Waldron
ENERGY

Annual Information Form

Year Ended December 31, 2012

April 1, 2013

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements and forward-looking information (collectively referred to herein as ñ**forward-looking statements**ò) within the meaning of applicable Canadian securities laws. Such forward-looking statements relate to future events or Waldronôs future performance and are based on Waldronôs current internal expectations, estimates, projections, assumptions and beliefs, including, among other things, assumptions with respect to production, future capital expenditures and cash flow. Readers are cautioned that the assumptions used in the preparation of such information may prove incorrect. All statements other than statements of historical fact may be forward-looking statements. Such forward-looking statements are often, but not always, identified by the use of words such as ñseekò, ñanticipateò, ñbudgetò, ñplanò, ñcontinueò, ñestimateò, ñexpectò, ñforecastò, ñmayò, ñwillò, ñprojectò, ñpredictò, ñpotentialò, ñtargetingò, ñintendò, ñcouldò, ñmightò, ñshouldò, ñbelieveò and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Waldron believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These forward-looking statements speak only as of the date of this Annual Information Form.

In particular, this Annual Information Form and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- Waldronôs future operating and financial results;
- the impact of acquisitions on Waldronôs operations, inventory and opportunities, financial condition, access to capital and overall strategy;
- development and drilling plans for Waldronôs assets;
- land expiries;
- abandonment and reclamation costs;
- the performance characteristics of Waldronôs oil and natural gas properties;
- anticipated finding and development costs and operating costs for Waldron;
- the quantity of Waldronôs existing oil and natural gas reserves;
- Waldronôs oil and natural gas production levels;
- capital expenditure programs and the timing thereof;
- the source of funding for Waldronôs activities;
- projections of market prices and costs;
- the tax horizon of Waldron;
- supply of and demand for oil and natural gas;
- expectations regarding Waldronôs ability to raise capital and to continually add to reserves through acquisitions, development and optimization; and
- treatment under governmental regulatory regimes and tax, environmental and other laws.

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

The actual results, performance or achievements of Waldron could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below under ñRisk Factorsò and elsewhere in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, including but not limited to:

- volatility in market prices for oil and natural gas and in foreign exchange rates;
- operational risks and liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;

- competition for, among other things, capital, drilling equipment, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- changes in general economic, market and business conditions;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of Waldronôs exploration and development program;
- unforeseen difficulties in integrating any acquired assets into Waldronôs operations;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory approvals and to obtain and maintain all required permits and licenses;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against Waldron;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under ñRisk Factorsò.

With respect to forward-looking statements contained in this Annual Information Form, Waldron has made assumptions regarding, among other things: that commodity prices will be consistent with the current forecasts of its engineers; royalty regimes and rates will not be subject to material modification; that the Corporation will be able to obtain skilled labour and other industry services at reasonable rates; the timing and amount of capital expenditures and implementation thereof will be consistent with the Corporationôs expectations; that future exchange rates will not vary materially from current levels; the impact of increasing competition; that the conditions in general economic and financial markets will not vary materially; that the Corporation will be able to access capital on acceptable terms; that drilling and other equipment will be available on acceptable terms; that government regulations and laws will not change materially; and that future operating costs will be consistent with the Corporationôs expectations.

Waldron has included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on Waldronôs current and future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Except as required by applicable securities laws, Waldron undertakes no obligation to publicly update or revise any forward-looking statements. Readers should also carefully consider the matters discussed under the heading ñRisk Factorsò in this Annual Information Form.

NON-GAAP MEASURES

Funds flow from operations and operating netbacks are not recognized measures under GAAP. Management of the Corporation believes that funds flow from operations and operating netbacks are useful supplemental measures as they demonstrate Waldron's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Readers are cautioned, however, that these measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of Waldron's performance. Waldron's method of calculating these measures may differ from other companies and accordingly they may not be comparable to measures used by other companies. For these purposes, Waldron defines ñfunds flow from operationsò as cash provided by operations before changes in non-cash operating working capital and decommissioning expenditures and defines ñoperating netbacksò as revenue less royalties and operating expenses.

GLOSSARY

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

"**971021 AB**" means 971021 Alberta Ltd., formerly Taylor Hill Resources Ltd., a corporation previously incorporated under the ABCA which amalgamated with Triton effective January 8, 2007;

"**ABCA**" means the *Business Corporations Act* (Alberta) as amended from time to time;

"**Acquired Assets**" means certain oil and gas assets acquired by Waldron pursuant to the Asset Acquisition;

"**Annual Information Form**" means this annual information form;

"**Asset Acquisition**" means the acquisition by Waldron on February 22, 2010 of the Acquired Assets from the Asset Vendor;

"**Asset Vendor**" means, together, a general partnership formed under the laws of Alberta and an affiliated corporation serving as managing partner of such partnership;

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

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

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

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

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

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

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

(d) provide improved recovery systems;

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

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

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

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

"**GAAP**" means Canadian generally accepted accounting principles;

"**GLJ**" means GLJ Petroleum Consultants;

"**GLJ Report**" means report of GLJ dated March 7, 2013 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2012;

"**Gross**" or "**gross**" means:

(a) in relation to the Corporation's interest in production and reserves which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

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

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

“IFRS” means International Financial Reporting Standards;

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

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

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

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

“NCIB” means effective October 7, 2008, Triton received regulatory approval to commence a normal course issuer bid to purchase for cancellation, from time to time, as Triton considered it advisable, up to a maximum of 319,200 Common Shares commencing October 9, 2008.

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

"**Net**" or "**net**" means:

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

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

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

"**NRF**" means the New Royalty Framework of the Province of Alberta effective January 1, 2009;

"**OPEC**" means the Organization of Petroleum Exporting Countries;

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

"**Performance Warrants**" means warrants to subscribe for Common Shares issued pursuant to the Private Placement, with each whole warrant entitling the holder to acquire one Common Share at a price of $1.70 per share until December 31, 2014, subject to certain vesting provisions;

"**Private Placement**" has the meaning ascribed thereto under the heading ñGeneral Development of the Business ï Year Ended December 31, 2009ò;

"**property**" includes:

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

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

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

but does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas;

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

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

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

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

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

"**Recapitalization**" has the meaning ascribed thereto under the heading ñGeneral Development of the Business ï Year Ended December 31, 2009ò;

"**Securities Act**" means the *Securities Act* (Alberta), R.S.A. c.S-4, as amended from time to time, including the regulations promulgated thereunder;

"**Tax Act**" means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5^{th} Supp.), as amended from time to time, including the regulations promulgated thereunder;

"**Trading Price**" means the 20-day weighted average trading price of the Common Shares on the TSX;

"**Triton**" means Triton Energy Corp., the name of the Corporation prior to the change of name to ñWaldron Energy Corporationò effective on June 14, 2010;

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

"**Waldron**" or the "**Corporation**" means Waldron Energy Corporation, a corporation amalgamated under the ABCA.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2012.

On June 11, 2010, Waldron completed a ten (10) to one (1) share consolidation. All share, stock option, warrant and per share comparative numbers in this Annual Information Form have been adjusted to reflect the share consolidation.

RESERVES DEFINITIONS

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

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

"**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;

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

"**developed 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; and

"**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.

Reserves 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 nonproducing. 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.

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

CONVENTIONS

Certain terms used herein are defined in the "Glossary". Unless otherwise indicated, references herein to "**$**" or "**dollars**" are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with GAAP.

