YOHO RESOURCES INC.

ANNUAL INFORMATION FORM

FOR THE FISCAL YEAR ENDED SEPTEMBER 30, 2008

DECEMBER 10, 2008

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ABBREVIATIONS AND CONVERSIONS

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	mcf	thousand cubic feet
bbls	barrels	mmcf	million cubic feet
Mbbls	thousand barrels	mcf/d	thousand cubic feet per day
mmbbls	million barrels	mmcf/d	million cubic feet per day
bbls/d	barrels per day	mmbtu	million British Thermal Units
boe	barrels of oil equivalent	bcf	billion cubic feet
boe/d	barrels of oil equivalent per day	GJ	gigajoule
mboe	1,000 barrels of oil equivalent	McfGE	thousand cubic feet of gas equivalent
ngls	natural gas liquids		

Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. The boe conversion ratio of 6 mcf:1 bbl 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.

Disclosure provided herein in respect of McfGE may be misleading, particularly if used in isolation. The McfGE conversion ratio of one bbl of oil to six thousand cubic feet of gas 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.

To Convert From	To	Multiply By
mcf	cubic meters	28.174
cubic meters	cubic feet	35.494
bbls	cubic meters	0.159
cubic meters	bbls oil	6.290
feet	meters	0.305
meters	feet	3.281
miles	kilometers	1.609
kilometers	miles	0.621
acres (Alberta)	hectares	0.400
hectares (Alberta)	acres	2.500

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

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

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

- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory and taxation regimes;
- capital expenditure programs; and
- risk management programs;

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

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

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

CERTAIN DEFINITIONS

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

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

"**Arrangement**" means the reorganization transaction which closed on December 23, 2004 pursuant to a plan of arrangement under the provisions of subsection 183(1) of the *Business Corporations Act* (Ontario) as fully described under the heading "*Corporate Structure – Incorporation*" herein;

"**Class B Non-Voting Common Shares**" means the non-voting common shares created on the conversion of the Non-Voting Common Shares into Common Shares and Class B Non-Voting Common Shares on the basis of 0.4 of a Common Share and 0.6 of a Class B Non-Voting Common Share for every one (1) Non-Voting Common Share and subsequently cancelled on February 28, 2007;

"**Class C Non-Voting Common Shares**" means the non-voting common shares created on the conversion of the Class B Non-Voting Common Shares into Common Shares and Class C Non-Voting Common Shares on the basis of 0.5 of a Common Share and 0.5 of a Class C Non-Voting Common Share for every one (1) Class B Non-Voting Common Share on March 11, 2008;

"**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;

"**Corporation**", "**Yoho**", "**we**", "**us**" or "**our**" means Yoho Resources Inc. and all its controlled entities on a consolidated basis;

"**Common Shares**" means the voting common shares in the capital of the Corporation;

"**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 reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

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

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

d) provide improved recovery systems.

"**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 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;

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.

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta;

"**GLJ Report**" means the report prepared by GLJ dated December 8, 2008 entitled "Reserves Assessment and Evaluation of Canadian Oil and Gas Properties" evaluating the crude oil, natural gas liquids and natural gas resources of Yoho as of September 30, 2008;

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

a) in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's 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.

"**JV Companies**" means 960330 Alberta Ltd., 960331 Alberta Ltd., 960332 Alberta Ltd., 960333 Alberta Ltd., 960334 Alberta Ltd., Atlee Joint Venture Ltd., Basset Lake Joint Venture Ltd. Basset Lake III Joint Venture Ltd., Edam Joint Venture Ltd., Hamilton Lake III Joint Venture Ltd. and Sousa Joint Venture Ltd.;

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

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

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

"**Non-Voting Common Shares**" means the non-voting common shares of the Corporation created through the Arrangement on December 23, 2004 and subsequently cancelled on February 28, 2007; and

"**TSXV**" means the TSX Venture Exchange.

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 fiscal year, being the fiscal year ended September 30, 2008.

CONVENTIONS

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101. Unless otherwise indicated, references in this Annual Information Form to "$" or "dollars" are to Canadian dollars. All financial information contained in this Annual Information Form has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. All operational information contained in this Annual Information Form relates to our consolidated operations unless the context otherwise requires.

