BOWOOD ENERGY INC.

ANNUAL INFORMATION FORM

for the year ended December 31, 2011

April 20, 2012

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following is a glossary of certain terms used in this Annual Information Form and exhibits hereto. 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.

"**ABCA**" means the *Business Corporations Act* (Alberta), from time to time as amended or re-enacted, including the regulations promulgated thereunder;

"**Acquired Blood Assets**" means the lease and other related assets acquired by the Corporation pursuant to the Acquisition and described under the heading "*Blood Acquisition*";

"**Acquisition**" means the acquisition by the Corporation of the Acquired Blood Assets pursuant to the Acquisition Agreement;

"**Acquisition Agreement**" means the letter agreement dated September 1, 2010 between the Corporation and the Vendor with respect to the Acquisition;

"**Amalgamation**" means the amalgamation of Numberco and Old Bowood under the provisions of the ABCA on the terms and conditions set forth in the Amalgamation Agreement;

"**Amalgamation Agreement**" means the amalgamation agreement among Old Bowood, Numberco and Bowood dated November 18, 2009 providing for the Amalgamation;

"**Bowood**" or the "**Corporation**" means Bowood Energy Inc., a corporation continued under the CBCA, formerly Roadrunner Oil & Gas Inc.;

"**Bowood Board**" or "**Bowood Board of Directors**" means the board of directors of Bowood as it may be constituted from time to time;

"**Bowood Option**" means an option to purchase Bowood Shares issued to directors, officers, employees and consultants pursuant to the Bowood Option Plan;

"**Bowood Option Plan**" means the stock option plan of Bowood ratified and confirmed by the shareholders on June 9, 2010;

"**Bowood Share**" means a common share in the capital of Bowood;

"**Brokered Private Placement**" means the brokered private placement financing completed by Bowood concurrently with the Amalgamation pursuant to which Bowood raised gross proceeds of $4,688,969.89 by the sale and issue of 15,410,000 Bowood Shares at a price of $0.15 per share and 13,985,117 Bowood Shares issued on a "flow through" basis priced at $0.17 per share;

"**CBCA**" means the Canada Business Corporations Act as amended or re-enacted, including the regulations promulgated thereunder;

6761899_5|CALDOCS

"**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;

"**GLJ**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the independent engineering evaluations of Bowood's oil, NGL and natural gas interests prepared by GLJ effective December 31, 2011 and dated March 27, 2012;

"**material adverse effect**" means with respect to a party, any matter or action that has an effect or change that is, or would reasonably be expected to be, material and adverse to the business, operations, assets, capitalization, financial condition or prospects of the party and its subsidiaries, taken as a whole, other than any matter, action, effect or change relating to or resulting from: (i) general economic, financial, currency exchange, securities or commodity prices in Canada or elsewhere; (ii) conditions affecting the oil and gas exploration, exploitation, development and production industry as a whole, and not specifically relating to the party and/or its subsidiaries, including changes in laws (including tax laws) and royalties; (iii) any decline in crude oil or natural gas prices on a current or forward basis; (iv) any matter which has been communicated in writing to the other party as of the date of the Amalgamation Agreement; or (v) any changes or effects arising from matters permitted or contemplated by the Amalgamation Agreement or consented to or approved in writing by the other party;

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

"**Numberco**" means 1501976 Alberta Ltd., a corporation incorporated under the ABCA and a wholly-owned subsidiary of Bowood;

"**Offering**" means the offering by the Corporation pursuant to a short form prospectus of 88,000,000 subscription receipts at a price of $0.25 per subscription receipt which closed on September 21, 2010, each subscription receipt converting into one Bowood Share upon the closing of the Acquisition;

"**Old Bowood**" means, prior to the Amalgamation, Bowood Energy Corp., a corporation incorporated under the ABCA, and following the Amalgamation, means Bowood Energy Ltd., a corporation amalgamated under the ABCA and currently a subsidiary of Bowood;

"**person**" includes any individual, firm, partnership, joint venture, venture capital fund, association, trust, trustee, executor, administrator, legal personal representative, estate group, body corporate, corporation, unincorporated association or organization, governmental entity, syndicate or other entity, whether or not having legal status;

"**Subsidiary**" has the meaning ascribed thereto in the ABCA;

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

"**Vendor**" means Kainaiwa Resources Inc.

Words importing the singular include the plural and vice-versa and words importing any gender include all genders.

Abbreviations and Conversion

In this Annual Information Form, 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
bbl/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 metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	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 metres
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 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 Bowood's natural gas and petroleum reserves does not represent the fair market value of Bowood's reserves.

Caution Respecting BOE

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

Definitions

Certain terms used in this Annual Information Form in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this Annual Information Form, 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.

Special Note Regarding Forward-Looking Statements

This Annual Information Form contains forward-looking statements. 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 statements. More particularly, this Annual Information Form contains forward-looking statements with respect to: (i) the anticipated timing of expenditures by Bowood to satisfy its asset retirement obligations; (ii) the anticipated impact of environmental laws and regulations on Bowood; (iii) Bowood's plans for the development of its proven and probable undeveloped reserves; (iv) Bowood's plans for funding future development costs; (v) Bowood's tax horizon; (vi) Bowood's planned capital expenditures and drilling activity in 2011; and (vii) the anticipated impact on Bowood of the factors discussed under the heading "Industry Conditions".

The forward-looking statements are based on certain key expectations and assumptions made by Bowood, including, but not limited to:

- oil and natural gas production levels;
- prevailing commodity prices and exchange rates;
- availability of labour and drilling equipment;
- timing and amount of capital expenditures;
- general economic and financial market conditions;

- government regulation in the areas of taxation, royalty rates and environmental protection; and
- the success of exploration and development activities.

Although Bowood believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Bowood can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to:

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling, production and processing problems;
- changes in legislation, including changes in tax laws, royalty rates and incentive programs relating to the oil and natural gas industry; and
- the other factors discussed under "Risk Factors".

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Bowood does not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

BOWOOD ENERGY INC.

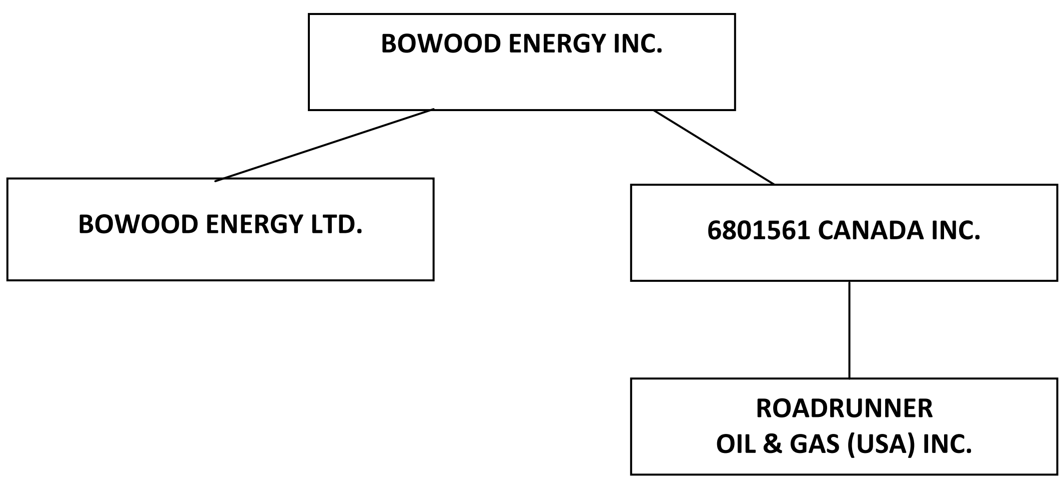
Bowood is a corporation engaged in the acquisition, exploration, development and production of oil and gas resources. Bowood was incorporated in British Columbia on January 30, 1987, under the name "Englefield Resources Ltd.". On April 22, 1992, it amended its articles to change its name to "Valu Concepts International Corp.". On September 8, 1994, it continued under the *Canada Business Corporations Act* under the name "Double Impact Communications Corp.". Bowood amended its articles on August 20, 1998 to change its name to "Next Millennium Commercial Corp." and consolidated its issued and outstanding common shares on a one for four basis. On July 17, 2008, Bowood amended its articles again to change its name to "Roadrunner Oil & Gas Inc.". On June 10, 2010, Bowood amended its articles again to change its name from "Roadrunner Oil & Gas Inc." to "Bowood Energy Inc.". Bowood is extra-provincially registered in the Provinces of British Columbia and Alberta.

Bowood's head office is located at Suite 1850, 717 – 7th Avenue S.W., Calgary, Alberta, T2P 0Z3, and its registered office is located at 850 - 2nd Street SW, Calgary AB, T2P 0R8.

Bowood is a reporting issuer in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario and Quebec and the Bowood Shares are listed and posted for trading on the TSXV under the symbol "BWD".

On December 22, 2009, Numberco amalgamated with Old Bowood and continued under the name Bowood Energy Ltd. and continued the business previously conducted by Old Bowood. Bowood also completed the Brokered Private Placement. Bowood's business currently consists of the business conducted by Old Bowood. Bowood Energy Ltd. is a wholly-owned subsidiary of Bowood.

Bowood owns all of the issued and outstanding shares of 6801561 Canada Inc. ("**6801561**"), a corporation incorporated under the federal laws of Canada, and all of the issued and outstanding shares of Bowood. 6801561 owns all of the issued and outstanding shares of Roadrunner Oil & Gas (USA) Inc. ("**Bowood USA**"), a company incorporated under the laws of Michigan. See below for a diagram setting forth the current corporate structure of Bowood.



DESCRIPTION OF THE BUSINESS

General

Bowood is currently engaged in the exploration, acquisition, development and production of oil and natural gas reserves primarily in the province of Alberta. Bowood currently has approximately 590 BOE/d of production (February 2012 average), weighted 77% to natural gas and 23% to light oil and natural gas liquids, and net interests of approximately 121,593 acres of undeveloped land in Canada and approximately 15,763 acres of undeveloped land in the United States.

Corporate Strategy

Bowood's business plan is to create sustainable and profitable per share growth in reserves, production and cash flow in western Canada. To accomplish this, Bowood pursues an integrated growth strategy including focused acquisitions, scaleable development projects, together with development and exploration drilling within its geographic project areas in Alberta. Bowood pursues the internal generation of exploration plays that have medium risk and multi-zone potential. Bowood intends to maintain a balance between exploration, exploitation and development drilling for oil and gas reserves, although management of Bowood will also consider asset and corporate acquisition opportunities that meet Bowood's business parameters. To achieve sustainable and profitable growth, management of Bowood believes in controlling the timing and costs of its projects wherever possible. Accordingly, Bowood seeks to become the operator of its properties to the greatest extent possible. Further, to minimize competition within its geographic areas of interest, Bowood strives to maximize its working interest ownership in its properties where reasonably possible. Bowood also implements strategic joint venture agreements to mitigate capital risk in exploration plays in furtherance of its business plan. Management of Bowood has industry experience in producing areas in western Canada and has the capability to expand the scope of its activities as opportunities arise. In reviewing potential drilling or acquisition opportunities, Bowood gives consideration to the following criteria:

(a) risk capital to secure or evaluate the opportunity;

(b) the potential return on the project, if successful;

(c) the likelihood of success; and

(d) risked return versus cost of capital.