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
Boe	barrels of oil equivalent of natural gas (on the basis of 6 Mcf of natural gas to 1 bbl of oil)
Boe/d	barrels of oil equivalent per day
Mboe	thousand Boe
NGLs	natural gas liquids
Mmbtu	million British thermal units
Mstb	thousand stock tank barrels
Stb	stock tank barrel

Natural Gas

Bcf	billion cubic feet
Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
GJ	gigajoule
GJ/d	Gigajoule per day

Other

AECO	The natural gas storage facility located at Suffield, Alberta
LSD	Legal site description
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NOTE REGARDING BARREL OF OIL EQUIVALENT

Disclosure provided herein in respect of Boe may be misleading, particularly if used in isolation. The Boe conversion ratio of 6 Mcf of natural gas to 1 Bbl of oil used throughout this document is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6Mcf:1Bbl, utilizing a conversion on a 6Mcf:1Bbl basis may be misleading as an indication of value.

CONVERSION

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Thousand cubic metres	Mcf	35.494
Bbls	Cubic metres ("**m^3**")	0.159
Cubic metres	Bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

THE CORPORATION

The Corporation was incorporated under the ABCA on February 4, 2004 under the name "Triton Energy Corp". The Corporation filed Articles of Amendment on September 28, 2004 to remove the private company provisions and share transfer restrictions. On April 28, 2005, the Corporation acquired 100% of the issued and outstanding shares of 971021 AB pursuant to a share purchase and sale agreement. Effective January 8, 2007, the Corporation amalgamated with 971021 AB by way of vertical short form amalgamation under the ABCA to form one corporation operating under the name Triton Energy Corp.

On December 31, 2009, Triton completed the Recapitalization, a series of transactions involving: (i) the Private Placement, (ii) the Waldron Acquisition, and (iii) the appointment of a new Board of Directors and management team. See ñGeneral Development of the Business ï Year Ended December 31, 2009ò.

Effective June 9 and 11, 2010 respectively, the Corporation amended its articles to change its name from ñTriton Energy Corp.ò to ñWaldron Energy Corporationò, and to consolidate its Common Shares on the basis of ten (10) pre-consolidation shares for one (1) post-consolidation share.

The registered office of the Corporation is located at Suite 1400, 700 ï 2nd Street S.W., Calgary, Alberta T2P 4V5 and its head office is located at Suite 2410, 520 ï 3rd Avenue SW, Calgary, Alberta T2P 0R3.

The Corporation does not have any subsidiaries. The Corporation's Common Shares trade on the TSX under the symbol "WDN".

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of the significant events in the development of the Corporation for the previous three year periods shown.

2009

On October 9, 2009, Tritonôs NCIB expired. During the course of the NCIB, Triton purchased and cancelled 296,794 Common Shares at an average price of $2.30 per share.

Recapitalization

On December 15, 2009, Triton announced, and on December 31, 2009, Triton completed a series of transactions involving: (i) a non-brokered private placement of Units and Common Shares for aggregate proceeds of $10.25 million (the ñ**Private Placement**ò), (ii) the acquisition of the undeveloped lands and drill-ready recompletion prospects as more particularly described under ñ- *Waldron Acquisition*ò (the ñ**Waldron Acquisition**ò), and (iii) the appointment of a new Board of Directors and management team (collectively, the ñ**Recapitalization**ò). The definitive agreement entered into by Waldron in connection with the Recapitalization also provided for a rights offering (the ñ**Rights Offering**ò) to holders of Common Shares.

Private Placement

Waldron issued an aggregate of 2,222,505 Common Shares at a price of $1.30 per Common Share and 2,831,280 units (ñ**Units**ò) at a price of $2.60 per Unit. Each Unit consists of one Common Share, one Common Share issued on a flow-through basis pursuant to the Tax Act and two Performance Warrants. Each Performance Warrant entitles the holder to purchase one Common Share at a price of $1.70 for a period of 5 years from the date of issuance. The Performance Warrants vest and become exercisable as to one-third upon the Trading Price equalling or exceeding $2.40, an additional one-third upon the Trading Price equalling or exceeding $3.60 and a final one-third upon the Trading Price equalling or exceeding $4.20.

Waldron Acquisition

Waldron also acquired from a company controlled by the new management team certain undeveloped land and drill ready and re-completion prospects in Alberta for an aggregate purchase price of $1.98 million. Such lands included a number of drill ready prospects and re-completions targeting deep basin liquids rich tight natural gas. In consideration thereof, Waldron issued 1,520,000 units (ñ**Waldron Units**ò) at a price of $1.30 per Waldron Unit. Each Waldron Unit consists of one Common Share and one Common Share purchase warrant, which has substantially the same terms as the Performance Warrants.

Rights Offering

As part of the Recapitalization, Waldron initiated the Rights Offering by way of a rights offering circular dated January 13, 2010. The Rights Offering allowed holders of Common Shares of Waldron, as at January 27, 2010, to be issued one right (a ñ**Right**ò) for each Common Share held. Each four full Rights entitled the holder to purchase one Common Share at the exercise price of $1.30 per share, being equal to the price of the Common Shares issued under the Private Placement. Subscribers for Common Shares or Units pursuant to the Private Placement and recipients of the Waldron Units were not entitled to participate in the Rights Offering with respect to any such securities and agreed not to exercise, sell or convey any Rights issuable to them by virtue of their ownership of such securities. The Rights expired on February 18, 2010. 1,043,049 Common Shares were issued pursuant to the Rights Offering for gross proceeds of $1.4 million.

Property Acquisition

On December 31, 2009, the Corporation acquired two gross (1.5 net) sections of land with approximately 40 Boe/d of production located in the Ricinus area of west central Alberta for cash consideration of $1.0 million from a third party public company.

2010

On January 20, 2010, Waldron entered into an agreement in respect of the Asset Acquisition with the Asset Vendor to purchase the Acquired Assets from the Asset Vendor with an effective date of November 1, 2009 (the ñ**Asset Acquisition Agreement**ò). The base purchase price for the Acquired Assets pursuant to the Asset Acquisition Agreement was $45.0 million before closing adjustments and interest, payable in cash. The Asset Acquisition closed on February 22, 2010.

The Acquired Assets included assets with net production of approximately 1,100 Boe/d of liquids rich natural gas (65%) and light oil (35%) and 37 net sections of undeveloped land. The Acquired Assets are located in the Crystal and Ferrybank areas of West Central Alberta. The Asset Acquisition increased Waldronôs exposure to the liquids rich natural gas Glauconite formation on the Hoadley trend, an area where industry players have experienced success with horizontal drilling and are expected to provide Waldron with multiple Glauconite and Belly River light oil drilling locations. In addition, the Acquired Assets are generally characterized by high working interests (averaging approximately 70%), operatorship, two dimensional and three dimensional seismic coverage and control of infrastructure, all attributes that are expected to provide Waldron with significant exposure to the benefits and upside of these properties. The Acquired Assets also include gathering and processing infrastructure capable of accommodating future production additions.

On February 22, 2010, the Corporation closed a bought deal equity offering pursuant to a short form prospectus for total gross proceeds of $25.0 million by issuing 10,417,000 Common Shares at a price of $2.40 per Common Share.

On March 31, 2010, the Corporation closed a bought deal private placement for total gross proceeds of $7.5 million by issuing 3,410,000 Common Shares on a ñflow-throughò basis under the Tax Act at a price of $2.20 per Common Share.

On June 11, 2010, Waldron completed a ten (10) to one (1) share consolidation.

On September 9, 2010, the Common Shares of the Corporation commenced trading on the TSX under the symbol ñWDNò.

On December 2, 2010, the Corporation closed the sale of nine (9) net sections of non-core undeveloped petroleum and natural gas Viking rights in the Crystal area for proceeds of $5.5 million. The Corporation also disposed of two (2) net sections of non-core undeveloped land for proceeds of $0.8 million. The Corporation did not have any production from, or reserves attributed to, the mineral rights sold. The proceeds from these dispositions were used to fund the Corporationôs capital program.

