of environmental law, regulations and requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, injury or death and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness. The imposition of new safety laws, regulations and requirements may significantly restrict Spyglass' operations, increase its costs or negatively impact its competitive position. See *"Risk Factors – Environmental Concerns"*.

PRINCIPAL PROPERTIES

The Company's core properties are located in Dixonville in northwest Alberta, Enchant, Retlaw, and Matziwin in southern Alberta, Halkirk-Provost in east-central Alberta, and Noel in northeast British Columbia. As of December 31, 2014, Spyglass held land inventory in these properties of over 545,900 gross acres (390,330 net) which is approximately 35% of the company's entire land portfolio. During 2014, capital expenditures including property acquisitions totaled approximately $80 million. For the year ended December 31, 2014, the Company's average production was 13,798 boe/d comprised of 5,839 bbls/d of oil, 404 bbls/d of liquids and 45,332 Mcf/d natural gas. Spyglass' total proved plus probable reserves of as of December 31, 2014 were 54,129 Mboe based on the McDaniel Report.

Dixonville, Alberta

The Dixonville property, located approximately 50 kilometers northwest of Peace River, consists primarily of the Montney C light oil (30° API) pool which has been developed using horizontal wells and is under waterflood using horizontal injection wells. Spyglass operates 104 producing oil wells, 90 water injectors and 16 producing gas wells. Production is mainly from the Dixonville Montney C Pool. As of December 31, 2014, Spyglass owned a 100% working interest in the oil pool and had an average working interest of approximately 90% in 59,643 gross (53,662 net) acres of land. Spyglass sold a non-operated 50% working interest in the Dixonville Montney C property as of January 1, 2015.

Spyglass' Dixonville property averaged production of 2,283 boe/d for the year ended December 31, 2014, comprising 1,984 bbls/d of oil and 1,791 Mcf/d of natural gas. These 2014 volumes are prior to the sale of 50% working interest. Dixonville comprises 25% of the net present value of Spyglass' total proved plus probable reserves discounted at 10%. Reserves assigned to this property as of December 31, 2014, based on the McDaniel Report, were total proved reserves of 7,566 Mboe and total proved plus probable reserves of 10,529 Mboe.

As of January 1, 2015, Spyglass has a 50% ownership in the central oil battery located at 2-25-86-26W5. All oil wells produce into this facility which has a treating capacity of approximately 4,000 bbls/d of oil and 37,000 barrels of water per day. The battery facility also contains a 400 horsepower three stage solution gas compressor. In addition, there are 23 test satellites and a gathering system consisting of 35 kilometers of emulsion pipeline and 25 kilometers of water injection pipelines. Solution and non-associated gas is gathered and processed at the Spyglass-operated (50% working interest) compressor station located at 14-36-86-26W5. This station is equipped with two compressors totaling 1,970 horsepower and gas hydration equipment with a capacity of approximately 10,000 Mcf/d. Sales gas is delivered to the TransCanada Pipelines Limited Meter Station located at the same site.

In 2014, Spyglass undertook a pipeline remediation program to install polyethylene liners in most of the emulsion pipelines. Most of the wells and pipelines were shut-in at various times to complete this remediation program; hence, the 2014 production volumes do not reflect the capability of the field.

Enchant, Alberta

Spyglass has an average working interest of approximately 62% in 81,045 gross (50,050 net) acres of land at Enchant, which is located approximately 170 kilometers southeast of Calgary in Southern Alberta. Average production from the Enchant property for the twelve months ending December 31, 2014, was 1,162 boe/d comprised of 679 bbls/d of oil, 51 bbls/d of NGLs and 2,594 Mcf/d of natural gas. Enchant comprises 14% of the net present value of the Company's total proved plus probable reserves discounted at 10%. Reserves assigned to this property as at December 31, 2014, based on the McDaniel Report, were total proved reserves of 3,416 Mboe and total proved plus probable reserves of 4,945 Mboe. Oil and gas wells at Enchant produce from a variety of formations including the Arcs, Sawtooth, Mannville, Basal Colorado, Bow Island, Second White Specks and Belly River. Spyglass drilled three (2.25 net) wells at Enchant during 2014, targeting Mannville oil. Spyglass operates and holds a 62% working interest in the Retlaw Mannville BBB and Enchant Upper Mannville NNN waterfloods.

Retlaw, Alberta

Spyglass has an average working interest of approximately 55% in 96,076 gross (53,304 net) acres of land at Retlaw, which is also located approximately 170 kilometers southeast of Calgary in Southern Alberta. Average production from Retlaw for the twelve months ending December 31, 2014, was 721 boe/d comprised of 294 bbls/d of oil, 37 bbls/d of NGLs and 2,338 Mcf/d of natural gas. Retlaw comprises 5% of the net present value of the Company's total proved plus probable reserves discounted at 10%. Reserves assigned to this property as at December 31, 2014, based on the McDaniel Report, were total proved reserves of 1,514 Mboe and total proved plus probable reserves of 2,177 Mboe. Oil and gas wells at Retlaw produce from a variety of formations including the Mannville, Basal Colorado, Bow Island, Second White Specks and Medicine Hat. Spyglass operates several high working interest Mannville waterfloods in Retlaw.

Matziwin, Alberta

Spyglass has an average working interest of approximately 81% in 79,526 gross (64,563 net) acres of land in the Matziwin and Cessford area, which is located approximately 150 kilometers east of Calgary. Average production from the Matziwin property for the twelve months ending December 31, 2014, was 771 boe/d comprised of 534 bbls/d of oil, 3 bbls/d of NGLs and 1,404 Mcf/d of natural gas. Matziwin comprises 6% of the net present value of the Company's total proved plus probable reserves discounted at 10%. Reserves assigned to this property as at December 31, 2014, based on the McDaniel Report, were total proved reserves of 1,377 Mboe and total proved plus probable reserves of 2,252 Mboe. Oil and gas wells at Matziwin produce from a variety of formations including the Banff, Pekisko, Mannville, Milk River and Medicine Hat.

Spyglass drilled four (4.0 net) 100 percent working interest wells in the Matziwin area in 2014 targeting Banff, Pekisko and Mannville oil.

Halkirk-Provost, Alberta

Spyglass has an average working interest of approximately 82% in 165,364 gross (136,022 net) acres of land at Halkirk-Provost. These properties are located approximately 100 kilometers east of Red Deer, Alberta and produce light oil (30 to 35 degrees API) and natural gas from the Viking formation and medium and heavy oil and natural gas from Mannville formations. The Company's Halkirk-Provost properties averaged production of 693 boe/d for the twelve months ending December 31, 2014, comprising 401 bbls/d of oil, 22 bbls/d of NGLs and 1,618 Mcf/d of natural gas. Halkirk-Provost properties comprise 13% of the net present value of the Company's total proved plus probable reserves discounted at 10%. Reserves assigned to Halkirk-Provost as at December 31, 2014, based on the McDaniel Report, were total proved reserves of 4,255 Mboe and total proved plus probable reserves of 7,050 Mboe.

Spyglass drilled ten (10.0 net) wells targeting Viking oil in the Halkirk-Provost area during 2014. Spyglass operates a 100% working interest natural gas processing plant at Choice 4-5-41-9W4 with a raw gas capacity of 12 MMcf/d and a 100% working interest oil battery at Neutral Hills 16-34-36-8W4 with a processing and treating capacity of 4,000 bbl/d.

Noel, British Columbia

Spyglass has an average working interest of approximately 51% in 64,240 gross (32,726 net) acres of land at Noel. The property is located in British Columbia approximately 110 kilometers south of Fort St. John. The Noel area is west of the Elmworth gas field and northwest of the Wapiti gas field in the Alberta Deep Basin. The majority of the Company's production is obtained from the gas bearing Cadotte, Falher and Cadomin formations. Sales gas is processed through the third-party-owned Elmworth Deep Cut Gas Plant.

The working interest production for 2014 averaged 819 boe/d and consisted of 4,875 Mcf/d of natural gas and 7 bbls/d of NGLs. Reserves assigned to this property as at December 31, 2014, based on the McDaniel Report, were total proved reserves of 3,152 Mboe and total proved plus probable reserves of 4,406 Mboe. Noel comprises approximately 3% of the net present value of Spyglass' total proved plus probable reserves discounted at 10%.

The Company has an interest in 25,525 gross acres (37 gross drilling spacing units) of Cadomin mineral rights in the Noel and Kelly Lake areas. Spyglass drilled one (1.0 net) horizontal Cadomin gas well at Noel during 2014. Management estimates (based on a third party technical review) that at full development the area could result in 83 gross (68 net) drilling locations. Four of these are booked as proved undeveloped reserves.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

McDaniel evaluated, as at December 31, 2014, the oil, natural gas and NGL reserves attributable to the properties of Spyglass in accordance with NI 51-101. The McDaniel Report is dated February 25, 2015.

The tables below are a summary of the oil, natural gas and NGL reserves attributable to the properties of Spyglass and the net present value of future net revenue attributable to such reserves as evaluated by McDaniel and presented in the McDaniel Report based on forecast price and cost assumptions. The tables summarize the data

contained in the McDaniel Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment costs for only those wells assigned reserves by McDaniel. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. For more information as to the risks involved, see *"Risk Factors"*.

The McDaniel Report is based on certain factual data supplied by Spyglass and McDaniel's opinion using reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Spyglass to McDaniel. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

The Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are included in Schedule B and Schedule C, respectively, to this AIF.

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue
As of December 31, 2014 at Forecast Prices and Costs

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	11,687	9,143	1,354	1,256	62,193	53,222	509	340	23,915	19,609
Developed Non-Producing	410	292	145	134	16,358	11,694	183	118	3,465	2,493
Undeveloped	4,174	3,519	301	251	23,893	21,021	156	114	8,612	7,387
Total Proved[(1)]	16,271	12,953	1,800	1,642	102,444	85,936	848	572	35,993	29,490
Probable	8,204	6,418	676	592	52,449	44,569	514	352	18,136	14,791
Total Proved Plus Probable[(1)]	24,475	19,371	2,476	2,234	154,893	130,506	1,362	925	54,129	44,280

Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year) ($ million)

Reserves Category	0%	5%	10%	15%	20%	Unit Value at 10%[(2)] $/boe
Proved						
Developed Producing	509	349	267	218	186	13.61
Developed Non-Producing	67	46	34	26	22	13.58
Undeveloped	162	93	56	34	20	7.60
Total Proved[(1)]	738	488	357	278	227	12.11
Probable	503	255	161	114	86	10.88
Total Proved Plus Probable[(1)]	1,241	744	518	392	312	11.70

Net Present Values of Future Net Revenue
After Income Taxes Discounted at (%/year)
($ million)

Reserves Category	0%	5%	10%	15%	20%	Unit Value at 10%[2] ($/boe)
Proved						
Developed Producing	509	349	267	218	186	13.61
Developed Non-Producing	67	46	34	26	22	13.58
Undeveloped	162	93	56	34	20	7.60
Total Proved[1]	738	488	357	278	227	12.11
Probable	413	227	151	110	84	10.20
Total Proved Plus Probable[1]	1,151	716	508	388	311	11.47

Notes:
(1) Numbers may not add due to rounding.
(2) Unit values are based on Net reserves.