In general, Bowood pursues a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure in an attempt to generate sustainable high levels of growth.

It should be noted that the Bowood Board may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon the Bowood Board's consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

Competition

The oil and natural gas industry is competitive in all its phases. Bowood competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Bowood's competitors include resource companies which have greater financial resources, staff and facilities than those of Bowood. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Bowood 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.

Environmental Regulation

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

Cyclical Nature of Business

Bowood's business is generally cyclical. The exploration and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variation, including freeze-up and break-up, affect access in certain circumstances.

Renegotiation or Termination of Contracts

It is not expected that Bowood's business will be affected in the current financial year by the renegotiation or termination of contracts or sub-contracts.

GENERAL DEVELOPMENT OF THE BUSINESS

General

Prior to its entry into the oil and gas business, Bowood had been inactive for several years. It had sold its operating subsidiary, Learning Systems Inc., in April, 2005.

In 2006, Bowood added new members to its board of directors and changed its corporate strategy to pursue opportunities in the oil and gas industry. In November 2006, Bowood entered into an agreement with Opal Energy Inc. to acquire a 25% working interest in the Sue Ann Tacquard #1 Well in Galveston, Texas.

In April 2008, Bowood acquired a private oil and gas company, Roadrunner Oil & Gas Inc. (now Roadrunner Oil & Gas (USA) Inc.), with approximately 30,000 acres located in Michigan. In June 2008, Bowood began its drilling program in Michigan. Bowood drilled two wells into the A-1 formation in order to prove the viability of the resource. Although there was some technical success, neither of these wells encountered economic hydrocarbons. Bowood decided not to pursue the development of these properties.

In 2008, Bowood also began acquiring its acreage position in North Dakota and entered into agreements to acquire its lease positions in Utah and Colorado.

In October 2008, Bowood appointed an experienced oil and gas executive as a new President of the company as well as a new Chief Financial Officer. For several months prior to this time, these individuals had been providing contract services to Bowood. With the appointments, Bowood's principal office moved to Denver, Colorado.

In June 2009, Bowood acquired additional oil and gas interests in Colorado. In October 2009, Bowood sold its interests in its North Dakota properties.

From 2007 to 2009 Bowood focused exclusively on exploring neglected oil horizons. It had conducted these development initiatives with partners or by itself. None of the wells in which Bowood has participated to date have demonstrated sufficient promise to warrant further exploration activities. Bowood's acreage positions in the Paradox Basin (San Juan County, Utah and San Miguel County, Colorado) have not been drilled. In October, 2009 Bowood announced the Amalgamation.

The Amalgamation

On November 18, 2009, Old Bowood, Numberco and Bowood entered into the Amalgamation Agreement. The Amalgamation was completed on December 22, 2009. Details of the Amalgamation, including financial information regarding Bowood can be found in the Business Acquisition Report of Bowood dated March 4, 2010, which information is hereby incorporated by reference.

Post-Amalgamation Operations

Following the Amalgamation, Bowood continued the operations and business of Old Bowood.

Bowood is currently engaged in the exploration, acquisition, development and production of oil and natural gas reserves primarily in the province of Alberta. Bowood currently has approximately 590 BOE/d of production (February 2012 average), weighted 77% to natural gas and 23% to light oil and natural gas liquids, and net interests in approximately 121,593 acres of undeveloped land in Canada and approximately 15,763 acres of undeveloped land in the United States.

Corporate Matters

Franco Civitarese was appointed as the new Chief Financial Officer on February 28, 2011.

In January of 2012, Pat Oliver resigned from the Board of Directors of Bowood.

In February of 2012, the Board of Directors determined to evaluate a range of strategic alternatives aimed at enhancing shareholder value. Bowood has engaged the services of GMP Securities to advise on these matters. There are no guarantees that the strategic review process will result in any transaction or, if a transaction were undertaken, as to its terms or timing.

Blood Acquisition

On September 1, 2010, the Corporation and the Vendor, a corporation wholly owned by the Blood Tribe First Nation (the "**Blood Tribe**"), entered into the Acquisition Agreement. Pursuant to the Acquisition, Bowood Energy Ltd., the operating subsidiary of the Corporation, acquired a lease (the "**Lease**") comprising 94.75 contiguous sections (24,256 hectares) of petroleum and natural gas rights (the “**Acquired Blood Assets**”).

The Acquired Blood Assets are located in southern Alberta between Townships 7, 8 and 9 and Ranges 22W4, 23W4 and 24W4. In total, the Acquired Blood Assets comprise 94.75 net sections (24,256 net hectares) of contiguous land and oil & gas mineral rights on trend and prospective for Devonian-Mississippian (Bakken equivalent) oil potential.

The Acquired Blood Assets included no producing wells and consisted only of a lease over undeveloped land. There were no reserves associated with the Acquired Blood Assets. Closing of the Acquisition occurred on October 25, 2010. The cash consideration paid by the Corporation pursuant to the

Acquisition was $14,128,000. The Corporation funded such amount with the net proceeds of the Offering. As the net proceeds of the Offering exceeded the consideration payable by the Corporation pursuant to the Acquisition, the Corporation used the remaining proceeds for its 2010 capital expenditure program and for general corporate purposes, in addition to paying down debt that was incurred to pay for the Corporation's capital expenditure program during 2010.

Pursuant to the Acquisition, the Corporation paid a land bonus to Her Majesty the Queen in Right of Canada, as represented by Indian Oil & Gas Canada ("**IOGC**"), on behalf of the Vendor and the Blood Tribe, in the amount of $12,128,000, as well as annual rent in the amount of $5.00 per hectare (approximately $122,000 per year). The initial term of the Lease was five years with royalties to be paid at substantially similar rates to standard Alberta crown equivalent rates.

Pursuant to the Acquisition, Bowood has committed to drill a minimum of one well on the Acquired Blood Assets in each of the first and second years of the Lease and a minimum of two wells in each of the third, fourth and fifth years of the Lease, in each case to a minimum depth of 1,000 metres or 5 metres into the Devonian, whichever occurs first. The well commitment for the first year (2011) was satisfied with the drilling of the Kipp 100/8-30-8-23W4 well ("**Kipp Well**") which is currently on production.

Also pursuant to the Acquisition, prior to the drilling of each well by Bowood on the Acquired Blood Assets, the Blood Tribe or its designated entity (the "**Participant**") has the option to elect to participate, on a straight-up basis, for a 20% working interest in the drilling and completion/equipping or abandonment of such well. Should the Participant make this participation election, the Participant shall be a 20% working interest partner and as such, shall be fully responsible and liable for its working interest share of all capital and operating costs including any liabilities and obligations associated therewith. The joint operations will be governed by standard CAPL operating procedures and will incorporate standard industry elections and terms, except that there will not be a right of first refusal on the Participant's working interest in favour of Bowood. The Blood Tribe elected to participate for its 20% working interest in the Kipp Well, with the Participant being designated as Kainai Energy Limited Partnership ("**Kainai**").

In order to provide the Participant with the start-up capital required to fund its participation in the joint wells on the Acquired Blood Assets and other lands, Bowood made a one time payment of $2,000,000 to the Participant. This payment was made on the closing date of the Acquisition and was non-refundable.

Pursuant to the Acquistion, should the Participant elect not to participate for its 20% working interest in a well as set out above, the Blood Tribe or its nominee shall be entitled to a 20% working interest in each well once Bowood has recovered 200% of the total capital costs associated with the well, such that the Blood Tribe shall end up with a 20% working interest in the well.

A copy of the Acquisition Agreement has been filed by the Corporation on SEDAR and may be viewed under the Corporation's profile at www.sedar.com.

Offering

On September 21, 2010 the Corporation completed a subscription receipt financing through a syndicate of agents pursuant to which a total of 88,000,000 subscription receipts ("**Subscription Receipts**") were issued at a price of $0.25 per Subscription Receipt to raise gross proceeds of $22 million, including the full exercise of the agents' over-allotment option.

The gross proceeds of the Subscription Receipt financing were held in escrow pending the completion of the Acquisition. Upon the closing of the Acquisition, the proceeds were released to Bowood and each Subscription Receipt was automatically exchanged for one Bowood Share for no additional consideration.

Legacy Joint Venture Farm-out and Equalization

On December 7, 2010, Bowood entered into a strategic joint venture farmout and equalization arrangement (the "**Joint Venture**") with Legacy Oil + Gas Inc. ("**Legacy**"), on Bowood's Alberta Bakken fairway lands (the "**Lands**"). The Lands consisted of 183 gross sections of land and comprised the Acquired Lands and Farmout Lands, as defined below.

Under the terms of the Joint Venture, Legacy, through a combination of land equalization and drilling, has the ability to earn 50 percent of Bowood's entire interest in the Lands. Initially, Legacy equalized into a portion of the Lands by providing a cash payment to Bowood of $8 million to purchase a 50 percent working interest in 33,280 gross acres (52 gross sections) of Lands (the "**Acquired Lands**"). The Acquired Lands consisted of a mix of Crown and freehold lands which were not located on the Blood Tribe Reserve.

On the other 131 gross sections of land (the "**Farmout Lands**"), including the 94.75 gross sections of Acquired Blood Assets, Legacy initially committed to drill two (2) horizontal test wells which targeted the lower Banff, Exshaw/Bakken and Big Valley formations. Both test wells were drilled, completed and commenced production in 2011. One of the test wells, the Kipp Well, was located on the Acquired Blood Assets and the other was located on the remaining non-Blood lands, at Spring Coulee. With each test well, Legacy was responsible for 80 percent of Bowood's share of the drilling and completions costs of such test well and earned a 50 percent working interest in 8 sections of the Farmout Lands, subject to an adjustment for Kainai's participation in the Kipp Well on the Acquired Blood Assets. Following the drilling of the two test wells, Legacy now has the right to continue earning in the Farmout Lands on a rolling option basis.

A copy of the Equalization, Farm-out and Option Agreement with Legacy is filed under the Corporation's profile on SEDAR at www.sedar.com.

Land Acquisition

In September 2011, Bowood and its partner Legacy jointly acquired an additional 9,658 acres (4,829 net to each partner) of contiguous land offsetting the Spring Coulee Well. The lands are expected to be prospective for the Bakken Petroleum System and the shallower Second White Specks oil resource play. This acquisition increased Bowood's net land position in the Southern Alberta Bakken fairway to approximately 110,000 acres.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Notes on Reserves Data

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

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

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

"**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

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

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

"**Undeveloped**" reserves are those reserves expected to be recovered from 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.

"**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 + probable reserves.

"**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.

Disclosure of Reserves Data

The reserves data set forth below is based upon GLJ's evaluation of certain crude oil, natural gas and natural gas liquids reserves of Bowood as at December 31, 2011 as set forth in the GLJ Report. The GLJ Report was prepared on March 27, 2012 in accordance with NI 51-101, using standards consistent with the Canadian Oil and Gas Engineering Handbook.