On December 7, 2010, Waldron closed a bought deal private placement for total gross proceeds of $5.0 million by issuing 1,725,000 Common Shares on a ñflow-throughò basis under the Tax Act at a price of $2.90 per Common Share.

Operations

Operational highlights for the year ended December 31, 2010 included:

- The Corporation incurred $65.7 million in capital expenditures whereby $3.6 million was spent on land acquisitions, $3.5 million on geosciences and exploration activities, $17.1 million on drilling and completions, $1.2 million on plant and facilities and $45.0 million on asset acquisitions. Non-core asset dispositions discussed above of $6.3 million offset total capital expenditures.
- The Corporation drilled 3.0 gross (2.9 net) wells and deepened 2.0 gross (1.8 net) wells.
- Production averaged 2,108 Boe/d for the year ended December 31, 2010.
- The Corporation exited 2010 with approximately 102,053 gross and 89,328 net acres of undeveloped land in Alberta.

2011

On January 1, 2011, IFRS became the generally accepted accounting principles in Canada for profit-oriented publicly accountable enterprises such as Waldron. The adoption date of January 1, 2011 required the restatement, for comparative purposes, of amounts reported by Waldron for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. The IFRS implementation phase continued into 2011 and concluded with the issuance of the first quarter financial statements for 2011. For more information, see our Management's Discussion and Analysis for the years ended December 31, 2010 and 2009, which includes a discussion of Waldron's IFRS transition plan and the expected policy impacts, which has been filed on SEDAR at www.sedar.com.

On February 18, 2011, the Corporation closed a bought deal private placement for total gross proceeds of $5.0 million by issuing 1,334,000 Common Shares on a ñflow-throughò basis under the Tax Act at a price of $3.75 per Common Share.

On June 15, 2011, Waldron closed a bought deal private placement for total gross proceeds of $10.0 million by issuing 2,532,000 Common Share on a ñflow-throughò basis under the Tax Act at a price of $3.95 per Common Share.

During 2011, the Corporation completed various minor non-core property dispositions for net proceeds of $0.5 million.

Operations

Operational highlights for the year ended December 31, 2011 included:

- The Corporation incurred $46.8 million in capital expenditures whereby $2.9 million was spent on land acquisitions, $1.6 million on geosciences and exploration activities, $35.2 million on drilling and completions, and $7.1 million on plant and facilities. Non-core asset dispositions discussed above of $0.5 million offset total capital expenditures.

- The Corporation drilled 8.0 gross (7.4 net) wells and deepened 2.0 gross (2.0 net) wells.

- Production averaged 2,687 Boe/d for the year ended December 31, 2011.

- The Corporation exited 2011 with approximately 108,439 gross and 89,297 net acres of undeveloped land in Alberta.

2012

On July 25, 2012, the Corporation closed a private placement for total gross proceeds of $3.25 million by issuing 5,701,800 Common Shares on a ñflow-throughò basis under the Tax Act at a price of $0.57 per Common Share.

On November 14, 2012, the Corporation announced it would pursue the disposition of its interests in the undeveloped Duvernay lands as well as a producing property at the Crystal area through the initiation of a formal process. This process is ongoing.

Operations

Operational highlights for the year ended December 31, 2012 included:

- The Corporation incurred $12.1 million in capital expenditures whereby $0.4 million was spent on land acquisitions, $0.2 million on geosciences and exploration activities, $10.1 million on drilling and completions, and $1.4 million on plant and facilities.

- The Corporation drilled 3.0 gross (3.0 net) Belly River wells and 2.0 gross (1.6 net) Crystal Glauconite wells.

- In December 2012, Waldron tied in Sullivan Lake 2-12-035-14W4 as a flowing Glauconite gas well.

- Production averaged 2,510 Boe/d for the year ended December 31, 2012.

- The Corporation exited 2012 with approximately 99,932 gross and 85,072 net acres of undeveloped land in Alberta.

Significant Acquisitions

The Corporation did not complete any significant acquisition or significant disposition during or since the end of the most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 *Continuous Disclosure Obligations*.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

General

Waldron is an Alberta-based petroleum and natural gas exploration and production company engaged in the acquisition of, exploration for, and development and production of petroleum and natural gas in strategically located areas currently within the province of Alberta.

Exploration and Development Strategy

Following the Recapitalization, the business plan of the Corporation is to focus on the deep basin of Alberta and to generate a repeatable inventory of liquids rich natural gas drilling prospects in central Alberta, complemented by light oil prospects. In order to achieve this plan, the Corporation intends to concentrate on the internal generation of prospects and strategic acquisitions followed by an aggressive exploration, development and exploitation program. Waldron also intends to be a significant player in its core areas, operate with high working interests, and achieve operating efficiency by controlling infrastructure.

Although the Corporation intends to follow this strategy, the Corporation is largely opportunity driven and will focus its expenditures in areas that provide the greatest economic return to the Corporation, recognizing that all drilling involves substantial risk and that a high degree of competition exists for prospects. No assurance can be given that drilling will prove successful in establishing commercially recoverable reserves. See ñRisk Factorsò.

The Board of Directors may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the foregoing description based upon the Board of Directorsô consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

Environmental Matters

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. See ñRisk Factors ï Environmentalò and ñIndustry Conditions ï Environmental and Climate Change Regulationò. Waldron undertakes continuing efforts to ensure compliance with applicable environmental laws and regulations and to ensure the safety of its employees, consultants and contractors and the general public in all areas where it conducts operations.

These efforts include the development and implementation of environmental, health and safety policies, procedures and manuals and the conduct of regular meetings and exercises. The Board of Directors reviews and monitors the environmental policies and activities of the Corporation on behalf of the Board of Directors as well as the activities of the Corporation as they relate to health and safety. In that regard, the Corporation has adopted corporate emergency response plans for the areas in which it operates, as well as other environment, health and safety policies.

Pursuant to applicable environmental regulations, Waldron is required to abandon, retire and reclaim wells, well sites and facilities. As of December 31, 2012, Waldron has recorded an asset retirement obligation of $11.7 million in its financial statements in accordance with GAAP. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of approximately thirty years. The Corporation has not established a separate reclamation fund for the purpose of funding estimated future environmental and reclamation obligations. Any reclamation or abandonment costs incurred in the ordinary course in a specific period will be funded out of cash flow from operations. There are significant uncertainties related to asset retirement obligations generally, and no assurance can be given as to the eventual timing of and costs of such costs, or their effect on the Corporation.

Other than asset retirement obligations, ordinary course operational expenditures necessary to ensure environmental compliance, and the cost of health, safety and environmental personnel and programs, the Corporation is not aware of any environmental protection requirements that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its areas of operations. Compliance with any existing or new environmental legislation or requirements may require significant expenditures by the Corporation. Given the evolving nature of such requirements, however, it is not possible at this time to predict the nature of future requirements or their impact on the Corporationôs business, financial condition, results of operations and prospects.

The Corporation believes that there is a general trend toward stricter standards in environmental and safety legislation and regulation. Waldron is committed to meeting its responsibilities to protect the environment and the safety of its workers in all areas where it conducts operations and will take such steps as required to ensure compliance with environmental and safety legislation. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

HUMAN RESOURCES

As at the date of this document, the Corporation had 13 full time employees (4 officers and 9 other technical staff) and 6 part time consultants. See "Directors and Officers of the Corporation".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 7, 2013. The effective date of the Statement is December 31, 2012 and the preparation date of the Statement is March 1, 2013.

Disclosure of Reserves Data and Other Information

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ with an effective date of December 31, 2012 contained in the GLJ Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Corporation believes is important to the readers of this information. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, specifically, in the province of Alberta.