CORPORATE STRUCTURE

Incorporation

Yoho was incorporated pursuant to the laws of the Province of Alberta by certificate of incorporation on July 12, 1993 under the name Torque Industries Inc. On March 15, 1994, the Corporation acquired BCB Technology Group Inc., a private Ontario corporation, through a share exchange. By Articles of Amendment dated March 18, 1994, the name of the Corporation was changed to BCB Holdings Inc. By Articles of Continuance dated October 1, 1996, the Corporation was continued under the laws of Ontario. By Articles of Amendment dated August 17, 1998 and August 31, 1998, the Corporation changed its name to BCB Voice Systems Inc. and consolidated its common shares on a 10 for one (1) basis. By Articles of Amendment dated October 4, 2000 the Corporation changed its name to VoiceIQ Inc.

On December 23, 2004, Yoho closed the Arrangement pursuant to an arrangement agreement dated as of November 18, 2004 among the Corporation, VIQ Solutions Inc. ("**VIQ Solutions**") and Yoho Resources Investment Partnership. Pursuant to the Arrangement, the Corporation divested its technology business and assets to its shareholders and changed its name to "Yoho Resources Inc." and changed its focus to developing an oil and gas exploration and production business. Articles of Arrangement of the Corporation were filed in Ontario effective December 23, 2004, changing the name of the Corporation to "Yoho Resources Inc." By Articles of Continuance dated December 24, 2004, the Corporation was continued under the laws of Alberta.

By Articles of Amendment dated February 28, 2007, Yoho reorganized its share capital to convert all of the outstanding Non-Voting Common Shares of the Corporation into Common Shares and Class B Non-Voting Common Shares on the basis of 0.4 of a Common Share and 0.6 of a Class B Non-Voting

Common Share for every one (1) Non-Voting Common Share, and to delete the Non-Voting Common Shares as an authorized class of shares of the Corporation.

By Articles of Amendment dated March 11, 2008, Yoho reorganized its share capital to convert all of the outstanding Class B Non-Voting Common Shares of the Corporation into Common Shares and Class C Non-Voting Common Shares on the basis of 0.5 of a Common Share and 0.5 of a Class C Non-Voting Common Share for every one (1) Class B Non-Voting Common Share, and to delete the Class B Non-Voting Common Shares as an authorized class of shares of the Corporation.

By Articles of Amalgamation dated August 1, 2008, Yoho amalgamated with its wholly owned subsidiary, Vision 2000 Exploration Ltd.

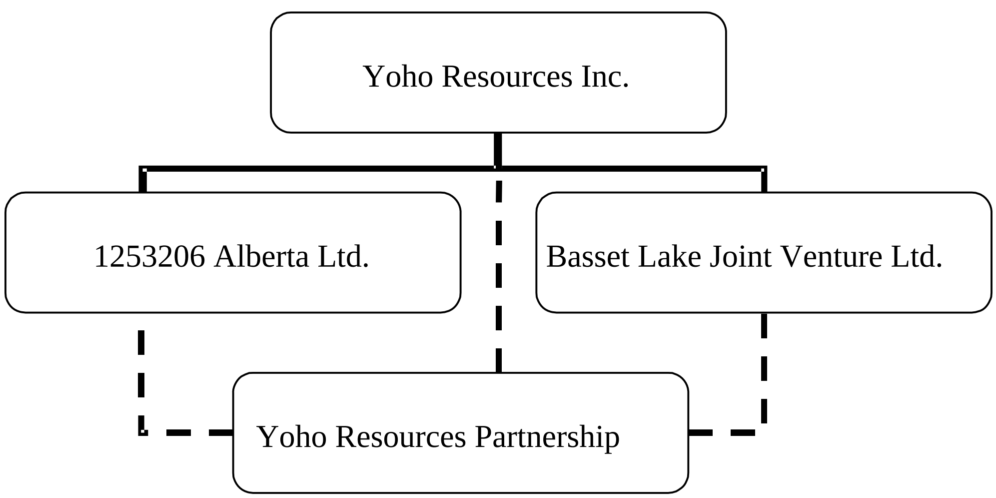
Yoho's head office is located at 750, 736 – 6th Avenue SW, Calgary, Alberta T2P 3T7 and the registered office is located at 1400, 350 – 7th Avenue SW, Calgary, Alberta T2P 4N9.

Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation of our subsidiaries as at the date hereof.

	Percentage of voting securities (directly or indirectly)	**Jurisdiction of Incorporation/ Organization**
1253206 Alberta Ltd.	100%	Alberta
Basset Lake Joint Venture Ltd.	100%	Alberta
Yoho Resources Partnership	100%	Alberta

The following diagram describes the inter-corporate relationships among us and our subsidiaries.



GENERAL DEVELOPMENT OF OUR BUSINESS

Prior to the completion of the Arrangement in December 2004, the Corporation carried out a technology related business, specifically a voice capture, digitization and compression business.