The following tables summarize the oil, natural gas and NGL reserves attributable to Bowood's principal properties and the present value of future net revenue for such reserves using forecast price assumptions and costs, all as estimated by GLJ in the GLJ Report. All of Bowood's principal properties are the properties owned by Bowood. Bowood does not consider the properties owned in the United States to be material and therefore they were not included in the GLJ Report.

All evaluations of future net production revenue set forth in the tables below are based on GLJ's pricing assumptions as at December 31, 2011. It should not be assumed that the discounted future net production revenue estimated by the GLJ Report represents the fair market value of the reserves set forth in such report. There is no assurance that the future price and cost assumptions used in the GLJ Report will prove accurate and variances could be material. The recovery and reserve estimates of oil, natural gas and NGLs provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein.

The Report on Reserves Data by GLJ in Form 51-101F2 and the Report of Management and Directors on Reserve Data and Other Information in Form 51-101F3 are included in Exhibit "1" and Exhibit "2", respectively, to this Annual Information Form.

All reported volumes are company interest unless otherwise stated.

All of Bowood's reserves are in the Province of Alberta.

Summary of Oil and Gas Reserves as of December 31, 2011

(Forecast Prices and Costs)

Reserve Category	Light and Medium Oil Mbbl		Natural Gas MMcf		Natural Gas Liquids Mbbl	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	108	84	4,328	3,661	21	15
Developed Non-Producing	44	42	551	464	2	2
Proved Undeveloped	62	28	640	573	2	2
Total Proved	214	169	5,519	4,697	25	18
Probable	125	97	2,667	2,310	14	10
Total Proved and Probable	339	265	8,187	7,007	39	29

Net Present Values of Future Net Revenue as of December 31, 2011

(Forecast Prices and Costs)

	Before Income Tax ($000s)					After Income Tax ($000s)				
	Discounted at					Discounted at				
Reserve Category	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	14,564	12,076	10,348	9,084	8,124	14,564	12,076	10,348	9,084	8,124
Developed Non-Producing	2,401	2,130	1,903	1,713	1,551	2,401	2,130	1,903	1,713	1,551
Proved Undeveloped	3,967	3,332	2,839	2,451	2,139	3,967	3,332	2,839	2,451	2,139
Total Proved	20,932	17,537	15,090	13,247	11,814	20,932	17,537	15,090	13,247	11,814
Probable	13,512	9,508	7,211	5,738	4,724	13,512	9,508	7,211	5,738	4,724
Total Proved and Probable	34,443	27,045	22,302	18,986	16,537	34,443	27,045	22,302	18,986	16,537

	Unit Value Before Income Tax Discounted at 10%/year ($/BOE)
Proved	
Developed Producing	14.40
Developed Non-Producing	17.77
Undeveloped	19.07
Total Proved	15.49
Probable	14.61
Total Proved Plus Probable	15.19

Undiscounted Total Future Net Revenue as of December 31, 2011

(Forecast Prices and Costs)

Reserves Category	Revenue ($000s)	Royalties ($000s)	Operating Costs ($000s)	Develop-ment Costs ($000s)	Abandon-ment and Reclama-tion Costs ($000s)	Future Net Revenue Before Income Taxes ($000s)	Future Income Taxes ($000s)	Future Net Revenue After Income Taxes ($000s)
Total Proved	50,545	8,015	17,900	2,371	1,085	14,564	0	14,564
Total Proved Plus Probable	80,719	12,847	28,419	3,406	1,604	34,443	0	34,443

Future Net Revenue by Production Group as of December 31, 2011

(Forecast Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Per Unit Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($/BOE)
Total Proved Reserves by Production Group	Light and Medium Crude Oil (including solution gas and other by-products)	9,066	37.10
	Heavy Oil (including solution gas and other by-products)	100	21.72
	Natural Gas	6,024	8.25
Total Proved Reserves		15,090	15.49
Total Proved Plus Probable Reserves by Production Group	Light and Medium Crude Oil (including solution gas and other by-products)	12,937	35.54
	Heavy Oil (including solution gas and other by-products)	121	21.04
	Natural Gas	9,365	8.48
Total Proved Plus Probable Reserves		22,302	15.19

Forecast Prices and Costs

The forecast price and cost assumptions used in the GLJ Report assume the continuance of current laws and regulations and increases in well-head selling prices and take into account inflation with respect to future operating capital costs.

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Report were GLJ's forecasts as at January 1, 2012, which were as follows:

	Medium and Light Crude Oil			Natural Gas	NGL		
Year	**WTI Cushing Oklahoma 40° API (US$/bbl)**	**Edmonton Par Price 40° API ($/bbl)**	**Cromer Medium 29º API ($/bbl)**	**Alberta Gas Reference Price Plantgate ($/MMBtu)**	**AECO - C Spot ($/MMBtu)**	**Pentanes Plus ($/bbl)**	**Exchange Rate ($US/$Cdn)**
2012	97.00	97.96	90.12	3.23	3.29	107.76	0.98
2013	100.00	101.02	92.94	3.85	3.93	108.09	0.98
2014	100.00	101.02	91.93	4.30	4.39	105.06	0.98
2015	100.00	101.02	91.93	4.74	4.84	105.06	0.98
2016	100.00	101.02	91.93	5.19	5.30	105.06	0.98
2017	100.00	101.02	91.93	5.64	5.75	105.06	0.98
2018	101.35	102.40	93.18	5.87	5.99	106.49	0.98
2019	103.38	104.47	95.07	5.98	6.11	108.65	0.98
2020	105.45	106.58	96.99	6.11	6.23	110.84	0.98
2021	107.56	108.73	98.85	6.23	6.36	113.08	0.98

Escalated at 2.0% per year thereafter.

Additional Information Relating to Reserves Data

Proved Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves included in the GLJ Report that were first attributed in the last three financial years.

	Light and Medium Crude Oil	**Heavy Crude Oil**	**Natural Gas Liquids**	**Natural Gas**
	(Mbbls)	**(Mbbls)**	**(Mbbls)**	**(MMcf)**
2009	-	-	-	468
2010	27	-	1	72
2011	48	-	1	174

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production.

Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped reserves included in the GLJ Report that were first attributed in the last three financial years.

	Light and Medium Crude Oil	**Heavy Crude Oil**	**Natural Gas Liquids**	**Natural Gas**
	(Mbbls)	**(Mbbls)**	**(Mbbls)**	**(MMcf)**
2009	60	-	3	725
2010	15	-	-	32
2011	8	-	-	28

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

Development

Bowood currently plans to pursue the development of the majority of its undeveloped reserves within the next two years through ordinary course capital expenditures. However, Bowood may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow.

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance 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.

Future Development Costs

The table below sets out the development costs deducted in the estimation in the GLJ Report of future net revenue attributable to the proved reserves and proved plus probable reserves evaluated in the GLJ Report.

	Forecast Prices and Costs	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
	(M$)	(M$)
2012	780	1,130
2013	1,212	1,678
2014	0	0
2015	0	53
2016	379	379
Thereafter	0	128
Total Undiscounted	2,371	3,406

Bowood estimates that internally generated cash flow and bank lines will be sufficient to fund the future development costs disclosed above. Bowood has available three sources of funding to finance its capital expenditure program; internally generated cash flow from operations, debt financing and new equity issues, if available on favourable terms.

Reconciliations of Changes in Reserves and Future Net Revenue – Forecast Prices and Costs

The following table sets forth the reconciliation of Bowood's gross reserves for the year ended December 31, 2011, derived from the GLJ Report using forecast prices and cost estimates, reconciled to the gross reserves of Bowood at December 31, 2010.

	Light and Medium Crude Oil	**Heavy Oil**	**Natural Gas**	**Natural Gas Liquids**	**BOE**
	(Mbbl)	Mbbl	(MMcf)	(Mbbl)	(Mboe)
Proved					
Balance at Dec. 31, 2010	182	4	5,694	24	1,159
Extensions and Improved Recovery	46	-	876	2	194
Technical Revisions	9	1	50	3	21
Discoveries	4	-	0	6	4
Acquisitions	1	-	2	-	2
Dispositions	-	-	-	-	-
Economic Factors	-	-	(171)	-	(28)
Production	(28)	(1)	(932)	(4)	(189)
Balance at Dec. 31, 2011	214	5	5,519	25	1,164
Probable					
Balance at Dec. 31, 2010	86	1	2,697	15	552
Extensions and Improved Recovery	28	-	179	-	58
Technical Revisions	9	-	(86)	(1)	(5)
Discoveries	1	-	-	-	-
Acquisitions	-	-	-	-	-
Dispositions	-	-	-	-	-
Economic Factors	-	-	(123)	-	(21)
Production	-	-	-	-	-
Balance at Dec. 31, 2011	125	2	2,667	14	585
Proved plus Probable					
Balance at Dec. 31, 2010	269	6	8,391	39	1,711
Extensions and Improved Recovery	74	-	1,056	2	252
Technical Revisions	19	1	(37)	2	(16)
Discoveries	5	-	-	0	5
Acquisitions	1	-	3	-	2
Dispositions	-	-	-	-	-
Economic Factors	-	-	(294)	-	(49)
Production	(28)	(1)	(932)	(4)	(189)
Balance at Dec. 31, 2011	339	6	8,187	39	1,749

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

The following is a description of the principal oil and natural gas properties, pipelines and installations in which Bowood has an interest and that are material to Bowood's operations and exploration activities. The production numbers stated refer to Bowood's working interest share before deduction of Crown and freehold royalties. The Canadian properties listed below are all held by Bowood through its interest in its wholly-owned subsidiary, Bowood Energy Ltd.

Southern Alberta

Alberta Bakken Petroleum System

In 2010, industry began acquiring and drilling exploratory wells in the Alberta Bakken Petroleum System. At December 31, 2011, Bowood held approximately 140,136 acres (105,697 net) in the prospective fairway of the Alberta Bakken Petroleum System, from Township 1 to Township 12, Ranges 21-24W4.These lands are primarily located in the areas of the Blood First Nations Reserve ("**Blood Tribe Reserve**") property and the McIntyre/Magrath/Spring Coulee property.

Blood Tribe Reserve

The Blood Tribe Reserve property is located about 10 kilometres west of the city of Lethbridge in Twps. 5-9, Rges. 21-25 W4M. In October 2010, Bowood completed the Acquisition of the Acquired Blood Assets which constitute the Blood Tribe Reserve property. Subsequently, in December of 2010, Bowood entered into the Joint Venture with Legacy, where Legacy would pay 80% of well costs to earn 50% of Bowood's working interest in the Farmout Lands (including the Acquired Blood Assets).

Bowood currently holds a working interest, ranging from 30% to 100%, in 98.75 sections (63,194 acres). Bowood's average working interest in these lands is 94%, resulting in 59,275 total net acres.

For 2011, natural gas sales production from the Blood Tribe Reserve averaged 63 Mcf/d (10 BOE/d) net to Bowood, and was attributed to Bowood's seven gross (2.7 net) wells producing natural gas from the Bow Island formation. Bowood's first Alberta Bakken horizontal oil well (0.4 net) on the Blood Tribe Reserve property was the Kipp Well which went on production in late December 2011.