Total Future Net Revenue (Undiscounted)
As Of December 31, 2014 at Forecast Prices and Costs
($ thousand)

	Proved	Proved Plus Probable
Revenue [1]	$2,261,398	$3,655,595
Royalties [2]	$429,978	$710,042
Operating Costs	$890,589	$1,424,645
Development Costs	$143,386	$211,327
Well Abandonment Costs	$59,484	$68,192
Future Net Revenue Before Income Taxes[3]	$737,961	$1,241,390
Income Taxes	-	$90,208
Future Net Revenue After Income Taxes[3]	$737,961	$1,151,183

Notes:
(1) Sales Revenue includes all non-producing income.
(2) Royalties includes any net profits interests paid.
(3) Numbers may not add due to rounding.

Future Net Present Value and Unit Value by Production Group[1]

	Net Reserves					
	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Total Oil Equivalent[2] (Mboe)	Future Net Revenue Before Income Taxes [3] (Discounted at 10%/year) ($ thousands)	Unit Value[4] ($/boe)
Light and Medium Oil						
Proved	12,948	13,614	161	15,378	270,437	17.59
Proved plus Probable	19,363	20,751	242	23,064	380,821	16.51
Heavy Oil						
Proved	1,642	1,247	17	1,867	29,611	15.86
Proved plus Probable	2,234	1,716	22	2,542	41,925	16.49
Non-Associated Gas				(MMcfe)		($/Mcfe)
Proved	5	71,075	393	73,463	56,973	0.78
Proved plus Probable	7	108,038	660	112,040	95,146	0.85

Notes:
(1) Production Groups include Major Products and other by-products. Solution Gas reserves are included in Light, Medium and Heavy Oil.
(2) Boes and MMcfes are calculated using a conversion of 6 MCF of natural gas to one boe.
(3) Includes processing and other revenue.
(4) Unit values are calculated using the Future Net Revenue discounted at 10% divided by the total net reserves for each product group.

Pricing Assumptions – Forecast Prices and Costs

The future net revenues and net present values presented in the McDaniel report were calculated using the McDaniel pricing, exchange rate and inflation rate assumptions as of January 1, 2015. Price offsets and differentials for each property were determined by comparing actual historical benchmark prices to actual prices received at the property.

Summary of Pricing and Inflation Rate Assumptions
Forecast Prices and Costs as of January 1, 2015

	Oil				Natural Gas	Edmonton Liquid Prices				
Year	WTI Crude Oil[1] ($US/bbl)	Edmonton Light Crude[2] ($Cdn/bbl)	Western Canadian Select Crude Oil[3] ($Cdn/bbl)	Alberta Bow River Hardisty Crude Oil[4] ($Cdn/bbl)	Alberta (AECO/ Spot ($Cdn/ MMbtu)	Propane ($Cdn/bbl)	Butanes ($Cdn/bbl)	Cond. & Natural Gasolines ($Cdn/bbl)	Inflation %	Exchange Rate ($US/$Cdn)
History										
2010	79.50	77.50	67.23	68.50	4.15	46.70	66.05	84.25		0.971
2011	95.10	95.00	77.10	78.55	3.70	55.15	76.50	104.20		1.012
2012	94.20	86.10	73.08	74.35	2.45	28.60	69.55	100.80		1.000
2013	97.95	93.05	75.25	76.55	3.20	38.90	69.40	104.65		0.971
2014	93.05	93.95	78.45	79.65	4.40	45.50	68.80	102.50		0.905
Forecast										
2015	65.00	68.60	57.60	58.30	3.50	26.10	52.80	72.60	2.0	0.860
2016	75.00	83.20	69.90	70.70	4.00	36.50	67.00	87.30	2.0	0.860
2017	80.00	88.90	74.70	75.60	4.25	44.50	71.60	93.10	2.0	0.860
2018	84.90	94.60	79.50	80.40	4.50	49.30	76.20	98.80	2.0	0.860
2019	89.30	99.60	83.70	84.70	4.70	51.80	80.30	103.90	2.0	0.860
2020	93.80	104.70	87.90	89.00	5.00	54.70	84.40	109.10	2.0	0.860
2021	95.70	106.90	89.80	90.90	5.30	56.20	86.10	111.40	2.0	0.860
2022	97.60	109.00	91.60	92.70	5.50	57.50	87.80	113.60	2.0	0.860
2023	99.60	111.20	93.40	94.50	5.70	85.90	89.60	115.90	2.0	0.860
2024	101.60	113.50	95.30	96.50	5.90	60.30	91.50	118.30	2.0	0.860
2025	103.60	115.70	97.20	98.30	6.00	61.50	93.20	120.60	2.0	0.860
2026	105.70	118.00	99.10	100.30	6.10	62.70	95.10	123.00	2.0	0.860
2027	107.80	120.40	101.10	102.30	6.25	64.00	97.00	125.50	2.0	0.860
2028	110.00	122.80	103.20	104.40	6.35	65.20	99.00	128.00	2.0	0.860
2029	112.20	125.30	105.30	106.50	6.50	66.60	101.00	130.60	2.0	0.860
2030+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.860

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.5% sulphur.
(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur.
(3) Western Canadian Select at Hardisty, Alberta.
(4) Alberta Bow River at Hardisty 25 degree API Crude Oil.
(5) Alberta AECO Spot Gas price assuming 1,000 btu/scf.

Spyglass' weighted average realized sales prices for the year ended December 31, 2014 were: $4.48/Mcf for natural gas, $86.46/bbl for light and medium crude oil, $78.66/bbl for heavy crude oil and $60.23/bbl for natural gas liquids.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of Spyglass' gross reserves as at December 31, 2014, derived from the McDaniel Report using forecast prices and costs, reconciled to the gross reserves of Spyglass as at December 31, 2013. Changes in reserves were primarily due to dispositions, acquisitions, production and drilling activity.

Reconciliation of Gross (Working Interest) Reserves by Principal Product Type
Forecast Prices and Costs

Reserve Category	Factors	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas Liquids (Mbbl)	Natural Gas (MMcf)	Total Oil Equivalent (Mboe)
Proved	December 31, 2013	26,971	2,096	1,114	146,960	54,675
	Discoveries	0	0	0	0	0
	Extensions & Improved Recovery	868	93	31	7,161	2,185
	Technical Revisions	(793)	66	205	(3,449)	(1,097)
	Acquisitions	103	9	11	871	269
	Dispositions	(9,076)	(135)	(346)	(29,038)	(14,397)
	Production	(1,807)	(306)	(144)	(16,147)	(4,948)
	Economic Factors	3	(23)	(22)	(3,914)	(694)
	December 31, 2014	16,271	1,800	848	102,444	35,993

Reserve Category	Factors	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas Liquids (Mbbl)	Natural Gas (MMcf)	Total Oil Equivalent (Mboe)
Probable	December 31, 2013	12,867	673	687	81,268	27,772
	Discoveries	0	0	0	0	0
	Extensions & Improved Recovery	639	23	13	2,678	1,121
	Technical Revisions	(914)	(4)	99	(9,340)	(2,376)
	Acquisitions	20	4	2	199	59
	Dispositions	(4,469)	(40)	(297)	(24,081)	(8,819)
	Production	0	0	0	0	0
	Economic Factors	61	21	10	1,725	379
	December 31, 2014	8,204	676	514	52,449	18,136
Proved Plus Probable	December 31, 2013	39,838	2,769	1,801	228,228	82,447
	Discoveries	0	0	0	0	0
	Extensions & Improved Recovery	1,508	115	43	9,839	3,306
	Technical Revisions	(1,707)	62	303	(12,788)	(3,473)
	Acquisitions	124	13	13	1,069	328
	Dispositions	(13,545)	(176)	(643)	(53,119)	(23,217)
	Production	(1,807)	(306)	(144)	(16,147)	(4,948)
	Economic Factors	64	(2)	(12)	(2,190)	(315)
	December 31, 2014	24,475	2,476	1,362	154,893	54,129

Note:
Numbers may not add due to rounding.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are assigned by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Generally, proved undeveloped reserves are those reserves related to drilling wells in or very near producing pools or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Generally probable undeveloped reserves are those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This category also includes probable reserves assigned to proved undeveloped locations.

The Company plans to pursue the development of its proven and probable undeveloped reserves over the next three years with some carryover into the first half of 2018. The time horizon is longer than two years to prudently manage the development and capital requirements. Capital spending during 2015 is constrained due to low commodity prices. The capital program continues to focus on low risk development opportunities intended to increase overall liquids weighting and improve netbacks. The Company may choose to accelerate or delay development depending on a number of circumstances, including the existence of higher priority expenditures, prevailing commodity prices and cash flow. A number of factors could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "Risk Factors".

Proved undeveloped reserves of 8,612 Mboe account for 24% of the Company's total proved reserves and 16% of total proved plus probable reserves at year-end 2014. Probable undeveloped reserves of 6,538 Mboe account for 12% of the Company's total proved plus probable reserves. Spyglass has 95 gross (78.9 net) proved undeveloped drilling locations and an additional 47 gross (36.8 net) probable drilling locations booked as of year-end 2014. In the proven category, 82 gross wells (72.9 net) are oil wells and in the probable category, 38 gross wells (33.1 net) are oil wells. Approximately 96% of the value of the Company's proved undeveloped reserves and 89% of the Company's probable undeveloped reserves are attributable to oil development projects.

Spyglass has 53 gross (50.5 net) proved undeveloped oil wells and an additional 25 gross (21.3 net) probable undeveloped oil wells booked in the Halkirk-Provost property targeting light oil in the Viking formation using horizontal wells and multi-stage fracturing technology. Thirty-five percent of Spyglass' proved undeveloped reserves and 34% of probable undeveloped reserves are attributable to the Halkirk-Provost Viking. Four (4.0 net) proved undeveloped plus two (2.0 net) probable undeveloped locations target medium oil in the Ellerslie formation using vertical wells at Provost.

Spyglass has seven gross (7.0 net) proved undeveloped oil wells and an additional three gross (3.0 net) probable undeveloped oil wells booked in the Matziwin property in Southern Alberta. These horizontal multi-stage frac wells offset existing wells, which are producing from the Banff, Pekisko and Glauconitic formations and are a continuation and complement to the Company's activity which began in this area in 2011. In the Enchant, Retlaw and Little Bow areas of Southern Alberta Spyglass has six gross (5.5 net) proved undeveloped and two gross (1.5 net) probable undeveloped locations targeting Mannville, Glauconitic and Arcs oil. In addition, proved and probable undeveloped reserves are booked for Enchant waterfloods. Proved undeveloped reserves in southern Alberta account for 20% of the Company's total proved undeveloped and 19% of total probable undeveloped reserves.

Cadomin gas is being developed at Noel, B.C. using horizontal well multi-stage frac technology. Four gross (4.0 net) proved undeveloped locations are booked, representing approximately 21% of Spyglass' proved undeveloped and 7% of probable undeveloped reserves.

The Company's Pouce Coupe lands are located in an area being actively developed for Montney gas using horizontal well multi-stage frac technology. Spyglass has identified nine gross (2.0 net) proved undeveloped Montney locations and an additional five (1.4 net) probable undeveloped Montney locations plus one (0.6 net) Baldonnel probable undeveloped location on its Pouce Coupe property. These wells account for 14% and 23% of the Company's proved undeveloped and probable undeveloped reserves, respectively. Proved undeveloped reserves are assigned to four gross (2.2 net) wells and probable undeveloped reserves are assigned to one (0.8 net) additional location in the Balsam, Boundary Lake and Gordondale properties in the Peace River Arch. These account for 3% of total proved undeveloped and 4% of the Company's probable undeveloped reserves.