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

	RESERVES SUMMARY [1]									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS[2]		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT[3]	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Producing	229	191	0	0	15,521	13,794	769	560	3,586	3,050
Developed Non-Producing	16	15	0	0	2,037	1,789	67	45	422	358
Undeveloped	0	0	0	0	4,814	4,180	268	199	1,070	896
TOTAL PROVED	245	206	0	0	22,373	19,763	1,104	804	5,078	4,304
PROBABLE	367	291	0	0	24,819	21,450	985	707	5,489	4,573
TOTAL PROVED PLUS PROBABLE	612	497	0	0	47,192	41,213	2,090	1,511	10,567	8,877

Notes:

(1) Columns may not add due to rounding.
(2) Natural gas volumes include solution gas volumes associated with the Corporationôs light and medium crude oil reserves.
(3) Natural gas is converted to Boes at a ratio of six thousand standard cubic feet to one barrel of oil.

	NET PRESENT VALUES OF FUTURE NET REVENUE[1][2][3]									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (M$)	5 (M$)	**10 (M$)**	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved										
Producing	74,417	57,879	**47,859**	41,125	36,274	74,417	57,879	47,859	41,125	36,274
Developed Non-Producing	7,805	5,338	**3,958**	3,090	2,498	7,805	5,338	3,958	3,090	2,498
Undeveloped	10,881	6,636	**4,046**	2,376	1,249	9,113	5,762	3,591	2,128	1,109
TOTAL PROVED	93,103	69,852	**55,863**	46,591	40,021	91,335	68,978	55,407	46,343	39,881
PROBABLE	86,132	48,096	**29,260**	18,434	11,644	64,784	35,470	20,936	12,572	7,328
TOTAL PROVED PLUS PROBABLE	179,235	117,949	**85,123**	65,025	51,665	156,119	104,448	76,343	58,915	47,209

Notes:

(1) Utilizes GLJ's price forecast as of January 1, 2013 as detailed below.
(2) Values are net of downhole abandonment liabilities for reserves wells. Non-reserve well and facility abandonment, surface reclamation and salvage values are not included.
(3) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	205,812	30,869	63,231	15,816	2,794	93,103	1,768	91,335
Proved Plus Probable Reserves	456,578	68,849	137,226	67,318	3,948	179,235	23,117	156,119

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	223	$8.88/boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	55,159	$2.18/Mcfe
	Coal Bed Methane	481	$1.22/Mcfe
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	2,631	$8.49/boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	81,233	$1.61/Mcfe
	Coal Bed Methane	1,259	$1.39/Mcfe

Reserve Categories

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:

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

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

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

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

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

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

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

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

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

Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Report were GLJ's forecasts, as at December 31, 2012, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL								
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Bow River 25° API Hardisty ($Cdn/Bbl)	Alberta AECO Average Gas Price ($Cdn/Mcf)	Pentanes Plus Edmonton ($Cdn/Bbl)	Butane Price Edmonton ($Cdn/Bbl)	Propane Price Edmonton ($Cdn/Bbl)	Inflation Rates(1) %/Year	Exchange Rate(2) ($US/$Cdn)
Forecast									
2013	90.00	85.00	71.63	3.38	96.63	65.45	34.06	2.0	1.00
2014	92.50	91.50	77.77	3.83	97.91	70.46	45.75	2.0	1.00
2015	95.00	94.00	79.90	4.28	97.76	72.38	56.40	2.0	1.00
2016	97.50	96.50	82.03	4.72	100.36	74.31	57.90	2.0	1.00
2017	97.50	96.50	82.03	4.95	100.36	74.31	57.90	2.0	1.00
2018	97.50	96.50	82.03	5.22	100.36	74.31	57.90	2.0	1.00
2019	98.54	97.54	82.91	5.32	101.44	75.11	58.52	2.0	1.00
2020	100.51	99.51	84.58	5.43	103.49	76.62	59.71	2.0	1.00
2021	102.52	101.52	86.29	5.54	105.58	78.17	60.91	2.0	1.00
2022	104.57	103.57	88.03	5.64	107.71	79.75	62.14	2.0	1.00
2023+	Escalated oil, gas and product prices at approximately 2% per year thereafter							2.0	1.00

Notes:

(1) Inflation rates for forecasting prices and costs.

(2) Exchange rates used to generate the benchmark reference prices in this table.

(3) Weighted average historical price realized by Waldron for the year ended December 31, 2012 was $2.50/Mcf AECO for natural gas. Approximately 73% of Waldron's production for the year ended December 31, 2012 was natural gas.

(4) Estimated future abandonment costs related to a working interest have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future reserves well downhole abandonment costs. No allowance was made, however, for the abandonment of non reserves wells, the reclamation of wellsites or the abandonment and reclamation of any facilities.

(5) The forecast price and cost assumptions assume the continuance of current laws and regulations.

(6) The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

(7) The impact of the optional Transitional Royalty Rate ("**TRR**") (announced by the Alberta Government on November 19, 2008) was considered in forecasts of future drilling in Alberta and taken into account in the above calculations of future net revenue. In the calculation of future net revenue, the Corporation was assumed to opt for TRR on new wells where justified by a comparison of economics under TRR and the NRF. The effects of the short term incentive program announced by the Government of Alberta on March 3, 2009 were not included or considered in the calculation of reserves and future net revenue. See "Industry Conditions ï Provincial Royalties and Incentives ï Alberta".

Reconciliation of Changes in Reserves and Future Gross Revenue

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

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2011	378	260	637	4	1	5
Extensions	-	143	143	-	-	-
Improved Recovery	6	(6)	-	-	-	-
Technical Revisions	(65)	(29)	(94)	(3)	(1)	(4)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(11)	(1)	(12)	-	-	-
Production	(62)	-	(62)	(1)	-	(1)
December 31, 2012	245	367	612	-	-	-

	NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS AND COAL BED METHANE		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved Plus Probable (Mmcf)
December 31, 2011	1,204	983	2,188	26,283	24,796	51,079
Extensions	104	(70)	34	1,280	485	1,765
Improved Recovery	-	-	-	2	(2)	-
Technical Revisions	14	84	98	8	(660)	(652)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(32)	(12)	(44)	(1,223)	200	(1,023)
Production	(186)	-	(186)	(3,978)	-	(3,978)
December 31, 2012	1,104	985	2,090	22,373	24,818	47,192

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to Waldron's assets for the years ended December 31, 2012, 2011 and 2010 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior thereto	-	-	623	623	2	2
2010	21	21	13,065	13,724	621	623
2011	120	120	1,916	6,675	87	390
2012	-	-	1,280	4,814	104	268

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior thereto	-	-	2,057	2,057	6	6
2010	313	313	17,734	19,903	722	729
2011	64	165	2,373	16,947	98	676
2012	142	264	1,765	17,537	34	672

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

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

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

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

Future Development Costs

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

Year	Forecast Prices and Costs (M$) Proved Reserves	Forecast Prices and Costs (M$) Proved Plus Probable Reserves
2013	6,240	9,605
2014	2,137	26,023
2015	7,439	24,952
Thereafter	-	6,739
Total Undiscounted	15,816	67,318

The future development costs are capital expenditures required in the future for Waldron to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $15.8 million for proved reserves and $67.3 million for proved plus probable reserves (in each case based on forecast prices and costs).

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

Other Oil and Gas Information

Principal Properties

The following is a description of Waldron's principal oil and gas properties as at December 31, 2012. Unless otherwise stated, all production volumes in this section represent Waldron's gross interest.