Upon completion of the Arrangement, Yoho became an oil and gas exploration, development and production company by acquiring the shares of the JV Companies, which resulted in the acquisition of oil and gas properties having approximately 868 mboe of proved plus probable reserves, 9,297 net acres of undeveloped land and production of approximately 736 boe/d. Effective August 1, 2004, each of the JV Companies conveyed substantially all of their oil and gas related properties to Yoho Resources Partnership in return for a percentage interest in the capital of that partnership.

Our focus is on natural gas and light oil projects, with an emphasis on medium risk, medium depth targets with multi-zone potential in the Peace River Arch and northeastern British Columbia where our expertise and experience is greatest. Our strategy is to deliver base line production and reserve growth on an annual basis from an internal inventory of exploration and development prospects. Complementary and accretive acquisitions will supplement the exploration and development program when they can be accomplished on economic terms.

We fund our exploration and development program with cash flow, additional debt and strategic use of new equity as appropriate.

Three Year History

Year Ended September 30, 2006

In October, 2005, Yoho issued to employees of the Corporation 140,000 units priced at $2.00 per unit, each unit being comprised of one (1) Common Share and 0.6587615 of a Common Share purchase warrant for total gross proceeds of $280,000. Each whole warrant entitled the holder to acquire one (1) Common Share of Yoho at an exercise price of $2.50 which warrants, under their original terms, vest after a period of 30 months from their issuance and are exercisable for a period of 30 days after vesting.

In October, 2005, the Common Shares were listed for trading on the TSXV under the symbol "YO".

In December, 2005, the Corporation issued 572,590 Common Shares on a "flow-through" basis at $6.96 per share for gross proceeds of $3,985,226.

In January, 2006, the Corporation completed a private placement financing of 177,410 Common Shares issued on a "flow-through" basis at the price of $6.96 per share for total proceeds of $1,234,774.

In June, 2006, the Corporation completed a private placement financing of 824,000 Common Shares issued on a "flow-through" basis at the price of $6.65 per share for total proceeds of $5,479,600.

During the period from closing the Arrangement on December 23, 2004 to September 30, 2006, the Corporation invested $32.2 million (net of dispositions and the July 2005 acquisition of a working interest in a gas production facility for $2,700,000) on exploration and development activities which resulted in the drilling of 41 gross wells in the Peace River Arch area of Alberta. These investments were funded by cash flow, debt and the equity financings as described above.

Year Ended September 30, 2007

On December 29, 2006, the Corporation acquired certain interests in oil and natural gas assets in northeastern British Columbia through the purchase of all of the units of Canada Southern Petroleum #3 LP for aggregate consideration of $25,000,000. For information regarding this acquisition please see the Corporation's business acquisition report, filed in the form of NI 51-102F4 dated and filed on SEDAR on February 27, 2007.

In December, 2006, the Corporation completed an equity private placement financing conducted through a syndicate of investment dealers of 2,063,050 Common Shares at the price of $4.75 per share for total proceeds of $10,108,945 and 800,000 Common Shares issued on a "flow-through" basis at the price of $6.25 per share for total proceeds of $5,000,000. Also in December, 2006, the Corporation entered into a six month, subordinated loan facility with a private lender for the principal amount of $6,000,000. As partial consideration for this loan, the Corporation issued 240,000 Common Share purchase warrants to the lender, with each warrant exercisable into one Common Share at a price of $5.25 at any time up to June 29, 2007. A portion of the proceeds of these financings were used to complete the acquisition of the assets located in northeast British Columbia acquisition pursuant to the purchase of all of the units of Canada Southern Petroleum #3 LP.

On February 28, 2007 at an annual and special meeting of holders of Common Shares, approval was received for the creation of a new class of non-voting shares, namely the Class B Non-Voting Common Shares, the conversion of the Corporation's Non-Voting Shares into Common Shares and Class B Non-Voting Common Shares on the basis of 0.4 of a Common Shares and 0.6 of Class B Non-Voting Common Share for every one (1) Non-Voting Common Share and the cancellation of Yoho's then outstanding Non-Voting Common Share. At a meeting of the holders of Non-Voting Common Shares on the same date, approval for the conversion of Non-Voting Common Shares into Common Shares and Class B Non-Voting Common Shares as described above was also received.

In July, 2007, the Corporation issued 210,500 Common Shares on a "flow-through" basis to a director of the Corporation at the price of $4.75 per share for total gross proceeds of $999,875. Under the flow-through share agreement, the Corporation is required to incur eligible expenditures for the total gross proceeds prior to December 31, 2008.