The remaining undeveloped reserves are in various properties throughout Alberta.

The following tables discloses, for each product type, the total volumes of gross proved and probable undeveloped reserves at December 31, 2014 and the year in which they were first attributed. The volumes first attributed during 2013 are primarily due to the acquisition of AvenEx and Charger reserves.

Proved Undeveloped Reserves and Year First Attributed

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	1,417	2,101	685	35	6,808	20,944	31	45	3,267	5,672
2011	776	2,568	25	25	3,127	20,022	5	62	1,327	5,993
2012	326	1,965	-	25	245	19,230	1	28	368	5,223
2013	3,679	5,446	266	292	19,667	38,582	196	233	7,419	12,400
2014	586	4,174	-	301	3,575	23,893	10	156	1,192	8,612

Probable Undeveloped Reserves and Year First Attributed

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	581	961	919	155	12,441	33,273	16	112	3,589	6,774
2011	422	1,315	51	51	5,525	44,573	7	253	1,400	9,047
2012	613	1,581	-	50	291	27,314	1	41	662	6,225
2013	3,476	4,828	108	158	14,277	35,070	268	322	6,231	11,154
2014	470	3,377	-	162	1,509	16,960	6	172	727	6,538

Note:

(1) "First Attributed" refers to the fiscal year during which the reserves were first assigned.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. The reserve 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.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

Other risk factors affecting the oil and gas industry are detailed in the "*Risk Factors*" section of this document.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the McDaniel Report of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

Future Development Costs	Forecast Prices and Costs (Undiscounted)	
Year	Proved Reserves	Proved Plus Probable Reserves
	($ thousands)	($ thousands)
2015	5,555	9,936
2016	64,336	81,638
2017	45,826	86,047
2018	27,137	31,953
2019	83	476
Remaining	449	1,276
Total[(1)]	143,386	211,327

Note:
Numbers may not add due to rounding.

Spyglass typically has three sources of funding to finance its capital expenditure programs: (i) internally generated cash flow; (ii) debt financing; and (iii) new equity issue, if available on favourable terms. There can be no assurance that debt or equity financing, or cash generated by operations, as a result of uncertain levels of near term commodity prices, will be available or sufficient to meet these requirements or, if debt or equity financing is available, that it will be on acceptable terms (See "*Risk Factors*").

OTHER OIL AND GAS INFORMATION

Oil and Gas Wells

The following table sets forth the number and status of Spyglass' producing and non-producing oil and gas wells effective December 31, 2014.

	Oil Wells				Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	692	448	321	244	1,374	838	496	349
British Columbia	0	0	0	0	54	24	24	15
Saskatchewan	1	0	1	0	0	0	0	0
Total	693	448	322	244	1,428	862	520	364

Note:
Wells classified as abandoned are not included in this list.

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2014, the gross and net undeveloped acres in which Spyglass has an interest and also the number of net acres for which Spyglass' rights to explore, develop or exploit will, absent further action, expire within one year.

	Undeveloped Acres		
	Gross	Net	Net Acres Expiring Within One Year
British Columbia	97,185	55,326	2,585
Alberta	492,231	368,234	62,161
Saskatchewan	498	15	0
Total[(1)]	589,915	423,574	64,746

Note:
(1) Numbers may not add due to rounding.

Of the 64,746 net undeveloped acres with expiries in 2015, the Company estimates that more than 32,390 net acres will be continued through submission of continuation applications.

The gross and net acreage is determined on a title document basis. The gross and net acreage is based on the acreage contained in each title document. Where different title documents exist over the same lands, acreage is counted on each of the title documents.

The next table summarizes, effective December 31, 2014, the gross and net undeveloped acres which have no proved reserves assigned.

	Undeveloped Acres - With No Proved Reserves		
	Gross	Net	Net Acres Expiring Within One Year
British Columbia	95,265	53,406	2,585
Alberta	469,075	349,645	51,785
Saskatchewan	498	15	0
Total	**564,839**	**403,065**	**54,370**

Note:
Numbers may not add due to rounding

No significant factors or uncertainties that affect the development or production activities on properties with no attributed reserves have been identified, other than those under “Risk Factors”.

Forward Contracts

The Company does not have any hedging or marketing arrangements that could materially impact the Company's realized sales prices that have not been disclosed as financial instruments in its financial statements. The Company has committed to certain transportation arrangements but has not committed volumes in excess of production from proved reserves estimates using forecast prices and costs.

Drilling Activity

The following table sets forth the gross and net exploration and development wells drilled by Spyglass during the year ended December 31, 2014.

	Development		Exploratory	
	Gross	Net	Gross	Net
Light and Medium Oil	19	15.3	1	1.0
Heavy Oil	-	-	-	-
Natural Gas	1	1.0	-	-
Service Wells	-	-	-	-
Stratigraphic Test Wells	-	-	-	-
Dry	-	-	-	-
Total	**20**	**16.3**	**1**	**1.0**

Additional Information Concerning Abandonment and Reclamation Costs

The following table discloses Spyglass' abandonment and reclamation costs anticipated as at December 31, 2014, calculated both at an undiscounted and at a 10% discount rate with the portion thereof anticipated to be incurred during the next three years. Downhole abandonment costs for wells assigned reserves have been included in the McDaniel evaluation. McDaniel has deducted $59.5 million in determining the net present value of future net revenue of total proved reserves on an undiscounted basis as disclosed herein.

Abandonment and Reclamation Costs	Undiscounted	Discounted at 10%
($ thousands)		
Total at December 31, 2014	348,941	45,100
Total expected to be incurred in the next three years	13,040	10,629

Spyglass will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Spyglass estimates the costs to abandon and reclaim all shut in and producing wells, facilities, gas plants, pipelines, batteries and satellites. Spyglass' model for estimating the amount and timing of future abandonment and reclamation expenditures is done on an operating area level. Estimated expenditures for each operating area are based on management's prior experience in the areas. Abandonment and reclamation costs have been estimated over an approximate 40 year period with the majority of the costs estimated to be incurred after 20 years. Facility reclamation costs are scheduled to be incurred in the year following the end of the reserve life of the associated reserves. At December 31, 2014, Spyglass expects to incur reclamation and abandonment costs in respect of 2,670 net wells.

Tax Horizon

Income taxes deducted in the calculations of future net revenues in the Reserves Data set forth in this AIF assumes that Spyglass produces out its existing reserves without reinvestment of cash flows and does not take into account general and administrative expenses or interest expenses. Under this scenario, using total proved reserves and forecast prices and costs, Spyglass would not be taxable during the life of the reserves. Using total proved plus probable reserves and forecast prices and costs, Spyglass would not be taxable until after 2029. Using a continuing business model whereby Spyglass re-invests cash flows at historic capital efficiencies and incurs general and administrative costs and interest on bank debt, Spyglass' tax horizon would be further extended.

Costs Incurred

The following table summarizes capital expenditures incurred by Spyglass during the year ended December 31, 2014.

Expenditures	($ thousands)
Property acquisition costs - Proved Properties[(1)]	2,458
Property acquisition costs - Undeveloped Properties [(1)(2)]	844
Exploration Costs [(3)]	4,274
Development Costs [(4)]	67,550
Non-oil and gas assets	4,864
Total	79,990

Notes:
(1) Acquisition costs include the amounts allocated to exploration and evaluation assets and property, plant and equipment for accounting purposes.
(2) Cost of land acquired, lease rentals on unproved properties. Unproved properties are included in table titled “Properties with No Attributed Reserves”.
(3) Geological and geophysical costs and drilling and completion costs for exploratory wells.
(4) Drilling and completion costs for development wells and equipping, tie in and facility costs for all wells.

Planned Capital Expenditures

Spyglass' capital program in 2015 will be focused on optimizations, recompletions and development of the Matziwin and Southern Alberta oil plays. Capital expenditures will be managed within cash flow from operations and will vary with commodity pricing.

Production Estimates

The following table discloses for each product type the annual daily volume of production estimated in the McDaniel Report for 2015 in the estimates of future net revenue from gross proved, gross probable and gross proved plus probable reserves.

Company Gross Production Estimates

	Light & Medium Oil	Heavy Oil	Natural Gas Liquids	Natural Gas	Total Oil Equivalent
	(bbl/d)	(bbl/d)	(bbl/d)	(Mcf/d)	(boe/d)
Proved Producing					
Dixonville	1,301	0	0	1,108	1,486
Enchant	540	0	40	1,894	895
Retlaw	221	68	32	2,095	670
Matziwin	353	1	2	1,262	566
Halkirk-Provost	346	73	19	1,635	710
Noel	0	0	6	4,290	721
Others	834	577	170	22,463	5,325
Total Proved Producing	**3,595**	**719**	**269**	**34,747**	**10,374**
Proved					
Dixonville	1,301	0	0	1,108	1,486
Enchant	627	6	42	1,988	1,007
Retlaw	221	68	32	2,106	672
Matziwin	353	1	2	1,262	566
Halkirk-Provost	346	112	19	1,644	751
Noel	0	0	6	4,290	721
Others	891	628	171	23,059	5,533
Total Proved	**3,739**	**815**	**273**	**35,457**	**10,737**
Probable					
Dixonville	17	0	0	25	21
Enchant	21	0	2	99	40
Retlaw	34	1	3	204	71
Matziwin	70	0	0	119	91
Halkirk-Provost	25	4	1	109	48
Noel	0	0	0	137	23
Others	27	21	9	1,130	245
Total Probable	**195**	**25**	**15**	**1,822**	**539**
Proved Plus Probable					
Dixonville	1,318	0	0	1,113	1,507
Enchant	649	6	44	2,087	1,047
Retlaw	255	69	35	2,310	743
Matziwin	423	1	3	1,382	657
Halkirk-Provost	371	116	20	1,752	799
Noel	0	0	7	4,427	744
Others	918	649	180	24,189	5,778
Total Proved Plus Probable	**3,934**	**841**	**288**	**37,279**	**11,276**

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2014, Spyglass' share of daily production, before royalties.

	Quarters Ended 2014			
Average Daily Production	**Q1**	**Q2**	**Q3**	**Q4**
Light and Medium Oil (bbls/d)	5,892	5,311	4,235	4,580
Heavy Oil (bbls/d)	892	853	810	809
Natural Gas Liquids (bbls/d)	391	535	410	280
Natural Gas (Mcf/d)	44,312	46,647	48,379	41,981
Combined (boe/d)	14,560	14,474	13,518	12,666

The following table summarizes, on a quarterly basis for the year ended December 31, 2014, certain information in respect of product prices received, royalties paid, operating expenses, transportation expenses and resulting netback for Spyglass.