McIntyre/Magrath/Spring Coulee

The McIntyre/Magrath/Spring Coulee property began as a natural gas asset which was purchased by Old Bowood in 2007. The McIntyre/Magrath/Spring Coulee property is located in Twps. 3-7, Rges. 21-22 W4M, and is directly east of and adjacent to the Blood Tribe Reserve property, approximately 20 kilometres south of the city of Lethbridge, Alberta.

The McIntyre/Magrath/Spring Coulee property consists primarily of an operated, 100% working interest in 35.6 producing gas wells (and associated facilities). A portion of gas production is used as fuel gas to power the facilities associated with the property. Production is primarily from the Bow Island formation. For the 2011 fiscal period, production from the property averaged 870 Mcf/d (145 BOE/d), which was less than capacity. Due to continued low natural gas prices in 2011, some compression remained shut off. There remains potential to reactivate further compression in the area and increase rates with increased gas prices.

In 2010, Bowood acquired approximately 27,880 gross acres on the McIntyre/Magrath/Spring Coulee property, prospective for the Alberta Bakken Petroleum system and in 2011 added approximately 22,483 additional gross acres. Also in 2011 Bowood acquired a wholly-owned interest in a producing Second White Specks oil well on the McIntyre/Magrath/Spring Coulee property. As part of the Joint Venture with Legacy, 50% of Bowood's interest in 52 sections of land on the McIntyre/Magrath/Spring Coulee property was sold to Legacy for $8 million in December 2010. Under the Joint Venture, Legacy has also farmed in on Bowood's remaining 100% working interest acreage at McIntyre/Magrath/Spring Coulee on the same basis as described under the heading *Blood Tribe Reserve* above. With the drilling of the Alberta Bakken oil well at Spring Coulee in 2011, Legacy has earned a 50% working interest in the Spring Coulee well and in 8 additional sections of land. Bowood owns a 50% interest in the Spring Coulee well.

Total land holdings in the McIntyre/Magrath/Spring Coulee property consist of 84,832 gross (55,486 net) acres.

Armada

The Armada Property is located in Twp. 17, Rge. 19 W4M, approximately 40 kilometres east of the town of Vulcan, Alberta. The Armada Property was a seismically driven prospect, secured through a strategic farm-in arrangement, which resulted in an oil discovery for Old Bowood in 2008. Bowood is the operator of the property.

The Armada property currently has 6 gross (3.65 net) producing oil and natural gas wells. Bowood's net production for the fiscal year 2011 averaged 229 BOE/d consisting of 916 Mcf/d of natural gas and 76 Bbls/d of oil. Total land holdings consist of 2,560 gross (1,824 net) acres.

The Armada discovery well, located at 10-2, was drilled in August of 2008 and produced in excess of 100 Bbls/d (60 Bbls/d net) of medium-light oil and associated natural gas. In 2008, a 3D seismic survey was conducted over the Armada lands to identify follow-up drilling locations in the Basal Quartz P pool.

A successful follow-up well, located at 7-2, was drilled in early 2009 and the results confirmed the geological and geophysical interpretation. The 7-2 well commenced production in April, 2009 at over 100 BOE/d net to Bowood.

Bowood applied to the ERCB and received Good Production Practice (GPP) for the Basal Quartz P pool in 2010 which allowed the 10-2 well to resume production. The 7-2 well remains shut in to preserve the reservoir energy from the associated gas cap. Four wells (2.55 net) were drilled and cased in 2010 and three are on production at this time. The 2010 drilling resulted in the discovery of three new gas pools and one new oil pool (Basal Quartz Q pool). Bowood applied for and received GPP from the ERCB for the Basal Quartz Q oil pool in mid 2011 and the discovery well continues to flow at 185 Bbls/d (65 Bbls/d net). Two locations were drilled in 2011 resulting in one (0.9 net) producing gas well and one well (0.35 net) standing cased.

Long Coulee

The Long Coulee property, also in southern Alberta, is located in Twps. 15-17, Rges. 20-22 W4M, approximately 25 kilometres east of Vulcan. The property consists of 8,960 gross (7,900 net) acres, and includes an interest in three gross (2.5 net) producing wells and five suspended wells. For 2011, Bowood's net production from the Long Coulee property averaged 243 Mcf/d of natural gas and 4

Bbls/d of oil and natural gas liquids, resulting in total net production to Bowood of 45 BOE/d. Bowood operates the Long Coulee property.

Enchant/Retlaw

The Enchant/Retlaw area is located in Twps. 12-15, Rges. 16-19, W4M, where Bowood holds an average 67% working interest in 20.75 sections of land, totalling 13,920 gross (9,379 net) acres. For the 2011 fiscal period, Bowood's net production from the Enchant and Retlaw properties averaged 128 Mcf/d of natural gas, resulting in total net production to Bowood of 25 BOE/d. The Enchant/Retlaw property includes an interest in six gross (2.7 net) producing wells and seven suspended wells.

Central Alberta

In Central Alberta, Bowood has a working interest in 4,445 (2,560 net) acres of land.

The Ukalta area is located in Twp. 58, Rge. 17 W4M. Bowood's working interest ranges from 20% to 100% in 2,685 gross (800 net) acres of primarily freehold lands. For the 2011 fiscal year, production from the Ukalta property averaged 136 Mcf/d (23 BOE/d) net to Bowood from two gross (0.4 net) wells.

Peace River Arch

On the Peace River Arch, Bowood holds non-operated interests ranging from 30% to 50% in three different areas: Balsam, located in Twp. 83, Rge. 11 W6M; Mirage, located in Twp. 79, Rge. 7 W6M; and Oak, located in Twp. 83, Rge. 11 W6M. Total land holdings consist of 2,080 gross (880 net) acres. For the 2011 fiscal year, Bowood's net production from the Peace River Arch properties averaged 62 Mcf/d of natural gas and 1 Bbl/d of oil and natural gas liquids, resulting in total net production to Bowood of 11 BOE/d, attributable to two gross (0.8 net) producing wells and one suspended well.

United States

Bowood holds approximately 22,274 gross acres (15,763 net) of exploratory acreage in Michigan, Utah and Colorado in the United States. Bowood has no further plans to explore or develop these lands at this time and currently holds a working interest in one (0.063 net) well. In 2011, Bowood closed the sale of 19,305 acres of land in Michigan for proceeds of approximately $595,400.

The following table sets forth Bowood's principal properties.

Property	2011 Average Production (BOE/d)	Net Acres Land	Average Working interest (land)	Bowood Operated
McIntyre/Magrath, AB	148	55,486	62	Yes
Blood, AB	12	59,275	90	No
Armada, AB	229	1,824	71	Yes
Long Coulee, AB	45	7,900	88	Yes
Enchant, AB	10	8,736	69	Yes
Central AB	23	2,560.6	58	No
Peace River Arch, AB	11	880	42	No

Properties with no Attributable Reserves

The following table summarizes, effective as at December 31, 2011, the gross and net acres of unproved properties in which Bowood has an interest and also the number of net acres for which Bowood's rights to explore, develop or exploit will, absent further action, expire within one year.

Area	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Alberta, Canada	193,750	149,879	2,619
Saskatchewan, Canada	640	640	-
Michigan, U.S.A.	9,042	9,042	31
Utah, U.S.A.	10,614	5,307	3,180
Colorado, U.S.A.	2,409	1,204	180

Oil and Gas Wells

The following table sets forth, as at December 31, 2011, the number and status of wells in which Bowood has an interest and which have not been abandoned:

	Producing Wells						Shut-in Wells(1)					
	Oil Wells		Natural Gas		Service Wells		Oil Wells		Natural Gas		Service Wells	
Area	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)
Alberta	8	4.2	56	42.1	-	-	8	5.8	35	28.3	-	-

Notes:

(1) "Shut-in" wells means wells which have encountered and are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons.

(2) "Gross" wells are the total number of wells in which Bowood has an interest.

(3) "Net" wells are the aggregate of the numbers obtained by multiplying each gross well by Bowood's percentage working interest therein.

Costs Incurred

The following table summarizes capital expenditures (including capitalized general and administrative expenses) of Bowood for the year ended December 31, 2011:

	Year ended December 31, 2011
Property Acquisition Costs	
Unproved Properties	$3,801,629
Proved Properties	286,144
Property Divestitures (proceeds)	(595,400)
Exploration Costs	6,470,831
Development Costs	1,073,239
Total Costs	**$11,036,443**

The costs as listed in the table do not include $62,664 in other capital assets including furniture, fixtures, computers and related equipment and $158,996 in abandonment capital.

Exploration and Development Activities

The following table summarizes the results of exploration and development activities of Bowood during the year ended December 31, 2011:

	Year Ended December 31, 2011	
	Gross	**Net**
Development Wells	1	.9
Gas	1	.9
Oil	-	-
Service	-	-
Dry	-	-
Exploratory Wells	3	1.25
Gas	1	0.35
Oil	2	0.9
Service	-	-
Dry	-	-
Total Wells	4	2.15

Additional Information Concerning Abandonment and Reclamation Costs

Bowood uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. Bowood currently has 42 gross (32.2 net) wells which are not producing. No abandonments are planned at this time for 2012.The total abandonment cost in respect of proved reserves using forecast prices is $1,328,000 (undiscounted) and $729,000 (discounted at 10%). All of such amounts were deducted as abandonment and reclamation costs in estimating future net revenue of Bowood in respect of proved reserves as disclosed above.

Tax Horizon

Bowood does not expect to pay income tax for the 2012 fiscal year. Based on the GLJ Report and existing tax pools, Bowood does not expect to pay current income taxes until at least 2015. Commodity prices, operating expenses, production and capital spending levels will all impact this estimate.

Hedging

At Dec 31, 2011, Bowood had no hedges in place.

Production Estimates

The following table discloses, by product type, the total volume of production estimated by GLJ in the GLJ Report for the year ended December 31, 2011, which is reflected in the estimates of future net revenue from gross proved and probable reserves disclosed in the tables above with respect to the GLJ Report.

	Light and Medium Crude Oil (bbls/d)	Heavy Oil (bbls/d)	NGL (bbls/d)	Natural Gas (Mcf/d)	BOE (BOE/d)
Total Proved					
Armada	103	-	5	1,234	314
Other Properties	37	3	7	1,429	286
Total Proved	**140**	**3**	**13**	**2,663**	**599**
Total Probable					
Armada	26	-	-	70	38
Other Properties	1	-	-	45	9
Total Probable	**28**	**-**	**0**	**115**	**47**
Total Proved Plus Probable	**168**	**3**	**13**	**2,778**	**647**

The Armada property as shown in the Table above is the only property estimated by GLJ in the GLJ Report for the year ended December 31, 2011, to produce more than 20% of Bowood's average daily production on a BOE/d basis.

Production History

The following table summarizes certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback with respect to the properties evaluated in the GLJ Report for the periods indicated below.