Year Ended September 30, 2008

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime that is to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". See "*Risk Factors – New Alberta Royalty Regime*" and "*Industry Conditions - Provincial Royalties and Incentives*".

In December 2007, the Corporation issued 850,000 Common Shares issued on a " flow-through" basis at the price of $2.70 per share for total gross proceeds of $2,295,000 to be incurred on eligible expenditures prior to December 31, 2008. Certain officers and directors of the Corporation acquired 145,000 Common Shares under this private placement.

In December 2007, the expiry dates of 1,000,000 outstanding Common Share purchase warrants issued in May 2005 and 92,226 outstanding Common Share purchase warrants issued in October 2005 were extended from December 13, 2007 to June 13, 2009 and from May 7, 2008 to November 7, 2009 respectively. These warrants are all exercisable for a period of 60 days prior to their respective expiry dates.

On December 31, 2007 the Corporation repaid $1 million of the principal due to the lender of the subordinated loan facility. This loan, which was due on January 3, 2008, was extended to become due on January 3, 2009. As partial consideration for the loan extension, the Corporation issued to the lender 500,000 Common Share purchase warrants. Each warrant was exercisable into one Common Share issued on a "flow-through" basis at a price of $2.75 at any time up to June 30, 2008. All the warrants were exercised in June, 2008. The balance of the Corporation's indebtedness pursuant to this facility was repaid by the Corporation in June 2008.

On March 11, 2008 at an annual and special meeting of holders of Common Shares, approval was received for the creation of a new class of non-voting shares, namely the Class C Non-Voting Common Shares, the conversion of the Corporation's outstanding Class B Non-Voting Common Shares into Common Shares and Class C Non-Voting Common Shares on the basis of 0.5 of a Common Share and 0.5 of a Class C Non-Voting Common Share for every one Class B Non-Voting Common Share and the cancellation of Yoho's then outstanding Class B Non-Voting Common Shares. Additionally, at the meeting, shareholder approval was received for the employee stock purchase plan whereby for each $1.00 contributed to the plan by an eligible person, the Corporation would match such contribution by up to $1.00 for the purpose of acquiring Common Shares for the account of such person (up to a maximum of 5% of such person's annual base salary). Unanimous approval for the conversion of Class B Non-Voting Common Shares into Common Shares and Class C Non-Voting Common Shares as described above was also received from all holders of Class B Non-Voting Common Shares on March 11, 2008.

On June 4, 2008, Yoho announced that it had acquired approximately 92% of the issued and outstanding common shares of Vision 2000 Exploration Ltd. ("**Vision 2000**") pursuant to its offer and take-over bid circular dated April 29, 2008, and that it would acquire the remaining shares of Vision 2000 pursuant to the compulsory acquisition procedures of the ABCA. All of the remaining common shares of Vision 2000 not previously acquired by Yoho were acquired by Yoho on June 23, 2008. Aggregate consideration paid by Yoho pursuant to the acquisition of Vision 2000 was $81,380 in cash and 2,273,237 Common Shares. Vision 2000 was a corporation incorporated pursuant to the laws of the Province of Alberta and had its common shares listed on the TSXV. Yoho amalgamated with Vision 2000 on August 1, 2008.

On September 17, 2008, the Corporation announced its intention to proceed with a normal course issuer bid to purchase for cancellation up to a maximum of 180,000 Common Shares or approximately 1.4% of the Corporation's "public float". A total of 7,300 Common Shares were acquired by Yoho for cancellation pursuant to the normal course issuer bid prior to September 30, 2008.

Events subsequent to September 30, 2008

On October 15, 2008, the Corporation announced that it had amended the terms of its normal course issuer bid in order to increase the number of Common Shares subject to purchase and cancellation by the Corporation from 180,000 common Shares to up to 600,000 Common Shares or 4.7% of the Corporation's "public float". As of the date hereof, a total of 379,000 Common Shares have been acquired by Yoho for cancellation pursuant to the normal course issuer bid.

On November 19, 2008 the Government of Alberta announced the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Companies drilling new natural gas or conventional oil deep wells (between 1000 and 3,500 meters) on or before November 19, 2008 will be given a one-time option to adopt the new transitional royalty rates or those outlined in the NRF. On December 2, 2008 Bill 47 *Mines and Minerals (New Royalty Framework) Amendment Act* received royal assent and will come into force on various dates, with the rate adjustments contemplated by it coming into effect on January 1, 2009. See "*Industry Conditions – Alberta*" and "*Risk Factors – New Alberta Royalty Regime*".