	Quarters Ended 2014			
	Q1	**Q2**	**Q3**	**Q4**
Light and Medium Oil ($/bbl)				
Average Price Received	91.29	96.30	88.47	67.24
Royalties Paid	19.54	22.78	21.18	16.35
Operating Expenses	23.04	18.48	21.28	20.40
Transportation Expenses	3.73	3.55	3.07	3.09
Netback Received	**44.98**	**51.49**	**42.94**	**27.40**
Heavy Oil ($/bbl)				
Average Price Received	81.64	88.97	82.93	60.40
Royalties Paid	10.25	9.91	11.53	11.77
Operating Expenses	30.48	31.12	35.19	19.29
Transportation Expenses	1.80	2.05	1.51	1.35
Netback Received	**39.11**	**45.89**	**34.70**	**27.99**
Natural Gas Liquids ($/bbl)				
Average Price Received	76.59	55.63	57.46	50.61
Royalties Paid	19.62	22.80	17.61	22.47
Operating Expenses	19.90	19.31	20.63	20.07
Transportation Expenses	-	-	-	-
Netback Received	**37.07**	**13.52**	**19.22**	**8.07**
Natural Gas ($/Mcf)				
Average Price Received	5.08	4.75	4.25	3.82
Royalties Paid	0.54	0.15	0.23	0.10
Operating Expenses	3.48	2.77	2.82	3.04
Transportation Expenses	0.24	0.21	0.23	0.20
Netback Received	**0.82**	**1.62**	**0.97**	**0.48**

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

Production Volume by Field

The following table indicates Spyglass' share of average daily production before royalties from Spyglass' important fields for the year ended December 31, 2014. All of Spyglass' production is in the provinces of Alberta and British Columbia.

	Light & Medium Oil	Heavy Oil	Natural Gas Liquids	Natural Gas	Total Oil Equivalent
	(bbls/d)	(bbls/d)	(bbls/d)	(Mcf/d)	(boe/d)
Dixonville	1,971	13	0	1,791	2,283
Enchant	675	4	51	2,594	1,162
Retlaw	272	22	37	2,338	721
Matziwin	514	20	3	1,404	771
Halkirk-Provost	257	144	22	1,618	693
Noel, British Columbia	0	0	7	4,875	819
Other	1,310	637	284	30,712	7,349
Total	4,999	840	404	45,332	13,798

Finding and Development Costs

Finding and development costs (F&D costs) include all costs to develop reserves, including land and seismic costs. The methodology to calculate F&D costs under NI 51-101 requires that F&D costs incorporate changes in the future development capital (FDC), which is included in the reserve evaluation. This development capital is part of the ongoing development process to bring production onstream and generate cash flow. Excluding technical revisions, F&D costs for 2014 were $23.57/boe proved and $13.10/boe proved plus probable. FD&A costs include the reserves acquired and the costs to acquire those reserves in the calculation. Excluding technical revisions, FD&A costs were $22.34/boe proved and $12.82/boe proved plus probable. The following table presents the details of the 2014 F&D and FD&A cost calculations, including and excluding technical revisions.

2014 F&D Costs

F&D Excluding Technical Revisions		
Working Interest Reserve Changes, Mboe	**Total Proved**	**Total Proved Plus Probable**
Drilling Extensions and Improved Recovery	2,185	3,306
Capital ($thousands)		
2014 Capital[(1)]	71,824	71,824
Change in FDC[(2)]	(20,319)	(28,527)
Total Capital	**51,505**	**43,297**
F&D, $/boe	**23.57**	**13.10**
F&D Including Technical Revisions		
Working Interest Reserve Changes, Mboe		
Drilling Extensions and Improved Recovery	2,185	3,306
Technical Revisions	(1,097)	(3,473)
Total Reserve Additions, Acquisitions and Technical Revisions	**1,088**	**(167)**
Capital ($thousands)		
2014 Capital[(1)]	71,824	71,824
Change in FDC[(2)]	(20,319)	(28,527)
Total Capital	**51,505**	**43,297**
F&D Including Technical Revisions, $/boe	**47.32**	**NA [(3)]**

2014 FD&A Costs

FD&A Excluding Technical Revisions

Working Interest Reserve Changes, Mboe	Total Proved	Total Proved Plus Probable
Drilling Extensions and Improved Recovery	2,185	3,306
Acquisitions	269	328
Dispositions[4]	-	-
Total Reserve Additions and Acquisitions	**2,454**	**3,634**
Capital ($thousands)		
2014 Capital[1]	75,126	75,126
Change in FDC[2]	(20,319)	(28,527)
Total Capital	**54,807**	**46,599**
FD&A, $/boe	**22.34**	**12.82**

FD&A Including Technical Revisions

Working Interest Reserve Changes, Mboe		
Drilling Extensions and Improved Recovery	2,185	3,306
Acquisitions	269	328
Dispositions[4]	-	-
Technical Revisions	(1,097)	(3,471)
Total Reserve Additions, Acquisitions and Technical Revisions	**1,357**	**161**
Capital ($thousands)		
2014 Capital[1]	75,126	75,126
Change in FDC[2]	(20,319)	(28,527)
Total Capital	**54,807**	**46,599**
FD&A Including Technical Revisions, $/boe	**40.39**	**289.05**

Notes:

(1) The 2014 capital expenditures exclude capitalized administration and office costs.
(2) Change in FDC excludes changes due to dispositions.
(3) Results are not applicable as total additions plus technical revisions are negative.
(4) Reserve Dispositions not included due to the magnitude of dispositions in 2014.

DESCRIPTION OF CAPITAL STRUCTURE

Spyglass is authorized to issue an unlimited number of Common Shares and unlimited number of Class A Preferred Shares ("**Preferred Shares**"). As at December 31, 2014 there were 127,804,720 Common Shares and no Preferred Shares outstanding.

The following is a description of the rights, privileges, restrictions and conditions attaching to Spyglass' Common Shares. Spyglass' share provisions have been filed under its profile on SEDAR at www.sedar.com.

Subject to the provisions of the ABCA, holders of Common Shares are entitled to receive notice of, to attend and vote at all meetings of shareholders and are entitled to one vote, in person or by proxy, for each Common Share held. Holders of Common Shares are entitled to receive, if, as and when declared by the Board of Directors, non-cumulative dividends at such rate and payable on such date as may be determined from time to time by the Board of Directors. Upon the liquidation, dissolution or winding up, or any other distribution of the Spyglass assets among its shareholders for the purpose of winding up its affairs, holders of the Common Shares shall be entitled to receive the Company's remaining property and assets.

Holders of any series of Preferred Shares will not be entitled (except as otherwise provided by law and except for meetings of the holders of Preferred Shares or a series thereof) to receive notice of, attend at, or vote at any meeting of Shareholders, unless the Board shall determine otherwise, in which case voting rights shall be determined by the Board and set out in the designations, rights, privileges, restrictions and conditions of such series of Preferred Shares Subject to the preferences accorded to holders of any other shares of the Company ranking senior to the Preferred Shares from time to time with respect to the payment of dividends, the holders of each series of Preferred Shares shall be entitled, in priority to holders of Common Shares and any other shares of the Company ranking junior to the Preferred Shares from time to time with respect to the payment of dividends, to be paid rateably with holders of each other series of Preferred Shares, the amount of accumulated dividends, if

any, specified as being payable preferentially to the holders of such series. Upon the liquidation, dissolution or winding up, or any other distribution of the Spyglass' assets among its shareholders for the purpose of winding up its affairs, holders Preferred Shares shall be entitled, in priority to holders of Common Shares and any other shares of the Company ranking junior to the Preferred Shares from time to time with respect to payment on a distribution, to be paid rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to the holders of such series on a distribution.

DIVIDEND POLICY

In 2014, the Company had established a dividend policy of paying monthly dividends to Shareholders. The objective of the Company's dividend policy was to provide Shareholders with relatively stable and predictable monthly dividends. An additional objective was to retain a portion of cash flow to fund ongoing development and optimization projects designed to enhance the sustainability of the Company's cash flow.

In response to lower crude prices and consistent with management's goal to improve financial flexibility, the Company announced in December 2014 it was suspending dividends to conserve cash.

In the future, the amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the board of directors and may vary depending on a variety of factors, including the prevailing economic and competitive environment, results of operations, fluctuations in working capital, the price of oil and gas, the taxability of Spyglass, Spyglass' ability to raise capital, the amount of capital expenditures and other conditions existing from time to time. There can be no guarantee that Spyglass will maintain its dividend policy.

During 2014, the Company paid or declared a monthly cash dividend of $0.2175 per share.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the symbol "SGL". The following table sets out the price range for and trading volume for the Common Shares from January 1, 2014 until the date hereof as reported by the TSX.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
2014			
January	2.14	1.83	5,849,313
February	2.13	1.91	5,795,752
March	2.09	1.71	8,142,844
April	1.97	1.76	7,054,756
May	1.86	1.64	8,975,779
June	1.83	1.69	6,813,941
July	1.77	1.64	4,011,341
August	1.71	1.55	5,485,717
September	1.57	1.37	6,662,136
October	1.40	1.02	6,400,693
November	1.15	0.64	10,087,222
December	0.71	0.29	10,964,628
2015			
January	0.35	0.28	3,634,211
February	0.50	0.28	4,827,803
March 1 - 25	0.37	0.26	2,346,868

DIRECTORS AND OFFICERS

As of March 25, 2015 the directors and executive officers of Spyglass as a group beneficially own, control or direct, directly or indirectly, approximately 3.5 million Common Shares, representing approximately 2.7 percent of the outstanding Common Shares. The information as to the number of Common Shares beneficially owned, controlled or directed, directly or indirectly, or over which control or direction is exercised, is based upon information received from such directors and officers.

Directors

Set forth below are the names, municipality of residence, and principal occupation for the prior five years of the directors of Spyglass.

Name and Municipality of Residence	Director Since	Principal Occupation and Positions for the Past Five Years
Dennis B. Balderston, CA Calgary, Alberta	2013	Mr. Balderston is a Chartered Accountant and independent businessman with over 36 years of public accounting experience in public and private energy sector companies. He also has experience serving as a director of a number of public oil and gas related companies. Previously, Mr. Balderston was a partner with Ernst & Young LLP from 1990 to 2005.
Thomas W. Buchanan, FCA Calgary, Alberta	2013	Mr. Buchanan is Chairman and Chief Executive Officer of Athabasca Oil Corporation. Until July 1, 2014 he was Chief Executive Officer of Spyglass Resources Corp., an oil and gas company created on March 28, 2013 through the amalgamation of Pace Oil and Gas Ltd., Avenex Energy Corp. and Charger Energy Corp. of which Mr. Buchanan was Chairman and Chief Executive Officer. Prior thereto he was Director, President and Chief Executive Officer of Provident Energy Trust, a diversified energy income trust with investments in upstream oil and gas production and natural gas liquids midstream services from March 2001 to April 2010. Mr. Buchanan is a Fellow of the Canadian Institute of Chartered Accountants.
Randall J. Findlay[(1)], P.Eng. Calgary, Alberta	2013	Mr. Findlay is a professional engineer with over 40 years of experience in resource industries. He is the past President of Provident Energy Trust and was a member of Provident's Board of Directors from 2001 to 2012. Prior to joining Provident, he was a senior Vice President at TransCanada Pipelines and President of TransCanada's North American midstream business. Mr. Findlay holds the ICD.D designation from the Institute of Corporate Directors.
Peter T. Harrison, CFA Brossard, Quebec	2013	Mr. Harrison is Manager, Oil and Gas Investments for CN Investments since August 2009. Previously, he was Senior Vice President of Montrusco Bolton Investments Inc. (Montreal) since December 1997, where he managed the firm's Canadian Equity portfolios. Mr. Harrison is a Chartered Financial Analyst (CFA).
Mr. Daniel J. O'Byrne Calgary, Alberta	2014	Mr. O'Byrne is a Director, President and Chief Executive Officer of Spyglass Resources Corp. He has over 33 years of diverse experience in the North American and international oil and natural gas sector, most recently as President of Spyglass Resources Corp., and Director and President of Charger Energy Corp. Prior positions include Executive Vice President and Chief Operating Officer of Provident Energy Trust, and executive positions at Nexen Inc. He has served as a director for a number of public energy companies.
M.H. (Mike) Shaikh[(2)], FCA Calgary, Alberta	2013	Mr. Shaikh is an independent businessman with over 35 years of experience in finance, oil and gas operations as well as mergers and acquisitions. Mr. Shaikh is currently and has served in the past as a Director of a number of private and public companies in a variety of industries and not-for-profit organizations. Mr. Shaikh is a Fellow of The Canadian Institute of Chartered Accountants.
Jeffrey T. Smith, P.Geol. Calgary, Alberta	2013	Mr. Smith is a corporate director, independent businessman and investor. He has over 40 years of oil and gas experience and retired in 1998 from his role as Chief Operating Officer of Northstar Energy. He also has 15 years of experience serving as a director of a number of private and public oil and gas related companies.
John D. Wright[(3)], B.Sc. Calgary, Alberta	2013	Mr. Wright is President and Chief Executive Officer of Lightstream Resources Ltd. and Chairman and Chief Executive Officer of Petrobank Energy Resources Ltd. (since 2000). Mr. Wright holds a B.Sc. in Petroleum Engineering and is a Chartered Financial Analyst (CFA).