Ferrybank

Ferrybank is located in west central Alberta about 60 kilometres northeast of Red Deer. Waldron has a 76.4% operated working interest in 65.0 sections of land in the area. At Ferrybank, sweet gas is produced from the upper and lower Mannville Formations at drill depths of 1,600 to 1,800 meters. The Mannville zones are deep basin sweet gas charged system with up to 70 bbls/Mmcf of natural gas liquids (including ethane). The oil targets at Ferrybank are in the Belly River and Ellerslie Formations. The drill depths are approximately 1,000 meters for the Belly River oil and 1,700 meters for the Ellerslie oil. The Corporation has 30 net operated natural gas wells and 31 net operated oil wells in the area. Waldron owns its own gathering system as well as an oil battery. Natural gas is tied into a third party gathering system which transports Waldronõs natural gas to the nearby Keyera Rimbey gas plant for processing. Waldron had 22,928 (20,148 net) acres of undeveloped land at Ferrybank.

Ricinus

Ricinus is located in west central Alberta about 80 kilometres west of Red Deer. Waldron has 75.6% operated working interest in 88.7 sections of land in the area. The main target at Ricinus is sweet gas in the Ellerslie and Glauconitic Formations at drill depths of 3,000 to 3,500 meters. The Ellerslie and Glauconitic zones are a deep basin sweet gas charged system with up to 40 bbls/Mmcf of natural gas liquids. The Corporation has nine net operated natural gas wells in the area. Waldron owns its own gathering system in north Strachan which transports Waldronǿs natural gas to the nearby Keyera Strachan gas plant for processing through Waldronǿs own gathering system. In south Ricinus, gas is transported to the Apache Ricinus gas plant for processing. Waldron had 59,840 (49,048 net) acres of undeveloped land at Ricinus.

Newton

Newton is located in west central Alberta about 60 kilometres northwest of Edmonton. Waldron has 94.7% operated working interest in 18 sections of Crown land in the area. Newton produces sweet gas from the Ellerslie and the Sparky Mannville Formations at drill depths under 1,200 meters. The Corporation has five net operated natural gas wells at Newton. Waldron owns its own gathering system, which is tied into a third party gathering system and transports Waldronǿs natural gas to the nearby Altagas Manola plant for processing. Waldron has 9,604 (8,964 net) acres of undeveloped land at Newton.

Sullivan Lake

Sullivan Lake is located in east central Alberta approximately 150 kilometres northeast of Calgary. Waldron has an average 99.2% operated working interest in 17 sections of land in the area. The Corporation produces sweet gas from the Lower Cretaceous Viking Formation and sweet gas and light oil in the Mannville Formation at drill depths under 1,200 meters, as well as multiple shallow gas horizons in the Belly River Formation at drill depths less than 450 meters. The Corporation has seven net operated natural gas wells, which are tied into Penn West and Apache gathering systems and one net operated oil well. Waldron has 6,600 (6,560 net) acres of undeveloped land at Sullivan Lake.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2012:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing(1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	35.0	32.0	71.0	57.0	68.0	47.6	38.0	30.0

Note:

(1) All non-producing oil and natural gas wells are located near existing infrastructure.

Properties with No Attributed Reserves

At December 31, 2012, the Corporation had 99,932 gross (85,072 net) acres of undeveloped land holdings in the Province of Alberta. The Corporation expects that rights of up to 13,312 net acres of its undeveloped land holdings will expire by December 31, 2013. Waldron is considering whether or not to drill or submit an application to continue, sell, swap or farm-out selected portions of the above acreage.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

See "*Additional Information Relating to Reserves Data – Significant Factors or Uncertainties*" above.

Forward Contracts and Marketing

Our crude oil and natural gas production is currently sold directly to credit-worthy counterparties, with the exception of small quantities of non-operated properties which are marketed by the operator.

We periodically hedge the price on a portion of our crude oil and natural gas production. During 2012, the prices received for crude oil was increased by $4.71 per barrel of sales oil as we entered into the following contract:

Period	**Commodity**	**Type of Contract**	**Quantity Contracted**	**Contract price**
Mar 1, 2012 - Dec 31, 2012	Crude Oil	Financial - Costless Collar	200 bbls/d	WTI $95.00 - 103.90/bbl CAD

As of the date hereof, the Corporation does not have any forward contracts.

Additional Information Concerning Abandonment Costs

Waldron estimates well abandonment costs on an area by area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The Corporation currently has 166.7 net wells for which it expects to incur abandonment costs.

Estimated costs of reserve well downhole abandonment were included in the GLJ Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices is $2.8 million undiscounted ($1.4 million using a 10% discount rate). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Corporation in respect of proved reserves as disclosed above. No allowance for surface reclamation or salvage value was included in these costs. The total proved plus probable abandonment costs are $3.9 million (undiscounted) and $1.4 million (discounted at 10%).

The table below indicates the expected timing of well abandonment costs for the Corporation and sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue:

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

Year	Abandonment Costs (Undiscounted)
2013	404
2014	148
2015	62
Thereafter	2,180
Total Undiscounted	2,794
Total Discounted @ 10%	1,363

Forecast Prices and Costs (Total Proved plus Probable) ($000s)

Year	Abandonment Costs (Undiscounted)
2013	338
2014	98
2015	88
Thereafter	3,424
Total Undiscounted	3,948
Total Discounted @ 10%	1,379

Tax Horizon

Based on the Corporationŏs available tax pools, expected capital expenditures and forecast net income for 2013, the Corporation does not anticipate paying current income taxes in 2013. Depending on levels of production, commodity prices, acquisitions and capital expenditures, Waldron could begin paying current income taxes in 2014 or beyond.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2012:

Capital Expenditures	$000s
Property acquisition costs:	
Proved properties	$ -
Undeveloped properties	375
Exploration costs	5,254
Development costs	6,505
Total	$ 12,134

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2012:

	Exploration		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	2.0	2.0
Heavy Oil	-	-	-	-
Natural Gas	1.0	1.0	2.0	1.6
Service	-	-	-	-
Dry	-	-	-	-
Total:	1.0	1.0	4.0	3.6

See "- Principal Properties" for a description of the Corporation's exploration and development plans.

Production Estimates

The following table sets out the volume of the Corporation's gross working interest production estimated for the year ended December 31, 2012 as evaluated by GLJ which is reflected in the estimate of future net revenue disclosed in the tables contained under "- Disclosure of Reserves Data and Other Information":

Forecast Prices and Costs

Total Proved

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	Boe *(Boe/d)*
Ferrybank	142	4,800	399	1,341
Ricinus	2	3,306	118	672
Other Properties	18	2,072	9	372
Total Proved	**162**	**10,178**	**526**	**2,384**

Total Proved Plus Probable

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	Boe *(Boe/d)*
Crystal	156	5,319	442	1,484
Ricinus	2	3,718	132	754
Other Properties	66	2,806	12	545
Total Proved plus Probable	**224**	**11,843**	**586**	**2,783**

Production History

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

	Quarter Ended			
	2012			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (Bbls/d)	160	195	191	150
Heavy Oil (Bbls/d)	-	-	-	-
Gas (Mcf/d)	10,715	9,632	11,069	12,404
NGLs (Bbls/d)	538	435	485	588
Combined (Boe/d)	2,484	2,235	2,520	2,806
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	$88.18	$79.00	$83.76	$88.45
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	$3.34	$2.47	$2.02	$2.23
NGLs ($/Bbls)	$44.02	$47.08	$52.44	$56.30
Combined ($/Boe)	$29.61	$26.69	$25.30	$26.38
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	$8.65	$12.18	$10.74	$11.50
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	$0.08	($0.77)	($0.51)	$0.06
NGLs ($/Bbls)	$9.15	$24.42	$14.76	$10.53
Combined ($/Boe)	$2.87	$2.49	1.41	$3.10
Operating & Transportation Expenses ($/Boe)				
Light and Medium Crude Oil ($/Bbls)	$10.47	$15.05	$17.60	$10.02
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	$1.55	$2.13	$1.84	$1.59
NGLs ($/Bbls)	$14.78	$21.43	$23.24	$15.02
Combined ($/Boe)	$9.44	$14.69	$10.62	$9.55
Netback Received ($/Boe)[2]				
Light and Medium Crude Oil ($/Bbls)	$69.06	$51.77	$55.42	$66.93
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	$1.71	$1.11	$0.69	$0.58
NGLs ($/Bbls)	$20.09	$1.23	$14.44	$30.75
Combined ($/Boe)	$17.30	$9.51	$13.27	$13.73

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2012:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLS (Bbls/d)	Boe (Boe/d)
Newton	-	-	1,160	5	198
Sullivan	17	-	1,504	-	268
Ricinus	3	-	4,168	158	856
Ferrybank	154	-	4,119	348	1,188
Total Alberta	174	-	10,951	511	2,510

The Corporation's production for the year ended December 31, 2012 was 7% light and medium crude oil, 20% natural gas liquids and 73% natural gas.