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Business Plans and Growth Strategies

The business plan of Yoho is to create sustainable and profitable per share growth in reserves, production and cash flow in the oil and gas industry in Western Canada. To accomplish this, Yoho has pursued and will continue to pursue an integrated growth strategy with active development and exploration drilling, together with focused acquisitions. Yoho will continue to target areas and prospects that it believes could result in meaningful reserve and production additions.

Yoho will continue to pursue internal generation of exploration plays that have low to medium risk and multi-zone potential. Yoho intends to maintain a balance between exploration, exploitation and development drilling largely targeting natural gas reserves over the course of the next several years. Management of Yoho considers asset and corporate acquisition opportunities from time to time that meet Yoho's business parameters.

Management of Yoho has industry experience in producing areas in western Canada in addition to its current geographic areas of interest and has the capability to expand the scope of Yoho' activities as opportunities arise.

In reviewing potential drilling or acquisition opportunities, Yoho gives consideration to the following criteria:

- Yoho's technical expertise in the opportunity;
- the amount of risk capital required to secure or evaluate the investment opportunity;
- the potential return on the project, if successful;
- the likelihood of success; and
- risked return versus cost of capital.

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

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

Competitive Conditions

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

SIGNIFICANT ACQUISITIONS

The Corporation has not made any significant acquisition during the year ended September 30, 2008 for which disclosure is required pursuant to Part 8 of National Instrument 51-102 *Continuous Disclosure Obligations*. See "*General Development of Business – Year Ended September 30, 2008*" for a description of the acquisition of Vision 2000 for which disclosure was not required pursuant to Part 8 of National Instrument 51-102.

PRINCIPAL PROPERTIES

Yoho is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of our current operations to the end of this fiscal year are in the Provinces of Alberta, British Columbia and Saskatchewan.

The following is a description of our oil and natural gas properties as at September 30, 2008. The term "net", when used to describe our share of production, means the total of our working interest share before deduction of royalties owned by others. Unless otherwise specified, well count information is as at September 30, 2008.

Western Peace River Arch: Yoho has a variety of exploration targets within the Western Peace River Arch in the province of Alberta. The main targets for exploration are the Triassic aged wedge of sediments that subcrop throughout the area, including the Doig, Halfway, Boundary Lake, Charlie Lake and Baldonnel formations and the Cretaceous aged sediments, including the Gething and Bluesky formations. The Company has also participated in several deeper tests targeting the Devonian Wabamun formation utilizing three dimensional seismic. The Wabamun, which is a higher risk target, also has higher potential rewards.

- *Basset Lake:* The Company holds a 50% working interest in 28 producing Bluesky gas wells.
- *Boundary Lake:* Yoho has interests ranging from 26% to 67% in 11 producing gas wells.
- *Manir:* We have interests in two producing oil wells of 55% and 60% respectively.
- *Sinclair:* The Company holds a 100% interest in one producing gas well.
- *Spirit River:* Yoho has a 15% interest in two producing gas wells along with a 25% working interest in a third producing gas well
- *Worsley:* We have a 50% interest in two producing gas wells and interests ranging from 20% to 50% in five producing oil wells.

Northeastern British Columbia: The area is similar geologically to the Western Peace River Arch and makes a natural extension to the successful results achieved in the Arch. The primary targets in the area are the Lower Mannville, Dunlevy and Bluesky formations and the Triassic formations of the Halfway, Baldonnel and Charlie Lake. Most of the targets Yoho has identified in this area are less than 1,200 meters in depth.

- *Buick Creek:* Yoho has varying interests in 16 producing gas wells with interest ranging from 5% to 58% in 15 wells and a 100% interest in one gas well.
- *Mike:* Yoho’s interests varies from 85% to 100% in three producing gas wells.

West Central Alberta: As a result of the recent Vision 2000 acquisition and other exploratory activity, we have a new core area in West Central Alberta. The main targets in this area are the Spirit River and Gething Formations within the Cretaceous period.

- *Kaybob:* The Company has interests ranging from 1% to 96% in 13 producing gas wells.

- *Windfall:* Yoho has a 50% interest in two producing gas wells.

The following table indicates our average daily production before deduction of royalties and including royalty interests for the year ended September 30, 2008.

	Light and Medium Crude Oil & NGLs (bbl/d)	**Heavy Oil (bbl/d)**	**Gas (Mcf/d)**
Basset Lake	6	-	976
Boundary Lake	12	-	2,656
Buick Creek	13	-	1,458
Manir	29	-	179
Mike	-	-	668
Sinclair	14	-	1,794
Spirit River	48	-	459
Windfall	18	-	416
Worsley	19	-	506
Other	24	117	1,349
Total	179	117	10,461

DISCLOSURE OF RESERVES DATA

The reserves data set forth below (the "**Reserves Data**") is based upon the GLJ Report. The Reserves Data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan as of September 30, 2008.