	Quarter Ended Dec. 31, 2011	Quarter Ended Sept. 30, 2011	Quarter Ended June 30, 2011	Quarter Ended March 31, 2011
Average Daily Production(1)				
Light and Medium Crude Oil (bbls/d)	99	79	45	96
NGLs (bbls/d)	16	8	10	13
Gas (Mcf/d)	2,905	2,753	2,258	2,290
Combined (BOE/d)	600	547	431	490
Light and Medium Crude Oil and NGL Netbacks(4)				
($/bbl)				
Revenue	90.88	77.67	96.17	78.92
Royalties	2.95	2.50	2.28	4.36
Operating Costs(2)(3)	9.68	11.02	12.48	7.96
Transportation Costs	2.69	0.46	8.31	1.84
Netback	75.56	63.69	73.10	64.76
Natural Gas Netbacks(4)				
($/Mcf)				
Revenue	3.33	3.75	4.13	3.96
Royalties	0.49	0.42	0.38	0.73
Operating Costs(2)(3)	2.08	2.20	2.43	1.79
Transportation Costs	0.03	0.05	0.03	0.26
Netback	0.73	1.08	1.29	1.18
Combined Netbacks(4)				
($/BOE)				
Revenue	33.64	31.33	33.93	35.97
Royalties	2.95	2.50	2.28	4.36
Operating Costs(2)(3)	11.99	13.19	13.53	10.68
Transportation Costs	0.64	0.33	1.23	1.64
Netback	18.06	15.31	16.89	19.29

Notes:

(1) Before deduction of royalties.

(2) Operating costs have been allocated to the primary product for the expense. A number of assumptions have been made in allocating these costs between oil and natural gas.

(3) Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(4) Netbacks are calculated by subtracting royalties, operating costs and transportation costs from revenues.

The following table indicates the average daily production from Bowood's important fields for the year ended December 31, 2011.

Field	Crude Oil bbl/d	NGLs bbl/d	Natural Gas Mcf/d	Total BOE/d
McIntyre/Magrath	-	2	866	148
Long Coulee	3	1	243	45
Armada	72	4	916	229
Other	5	5	529	95
Total	80	12	2554	517

DESCRIPTION OF SHARE CAPITAL

Bowood Shares

The authorized share capital of Bowood consists of an unlimited number of Bowood Shares. As of the date hereof there are 274,933,373 Bowood Shares issued and outstanding.

Subject to the provisions of the CBCA, the holders of Bowood Shares are entitled to receive notice of, to attend and vote at all meetings of the shareholders of Bowood and are entitled to one vote, in person or by proxy, for each Bowood Share held.

The holders of Bowood Shares are entitled to receive, if, as and when declared by the directors of Bowood, non-cumulative dividends at such rate and payable on such date as may be determined from time to time by the directors of Bowood.

On the liquidation, dissolution or winding-up of Bowood, or any other distribution of the assets of Bowood among its shareholders for the purpose of winding-up its affairs, the holders of the Bowood Shares shall be entitled to receive the remaining property and assets of Bowood.

Trading Price and Volume

The following table sets out the high and low closing prices and the volume of trading of the Bowood Shares for the periods indicated as reported by the TSXV.

	Price Range ($)		
	High	**Low**	**Trading Volumes**
2011			
January	0.71	0.55	19,803,200
February	0.60	0.53	12,046,200
March	0.55	0.41	23,434,100
April	0.50	0.43	12,902,700
May	0.50	0.44	11,032,500
June	0.48	0.36	9,409,800
July	0.50	0.42	9,105,300
August	0.46	0.35	8,523,400
September	0.42	0.24	6,871,700
October	0.34	0.21	18,566,600
November	0.37	0.24	7,014,000
December	0.26	0.14	15,733,500
2012			
January	0.19	0.12	12,033,700
February	0.23	0.13	16,513,100
March	0.18	0.12	8,149,900
April 19	0.15	0.12	3,008,900

PRIOR SALES

In the 12 months prior to the date hereof, no securities of Bowood other than Bowood Shares and Bowood Options have been issued.

ESCROWED SECURITIES

There are no escrow arrangements that currently exist with respect to any of the Bowood Shares.

DIRECTORS AND OFFICERS

The names and municipality of residence, the position held and the principal occupation during the last five years of each of the directors and executive officers of Bowood are set forth below. Directors serve until the next annual meeting of shareholders or until a successor is elected or appointed.

Name	Position(s) Presently Held	Principal Occupation during the last Five Years	Director Since	Bowood Shares Beneficially Owned or Controlled
Robert Mercier(5)(6) Okotoks, Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Bowood since December 22, 2009. Prior thereto, Chief Operating Officer of Bowood Energy Corp. from March 2005 to December 22, 2009. Prior thereto, Production Manager, Forte Oil Corporation from 2002 to 2005.	December 22, 2009	2,783,474 (1)
Franco Civitarese Calgary, Alberta, Canada	Vice-President, Finance and Chief Financial Officer(7)	Vice-President, Finance and Chief Financial Officer of Bowood since February 28, 2011 Prior thereto, Vice-President, Finance of Bowood from December 22, 2009 to February 28, 2011. Prior thereto, Chief Financial Officer of Bowood Energy Corp. from June 5, 2009 to December 22, 2009. Prior thereto, VP Finance and CFO of E4 Energy Inc. from August 2005 to February 2008. Prior thereto, Controller of E3 Energy Inc. from 2003 to 2005.	N/A	Nil
Christine Robertson De Winton, Alberta, Canada	Vice-President, Engineering and Chief Operating Officer	Vice-President Engineering and Chief Operating Officer of Bowood since February 1, 2010. Prior thereto, a self-employed engineering consultant from August 2007 until February 2010. Vice-President, Operations and Chief Operating Officer of Sabretooth Energy from 2006 to 2009 and Vice-President Engineering of Valiant Energy from 2005 to 2006.	N/A	80,000(8)
Michael J. Kryczka Calgary, Alberta, Canada	Vice-President, Business Development(7)	Vice-President, Business Development since February 28, 2011. Prior thereto, Vice-President, Business Development and Chief Financial Officer of Bowood from December 22, 2009 to February 28, 2011. Prior thereto, President and CEO of Bowood Energy Corp. from October 3, 2003 to December 22, 2009. Prior thereto President and CEO for Durness Resources Inc. from 2000 to 2004.	N/A	631,204

Name	Position(s) Presently Held	Principal Occupation during the last Five Years	Director Since	Bowood Shares Beneficially Owned or Controlled
David Cassidy Calgary, Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration of Bowood since December 22, 2009. Prior thereto, Vice-President, Exploration and Development of Bowood Energy Corp. from March 2005 to December 22, 2009.	N/A	5,906,930 (2)
Chris Bloomer(3)(5) Calgary, Alberta, Canada	Director	Mr. Bloomer currently serves as Senior Vice-President and Chief Operating Officer of the Heavy Oil Business Unit as well as a Director of Petrobank Energy and Resources Ltd. Previously, he also held the position of CFO. Mr. Bloomer has been at Petrobank since 2002.	December 22, 2009	1,500,000
Michelle Gahagan(4)(6) Vancouver, British Colombia, Canada	Director	Ms. Gahagan is currently a principal of a privately held merchant bank based in Vancouver, Canada and London, England. Prior to the commencement of her involvement in merchant banking five years ago, Ms. Gahagan practiced corporate law for 20 years.	November 21, 2006	200,000
Craig E. Kelly(3)(4) Geneva, Switzerland	Director	Mr. Kelly has been the Chief Financial Officer for Oryx Petroleum Services SA based in Geneva, Switzerland since September 2010. Mr. Kelly was formerly Head of Corporate Finance for Addax Petroleum Corporation based in Geneva, Switzerland from May 2006 to August 2010.	April 1, 2010	100,000
Jim Welykochy(3)(4)(5) Calgary, Alberta, Canada	Director	Mr. Welykochy is a self-employed financial consultant to the oil & gas industry capital markets. Prior thereto, Mr. Welykochy served as Vice President, Corporate Development and Director of Ryland Oil Corporation from August 2008 until the sale of Ryland to Crescent Point Energy in August, 2010. Prior to joining Ryland, Mr. Welykochy served as Vice President of institutional sales for PI Financial Corp from February 2007 to August 2008. Prior thereto Mr. Welykochy was an oil and gas research analyst with Genuity Capital Markets from January 2006 to February 2007.	December 22, 2009	Nil

Notes:

(1) Includes 1,133,400 shares held by Mr. Mercier's spouse.
(2) Includes 758,245 shares held by Mr. Cassidy's spouse and children.
(3) Member of the Audit Committee.
(4) Member of the Compensation and Nominating Committee.
(5) Member of the Reserves Committee.
(6) Member of the Environmental, Health & Safety Committee
(7) Effective February 28, 2011, Mr. Kryczka resigned as Chief Financial Officer and Mr. Civitarese was appointed Chief Financial Officer.
(8) Includes 40,000 shares held by Ms. Robertson's spouse.
(9) Effective January 6, 2012, Mr. Pat Oliver resigned from the Board of Directors of the Corporation. He had been a director of the Corporation since January 2010.

The directors and officers of the Corporation, as a group beneficially own, directly or indirectly, or exercise control or direction over, an aggregate of 11,201,608 Bowood Shares representing 4.07**%** of the issued and outstanding common shares of the Corporation as of the date hereof.

Corporate Cease Trade Orders

Except as disclosed below, to the knowledge of management of Bowood, no director or executive officer of Bowood, or a personal holding company of any such person, is, or within the 10 years before the date of this Annual Information Form 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.

Mr. Chris J. Bloomer was a director of Canadian Energy Exploration Inc. ("**CEE**") (formerly TALON International Energy, Ltd.), a reporting issuer listed on the TSX Venture Exchange, until his resignation on September 15, 2011. A cease trade order (the "**ASC Order**") was issued on May 7, 2008 against CEE by the Alberta Securities Commission (the "**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 Order, the TSX Venture Exchange 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.

Bankruptcies

To the knowledge of management of Bowood, other than listed herein, no director or executive officer, or any shareholder holding sufficient number of securities of Bowood to affect materially the control of Bowood, or a personal holding company of any such person:

(a) is, at the date of this Annual Information Form or has been within the 10 years before the date of this Annual Information Form, 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 Annual Information Form, 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 Bowood, no director or officer, or any shareholder holding a sufficient number of securities of Bowood to affect materially the control of Bowood, 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

Certain directors of Bowood may have interests in other oil and gas companies and oil and gas properties which may from time to time conflict with the interests of Bowood. Any such conflicts will be resolved in accordance with the requirements of the CBCA.

PERSONNEL

Bowood currently employs 8 full-time employees and 5 full and part-time consultants.

AUDIT COMMITTEE

Bowood's charter of the audit committee and the other information required to be disclosed by National Instrument 52-110, Form 52-110F2 is attached hereto as Exhibit 3 to this Annual Information Form.

INDEBTEDNESS OF DIRECTORS AND OFFICERS

Other than as set forth in the financial statements of Bowood, no director or executive officer of Bowood, or any associate of any such director or officer is, or has been at any time since the beginning of the most recently completed financial year of Bowood, indebted to Bowood nor is, or at any time since the beginning of the most recently completed has, any indebtedness of any such person been the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by Bowood.