Notes:

(1) Mr. Findlay was a director of Wellpoint Systems Inc. ("**Wellpoint**") from July 21, 2008 to January 31, 2011. Wellpoint was a TSXV listed company engaged in providing software solutions to the energy industry. On January 31, 2011, Quorum Oil and Gas Technology Fund Ltd. obtained an Order from the Court of Queen's Bench of Alberta appointing Ernst & Young as receiver and manager of all the current and future assets, undertakings and properties of every nature and kind whatsoever, including all of the proceeds thereof of Wellpoint and its subsidiary companies. As part of the Order, the Court approved a sales process for all or substantially all of the property that was administered by the receiver. On April 19, 2011, the receiver announced that the property of Wellpoint had been sold to P2 Energy Solutions Inc., with the sale closing on April 29, 2011.

(2) Mr. Shaikh was a director of Mystique Energy Inc. ("**Mystique**") from November 11, 2004 until his resignation on April 24, 2007. On April 25, 2007 the

Court of Queen's Bench of Alberta granted an initial order to Mystique for creditor protection under the Companies' Creditors Arrangement Act ("**CCAA**"). The initial order grants CCAA protection for an initial period of 30 days, expiring May 24, 2007, to be extended thereafter as the court deems appropriate. The CCAA proceedings have been completed and Mystique has settled with its creditors.

(3) Mr. Wright was a director of Canadian Energy Exploration Inc. ("**CEE**") (formerly TALON International Energy, Ltd.), a reporting issuer listed on the TSXV, until September 15, 2011. A cease trade order (the "**ASC Order**") was issued on May 7, 2008 against CEE by the Alberta Securities Commission ("**ASC**") for the delayed filing of CEE's audited annual financial statements and management's discussion and analysis for the year ended December 31, 2007 ("**Annual Filings**"). The Annual Filings were filed by CEE on SEDAR on May 8, 2008. As a result of the ASC Order, the TSXV suspended trading in CEE's shares on May 7, 2008. In addition, on June 4, 2009 the British Columbia Securities Commission ("**BCSC**") issued a cease trade order (the "**BCSC Order**") against CEE for the failure of CEE to file its audited annual financial statements and management's discussion and analysis for the year ended December 31, 2008 and its unaudited interim financial statements and management's discussion and analysis for the three months ended March 31, 2009. CEE made application to the ASC and BCSC for revocation of the ASC Order and BCSC Order. The ASC and BCSC have issued revocation orders dated October 14, 2009 and November 30, 2009, respectively, granting full revocation of compliance-related cease trade orders issued by the ASC and the BCSC in respect of CEE.

Each of the directors will hold office until the next annual meeting of Spyglass' shareholders or until his successor is duly elected or appointed, unless his office is earlier vacated in accordance with Spyglass' articles or by-laws.
To assist the Board with its fiduciary responsibilities, the board is currently supported by three standing committees: Audit Committee, Governance, Human Resources and Compensation Committee and Operations, Reserves and Environmental, Health & Safety Committee. The members of each of these committees are identified below:

Audit Committee	Governance, Human Resources and Compensation Committee	Operations, Reserves and Environmental, Health & Safety Committee
M.H. (Mike) Shaikh (Chair)	Randall J. Findlay (Chair)	Jeffrey T. Smith (Chair)
Dennis B. Balderston	Jeffrey T. Smith	Peter T. Harrison
Peter T. Harrison	John D. Wright	John D. Wright

Officers and Senior Management

Set forth below are the names, titles, municipality of residence, and principal occupation for the prior five years of the officers of Spyglass.

Name and Municipality of Residence	Title	Principal Occupation and Positions for the Past Five Years
Daniel (Dan) J. O'Byrne (P.Eng., MBA) Calgary, Alberta	President & Chief Executive Officer	President and COO of Charger Energy Corp. and prior thereto was Executive Vice President and COO of Provident Energy Trust
Mark N. Walker (CMA) Calgary, Alberta	Senior Vice President Finance and Chief Financial Officer	Vice President Finance and CFO of Charger Energy Corp. and prior thereto was Senior Vice President Finance and CFO of Provident Energy Trust
Kelly D. Cowan Calgary, Alberta	Senior Vice President Corporate Development and Land	Vice President Corporate Development and Land of Charger Energy Corp. and prior thereto was CEO of Churchill Energy Inc.
Lynn M. Rannelli Calgary, Alberta	Corporate Secretary	Assistant Corporate Secretary at Provident Energy Ltd.
Dallas McConnell (MBA) Calgary, Alberta	Vice President, Corporate Development & Investor Relations	Director of Corporate Development and Planning at Charger Energy Corp. and prior thereto was Director of Investor Relations and Capital Markets at Provident Energy Ltd.
Brad I. Likuski (P.Eng.) Calgary, Alberta	Vice President, Production and Operations	Vice President, Engineering at AvenEx Energy Corp. Prior thereto held positions at Clear Energy, Husky Energy, Barrington Petroleum & Chevron Canada Resources.
Floyd E. Siegle (P.Eng., MBA) Cochrane, Alberta	Vice President, Engineering	Vice President Engineering at Charger Energy Corp. and prior thereto was the Senior Manager, Reserves and Evaluations at Provident Energy Trust.
Frank Serpico (BA) Calgary, Alberta	Vice President, Marketing	Director, Marketing, with Pace Oil & Gas Ltd., and prior thereto was the Manager, Marketing for Provident Energy Trust.

Corporate Cease Trade Orders

Other than as noted in the footnotes to the Directors table above, to the knowledge of management of Spyglass, no director or executive officer of Spyglass, or a personal holding company of any such person, is, or within the 10 years before the date of this AIF has been, a director, chief executive officer or chief financial officer of any other issuer that:

a) was the subject of a cease trade or similar order or an order that denied the other issuer access to any exemptions under Canadian securities legislation that lasted for a period of more than 30 consecutive days that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or

b) was subject to a cease trade order or an order that denied the relevant issuer access to any exemption under securities legislation that lasted for a period of more than 30 consecutive days that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while the was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

Other than as noted in the footnotes to the Directors table above, to the knowledge of management of Spyglass, no director or executive officer or any shareholder holding sufficient number of securities of Spyglass to affect materially the control of Spyglass, or a personal holding company of any such person:

a) is, at the date of this AIF or has been within the 10 years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

b) has, within the 10 years before the date of this AIF, become 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 the assets of the director, officer or shareholder.

Penalties or Sanctions

To the knowledge of management of Spyglass, no director or officer, or any shareholder holding a sufficient number of securities of Spyglass to affect materially the control of Spyglass, has:

a) 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

b) 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.

Conflicts of Interest

The directors and officers of Spyglass may participate in activities and investments in the oil and natural gas industry outside the scope of their engagement or employment as directors or officers of Spyglass. As a result, the directors and officers may become subject to conflicts of interest. The ABCA provides that, in the event that a director has an interest in a contract or 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 under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA, the written mandate of the Board of Directors and Spyglass' corporate governance policies.

As at the date hereof, other than what has been disclosed above, Spyglass is not aware of any existing or potential material conflicts of interest between Spyglass and a director or officer of Spyglass.

AUDIT COMMITTEE

Audit Committee Mandate

The Audit Committee of the Board of Directors operates under a mandate and terms of reference that sets out its responsibilities and composition requirements. A copy of the mandate and terms of reference is attached to this AIF as Schedule "A".

Education and Experience of Members

The education and experience of each director relevant to the performance of his duties as a member of the Audit Committee are described below. All members of the Audit Committee are financially literate and independent within the meaning of applicable securities laws.

Name	Relevant Education and Experience
M.H. (Mike) Shaikh, FCA	Mr. Shaikh is an independent businessman with extensive experience in finance, oil and gas operations and mergers and acquisitions. Mr. Shaikh is a Fellow of the Canadian Institute of Chartered Accountants. As a Chartered Accountant, Mr. Shaikh attained experience in preparing, auditing, analyzing and evaluating financial statements. Mr. Shaikh has an understanding of the accounting principles used by Spyglass as well as the implications of those accounting principles on the Corporation's financial results. Mr. Shaikh has also obtained significant financial experience and exposure to accounting and financial issues as the President of M.H. Shaikh Professional Corporation and in his role as a director and audit committee member of various public companies. He was also a Board member of the Alberta Securities Commission from 2003 to 2006.
Dennis B. Balderston, CA	Mr. Dennis B. Balderston is a Chartered Accountant and independent businessman with over 35 years of public accounting experience in public and private energy sector companies. He also has 8 years of experience serving as a director of a number of public oil and gas related companies. Previously, Mr. Balderston was a partner with Ernst & Young LLP from 1990 to 2005.
Peter T. Harrison, CFA	Mr. Harrison is Manager, Oil and Gas Investments for CN Investments since August 2009. Previously, he was Senior Vice President of Montrusco Bolton Investments Inc. (Montreal) since December 1997, where he managed the firm's Canadian Equity portfolios. Mr. Harrison is a Chartered Financial Analyst (CFA).

Auditors' Fees

PricewaterhouseCoopers LLP have been the auditors of Spyglass and Pace since the completion of the Midnight/Provident Arrangement. The following table sets out the aggregate fees billed by PricewaterhouseCoopers LLP to Spyglass in 2014 and 2013.

Year	Audit Fees[(1)]	Audit-Related Fees[(2)]	Tax Fees[(3)]	Other Fees[(4)]
2014	$239,936	$0	-	-
2013	$261,171	$45,150	-	-

Notes:

(1) Audit fees consist of fees for the audit of annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. The services provided in this category include quarterly review fees.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of Spyglass' financial statements and are not reported as Audit Fees. The services provided in this category included research of accounting and audit-related issues as well as services rendered in filing prospectuses.

(3) Fees for tax compliance, tax advice and tax planning.

(4) Fees for review of internal controls.

No additional fees for professional services have been paid to PricewaterhouseCoopers in 2014 or 2013.

Pre-approval Policies and Procedures

The Audit Committee has adopted specific policies and procedures for the engagement of non-audit services whereby any financial services in excess of $75,000 and outside the audit plan of the Company's auditors must be approved by the Chairman of the Audit Committee.

INDUSTRY CONDITIONS

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted.