Disclosure provided herein in respect of boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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 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
AS OF SEPTEMBER 30, 2008
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	Gross[1] (Mbbl)	Net (Mbbl)	Gross[1] (Mbbl)	Net (Mbbl)	Gross[1] (MMcf)	Net (MMcf)	Gross[1] (Mbbl)	Net (Mbbl)	Gross[1] (Mboe)	Net (Mboe)
PROVED										
Developed Producing	101	97	162	129	14,428	12,037	276	212	2,943	2,444
Developed Non-Producing	3	3	-	-	840	712	11	10	154	132
Undeveloped	-	-	-	-	824	670	14	10	152	122
TOTAL PROVED	104	100	162	129	16,093	13,420	301	233	3,249	2,698
PROBABLE	105	95	32	26	7,120	5,980	113	86	1,437	1,203
TOTAL PROVED PLUS PROBABLE	209	195	194	155	23,212	19,400	414	318	4,686	3,901

Note:

(1) The gross reserves in the above table are stated on a total Company working interest basis and do not include royalty interests paid to Yoho.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF SEPTEMBER 30, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE *BEFORE INCOME TAXES DISCOUNTED AT* 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	Unit Value Before Income Tax Discounted at 10% per Year $/boe	$/McfGE
PROVED							
Developed Producing	98,293	81,475	70,310	62,303	56,251	28.77	4.79
Developed Non-Producing	4,866	4,287	3,835	3,473	3,176	28.98	4.83
Undeveloped	3,293	2,258	1,573	1,098	755	12.94	2.16
TOTAL PROVED	106,452	88,019	75,718	66,874	60,181	28.06	4.68
PROBABLE	53,575	35,384	25,712	19,809	15,882	21.38	3.56
TOTAL PROVED PLUS PROBABLE	160,027	123,403	101,430	86,684	76,064	26.00	4.33

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF SEPTEMBER 30, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE *AFTER INCOME TAXES DISCOUNTED AT* 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
PROVED					
Developed Producing	86,508	71,971	62,384	55,526	50,344
Developed Non-Producing	3,534	3,093	2,752	2,479	2,256
Undeveloped	2,448	1,624	1,078	697	423
TOTAL PROVED	92,489	76,689	66,213	58,702	53,023
PROBABLE	40,084	26,271	18,966	14,522	11,572
TOTAL PROVED PLUS PROBABLE	132,574	102,959	85,179	73,225	64,595

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF SEPTEMBER 30, 2008
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$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved Reserves	192,577	36,780	45,056	2,266	2,023	106,452	13,962	92,489
Total Probable	98,078	17,170	24,263	2,574	496	53,575	13,491	40,084
Proved Plus Probable Reserves	290,655	53,950	69,319	4,840	2,519	160,027	27,453	132,574

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF SEPTEMBER 30, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES discounted at 10%/year (M$)	$/boe	$/McfGE
Proved Producing	Light and Medium Crude Oil (including solution gas and other by-products)	4,078	33.38	5.56
	Heavy Oil (including solution gas and other by-products)	4,467	34.65	5.78
	Natural Gas (including by-products but excluding solution gas from oil wells)	61,008	28.11	4.68
	Non-conventional natural gas	758	33.64	5.61
	Total	70,310	28.77	4.79
Total Proved	Light and Medium Crude Oil (including solution gas and other by-products)	5,281	33.96	5.66
	Heavy Oil (including solution gas and other by-products)	4,467	34.65	5.78
	Natural Gas (including by-products but excluding solution gas from oil wells)	65,213	27.27	4.55
	Non-conventional natural gas	758	33.64	5.61
	Total	75,718	28.06	4.68
Total Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	6,722	31.43	5.24
	Heavy Oil (including solution gas and other by-products)	5,142	33.28	5.55
	Natural Gas (including by-products but excluding solution gas from oil wells)	88,620	25.30	4.22
	Other Company Revenue/Costs	945	31.37	5.23
	Total	101,430	26.00	4.33

RESERVES RECONCILIATION

RECONCILIATION OF COMPANY GROSS RESERVES
AS OF SEPTEMBER 30, 2008
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL		
RESERVES CATEGORY	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
September 30, 2007	106	94	200	176	39	215
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-
Technical Revisions	(13)	(32)	(45)	28	(7)	22
Acquisitions	28	44	72	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(17)	-	(17)	(43)	-	(43)
September 30, 2008	104	105	209	162	32	194