INDUSTRY CONDITIONS

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

Pricing and Marketing - Natural Gas

In Canada, natural gas is sold throughout the country at various market hubs that are connected to several pipelines within Canada and the United States. The transaction price is determined by negotiation between buyers and sellers and includes the utilization of electronic trading platforms and various publications and reference indexes. Prices depend on many variables including but not limited to supply and demand fundamentals, the price of NYMEX natural gas contracts, distance to alternate markets, pipeline costs, natural gas storage, competing fuels, contract term, weather conditions and foreign exchange rates. Natural gas exported from Canada is subject to regulation by the National Energy Board of Canada (the "**NEB**") and the Government of Canada. The price received for natural gas that is exported depends largely on the same variables noted above including the market hub prices at the delivery end of the export pipelines. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. As in the case with oil, natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 cubic metres per day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The government of Alberta also regulates the removal of natural gas from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Pricing and Marketing - Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

Pipeline Capacity

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 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 and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

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

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal. Recent actions taken by provincial governments (and in particular the Alberta government) in response to the quick and significant decrease in commodity prices signal that this trend has slowed and may be changing course (at least temporarily until commodity prices recover). See below for further details.

The Canadian federal corporate income tax rate levied on taxable income is 19.5% effective January 1, 2008 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate decreased to 15% in four additional steps: 19% on January 1, 2009; 18% on January 1, 2010; 16.5% on January 1, 2011; and 15% on January 1, 2012.

Alberta

In Alberta, the Crown royalty rates on conventional oil and natural gas fluctuate, depending on when a well was drilled, well depth, well production volume and the price of oil and natural gas. On October 25, 2007 the Alberta Government introduced a new royalty regime which became effective on January 1, 2009 applicable to all conventional oil and natural gas wells in Alberta ("**New Royalty Regime**"). The New Royalty Regime assesses the applicable royalty rate on a well by well basis using a sliding scale which takes into account the price of oil and/or natural gas and the well's production volumes. On November 19, 2008 and November 24, 2008 the Alberta Government announced an optional transitional royalty program ("**Transitional Program**"). On March 11, 2010 the Alberta Government announced modifications to the New Royalty Regime and the Transitional Program ("**Modified Regime**").

Under the New Royalty Regime the royalty reserved to the Alberta Crown on conventional oil production rages from zero percent (0%) to fifty percent (50%) and is capped at fifty percent once the price of conventional oil reaches $120 per barrel. The royalty applicable to natural gas production under the new royalty regime ranges from five percent (5%) to fifty percent (50%) and is capped once the price of natural gas reaches $17.75 per gigajoule. The New Royalty Regime has retained the Natural Gas Deep Drilling Program and the Deep Oil Exploration Program. The New Royalty Regime also sets royalties for natural gas liquids at forty percent (40%) for pentanes and thirty percent (30%) for butanes and propane.

The Modified Regime became effective on January 1, 2011 and reduced the maximum royalty rates under the New Royalty Regime as follows: for conventional oil production from fifty percent (50%) to forty percent (40%) and for natural gas from fifty percent (50%) to thirty six percent (36%). The Modified Regime also makes permanent the 5% maximum royalty rate on the first 12 production months, 50,000 barrels of oil production, or 500 million cubic feet (MMcfe) of gas production from a well, whichever is reached first.

The Transitional Program, as amended, applies to conventional oil and natural gas wells drilled to measured depths between 1,000 to 3,500 meters between November 19, 2008 and December 31, 2010. For each well, the producer can make a one time election to produce the well under the old royalty regime or the New Royalty Regime. As of January 1, 2014 all production subject to the Transitional Program will revert to the New Royalty Regime, as modified. The Natural Gas Deep Drilling and Deep Oil Exploration programs are not available to wells producing under the Transitional Program. Wells subject to the Transitional Program will be permitted to switch to the Modified Regime effective January 1, 2011.

For conventional oil produced under the Transitional Program, the royalty reserved to the Alberta Crown is variable depending on the pools' vintage (when the pool was discovered), oil density, well production volume, and the price of oil. The royalty is capped at thirty-five percent (35%), which maximum is reached at an oil price of approximately $30 per barrel, depending on other factors such as production rates.

For natural gas produced under the Transitional Program, the royalty reserved to the Alberta Crown varies depending on the vintage, production volume and the inflation adjusted price of gas less adjustments for the cost of processing the Crown's share of the gas. The royalty will vary between fifteen percent (15%) to thirty-five percent (35%), the maximum is reached at a natural gas price of approximately $3.70 per gigajoule, depending on other factors such as production rates.

Land Tenure

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

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the Climate *Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12 percent. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or

(iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12 percent by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. Bowood will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. Bowood believes that it is in material compliance with applicable environmental laws and regulations.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO2 from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40 percent gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the federal government (see below), that the Kyoto target of 6 percent below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20 percent by 2020 and by 60 percent to 70 percent by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18 percent from the 2006 baseline starting in 2010 and an additional 2 percent in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oils sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2 percent continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25 percent increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO2 equivalent per upstream oil and gas facilities; and (iii) 10,000 BOE/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70 percent in 2010 to 0 percent in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

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

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10 percent of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 metric tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict

Trends

An important trend that appears to be shaping the near future of the oil and gas industry is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility. Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services.

Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

RISK FACTORS

An investment in Bowood is subject to certain risks. The reader is cautioned to carefully consider the following additional risk factors with respect to ownership of Bowood Shares in its assessment of Bowood:

Operational Risks

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering and oil spills, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. In accordance with industry practice, Bowood is not fully insured against all of these risks, nor are all such risks insurable. Although Bowood maintains liability insurance in an amount which it considers adequate, the nature of these risks is such that liabilities could exceed policy limits, in which event Bowood could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

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 Bowood and may delay exploration and development activities.

To the extent Bowood will not be the operator of its oil and gas properties, the company will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent.

In addition, the success of Bowood will be largely dependent upon the performance of its management and key employees. Bowood 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.

Bowood's ability to market oil and natural gas from its wells also depends upon numerous other factors beyond its control, including, among other things, the availability of natural gas processing and storage capacity, the availability of pipeline capacity, the price of oilfield services and the effects of inclement weather. Because of these factors, Bowood may be unable to market some or all of the oil and natural gas it produces or to obtain favourable prices for the oil and natural gas it produces.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors beyond the control of Bowood. The reserve and cash flow information set forth herein represent estimates only. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of Bowood. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. These evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Reserve Replacement

Bowood's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Bowood may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in reserves will depend not only on Bowood'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 Bowood's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas. Bowood Shares will have no value when reserves from Bowood's properties can no longer be economically produced.

Industry Regulation and Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Bowood will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Bowood. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw. Bowood's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling.

The marketability of oil and natural gas acquired or discovered will be affected by numerous factors beyond the control of Bowood. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. 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. Bowood's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment.

Alberta Royalty Regime

On January 1, 2009 the Alberta government's Alberta Royalty Framework ("**ARF**") took effect. Under the ARF, royalty rates on conventional and non-conventional oil and natural gas production in Alberta may increase to a maximum of 50 percent. The sliding scale royalty calculations are based on a broader range of commodity prices and production rates.

In response to the drop in commodity prices experienced during the second half of 2008, on November 19, 2008, the Government of Alberta announced the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program, companies drilling new natural gas or conventional oil wells (deeper than 1,000 metres and no deeper than 3,500 metres) will be given a one-time option, on a producing zone per well basis, to adopt either the new transitional royalty rates or those outlined in the ARF. In order to qualify for this program, wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the ARF.

The potential for additional future changes to the royalty regime in Alberta and corresponding changes in the royalty regimes in other jurisdictions where Bowood operates has created uncertainty surrounding the ability to accurately estimate future royalties, resulting in additional volatility and uncertainty in the oil and gas market. Increases to royalty rates in jurisdictions in which Bowood operates may negatively impact results from operations and Bowood's ability to economically develop existing reserves or add new reserves.

On March 11, 2010, the Alberta government announced the modified Regime. See under the heading "Industry Conditions – Provincial Royalties and Incentives – Alberta" for specifics of the Modified Regime.

Risks Associated with the Acquisition

In addition to the normal commercial risks associated with the acquisition of land for the purposes of developing oil and gas properties, the Acquisition may have additional risks due to the fact that the Lease is over lands on the Blood reserve No. 148 and could be vulnerable to challenge or forfeiture as a result of: (i) the risk that the original surrender of the lands from the Blood Tribe to the Federal Government was not properly approved by the Blood Tribe; (ii) the land registry system for Indian lands cannot provide the certainty of title offered by the Alberta Land Titles system; and (iii) the development of the Lease and the drilling of wells on the lands relies on obtaining surface access over reserve lands.

Market Volatility

In recent years, the securities markets in Canada and the United States have experienced a high level of price and volume volatility, and the market price of securities of many companies, particularly those considered to be development stage companies, have experienced wide fluctuations in price which have not necessarily been related to the operating performance, underlying asset values or prospects of such companies. There can be no assurance that continual fluctuations in price will not occur. It is likely that the market price for the Bowood Shares will be subject to market trends generally, notwithstanding the financial and operational performance of the Corporation.

Volatility of Oil and Gas Prices and Markets

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Bowood's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Bowood's reserves. Bowood might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Bowood's net production revenue causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Bowood will in part be determined by the company's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

From time to time Bowood 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, Bowood will not benefit from such increases.

Variations in Foreign Exchange Rates and Interest Rates

Bowood's expenses will be denominated in Canadian dollars or the currency in other jurisdictions in which it operates, while the price of oil and natural gas will generally be denominated in U.S. dollars or impacted by the Canadian dollar to U.S. dollar exchange rate. As the exchange rate for the Canadian dollar versus the U.S. dollar increases, Bowood will generally receive fewer Canadian dollars for its production. If the value of the Canadian dollar against the U.S. dollar continues to increase as it has over recent years, the financial results of Bowood may be negatively affected. Bowood management may initiate certain hedges to mitigate these risks. Future fluctuations in foreign exchange rates may impact the future value of Bowood's reserves as determined by independent evaluators. In addition, variations in interest rates could result in a significant change in the amount Bowood will pay to service debt, potentially adversely affecting the value of the Bowood Shares.

Substantial Capital Requirements; Liquidity

Bowood may have to make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If revenues or reserves decline, Bowood 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 Bowood to alter its capitalization significantly. The inability of the company to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects.

Issuance of Debt

From time to time Bowood may enter into transactions to acquire assets or shares of other corporations. These transactions may be financed partially or wholly through debt, which may increase debt levels above industry standards. Bowood's articles and by-laws do not limit the amount of indebtedness it may incur. The level of Bowood's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Failure to Realize Benefits of Acquisitions

Bowood may complete acquisitions to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, among other things, potential cost savings. Achieving the benefits of any future acquisitions depends, in part, on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as Bowood's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with its own. The integration of acquired businesses requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect Bowood's' ability to achieve the anticipated benefits of these and future acquisitions.

Risks Associated with Acquisitions

Acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated. No such assessments as discussed above were conducted on the Acquired Blood Assets.