Canadian Government Regulation

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect the operations of the Company in a manner materially different than they would affect other oil and gas companies of similar size. 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 issue of such a licence requires the approval of the Governor in Council.

Pricing and Marketing - Natural Gas

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) require the prior receipt of an NEB order authorizing export. 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 Alberta, British Columbia and Saskatchewan 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

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

The North American Free Trade Agreement

On January 1, 1994, NAFTA became effective among the governments of Canada, the United States of America 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 of America 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, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. 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 natural gas exports.

Royalties and Incentives

General

Each of the provinces in which the Company operates has legislation and regulations governing royalties, land tenure, production rates and taxes, environmental protection, and other matters under their respective jurisdictions. The royalty regime applicable in the provinces in which the Company operates is a significant factor in the profitability of the Company's production. Crown royalties apply to production on Crown lands, are determined by government regulation and are typically calculated as a percentage of the value of production. The value of the production and the rate of royalties payable depend on prescribed reference prices, well productivity, geographical location, and the type of product produced.

Royalties payable on production of privately–owned minerals are determined by negotiations between the Company and the mineral rights owners. Other royalties and similar interests, such as overriding royalties, gross overriding royalties, net profit interests or net carried interests, may also be carved out of a working interest through non-public transactions.

Governments sometimes adopt incentive programs to stimulate oil and natural gas exploration and development activity in their jurisdictions, which may include royalty rate reductions, drilling credits, royalty holidays, or royalty tax credits. Such programs are often of limited duration and target specified types of oil and natural gas activities.

Alberta

On October 25, 2007, the Government of Alberta released its New Royalty Framework ("**NRF**") proposals, which included significant changes to Alberta's oil and natural gas royalty system applicable to Crown lands. The NRF was implemented on January 1, 2009. On March 11, 2010, the Government of Alberta announced further adjustments to the royalty framework, reducing maximum royalty rates and making certain temporary incentive programs permanent effective January 1, 2011, and re-naming the NRF the Alberta Royalty Framework ("**ARF**").

The ARF established new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and natural gas activities and oil sands projects. Under the ARF, the royalties payable for conventional oil and natural gas are derived using sliding rate formulae, which incorporate a market price component and a production volume component.

In November 2008, in connection with the implementation and phase-in of the NRF, the Alberta Government announced a five-year program of "transitional" royalty rates providing for lower royalties at certain price points in the initial years of a qualifying well's life. Under the transitional royalty program, companies drilling new natural gas and conventional deep oil wells at depths between 1,000 meters and 3,500 meters (3,281 feet and 11,483 feet) spud after November 19, 2008 had a one-time option, on a well-by-well basis, to elect for the production from such wells to be subject to the transitional royalty rates or those provided for under the NRF. The option for producers to elect for transitional royalties in respect of qualifying deep wells ended on December 31, 2010. Any wells spudded on or after January 1, 2011 are subject to the royalty rates provided for under the ARF. Wells that are subject to transitional royalty rates automatically reverted to ARF rates on January 1, 2014.

Under the ARF, royalty rates for conventional oil currently range from 0% to 40% and royalty rates for natural gas (methane and ethane) currently range from 5% to 36%. ARF rates for propane and butane are fixed at 30% and for pentane are fixed at 40%. Condensate royalties under the ARF are calculated on a basis similar to royalties for conventional oil and currently range from 0% to 40%.

The Government of Alberta has also introduced a number of royalty reduction and credit incentive programs to encourage oil and natural gas exploration and development in Alberta, which include the following programs:

- The New Well Royalty Rate, or NWRR, creates incentives for new wells that commence production on or after April 1, 2009. Other wells may also qualify for the NWRR depending on the periods in which they may have previously been shut-in or producing prior to April 1, 2009. Eligible wells under the NWRR are subject to a flat royalty rate of 5% for the first 12 months of production to a maximum of 500 mmcf of natural gas or 50,000 bbls of oil. The NWRR was originally announced in March 2009 as a temporary measure but was made permanent (subject to the same 12-month time and specified volume limitations) on May 1, 2010.

- The Deep Oil Exploration Program provides royalty relief of up to $1,000,000 or 12 months of production, whichever comes first, for qualifying deep exploration oil wells with a true vertical depth greater than 2,000 meters (6,562 feet) that spud on or after January 1, 2009. Wells drilled after December 31, 2013 will not qualify for relief under this program and the relief will expire on December 31, 2018.

- The Natural Gas Deep Drilling Program, as revised effective May 1, 2010, provides for a sliding scale production royalty credit for qualifying deep exploration and development natural gas wells with a true vertical depth greater than 2,000 meters (6,562 feet) that spud on or after May 1, 2010. The production credit is calculated according to the measured (drilled) depth to the bottom of the lowest producing interval of the qualifying wells, and increases at certain trigger depths. The credit ranges from $625 per meter ($191 per foot) to a maximum of $3,000 per meter ($914 per foot) for a qualifying development well and $3,750 per meter ($1,143 per foot) for a qualifying exploration well. A minimum 5% royalty will apply to these natural gas wells.

On May 27, 2010, the Alberta Government announced a number of additional incentive programs for qualifying wells coming on production after May 1, 2010, as follows:

- the Shale Gas New Well Royalty Rate, which extends the 5% NWRR on qualifying shale gas wells from 12 months to 36 months and removes the 500 mmcf volume limit;

- the Coalbed Methane New Well Royalty Rate, which extends the 5% NWRR on qualifying coalbed methane wells from 12 months to 36 months and increases the 500 mmcf volume limit to 750 mmcf;

- the Horizontal Gas New Well Royalty Rate, which extends the 5% NWRR on qualifying horizontal gas wells from 12 months to 18 months and maintains the 500 mmcf volume limit; and

- the Horizontal Oil New Well Royalty Rate, which extends the 5% NWRR on qualifying horizontal oil wells from 12 months to a minimum of 18 months and increases producing time and volume limits according to the measured depth of the well's qualifying interval to a maximum of 48 months or 100,000 bbls, respectively.

Saskatchewan

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

The Crown royalty payable in respect of natural gas depends on the vintage of the gas, the type of gas produced, the quantity of gas produced in a month, and the price of the gas. Natural gas is categorized as either "associated gas" (being gas produced from oil wells) and "non-associated gas (being as produced from gas wells). Additionally, gas is divided into vintage categories, dependent on when the well was drilled ("fourth tier gas", "third tier gas", "new gas", and "old gas"). The royalty is also dependent upon the quantity of gas produced from a well in a month. Finally the royalty is adjusted based on a reference price determined monthly by the Saskatchewan Ministry of Energy and Resources or a reference price determined by the operator of the well based on the average gas price it received in the month. The reference price determined by the Ministry of Energy and Resources is based on the weighted average fieldgate price received by producers during the month for the sale of natural gas subject to royalty.

As of April 2, 2012, Saskatchewan has implemented Petrinex (formerly known as the Petroleum Registry) which is

used by the industry to report specific volumetric, infrastructure, valuation and royalty-related information to the Ministry of Energy and Resources. Pursuant to this implementation, all natural gas, subject to certain exceptions will be based on the Crown determined reference price. Moreover, the volumetric based royalty calculation has been converted to an energy based calculation (expressed in dollars per gigajoule).

The Crown royalty payable in respect of crude oil depends on the vintage of the oil, the type of oil produced, the quantity of oil produced in a month, and the price of the oil. Crude Oil is categorizes as "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". Additional, crude oil is divided into vintage categories, dependent on when the well was drilled ("fourth tier oil", "third tier oil", "new oil", and "old oil"). The royalty is also dependent on the quantity of crude oil produced from a well in a month. Finally, the royalty is adjusted based on a reference price determined monthly by the Ministry of Energy and Resources which is based on the weighted average wellhead price received by producers during the month for the sale of crude oil subject to royalty.

The Government of Saskatchewan has introduced a number of oil and natural gas royalty reduction and credit incentive programs to encourage oil and natural gas exploration and development in Saskatchewan. Such programs include:

- an incentive volume for exploratory oil and gas wells drilled on or after October 1, 2002 and for horizontal gas wells drilled on or after June 1, 2010 and before April 1, 2013. A lower royalty rate applies to natural gas produced from such wells up to 25 million cubic metres.

- a cost sensitive royalty structure that applies to incremental production from enhanced oil recovery projects that are not waterflood projects. There are different royalty structures for projects that commenced operation prior to April 1, 2005 and for those that commence operation on or after April 1, 2005. There is also another royalty structure that applies to incremental oil produced from new or expanded waterflood projects that are implemented on or after October 1, 2002. Each of these royalty structures incorporates lower royalty and freehold production tax rates before the project reaches payout of investment and operating expenditures.

- individual oil wells or a group of them that are either producing conventional oil at an average water-cut of 95% or greater in the twelve calendar months preceding an application under the program or have been shut-in or suspended for twelve or more consecutive calendar months prior to making investments under the program and produced at an average water-cut of 95% or greater during the three producing months immediately preceding the shut-in or suspension qualify for a royalty incentive that is designed to extend the producing lives and improve the recovery rate of high water-cut oil wells. Oil produced from a well that has an average water-cut of 50% or greater that is part of a group of oil wells that produce at an average water-cut of 95% or greater and benefit from the same qualifying investment also qualifies under this incentive program.

Saskatchewan has introduced a new orphan oil and natural gas well and facility program, funded by oil and natural gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

British Columbia

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

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

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

The royalties payable on oil and natural gas may also be reduced pursuant to various incentive programs made available, including royalty credits for deep gas exploration, summer drilling, and infrastructure development, special royalty rates for marginal and ultra-marginal gas, and a recent stimulus package aimed at increasing exploration and production in the British Columbia oil and gas industry. Eligibility for such incentive programs is subject to the satisfaction of specified criteria and conditions provided in legislation, regulation and guidelines.

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 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.

Environmental Regulation

All phases of the oil and natural 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 and surface improvements, such as dwellings. 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, and past and present owners and occupiers of the property. Compliance with such legislation can require significant expenditures and a violation 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 Company to statutory strict liability in the event of an accidental spill or discharge from operations, meaning that fault need not be established by claimants affected by such a spill or discharge.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* (the "**EPEA**") and, for the oil and gas industry, 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 EPEA imposes significant penalties for non-compliance.

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. The South Saskatchewan Regional Plan was approved on July 23, 2014 and will be further developed and implemented from 2014 to 2024. Also, the planning process is well underway for the Lower Athabasca Region (which contains the majority of oil sands development). While the impact of the regional plans developed and implemented under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

In 2008, the Company commenced operations in Saskatchewan , and as such is 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. A new *Environmental Management and Protection Act, 2011* has been passed by the Saskatchewan Legislature, but not yet proclaimed. The new Act will include authority for the *Saskatchewan Environmental Code*, which adopts a new results-based regulatory framework for managing and protecting the environment. The Act and the Code will be proclaimed into force on June 1, 2015.

British Columbia's *Oil and Gas Activities Act* regulates the oil and gas industry, including imposing environmental standards, requiring compliance, reporting and monitoring obligations and imposing penalties.