RESERVES CATEGORY	NATURAL GAS LIQUIDS Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	TOTAL GAS Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
September 30, 2007	250	82	332	13,051	5,163	18,214
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	75	29	104	4,312	2,029	6,341
Technical Revisions	(14)	(18)	(32)	503	(1,090)	(587)
Acquisitions	38	19	58	1,967	1,018	2,985
Economic Factors	-	-	-	-	-	-
Production	(48)	-	(48)	(3,740)	-	(3,740)
September 30, 2008	301	113	414	16,093	7,120	23,212

RESERVES CATEGORY	CONVENTIONAL NATURAL GAS Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	COAL BED METHANE Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
September 30, 2007	13,051	5,163	18,214	-	-	-
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	4,312	2,029	6,341	-	-	-
Technical Revisions	503	(1,090)	(587)	-	-	-
Acquisitions	1,918	801	2,718	49	218	267
Economic Factors	-	-	-	-	-	-
Production	(3,740)	-	(3,740)	-	-	-
September 30, 2008	16,044	6,902	22,946	49	218	267

RESERVES CATEGORY	BOE Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)
September 30, 2007	2,707	1,075	3,782
Discoveries	-	-	-
Extensions & Improved Recovery	794	367	1,161
Technical Revisions	85	(238)	(153)
Acquisitions	394	233	627
Economic Factors	-	-	-
Production	(731)	-	(731)
September 30, 2008	3,249	1,437	4,686

Yoho had no dispositions during the year ended September 30, 2008.

DEFINITIONS AND OTHER NOTES

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form, the following definitions and other notes are applicable:

Definitions used for reserve categories are as follows:

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

(a) analysis of drilling, geological, geophysical and engineering data;
(b) the use of established technology; and
(c) specified economic conditions (see the discussion of "Economic Assumptions" below).

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.

Development and Production Status

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.

Levels of Certainty for Reported Reserves

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

(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 sum of the estimated proved plus probable reserves.

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

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

Numbers in the tables may not add due to rounding.

The estimates of future net revenue presented in the tables above do not represent fair market value.

Pricing Assumptions

The following data sets forth the benchmark reference prices, as at September 30, 2008, reflected in the Reserves Data. The forecast prices and cost assumptions were provided to us by GLJ, our independent qualified reserves evaluator.

Forecast Prices and Costs

These are prices and costs that are:

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

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

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, natural gas and natural gas liquids benchmark reference pricing, as at September 30, 2008, inflation and exchange rates utilized in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF SEPTEMBER 30, 2008
FORECAST PRICES AND COSTS

	Crude Oil			Natural Gas Liquids		
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40 API ($Cdn/bbl)**	**Hardisty Heavy 12 API ($Cdn/bbl)**	**Edmonton Propane ($/bbl)**	**Edmonton Butane ($/bbl)**	**Edmonton Pentanes Plus ($/bbl)**
2008 Q4	100.00	101.64	74.57	60.98	77.25	102.66
2009	100.00	99.10	65.94	62.43	77.30	101.08
2010	100.00	99.10	64.87	62.43	77.30	101.08
2011	100.00	99.10	64.65	62.43	77.30	101.08
2012	100.00	99.10	64.65	62.43	77.30	101.08
2013	100.00	99.10	64.65	62.43	77.30	101.08
2014	101.35	100.45	65.55	63.28	78.35	102.46
2015	103.38	102.48	66.89	64.56	79.93	104.53
2016	105.45	104.55	68.26	65.87	81.55	106.64
2017	107.56	106.66	69.66	67.20	83.19	108.79

	Natural Gas			
Year	**AECO ($Cdn/MMBtu)**	**Westcoast Station 2 ($Cdn/MMBtu)**	**INFLATION RATES(1) %/Year**	**EXCHANGE RATE(2) ($US/$Cdn)**
2008 Q4	6.91	6.93	2.0	0.975
2009	7.13	7.30	2.0	1.00
2010	7.14	7.45	2.0	1.00
2011	7.32	7.80	2.0	1.00
2012	7.41	8.05	2.0	1.00
2013	7.49	8.30	2.0	1.00
2014	7.78	8.80	2.0	1.00
2015	8.13	9.39	2.0	1.00
2016	8.14	9.59	2.0	1.00
2017	8.17	9.81	2.0	1.00

Thereafter escalate at 2% per year.