For the twelve months ended December 31, 2012, approximately 41% of the Corporation's gross revenue was derived from natural gas production and the remaining 59% of the Corporation's gross revenue was derived from natural gas liquids, light and medium oil production.

DESCRIPTION OF SHARE CAPITAL

The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the preferred shares of the Corporation. No preferred shares are presently issued and outstanding.

Common Shares

The Corporation has an unlimited number of Common Shares authorized. At April 1, 2013, there were 40,034,611 Common Shares of the Corporation issued and outstanding. All Common Shares have been issued as fully paid and non-assessable. The holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors, to one vote per Common Share at any meeting of the shareholders of the Corporation and, upon liquidation, to receive all assets of the Corporation as are distributable to the holders of Common Shares.

Preferred Shares

Waldron is authorized to issue an unlimited number of preferred shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of Waldron, whether voluntary or involuntary, the preferred shares are entitled to preference over the Common Shares and any other shares ranking junior to the preferred shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the preferred shares as may be determined at the time of creation of such series. At the date hereof, no series of preferred shares has been created.

PRICE RANGE AND TRADING VOLUME OF THE COMMON SHARES

The outstanding Common Shares are currently traded on the TSX under the trading symbol "WDN". The following table sets forth the price range and trading volume of the Common Shares as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2012			
January	1.23	0.85	1,092,700
February	0.91	0.75	1,270,500
March	0.81	0.73	676,100
April	0.75	0.51	624,300
May	0.65	0.49	260,900
June	0.58	0.45	512,400
July	0.57	0.48	361,700
August	0.60	0.52	392,300
September	0.56	0.45	471,700
October	0.58	0.45	2,329,800
November	0.49	0.32	4,232,200
December	0.40	0.29	1,413,300
2013			
January	0.45	0.31	1,797,200
February	0.43	0.36	1,639,600
March	0.40	0.33	260,300

DIVIDENDS

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

PRIOR SALES

The following table summarizes the issuances of securities of the Corporation, which are outstanding but not listed or quoted on a marketplace, as at December 31, 2012.

Date of Issuance	Securities	Number of Securities	Price per Security
April 18, 2012	Stock Options	208,000	$0.58
August 15, 2012	Stock Options	2,150,000	$0.60
October 1, 2012	Stock Options	250,000	$0.60
October 15, 2012	Stock Options	125,000	$0.47

ESCROWED SECURITIES

As at April 1, 2013, no Common Shares, Performance Warrants nor other Common Share purchase warrants of the Corporation are subject to escrow.

DIRECTORS AND OFFICERS OF THE CORPORATION

The name, municipality of residence, and position held with the Corporation of each of the directors and officers of the Corporation as of the date of this Annual Information Form are as follows:

Name and Municipality of Residence	Position Held
Ernie Sapieha[(2)] Calgary, Alberta, Canada	President and Chief Executive Officer and a Director (Since December 31, 2009)
Donald F. Archibald[(1)(3)] Calgary, Alberta, Canada	Chairman and Director (Since December 31, 2009)
Greg Bay[(1)(2)] Vancouver, British Columbia, Canada	Director (Since July 6, 2010)
Thomas A. Budd[(1)] Kelowna, British Columbia, Canada	Director (Since December 31, 2009)
David R. J. Lefebvre [(3)] Calgary, Alberta, Canada	Director (Since December 31, 2009)
John E. Zahary [(2)(3)] Calgary, Alberta, Canada	Director (Since December 31, 2009)
Murray J. Stodalka Calgary, Alberta, Canada	Executive Vice President, Engineering and Operations
John (Jack) C. Marsh[(5)] Calgary, Alberta, Canada	Vice President, Engineering
Jeffrey A. Kearl[(6)] Calgary, Alberta, Canada	Vice President, Finance and Chief Financial Officer

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation and Governance Committee.
(4) The Corporation does not have an Executive Committee.
(5) Mr. Marsh was a Director of the Corporation from June 8, 2010 to August 15, 2012, when resigned from the Board on August 15, 2012 to become the Corporationô Vice President, Engineering.
(6) Mr. Kearl was appointed Vice President, Finance and Chief Financial Officer on January 9, 2013.

As at the date hereof, the directors, officers and management of the Corporation as a group own or control, directly or indirectly, 7,320,400 Common Shares or 18% of the issued and outstanding Common Shares.

The term of office of all directors will expire at the next annual meeting of the shareholders of the Corporation.

Messrs. Sapieha, Stodalka, Marsh and Kearl devote their full time and attention to the business and affairs of the Corporation. The other directors of the Corporation devote time and attention to the affairs of the Corporation as required.

Profiles of the Corporation's directors and senior officers and the particulars of their respective principal occupations during the last five years are set forth below.

Ernest G. Sapieha, C.A. – President, Chief Executive Officer and a Director

Mr. Sapieha has in excess of 30 years of executive experience in the oil and gas industry. Previously, Mr. Sapieha was the founder of Compton Petroleum Corporation (ñ**Compton**ò) and acted as President & CEO of Compton until December 2008. He is a Chartered Accountant and is a member of the Canadian Institute of Chartered Accountants.

Murray J. Stodalka, P.Eng. – Executive Vice President, Engineering and Operations

Mr. Stodalka is a professional engineer with over 25 years of engineering and operations experience in the oil and gas industry. Previously, Mr. Stodalka was VP Engineering and Operations at Compton from 1996 to March 2009.

John (Jack) C. Marsh – Vice President, Engineering

Mr. Marsh is a professional engineer with over 35 years of experience in the oil and gas industry. Mr. Marsh was President and Director at Bulldog Oil & Gas Inc. from November 2008 to March 2012. Prior to joining Bulldog Oil & Gas Inc., Mr. Marsh was President & CEO of Kootenay Energy Inc. from December 2006 until its sale in September 2008, and acted as Vice President, Engineering & Business Development from October 2005 to December 2006. Prior to that time Mr. Marsh was Vice President, Engineering & Business Development at Olympia Energy Inc. from August 1994 until its sale in June 2004. Mr. Marsh acted as a Director of Waldron from June 2008 until August 2012 when he resigned to become Waldronôs Vice President, Engineering.

Jeffrey A. Kearl, C.A. – Vice President, Finance and Chief Financial Officer

Mr. Kearl joined Waldron in October 2012 as Controller and was appointed Vice-President, Finance and Chief Financial Officer in January 2013. He is a Chartered Accountant and holds a Bachelor of Commerce degree with an accounting concentration from the University of Calgary (2004) and is a member of the Canadian Institute of Chartered Accountants. Previously, Mr. Kearl was at Fairborne Energy Ltd as Manager, Financial Reporting from July 2009 to October 2012 and prior to that he was at Axia NetMedia Corporation from September 2007 ï July 2009 where he was a key member of the business development group, providing accounting and business modeling support to various corporate initiatives.