On February 27, 2007, the Government of British Columbia unveiled the BC Energy Plan, which outlines the province's energy strategy. The BC Energy Plan sets targets for reducing greenhouse gas ("GHG") emissions, promoting investments in innovation, and sustainable environmental management. The BC Energy Plan's objectives are to achieve clean energy through conservation and energy efficient practices, and to increase competitiveness in order to attract new investment in the oil and natural gas industry. The changes proposed include: (i) the creation of policies and measures for the reduction of emissions; (ii) the elimination of routine flaring at producing wells; (iii) the establishment of the Innovative Clean Energy Fund, in order to find new technologies that will help solve energy and environmental issues; (iv) a new Oil and Gas Technology Transfer Incentive Program, which encourages the research, development and use of innovative technologies to responsibly develop new oil and gas reserves and increase recoveries from existing reserves; and (v) the development of unconventional resources such as tight gas and coalbed gas.

In furtherance of these initiatives, the Government of British Columbia introduced the *Carbon Tax Act* on July 1, 2008. The carbon tax applies to fuels such as gasoline, diesel, natural gas, propane and coal, and it is revenue-neutral, meaning tax revenues will be returned to taxpayers through reductions in other provincial taxes.

On May 29, 2008, the Government of British Columbia enacted the *Greenhouse Gas Reduction (Cap and Trade) Act*, which allows participation in the Western Climate Initiative cap and trade systems being developed. The proposed system establishes a limit on GHG emissions, and allows regulated emitters to buy/sell GHG emission allowances or offset emits. The emitter is obliged to obtain GHG emission allowances (compliance units) which are equal to the amount of GHG emitted within a certain period of time, which are then to be surrendered to the British Columbia government as proof of compliance.

In support of an eventual cap and trade system, British Columbia has also enacted certain regulations under the *Greenhouse Gas Reduction (Cap and Trade) Act*, including the *Reporting Regulation* which was approved by the Governor in Council on November 25, 2009. The *Reporting Regulation* sets out the requirements for the reporting of the greenhouse gas emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under further development.

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 the Company to incur costs to remedy any such discharge not covered by the Company's insurance. Although the Company 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, the Company 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 reduction devices and the verification of emissions data.

The Company believes it is in material compliance with environmental legislation at this time. The Company 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 Company's financial condition, results of operations or prospects.

The Company estimates abandonment and reclamation costs by taking into consideration the costs associated with decommissioning, abandonment, remediation, and reclamation, and also includes the salvage values of any existing equipment which can be reasonably salvaged, all adjusted according to its working interest and discounted in accordance with NI 51-101. The costs and salvage values are individually attributed to assets then aggregated to determine the aggregate liability.

Title to Properties

Title to the Company's oil and natural gas properties may be subject to royalty, overriding royalty, carried, net profits, working, and similar interests customary in the oil and natural gas industry.

The Company's leases could be subject to prior unregistered agreements or interests, or claims or interests of which the Company is currently unaware. If such an event were to occur, the Company's rights to the production and reserves associated with such leases could be jeopardized, which could have a material adverse effect on the Company's results of operations, financial condition and prospects.

Prior to the commencement of drilling operations often a title examination and, if necessary, curative work is performed. The methods of title examination that the Company has adopted are reasonable in the opinion of management and are designed to ensure that production from the Company's properties, if obtained, will be saleable for the Company's account.

Competitive Conditions

The oil and natural gas industry is highly competitive. The Company competes for acquisitions and in the exploration, development, production and marketing of oil and natural gas with numerous other participants, some of whom may have greater financial resources, staff and facilities than the Company.

The Company's ability to increase reserves in the future will depend not only on its ability to develop or continue to develop existing properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods and reliability of delivery and availability of imported products.

Environmental and Worker Protection

The Company's operations are subject to environmental and occupational health and safety regulations. Such regulations cover a wide variety of matters, including, without limitation, prevention of waste, pollution and protection of the environment, labour regulations and worker safety. Under such regulations there are clean-up costs and liabilities for toxic or hazardous substances which may exist on or under any of its properties or which may be produced as a result of its operations. Environmental legislation and legislation relating to exploration and production of natural resources are likely to evolve in a manner which will require stricter standards and

enforcement, increased fines and penalties for non-compliance, more stringent environmental assessments of proposed projects and a heightened degree of responsibility for companies and their directors and employees. Such stricter standards could impact on the Company's costs and have a material adverse effect on the Company's business, financial condition or results of operations. See "*Risk Factors*" in this AIF.

Specialized Skill and Knowledge

The Company believes its success is largely dependent on the performance of its management and key employees, many of whom have specialized skills and knowledge relating to oil and natural gas operations. The Company believes that it has adequate personnel with the specialized skills and knowledge to successfully carry out the Company's business and operations.

Greenhouse Gases and Industrial Air Pollutants

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol (the "**Kyoto Protocol**") established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other GHGs. However, the Government of Canada has concluded that Canada will not meet its commitment to the Kyoto Protocol and has been developing an alternative strategy for reducing Canada's GHG emissions. On December 5, 2011, Canada announced that it would be withdrawing as a signatory to the Kyoto Protocol.

Over the last several years, the federal Government has undertaken a number of initiatives to achieve domestic GHG reductions. These measures include regulations, codes and standards, targeted investments, incentives, tax measures and programs that directly reduce GHG emissions.

Going forward, the Government has announced that it will focus on a sector-by-sector regulatory approach, beginning with the largest sources of emissions. Given the high degree of economic integration between Canada and the U.S., Canada has stated that it will be aligned with future U.S. emissions reduction regulations where it is appropriate and in Canada's best interests to do so. This regulatory agenda will continue to be supported by targeted complementary measures designed to advance Canada's transition to a clean energy economy.

Under Canada's plan to address climate change, actions have been taken regarding two of the largest sources of GHG emissions: the electricity and transportation sectors. The oil sands industry is expected to be a sector of the economy where the federal Government will next regulate GHG emissions.

There has been much public debate surrounding Canada's ability to meet emission reduction targets and the strategies proposed for controlling climate change and GHG emissions. It is likely that any such strategies which are eventually adopted by the Canadian government will materially impact the nature of oil and gas operations, including those carried out by the Company. At present, it is not possible to predict the impact such strategies will have on the business, operations and/or finances of the Company.

Alberta

Alberta currently regulates GHG emissions under the *Climate Change and Emissions Management Act*, the Specified Gas Reporting Regulation (the "**SGRR**"), which imposes GHG emissions reporting requirements, and the *Specified Gas Emitters Regulation* (the "**SGER**"), which imposes GHG emissions limits. Under the SGRR, GHG emissions of 100,000 tonnes or more from a facility in any year must be reported to Alberta Environment an Sustainable Resource Department ("ESRD"). ESRD has publicly announced its intention to lower this reporting threshold for facilities to 50,000 tonnes of GHG emissions annually. The SGER applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year and requires reductions in GHG emissions intensity (i.e. the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000, or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005, and for a new facility emissions intensity in the third year of commercial operation. For an

established facility, the required reduction in GHG emissions is 12% from its baseline, and such reduction must be maintained over time. For a new facility, the reduction requirement from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the maximum 12% reduction requirement imposed on established facilities is reached.

There are three ways to comply with reduction requirements: (i) actual physical reductions in GHG emissions intensity; (ii) purchase of Alberta–based emission offset credits and/or emission performance credits; or (iii) purchase of fund credits at a cost of $15 per tonne of GHG emissions, with the proceeds going to the Government of Alberta's Climate Change and Emissions Management Fund. Compliance reports to ESRD for facilities subject to the SGER are due on March 31 annually. The Government of Alberta has previously announced in its 2008 Provincial Energy Strategy that it may modify the SGER towards stricter standards. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations.

Saskatchewan

The *Management and Reduction of Greenhouse Gases Act* received Royal Assent in the Province of Saskatchewan on May 20, 2010. However, this Act is still awaiting proclamation. The Act sets a policy and regulatory framework for reducing GHG emissions in Saskatchewan and sets a provincial target of a 20% reduction in GHG emission from 2006 levels by 2020. The specific GHG emission reduction requirements, and the industries required to meet those reductions, as well as details on the methods by which reductions may be achieved, are to be set by further regulations. It is expect that facilities which emit 50,000 tonnes of CO_2 per year will be required to reduce GHG emissions by 2% per year over a baseline emission level from 2010 to 2019. New facilities constructed after 2006 that have emissions of 50,000 tonnes of CO_2 annually will also be required to achieve emission reduction targets.

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at $10 per tonne of CO2 equivalent and increased at a rate of $5 per tonne of CO2 equivalent on July 1 of every year until it reached $30 per tonne of CO2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On May 29, 2008, the Government of British Columbia enacted the *Greenhouse Gas Reduction (Cap and Trade) Act*, which allows for participation in the Western Climate Initiative cap and trade system currently being developed by a group of Canadian Provinces and US States. The proposed system establishes a limit on GHG emissions, and allows regulated emitters to buy/sell GHG emission allowances or offset credits. The emitter is obliged to obtain GHG emission allowances (compliance units) which are equal to the amount of GHG emissions released within a certain period of time, which are then to be surrendered to the Government of British Columbia as proof of compliance. In support of an eventual cap and trade system, British Columbia has also enacted certain regulations under the *Greenhouse Gas Reduction (Cap and Trade) Act*, including the *Reporting Regulation* which sets out the requirements for the reporting of greenhouse gas emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under further development.

RISK FACTORS

An investment in Common Shares would be subject to certain risks. Investors should carefully consider the following risk factors:

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on future exploration by the Company will result in new discoveries of oil or natural gas in commercial quantities. It is

difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The Company currently has a limited number of specific identified exploration or development prospects. Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and their past practices. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

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

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires, spills or leaks. These risks could result in personal injury, loss of life, and environmental or property damage. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Limitations of Insurance

The Company's involvement in the exploration for and development of oil and gas properties may result in the Company becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although the Company has obtained insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Company's financial position, results of operations or prospects.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil, NGL and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of the Company. World prices for oil and natural gas have fluctuated widely in recent years and in particular over the past six months and are determined by supply and demand factors and a variety of other factors which are beyond the Company’s control, including without limitation, worldwide and domestic supplies of, and demand for, oil, NGL and natural gas; price levels and expectations about future prices of oil, NGL and natural gas; the price and level of foreign imports; OPEC’s policies and actions; speculative trading in oil, NGL and natural gas derivative contracts; conflicts in oil and natural gas producing regions, including the Middle East, South America and Russia; and the overall domestic and global economic environment. Oil, NGL and natural gas prices are expected to remain volatile and at relatively low prices for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC policies and actions and sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of the Company's oil and gas reserves. The

Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Company are in part determined by the borrowing base of the Company. A sustained material decline in prices from historical average prices could limit or reduce the Company's borrowing base, therefore reducing the bank credit available to the Company, and could require that a portion of any existing bank debt of the Company be repaid.

In addition to establishing markets for its oil and natural gas, the Company must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by the Company will be affected by numerous factors beyond its control. The Company will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by the Company. The ability of the Company to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Company will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business. The Company has limited direct experience in the marketing of oil and natural gas.

Substantial Capital Requirements; Liquidity

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

Financial Markets

In the future, the Company may require financing to grow its business. The Company's costs associated with borrowing, liquidity and its ability to access the credit or capital markets may also be adversely affected by changes in the financial markets, commodity prices and the global economy generally. Any turmoil in the financial markets could make it more difficult for the Company to access capital, sell assets, refinance existing indebtedness, enter into agreements for new indebtedness or obtain funding through the issuance of securities. In addition, there could be a number of follow-on effects from turmoil in the financial markets that may directly impact the Company, including insolvency of customers, key suppliers and other counterparties to the Company and foreign exchange derivative instruments.

Competitive Conditions

The Company actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than the Company. The Company's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. The Company's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities, include companies that have greater financial and personnel resources available to them than the Company.