Although title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Corporation's title to certain assets or that environmental defects or deficiencies do not exist.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or the issuance of clean up orders in respect of Bowood or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Bowood. In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol which requires participating countries, upon ratification, to reduce their emissions of carbon dioxide and other greenhouse gases. Canada ratified the Kyoto Protocol in late 2002, and the Canadian federal government and various Canadian provincial governments are currently evaluating other proposals and legislative measures that would achieve similar objectives. Canadian oil and gas sector is in discussions with various federal and provincial levels of government regarding the development of greenhouse gas regulations for the industry. The Canadian federal government has stated that it intends to limit emissions and set emission reduction targets for the industry and regulate the cost of emission credits and has released a broad overview of its intensity-based emission targets, which could result in increased capital expenditures and operating costs, but it has not released the specific details of any implementation plan. However, until a detailed implementation plan is developed, it is difficult to determine what, if any, impact future environmental laws and regulations may have on Bowood's environmental liabilities, on prices for oil and natural gas or on other general economic factors which may affect Bowood's financial position and results.

Abandonment and Reclamation Costs

Bowood will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding abandonment and reclamation in respect of its properties, which abandonment and reclamation costs may be substantial. A breach of such legislation or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made.

Delay in Cash Receipts

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of Bowood's properties, and by the operator to Bowood, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of Bowood's properties or the establishment by the operator of reserves for such expenses.

Dilution

Bowood Shares, including rights, warrants, special warrants, subscription receipts and other securities to purchase, to convert into or to exchange into Bowood Shares, may be created, issued, sold and delivered on such terms and conditions and at such times as the Bowood Board may determine. In addition, Bowood may issue additional Bowood Shares from time to time pursuant to the Bowood Options. The issuance of these Bowood Shares could result in dilution to holders of Bowood Shares.

Net Asset Value

Bowood's net asset value will vary dependent upon a number of factors beyond the control of Bowood management, including oil and natural gas prices.

Reliance on Bowood Management

Bowood shareholders will be dependent on the management of Bowood in respect of the administration and management of all matters relating to Bowood and its properties and operations. Investors who are not willing to rely on the management of Bowood should not invest in Bowood Shares.

Impact of Future Capital Expenditures

The reserve value of Bowood's properties, as estimated by independent engineering consultants, are based in part on cash flows to be generated in future years as a result of future capital expenditures. The reserve value of Bowood's properties, as estimated by independent engineering consultants, will be reduced to the extent that such capital expenditures on such properties do not achieve the level of success assumed in such engineering reports.

Permits and Licenses

The operations of Bowood may require licenses and permits from various governmental authorities. There can be no assurance that Bowood will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat a claim of Bowood which could result in a reduction of the revenue received by the company.

Aboriginal Claims and Title to Aboriginal Lands

Aboriginal peoples have claimed aboriginal title and rights to resources and various properties in western Canada. Such claims, in relation to any of Bowood's lands, if successful, could have an adverse effect on its operations.

The acquisition of title to petroleum and natural gas properties on Aboriginal lands is a very detailed and time-consuming process. While the Corporation has diligently investigated title to the Lease, all or any of the lands included in the Lease may be subject to prior unregistered agreements or transfers and title may be affected by undetected defects. There is no guarantee that title to the Lease or any of the lands included in the Lease will not be challenged or impugned. There may be valid challenges to the title of the Lease or any of the lands included in the Lease, which, if successful, could impair the Corporation's ability to explore, develop and/or operate the Acquired Blood Assets or to enforce its rights with respect thereto. In addition, other parties may dispute the Corporation's title to the lands included in the Lease in which it has an interest and such properties may be subject to prior unregistered agreements or transfers or claims by aboriginal people, and title may be affected by undetected encumbrances or defects or government actions.

An impairment to or defect in the Corporation's title to the Lease or any of the lands included in the Lease could have a material adverse effect on the Corporation's business, financial condition or results of operation. In addition, such claims, whether or not valid, will involve additional costs and expenses to defend or settle, which could adversely affect the Corporation's profitability.

Corporate Matters

To date, Bowood has not paid any dividends on its outstanding common shares. Certain of the directors and officers of Bowood 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 Bowood, as the case may be, and as officers and directors of such other companies.

Failure to Maintain Listing of the Bowood Shares

The Bowood Shares are currently listed for trading on the facilities of the TSXV. The failure of Bowood to meet the applicable listing or other requirements of the TSXV in the future may result in the Bowood Shares ceasing to be listed for trading on the TSXV, which would have a material adverse effect on the value of the Bowood Shares. There can be no assurance that the Bowood Shares will continue to be listed for trading on the TSXV.

Structure of Bowood

From time to time, Bowood may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of Bowood and its subsidiaries. If the manner in which Bowood structures its affairs is successfully challenged by a taxation or other authority, Bowood and the holders of Bowood Shares may be adversely affected.

Changes in Legislation

It is possible that the Canadian federal and provincial government or regulatory authorities could choose to change the Canadian federal income tax laws, royalty regimes, environmental laws or other laws applicable to oil and gas companies and that any such changes could materially adversely affect Bowood and the Bowood shareholders and the market value of the Bowood Shares.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Consequently, seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity.

Expiration of Licences and Leases

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

Third Party Credit Risk

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

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and executive officers of Bowood, any shareholder who beneficially owns more than 10% of the Bowood Shares, or any known associate or affiliate of such persons in any transaction completed since the beginning of the most recently completed financial year or in any proposed transaction which has materially affected or would materially affect Bowood or any of its subsidiaries, except as otherwise disclosed in this Annual Information Form.

DIVIDEND RECORD AND POLICY

Bowood has not paid any dividends on the Bowood Shares and does not intend to pay dividends on the Bowood Shares in the foreseeable future. The future payment of dividends will be dependent upon the financial requirements of Bowood to fund future growth, the financial condition of Bowood and other factors the Bowood Board may consider appropriate in the circumstances.

LEGAL PROCEEDINGS

Management of Bowood is not aware of any existing or contemplated legal proceedings material to Bowood to which Bowood is a party or to which any of its properties are subject.

There have been (i) no penalties or sanctions imposed against Bowood 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 Bowood that Bowood believes would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by Bowood with a court relating to securities legislation or with a securities regulatory authority.

EXPERTS

Legal services are currently being provided to Bowood by Fraser Milner Casgrain LLP. As of the date hereof, the partners and associates of Fraser Milner Casgrain LLP own less than 1% of the issued and outstanding Bowood Shares. GLJ, Bowood's independent qualified reserves evaluator, owns less than 1% of the issued and outstanding Bowood Shares**.**

The audit report contained in filings made by Bowood under National Instrument 51-102 – *Continuous Disclosure Requirements* during the year ended December 31, 2011 was prepared by PricewaterhouseCoopers LLP. PricewaterhouseCoopers LLP were appointed auditors of Bowood on May3, 2010. PricewaterhouseCoopers LLP are independent of Bowood pursuant to the rules of professional conduct of the Institute of Chartered Accountants of Alberta.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only agreements entered into by Bowood since its incorporation to the date hereof which can reasonably be regarded as presently material to Bowood are as follows:

1. the Amalgamation Agreement between Bowood Energy Ltd., 1501976 Alberta Ltd. and Bowood Energy Inc. dated November 18, 2009.;

2. the Acquisition Agreement between Bowood Energy Inc. and Kainaiwa Resources Inc. dated September 1, 2010; and

3. the equalisation, farm-out and option agreement dated December 2, 2010 between the Corporation and Legacy with respect to the Joint Venture with Legacy.

TRANSFER AGENT AND REGISTRAR

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

ADDITIONAL INFORMATION

Additional information relating to Bowood can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Bowood's securities and securities authorized for issuance under equity compensation plans is contained in Bowood's information circular and proxy statement for Bowood's last annual meeting of shareholders held on June 3, 2011. Additional financial information is contained in Bowood's consolidated financial statements and the related management's discussion and analysis for the year ended December 31, 2011.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph and any other document incorporated herein by reference are available on the foregoing basis and upon request by contacting the Office Manager, Kristine Helfrich at Suite 1850, 717 – 7th Avenue S.W., Calgary, Alberta, T2P 0Z3, by phone at (403) 265-2525 or by fax at (403) 263-8555.

EXHIBIT 1 - FORM 51-101F2

EXHIBIT 2 -FORM 51-101F3

REPORT OF MANAGEMENT ON OIL AND GAS DISCLOSURE
BOWOOD ENERGY INC.

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

1. Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.

2. The report referred to in item 3 of section 2.1 of NI 51-101 must in all material respects be as follows:

Report of Management and Directors on Reserves Data and Other Information

Management of Bowood Energy Inc. (the "Company") is 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, 2011, estimated using forecast prices and costs.

GLJ Petroleum Consultants Ltd. ("GLJ"), independent qualified reserves evaluators, has evaluated the Company's reserves data. The report of GLJ has been presented on Form 51-101F2.

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

(a) reviewed the Company's procedures for providing information to GLJ;

(b) met with GLJ to determine whether any restrictions affected the ability of GLJ to report without reservation.

(c) reviewed the reserves data with management and GLJ.

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 approved:

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

(b) the filing of Form 51-101F2 which is the report of GLJ 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "*Robert Mercier*"	(signed) "*Franco Civitarese*"
Robert Mercier President and Chief Executive Officer	Franco Civitarese Vice-President, Finance and Chief Financial Officer
(signed) "*Chris Bloomer*"	(signed) "*Jim Welykochy*"
Chris Bloomer Director	Jim Welykochy Director

April 20, 2012

EXHIBIT 3 - FORM 52-110F2

AUDIT COMMITTEE DISCLOSURE

ITEM: 1 THE AUDIT COMMITTEE'S CHARTER

1. Mandate

The Audit Committee will be responsible for managing, on behalf of shareholders of Bowood Energy Inc. (the "**Corporation**"), the relationship between the Corporation and the external auditors. In particular, the Audit Committee will have responsibility for the matters set out in this Charter, which include:

(a) overseeing the work of external auditors engaged for the purpose of preparing or issuing an auditing report or related work;

(b) recommending to the board of directors the nomination and compensation of the external auditors;

(c) reviewing significant accounting and reporting issues;

(d) reviewing the Corporation's financial statements, MD&A and earnings press releases before the Corporation publicly discloses this information;

(e) focusing on judgmental areas such as those involving valuations of assets and liabilities;

(f) considering management's handling of proposed audit adjustments identified by external auditors;

(g) being satisfied that all regulatory compliance matters have been considered in the preparation of the financial statements of the Corporation;

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

(i) evaluating whether management is setting the appropriate tone by communicating the importance of internal control and ensuring that all individuals possess an understanding of their roles and responsibilities.

2. Membership of the Audit Committee

Composition

The audit committee will be comprised of at least such number of directors as required to satisfy the audit committee composition requirements of National Instrument 52-110, as amended from time to time. Each member will be a director of the Corporation.

Independence

The Audit Committee will be comprised of a number of independent directors required to enable the Corporation to satisfy:

(a) the independent director requirements for audit committee composition required by National Instrument 52-110, as amended from time to time, and

(b) the independent director requirements of the TSX Venture Exchange, or such other stock exchange on which the Corporation's shares are traded from time to time.

Chair

The Audit Committee shall select from its membership a chair. The job description of the chair is attached as Appendix A hereto.