Donald F. Archibald – Director

Mr. Archibald is an independent businessman and brings an extensive wealth of knowledge and experience as a leader in the public oil and gas industry. Currently, Mr. Archibald is Chairman at Cequence Energy Ltd., and serves as a director at Chinook Energy Inc. and several private companies. Previously, Mr. Archibald held the position of Chairman & CEO at Cyries Energy Inc. from June 2004 to March 2008, President & CEO at Cequel Energy Inc. from January 2002 to June 2004 and Cypress Energy Inc. from April 1996 to March 2001.

Greg Bay – Director

Mr. Bay is the founding partner and President of Cypress Capital Management Ltd. (ñ**Cypress**ò). Mr. Bay brings with him over 25 years of experience in the investment industry with emphasis on the oil and gas sector. Prior to founding Cypress, Mr. Bay was a managing partner at M.K. Wong & Associates (now HSBC Asset Management Canada Ltd.) and prior to that he was Assistant Vice President of Investments at National Trust. Mr. Bay holds the CFA designation and currently serves on the board of directors of various public companies.

Thomas A. Budd – Director

Mr. Budd is an independent investor and has many years of experience providing mergers and acquisitions and financial advice on a significant number of Canadaôs oil and gas transactions. Most recently, Mr. Budd served as President and Vice Chairman, Head of Investment Banking at GMP Corp. and Griffiths McBurney Canada Corp. from April 1996 until 2008. Prior thereto, Mr. Budd was a founding partner and director of an independent investment dealer in Calgary for six years. Prior to that, he held corporate finance positions with two national investment dealers for eight years.

David R. J. Lefebvre – Director

Mr. Lefebvre has been a partner of Gowling Lafleur Henderson LLP since February 2011, practising corporate, securities and mergers and acquisitions law. Prior thereto, he was a partner of Stikeman Elliott LLP. Mr. Lefebvre's focus has been on national and international mergers and acquisitions, capital markets, project financings, private equity and corporate governance. Mr. Lefebvre currently serves on the board of directors of a number of companies.

John E. Zahary – Director

Mr. Zahary is a Professional Engineer and currently acts as President & CEO of Sunshine Oilsands Ltd. since December 2011. Prior to his current role, Mr. Zahary was President & CEO of Harvest Operations Corp. and a predecessor company from April 2004 to January 2012. Prior thereto, he was President of Petrovera Resources, a 46,000 boe/d oil and natural gas producer with assets in Saskatchewan and Alberta. Previously, Mr. Zahary held senior positions at PanCanadian Petroleum Limited, Canadian Oil Sands Trust, Gulf Canada Resources Ltd., Imperial Oil Limited and Texaco Canada Resources. Mr. Zahary is a Past Governor of the Canadian Association of Petroleum Producers, a past Director and President of the Alberta Chamber of Resources, and Chairman of the Western Canada Rhodes Scholarship Selection Committee. Mr. Zahary holds a B.Sc. in Mechanical Engineering from the University of Calgary and a M.Phil. in Management from the University of Oxford.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the Corporation's knowledge, no director or officer of the Corporation: (i) is, or has been in the last 10 years, a director, Chief Executive Officer or Chief Financial Officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, for a period of more than 30 consecutive days (an "**order**"), (b) was subject to an order that was issued after the director or officer ceased to be a director, Chief Executive Officer or Chief Financial Officer and which resulted from an event that occurred while that person was acting in the capacity as director, Chief Executive Officer or Chief Financial Officer, or (c) 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; (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver or receiver manager or trustee appointed to hold his assets; or (iii) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. See "Directors and Officers of the Corporation". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

AUDIT COMMITTEE

Audit Committee's Mandate

A copy of the audit committee's mandate is attached to this Annual Information Form as Schedule "C".

Composition of the Audit Committee

The members of the audit committee are Donald F. Archibald, Greg Bay and Thomas A. Budd. Each member of the audit committee is financially literate and is independent.

A member of the audit committee is independent if the member has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board of Directors, reasonably interfere with the exercise of a member's independent judgment.

A member of the audit committee is considered financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation.

Relevant Education and Experience

The following sets out the education and experience of each director relevant to the performance of his duties as a member of the audit committee.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Donald F. Archibald Calgary, Alberta	Yes	Yes	Mr. Archibald has been the President of Cypress Energy Corp., a private investment company, since March 2008 and currently serves as chairman of Cequence Energy Ltd. From July 2004 to March 2008, Mr. Archibald was the Chairman and Chief Executive Officer of Cyries Energy Inc. From January 2002 to July 2004, Mr. Archibald was the President and Chief Executive Officer of Cequel Energy Inc. From, 1995 to March 2001, Mr. Archibald was the President and Chief Executive Officer of Cypress Energy Inc. He has considerable public company experience and holds a Bachelor of Commerce degree and Masters of Business Administration degree.
Greg Bay, CFA Vancouver, BC	Yes	Yes	Mr. Bay is the founding partner and President of Cypress Capital Management Ltd., a private-client and institutional firm managing more than $2.8 billion in assets. Cypress manages the AGF Small Cap Fund and the AGF Tactical Income Fund on behalf of AGF Management Limited. Mr. Bay has more than 25 years of investment industry experience and specializes in private client and institutional portfolio management. He holds a Bachelor of Commerce degree as well as a Certified Financial Analyst (CFA) designation.
Thomas A. Budd Kelowna, BC	Yes	Yes	Mr. Budd was the President and Vice Chairman, Head of Investment Banking at GMP Corp. and Griffiths McBurney Canada Corp. from 1996 to 2008. He has considerable mergers and acquisitions, corporate finance and capital markets experience.

Pre-Approval Policies and Procedures

The audit committee has adopted a policy to review and may pre-approve any non-audit services to be provided to the Corporation by the external auditors and consider the impact on the independence of such auditors. The committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the committee at the next scheduled meeting such pre-approval and the members comply with such other procedures as may be established by the committee from time to time.

External Auditor Service Fees (By Category)

The audit committee has reviewed the nature and amount of non-audit services provided by KPMG LLP to the Corporation to ensure auditor independence. Fees incurred with KPMG LLP for the fiscal years ended December 31, 2012 and December 31, 2011 for audit and non-audit services are outlined in the following table.

Nature of Services	Fees Paid to Auditors in Year Ended December 31, 2012	Fees Paid to Auditors in Year Ended December 31, 2011
Audit Fees(1)	$146,000	$245,000
Audit-Related Fees(2)	Nil	Nil
Tax Fees(3)	$16,100	$3,600
All Other Fees(4)	Nil	Nil
Total	$162,100	$248,600

Notes:

(1) ñAudit Feesò include fees necessary to perform the annual audit and quarterly reviews of the Corporationôs financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) ñAudit-Related Feesò include services that are traditionally performed by the auditor. These audit-related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.

(3) ñTax Feesò include fees for all tax services other than those included in ñAudit Feesò and ñAudit-Related Feesò. This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.

(4) ñAll Other Feesò include all other non-audit services.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation is a party, or was a party to in 2012, or that any of its properties is or was the subject matter of in 2012, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2012, there were: (i) no penalties or sanctions imposed against the Corporation or 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 the Corporation that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Corporation entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or officers of the Corporation, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or any other Informed Person (as defined in National Instrument 51-102 ï Continuous Disclosure Obligations) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect the Corporation.

MATERIAL CONTRACTS

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

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

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

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

In addition to the usual delays in payments by purchasers of oil and natural gas to Waldron or to the operator, and the delays by operators in remitting payment to Waldron, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connections of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of Waldron in a given period and expose Waldron to additional third party credit risks.