Certain of the Company's customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect the Company's ability to sell or supply oil or gas to these customers in the future. The Company's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate

transactions in a highly competitive environment.

Environmental Protection Requirements

All phases of the oil and natural 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. 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.

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 Company estimates the liability associated with its legal asset retirement obligations and provides for this estimate in its financial statements. Such liability will be funded by future cash flow as required.

The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require the Company to incur costs to remedy such discharge. 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 adversely affect the Company's financial condition, results of operations or prospects.

Reserve Replacement

The Company's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Company successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on the Company'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 the Company's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Reliance on Operators and Key Employees

The Company may not be the operator of certain oil and gas properties in which it acquires an interest. To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Company will be largely dependent upon the performance of its management and key employees. The Company does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Company.

Corporate Matters

Certain of the directors and officers of the Company are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of the Company and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the ABCA.

Permits and Licenses

The operations of the Company may require licenses and permits from various governmental authorities. There

can be no assurance that the Company will be able to obtain all necessary licenses and permits that may be required to carry out its exploration and development projects. In addition, the requirements applicable to sustain existing permits and licenses may change or become more stringent over time and there is no assurance that the Company will have the resources or expertise to meet its obligations under such licenses and permits.

Additional Funding Requirements

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

Issuance of Debt

From time to time the Company may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Availability of Drilling Equipment and Access Restrictions

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Company 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 Company's net production revenue.

In addition, the Company's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Company's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on the Company. The Company will not have insurance to protect against the risk from terrorism.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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. 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 natural gas industry could reduce demand for natural gas and crude oil and increase the Company's costs, any of which may have a material adverse effect on the Company's intended business, financial condition and results of operations. In order to conduct oil and natural gas operations, the Company will require licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. See *"Industry Conditions"* in this AIF.

Aboriginal Claims

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

Business Cycle and Seasonality

The level of activity in the Canadian oil and natural 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 natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company. Furthermore, while the Company's business is generally not cyclical, its revenue from the sale of natural gas is highly seasonal, with demand for natural gas rising during cold winter months and hot summer months.

Title to Assets

While title reviews will generally be conducted prior to the purchase of most 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 Company's claim which could result in a reduction of the revenue received by the Company.

Management of Growth

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

Hedging

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

Third Party Credit Risk

The Company is or 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 Company, such failures could have a material adverse effect on the Company and its cash flow from operations. 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 Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

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. The Company 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 Company's business, financial condition, results of operations and cash flows.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings involving claims for damages for which the potential exposure is more than 10% of Spyglass' current assets to which Spyglass is or was a party or in respect of which any of its properties are or were subject during the year ended December 31, 2014, nor are there any such proceedings known to Spyglass to be contemplated.

During the year ended December 31, 2014, there were (i) no penalties or sanctions imposed against Spyglass by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against Spyglass that it believes would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by Spyglass with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as may be disclosed elsewhere in this AIF, none of the directors, officers or principal shareholders of Spyglass, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction which has materially affected or is reasonably expected to materially affect Spyglass or any of its affiliates.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of Spyglass are PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5th Avenue SW, Calgary, Alberta, T2P 5L3. PricewaterhouseCoopers LLP have been the auditors of Spyglass since the completion of the Arrangement.

The transfer agent and registrar for the Common Shares is Computershare Investor Services at its principal offices in Calgary, Alberta.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTEREST OF EXPERTS

The McDaniel Report was prepared by McDaniel. As at the date of preparation of the McDaniel Report, the directors, officers, employees and consultants of McDaniel who participated in the preparation of the McDaniel Report or who were in a position to directly influence the preparation or outcome of the preparation of the

McDaniel Report, as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares.

An audit report contained in filings made by Spyglass under National Instrument 51-102 – Continuous Disclosure Requirements during the year ended December 31, 2014 was prepared by PricewaterhouseCoopers LLP. PricewaterhouseCoopers LLP were appointed auditors of Spyglass upon the completion of the Arrangement and are independent of Spyglass pursuant to the rules of professional conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information concerning Spyglass may be found under Spyglass' profile on SEDAR at www.sedar.com. Additional information, including information concerning directors' and officers' remuneration and indebtedness, and principal holders of Spyglass' securities is contained in the information circular of Spyglass dated March 25, 2015 in respect of the annual general meeting of holders of Common Shares held on May 13, 2015. Additional financial information is provided in Spyglass' comparative consolidated financial statements and management's discussion and analysis for the year ended December 31, 2014.

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SCHEDULE A

AUDIT COMMITTEE CHARTER

This Charter sets out the roles and responsibilities of the Audit Committee of Spyglass Resources Corp. ("Spyglass" or the "Company"). The roles and responsibilities described in this Charter must be exercised in accordance with the requirements of the legislation and regulations governing the Company.

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Spyglass Resources Corp. ("Spyglass ") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

Audit Committee Objectives

The primary objectives of the Committee are as follows:

- to assist directors in meeting their responsibilities in respect of the review and approval of the financial statements of Spyglass and related documentation;
- to provide a communication link between independent directors and external auditors;
- to enhance the external auditor's independence;
- to increase the credibility and objectivity of financial reports; and
- to strengthen the role of the outside directors by facilitating meaningful discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee shall be comprised of at least three directors of Spyglass, none of whom are members of management of Spyglass and all of whom are independent under applicable securities laws and regulations or as otherwise permitted thereunder.

2. The Board shall appoint the Committee Chair, who shall be an independent director.

3. All of the members of the Committee shall be "financially literate" as required under applicable laws and regulations.

Audit Committee Responsibilities

4. The Committee shall provide oversight on the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

5. The Committee shall satisfy itself on behalf of the Board with respect to Spyglass 's Internal Control Systems and its ability to:

    - identify, monitor and mitigate financial risks; and
    - oversee Management's establishment and maintenance of processes to provide for compliance with legal, ethical and regulatory requirements.

    The primary responsibility of the Committee is to review the annual and interim financial statements of Spyglass and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:

    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
    - reviewing significant accruals, reserves or other estimates and judgements such as the impairment tests;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - reviewing disclosure requirements for commitments and contingencies;
    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    - reviewing unresolved differences between management and the external auditors; and
    - obtaining explanations of significant variances with comparative reporting periods.

    The Committee is to review the financial statements, prospectuses, MD&A, annual information form ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Spyglass' disclosure of all other financial information.

    With respect to the appointment of external auditors by the Board, the Committee shall:

    - recommend to the Board the external auditors to be nominated;
    - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;
    - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
    - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
    - review and pre-approve any non-audit services to be provided to Spyglass or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

In consultation with the CEO, review and approve suitable candidates for CFO position and recommend to the Board for approval.

Review with external auditors (and internal auditor if one is appointed by Spyglass) their assessment of the internal controls of Spyglass, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Spyglass and its subsidiaries.

The Committee shall review with Management and the external auditor, significant financial risks and exposures and review, assess and oversee steps Management has taken to identify, manage and mitigate such risks and exposures. This relates to financial, reporting, internal controls, information services, insurance and business continuity.

The Committee shall establish a procedure for:

- the receipt, retention and treatment of complaints received by Spyglass regarding accounting, internal accounting controls or auditing matters; and
- the confidential, anonymous submission by employees of Spyglass of concerns regarding questionable accounting or auditing matters.

The Committee shall review and be apprised of any intent of Spyglass regarding the hiring of partners and employees who work on Spyglass 's account and former partners and employees of the present and former external auditors of Spyglass .

The Committee shall review and act accordingly under any complaints received under the Corporation's Whistleblower policy.

The Committee shall have the authority to investigate any financial activity of Spyglass. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of Spyglass without any further approval of the Board.

Meetings and Administrative Matters

6. At meetings of the Committee motions shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall not be entitled to a second or casting vote.

7. The Chair shall preside at meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.

8. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Board.

9. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair.

10. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at least quarterly with the preparation of the Interim unaudited financial statements and such other times as the external auditor and the Committee consider appropriate. At each of these meetings, the Committee will have an "in-camera" session with the external auditors.

11. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

12. The Committee may invite such officers, directors and employees of Spyglass as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.

13. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

14. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of Spyglass.

15. Any member of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its qualified members. If a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders following appointment as a member of the Committee.

16. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chair of the Board by the Committee Chair.

Definitions – In this Charter:

"**financially literate**" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by Spyglass 's financial statements.

TERMS OF REFERENCE FOR THE AUDIT COMMITTEE CHAIR

The following sets forth the terms of reference of chair ("**Chair**") of the Audit Committee (the "**Committee**") of the board of directors (the "**Board**") of Spyglass Resources Corp. (the "**Corporation**")

Introduction

- The Chair is appointed annually by and reports to the Board;
- The Chair's primary role is managing the affairs of the Committee, including ensuring the Committee is organized properly, functions effectively and meets its obligations and responsibilities, including those matters set forth in the mandate of the Committee;
- The Chair works with the Chief Financial Officer ("**CFO**") of the Corporation to ensure an effective working relationship with Committee members;
- The Chair maintains on-going communications with the CFO and with such other officers and employees of the Corporation as the Chair determines appropriate; and
- The Chair, in conjunction with the Committee, maintains ongoing communications with the external auditors of the Corporation.

Duties and Responsibilities

Working With the Corporation and Corporation's External Auditors

The Chair has the responsibility to:

- lead the Committee in overseeing the work of the Corporation's financial management team and the Corporation's external auditors;
- lead the Committee in overseeing the integrity of the Corporation's financial statements and financial reporting process, including the audit process and review and approval of changes to accounting policies, and the Corporation's internal accounting controls and procedures and compliance with related legal and regulatory requirements; and
- report to the Board after each Committee meeting at the Board's next meeting.

Managing the Committee

The Chair has the responsibility to:

- assist the Committee in understanding its obligations to the Board and pursuant to applicable law;
- chair Committee meetings;
- establish the frequency of Committee meetings and review such frequency from time to time, as considered appropriate (provided, however, that Committee meetings shall be called by the Chair at the request of two members of the Committee or at the request of the Corporation's external auditors);
- in conjunction with the Governance, Human Resources and Compensation Committee, review and assess Committee members' attendance, performance and suitability, and the size and composition of the Committee;
- ensure the proper co-ordination of the agenda, information packages and related events for Committee meetings in conjunction with the CFO;
- maintain a liaison and communication with Committee members, other directors and the Board Chair to co-ordinate input from Committee members and directors, and optimize the effectiveness of the Committee; and
- in collaboration with the CFO, ensure information requested by Committee members is provided and meets their needs.

SCHEDULE B

FORM 51-101F2

REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD.

To the Board of Directors of Spyglass Resources Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014 estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

		Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Preparation Date of Evaluation Report	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
February 25, 2015	Canada	–	517,891.40	–	517,891.40

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

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

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

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(signed)
P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
February 25, 2015

SCHEDULE C

FORM 51-101F3

Report of Management and Directors on Reserves Data and Other Information

Management of Spyglass Resources Corp. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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

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

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

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

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information, which can be found in the company's A*nnual Information Form*;

(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 judgments regarding future events, actual results will vary and the variations may be material.

(*signed)*
Daniel J. O'Byrne, President & Chief Executive Officer

(*signed*)
Mark N. Walker, Senior Vice President Finance and Chief Financial Officer

(signed)
Jeffrey T. Smith, Director

(signed)
John D. Wright, Director

Dated: March 10, 2015