Expertise of Audit Committee Members

Each member of the Audit Committee must be financially literate. Financially literate means the ability to read and understand a set of financial statements that represent a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

Financial Expert

The Corporation will strive to include a financial expert on the Audit Committee. An Audit Committee financial expert means a person having: (i) an understanding of financial statements and accounting principles; (ii) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (iii) experience in preparing, auditing, analyzing or evaluating financial statements that present a similar breadth and level of complexity as the Corporation's statements; (iv) an understanding of internal controls; and (v) an understanding of an Audit Committee's functions.

3. Meetings of the Audit Committee

The Audit Committee must meet in accordance with a schedule established each year by the board of directors, and at other times as the Audit Committee may determine. A quorum for transaction of business in any meeting of the Audit Committee is a majority of members. At least twice a year, the Audit Committee must meet with the Corporation's chief financial officer and external auditors separately.

4. Responsibilities of the Audit Committee

The Audit Committee will be responsible for managing, on behalf of the shareholders of the Corporation, the relationship between the Corporation and the external auditors. In particular, the Audit Committee has the following responsibilities:

External Auditors

(a) the Audit Committee must recommend to the board of directors:

(i) the external auditors to be nominated for the purpose of preparing or issuing an audit report or performing other audit or review services for the Corporation; and

(ii) the compensation of the external auditors;

(b) the Audit Committee must be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditors regarding financial reporting;

(c) with respect to non-audit services:

(i) the Audit Committee must pre-approve all non-audit services provided to the Corporation or its subsidiaries by its external auditors or the external auditors of the Corporation's subsidiaries, except for tax planning and transaction support services in an amount not to exceed $15,000 for each service in a fiscal year; and

(ii) the Audit Committee must pre-approve all non-audit services provided to the Corporation or its subsidiaries by its external auditors or the external auditors of the Corporation's subsidiaries, except *de minimis* non-audit services as defined in applicable law.

(d) the Audit Committee must also:

(i) review the auditors' proposed audit scope and approach;

(ii) review the performance of the auditors; and

(iii) review and confirm the independence of the auditors by obtaining statements from the auditors on relationships between the auditors and the Corporation, including non-audit services, and discussing the relationships with the auditors;

Accounting Issues

(e) the Audit Committee must:

(i) review significant accounting and reporting issues, including recent professional and regulatory pronouncements, and understand their impact on the financial statements; and,

(ii) ask management and the external auditors about significant risks and exposures and plans to minimize such risks.

Financial Statements, MD&A and Press Releases

(f) the Audit Committee must:

(i) review the Corporation's financial statements, MD&A and earnings press releases before the Corporation publicly discloses this information;

(ii) in reviewing the annual financial statements, determine whether they are complete and consistent with the information known to committee members, and assess whether the financial statements reflect appropriate accounting principles;

(iii) pay particular attention to complex and/or unusual transactions such as restructuring charges and derivative disclosures;

(iv) focus on judgmental areas such as those involving valuation of assets and liabilities, including, for example, the accounting for and disclosure of loan losses, warranty, professional liability, litigation reserves and other commitments and contingencies;

(v) consider management's handling of proposed audit adjustments identified by the external auditors;

(vi) ensure that the external auditors communicate certain required matters to the committee;

(vii) be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the disclosure referred to in paragraph (f(i) (above), and must periodically assess the adequacy of those procedures;

(viii) be briefed on how management develops and summarizes quarterly financial information, the extent to which the external auditors review quarterly financial information and whether that review is performed on a pre- or post-issuance basis;

(ix) meet with management, either telephonically or in person to review the interim financial statements;

(x) to gain insight into the fairness of the interim statements and disclosures, the Audit Committee must obtain explanations from management on whether:

(A) actual financial results for the quarter or interim period varied significantly from budgeted or projected results;

(B) changes in financial ratios and relationships in the interim financial statements are consistent with changes in the Corporation's operations and financing practices;

(C) generally accepted accounting principles have been consistently applied;

(D) there are any actual or proposed changes in accounting or financial reporting practices;

(E) there are any significant or unusual events or transactions;

(F) the Corporation's financial and operating controls are functioning effectively;

(G) the Corporation has complied with the terms of loan agreements or security indentures; and

(H) the interim financial statements contain adequate and appropriate disclosures;

Compliance with Laws and Regulations

(g) the Audit Committee must:

(i) periodically obtain updates from management regarding compliance;

(ii) be satisfied that all regulatory compliance matters have been considered in the preparation of the financial statements;

(iii) review the findings of any examinations by regulatory agencies such as the Ontario Securities Commission; and

(iv) review, with the Corporation's counsel, any legal matters that could have a significant impact on the Corporation's financial statements;

Employee Complaints

(h) the Audit Committee must establish procedures for:

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

(ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;

Other Responsibilities

(i) the Audit Committee must:

(i) review and approve the Corporation's hiring policies of employees and former employees of the present and former external auditors of the Corporation;

(ii) evaluate whether management is setting the appropriate tone by communicating the importance of internal control and ensuring that all individuals possess an understanding of their roles and responsibilities;

(iii) focus on the extent to which internal and external auditors review computer systems and applications, the security of such systems and applications, and the contingency plan for processing financial information in the event of a systems breakdown;

(iv) gain an understanding of whether internal control recommendations made by external auditors have been implemented by management;

(v) periodically review and reassess the adequacy of this Charter and recommend any proposed changes to the Corporate Governance and Nominating Committee and the board for approval;

(vi) review, and if deemed appropriate, approve expense reimbursement requests that are submitted by the chief executive officer or the chief financial officer to the Corporation for payment;

(vii) assist the board to identify the principal risks of the Corporation's business and, with management, establish systems and procedures to ensure that these risks are monitored; and

(viii) carry out other duties or responsibilities expressly delegated to the Audit Committee by the board.

5. Authority of the Audit Committee

The Audit Committee shall have the authority to:

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

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

(c) communicate directly with the internal and external auditors.

ITEM: 2 COMPOSITION OF THE AUDIT COMMITTEE

The current members of the Audit Committee are Craig Kelly, Chris Bloomer and Jim Welykochy. All of the members are independent and financially literate. "Independent" and "financially literate" have the meaning used in National Instrument 52-110 ("**NI 52-110**") of the Canadian Securities Administrators.

ITEM: 3 RELEVANT EDUCATION AND EXPERIENCE

Mr. Craig Kelly

Mr. Kelly is currently the Chief Financial Officer for the privately-owned Oryx Petroleum Services SA based in Geneva Switzerland. From 2006 to 2010, Mr. Kelly was the Head of Corporate Finance for Addax Petroleum Corporation based in Geneva, Switzerland. Prior to joining Addax Petroleum, Mr. Kelly was a Director for RBC Capital Markets in Calgary, Canada, where he advised a broad spectrum of clients on mergers, acquisitions and corporate finance activities in all aspects of the domestic and international energy industry. Mr. Kelly also worked with Ernst & Young LLP in Toronto and Vancouver, Canada, and is a member of the Institute of Chartered Accountants of Alberta.

Mr. Chris Bloomer

Mr. Bloomer has over 30 years experience in the domestic and international energy industry spanning both the upstream and downstream sectors. He joined Petrobank in December 2002 and is Senior Vice President and Chief Operating Officer, Heavy Oil and a Director of Petrobank. Previously, he also held the position of CFO. His career began in 1978 at Shell Canada Limited where he moved to positions with increasing responsibility from exploration to economics and finance, oil sands development, planning and marketing, culminating in his role as Director, Liquids Business Centre. From 1993 until 1995 Mr. Bloomer was Senior Vice President of Castle Energy Corporation (NASDAQ), and Chief Operating Officer of its Canadian interests and natural gas production and pipeline operations in Texas. From 1996 until 1998 he was a founder and President and Chief Operating Officer and Director of Canadian TALON Resources, Ltd. (TSX), engaged in developing energy projects primarily in Latin America. Subsequently Mr. Bloomer was a Managing Director of Korn/Ferry International's Calgary office from May 1998 until December 2002 focusing on the domestic and international energy industry. Mr. Bloomer is a member of the Association of Professional Engineers Geologists and Geophysicists of Alberta ("APEGGA"). He is also a Director of CALMENA Energy Services (TSX).

Mr. Jim Welykochy

Mr. Welykochy is a self-employed financial consultant to the oil & gas industry capital markets. Prior thereto, Mr. Welykochy served as Vice President, Corporate Development and Director of Ryland Oil Corporation until the sale of Ryland to Crescent Point Energy in August, 2010. Prior to joining Ryland, Mr. Welykochy served as Vice President of institutional sales for PI Financial Corp. where he was responsible for developing relationships with institutional clients with a focus on Canadian listed junior oil and gas companies. Mr. Welykochy was an oil and gas analyst with Genuity Capital Markets, Acumen Capital Finance Partners and Jennings Capital Inc. and also served in investment banking and corporate finance positions with COSCO Capital, Rogers & Partners Securities Inc. and Loewen, Ondaatje McCutcheon Ltd. Mr. Welykochy is a Professional Geologist and member of the Association of Professional Engineers Geologists and Geophysicists of Alberta ("**APEGGA**").

ITEM: 4 AUDIT COMMITTEE OVERSIGHT

At no time since the commencement of Bowood's most recently completed financial year was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Bowood Board.

ITEM: 5 RELIANCE ON CERTAIN EXEMPTIONS

Since the effective date of NI 52-110, Bowood has not relied on the exemptions contained in sections 2.4 or 8 of NI 52-110. Section 2.4 provides an exemption from the requirement that the audit committee must pre-approve all non-audit services to be provided by the auditor, where the total amount of fees related to the non-audit services are not expected to exceed 5% of the total fees payable to the auditor in the fiscal year in which the non-audit services were provided. Section 8 permits a company to apply to a securities regulatory authority for an exemption from the requirements of NI 52-110, in whole or in part.

ITEM: 6 PRE-APPROVAL POLICIES AND PROCEDURES

Formal policies and procedures for the engagement of non-audit services have yet to formulated and adopted. Subject to the requirements of NI 52-110, the engagement of non-audit services is considered by Bowood's Board of Directors, and where applicable by the Audit Committee, on a case by case basis.

ITEM: 7 EXTERNAL AUDITOR SERVICE FEES (BY CATEGORY)

The aggregate fees charged to Bowood by the external auditor in each of the last two fiscal years are as follows:

	FYE 2011	**FYE 2010**
Audit Fees Including T2 Corporate Tax Returns for the year ended	$77,000	$83,025
All other fees (non-tax) and Assistance with Quarterly Report Preparation:	$82,775	$118,750
Total Fees:	**$159,775**	**$201,775**

ITEM: 8 EXEMPTION

In respect of the most recently completed financial year, Bowood is relying on the exemption set out in section 6.1 of the Instrument with respect to compliance with the requirements of Part 3 (Composition of the Audit Committee) and Part 5 (Reporting Obligations) of NI 52-110.

Appendix A to Audit Committee Charter

Job Description — Audit Committee Chair

The responsibilities of the Audit Committee chair include, among other things:

(a) managing the affairs of the Committee and monitoring its effectiveness;

(b) managing the meetings of the Committee by ensuring meaningful agendas are prepared and guiding deliberations of the Committee so that appropriate decisions and recommendations are made; and

(c) setting up agendas for meetings of the Committee and ensuring that all matters delegated to the Committee by the board are being dealt with at the Committee level during the course of the year.