Prices, Markets and Marketing

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

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

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle-East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Issuance of Debt

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

Borrowing

Waldronôs lenders have been or may be provided with security over substantially all of the assets of Waldron. If Waldron becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell Waldronôs properties. The proceeds of such sale would be applied to satisfy amounts owed to Waldronôs lenders and other creditors and only the remainder, if any, would be available to Waldron or to its shareholders upon liquidation.

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

Substantial Capital Requirements

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

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Competition

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

Assessments of Value of Acquisitions

Acquisitions of oil and gas issuers and oil and gas assets are typically based on engineering and economic assessments made by independent engineers and the acquirerǒs own assessments. Both of these assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, 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 Waldronǒs control. In particular, the prices of and markets for oil and natural gas products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm Waldron uses for its year end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm used by Waldron. Any such instance may offset the return on and value of the securities of Waldron.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Management of Growth

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

Reliance on Key Personnel

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

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

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

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Geo-Political Risks

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

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

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009 and 2010, causing a loss of confidence in the broader U.S. and global credit and financial markets. Although conditions have stabilized, these factors may negatively impact valuations of the Corporation and are expected to continue to impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions, political instability in the Middle East and elsewhere and the global credit and liquidity concerns.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Changes to Royalty Regime

There can be no assurance that the Government of Alberta or the Canadian federal government will not adopt a new royalty regime or modify the methodology of royalty calculations which could increase the royalties paid by Waldron. An increase in royalty could reduce Waldronôs earnings and/or could make capital expenditures by Waldron uneconomic.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

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 business, financial condition, results of operations and prospects. In addition, there can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Albertaôs greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The Corporation will also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which are now expected to be consistent with regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the

Corporationȏs business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gas emissions could have a material impact on the nature of oil and gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions ï Environmental and Climate Change Regulation".

Availability of Drilling Equipment and Access

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

Operational Dependence

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

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 may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Insurance

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

Alternatives to and Changing Demand for Petroleum Products

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

Seasonality

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

Title to Assets

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

Aboriginal Claims

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

Dividends

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

Conflicts of Interest

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

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 the Corporation'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 the Corporation 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 - Oil and Natural Gas

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 National Energy Board of Canada (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.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Pipeline Capacity

Interprovincial and international natural gas pipelines are regulated by the NEB and provide the opportunity for firm pipeline capacity. Interprovincial and international crude oil pipelines are also regulated by the NEB and operate on a common carrier basis. The NEB has allowed some crude oil pipelines to meet common carrier obligations by providing firm contract service. Depending upon the pipeline, there is therefore some apportionment risk (i.e. risk of pro-rationing capacity) relating to crude oil service that is not subject to firm contracts, which may affect the ability to produce and market production.

The North American Free Trade Agreement

NAFTA, entered into by 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 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

General

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 negotiation between the mineral freehold 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, and consequently few such incentive programs are currently operative.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" containing the Alberta Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF established new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, 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 deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. 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 NRF.

Oil sands projects are now subject to the NRF, and regulated, among others, by the *Oil Sands Royalty Regulation, 2009, Oil Sands Allowed Costs (Ministerial) Regulation* and the *Bitumen Valuation Methodology (Ministerial) Regulation, 2009*, all approved by the Government of Alberta on December 10, 2008.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Alberta Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior to January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the Corporation's production levels in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on Waldron's 2008 production it will be entitled to a maximum credit of 50% of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

On March 11, 2010, the Government of Alberta announced that the maximum royalty rate for conventional oil would be reduced to 40% and the maximum for methane and ethane would be reduced to 36%. New well royalty rates became a permanent feature of the royalty system effective May 2010. In addition, transitional royalty rates could only be elected until December 31, 2010. Well events that have elected the transitional royalty could choose to opt out only between January 1, 2011 and February 15, 2011.

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

Land Tenure

Crude oil and natural gas located in the western 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 and Climate Change Regulation

General

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.

The operations of the Corporation are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation expects to meet 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 are required to ensure compliance with applicable environmental legislation. It also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Corporation is not currently able to quantify any increased expenditures to meet current or future environmental requirements, but does not anticipated that its competitive position will be adversely affected by environmental laws and regulations governing its oil and natural gas operations.

Alberta

Environmental legislation in 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%. 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% 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.

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 carbon dioxide 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.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statues Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to satisfaction of certain conditions.

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol. The Kyoto Protocol called for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. The Kyoto Protocol came into force on February 16, 2005 and committed Canada to reduce its greenhouse gas emissions levels to 6% below 1990 ñbusiness-as-usualò levels by 2012. In December 2011, Canada withdrew from the Kyoto Protocol.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing greenhouse gas emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding greenhouse gas emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada has indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents, which are discussed below.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the United States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, 43 upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors govern by the Updated Action Plan, all facilities will be subject to regulation

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 tonnes per CO_2 equivalent for the 2010-12 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce 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 described 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 purchase the offset credits for cancellation or banking 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 which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

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

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of the Corporation are KPMG LLP, Chartered Accountants, 2700, 205 ï 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

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

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than GLJ, the independent reserve evaluator, and KPMG LLP, the Corporation's auditors. None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. KPMG LLP is independent in accordance with the auditors' rules of professional conduct in Canada.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's information circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided for in our financial statements and management's discussion and analysis for the year ended December 31, 2012.

SCHEDULE "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Waldron Energy Corporation (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

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

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

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

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

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

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that the reserves are categorized according to the probability of their recovery.

DATED as of this 1st day of April 2013.

(signed) "*Ernest G. Sapieha*"
Ernest G. Sapieha
President and Chief Executive Officer

(signed) "*Murray J. Stodalka*"
Murray J. Stodalka
Executive Vice-President, Engineering and Operations

(signed) "*John E. Zahary*"
John E. Zahary
Director

(signed) "*Greg Bay*"
Greg Bay
Director

SCHEDULE "B"

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

To the board of directors of Waldron Energy Corporation (the ñCompanyò):

1. We have prepared an evaluation of the Companyǿs reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2012, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Companyǿs board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
			Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	Corporate Summary March 1, 2013	CANADA	-	85,123	-	**85,123**

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

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 7, 2013

"Originally Signed by"

Bryan M. Joa, P. Eng. Vice-President
GLJ Petroleum Consultants

SCHEDULE "C"

AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the ñ**Committee**ò) is a committee of the board of directors (the ñ**Board**ò) of Waldron Energy Corporation (ñ**Waldron**ò or the ñ**Corporation**ò) to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of managementôs reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Waldron and related matters;

2. To provide better communication between directors and external auditors;

3. To enhance the external auditorôs independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Waldron or such greater number as the Board may determine from time to time and all members of the Committee shall be ñindependentò (as such term is used in National Instrument 52-110 ð Audit Committees (ñ**NI 52-110**ò) unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be ñfinancially literateò (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Waldronôs internal control systems:

    - identifying, monitoring and mitigating business risks; and

    - ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of Waldron and related managementôs discussion and analysis (ñ**MD&A**ò) prior to their submission to the Board for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future yearsô financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms (ñ**AIF**ò) and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Waldronôs disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

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

6. Review with external auditors (and internal auditor if one is appointed by Waldron) their assessment of the internal controls of Waldron, their written reports containing recommendations for improvement, and managementôs response and follow-up to any identified weaknesses. The Committee will also review

annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Waldron and its subsidiaries.

7. Review risk management policies and procedures of Waldron (i.e. hedging, litigation and insurance).

8. Establish a procedure for:

- the receipt, retention and treatment of complaints received by Waldron regarding accounting, internal accounting controls or auditing matters; and

- the confidential, anonymous submission by employees of Waldron of concerns regarding questionable accounting or auditing matters.

9. Review and approve Waldronọs hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Waldron.

10. The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Waldron. All employees of Waldron are to cooperate as requested by the Committee.

11. The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Waldron without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

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

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The CFO will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

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

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

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

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

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

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