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical wellhead prices realized by Yoho for the year ended September 30, 2008, were $8.33/Mcf for natural gas, $82.11/bbl for light oil and natural gas liquids, and $64.80/bbl for heavy oil.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Proved and Probable Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Most of Yoho's proved undeveloped reserves relate to wells budgeted and scheduled to be drilled in our 2009 fiscal year and to secondary zones that will be brought on production once the primary zone has been depleted.

Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. The probable reserves are attributed to infill and step-out drilling locations, re-completions, and tie-ins that are anticipated to proceed within one to two years but do not meet the confidence factor to be booked as proved reserves.

Yoho's proved undeveloped reserves are attributed in accordance with NI 51-101, the majority of which are presented by development drilling at McLeod, Alberta and Mike/Pickell, B.C. These reserves will be developed over the following two years.

Company Gross Reserves First Attributed by Year

	LIGHT AND MEDIUM OIL(Mbbl)		**HEAVY OIL (Mbbl)**		**NATURAL GAS (MMcf)**		**NATURAL GAS LIQUIDS (Mbbl)**	
Proved Undeveloped Reserves	First Attributed	Total At Year End	First Attributed	Total At Year End	First Attributed	Total At Year End	First Attributed	Total At Year End
Prior	-	-	-	-	386	386	1	1
2006	-	-	-	-	-	289	-	1
2007	-	-	-	-	1,300	1,300	17	17
2008	-	-	-	-	401	824	14	14

	LIGHT AND MEDIUM OIL(Mbbl)		**HEAVY OIL (Mbbl)**		**NATURAL GAS (MMcf)**		**NATURAL GAS LIQUIDS (Mbbl)**	
Probable Undeveloped Reserves	First Attributed	Total At Year End	First Attributed	Total At Year End	First Attributed	Total At Year End	First Attributed	Total At Year End
Prior	-	-	-	-	234	234	1	1
2006	-	-	-	-	212	436	1	2
2007	25	25	-	-	744	856	12	12
2008	-	-	-	-	394	1,070	7	8

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

	Forecast Prices and Costs	
	Proved Reserves	**Proved Plus Probable Reserves**
Year	**(M$)**	**(M$)**
2008 Q4	1,209	1,251
2009	924	2,427
2010	133	608
2011	-	-
2012	-	162
2013	-	-
2014	-	
2015		287
2016	-	105
2017	-	-
Total Undiscounted (all years)	2,266	4,840
Total discounted 10%	2,168	4,325

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, equity and debt financing.

There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on our future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates. The funding costs are minimal and will not significantly affect the economics of developing the properties.

Estimated future well abandonment costs related to our wells have been taken into account by GLJ in determining reserves that should be attributed to us. In determining the aggregate future net revenue, reasonable estimated future well abandonment costs were deducted from the gross revenue amount.

The forecast price and cost assumptions assumed the continuance of current laws and regulations.

The extended character of all factual data supplied to GLJ was accepted by GLJ as represented. No field inspection was conducted.

Alberta New Royalty Framework

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime that is scheduled to be effective on January 1, 2009. The NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity. 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. Companies drilling new natural gas or conventional oil deep wells (between 1.000 and 3,500 meters) will be given a one-time option per well to adopt the new transitional royalty rates or those outlined in the NRF. See "*Risk Factors – New Alberta Royalty Regime*" and *"Industry Conditions - Provincial Royalties and Incentives".*

Based upon their understanding of the New Royalty Framework, GLJ has rerun our corporate total economic forecasts with the New Royalty Framework to examine the impact of the proposed changes. The results of this process are disclosed in the following tables.

SUMMARY OF OIL AND GAS RESERVES
AS OF SEPTEMBER 30, 2008
FORECAST PRICES AND COSTS – NEW ROYALTY FRAMEWORK
TOTAL COMPANY INTEREST (INCLUDING ROYALTY INTEREST)

	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED DEVELOPED PRODUCING	100	85	162	127	15,196	11,803	291	210	3,086	2,390
TOTAL PROVED	104	89	162	127	16,892	13,174	318	230	3,399	2,641
TOTAL PROVED PLUS PROBABLE	212	169	194	152	24,307	18,968	437	314	4,894	3,796

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF SEPTEMBER 30, 2008
FORECAST PRICES AND COSTS – NEW ROYALTY FRAMEWORK

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT				
RESERVES CATEGORY	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**
PROVED DEVELOPED PRODUCING	95,706	79,053	68,037	60,162	54,227
TOTAL PROVED	103,750	85,481	73,327	64,615	58,040
TOTAL PROVED PLUS PROBABLE	154,223	118,565	97,221	82,931	72,663

OTHER OIL AND GAS INFORMATION

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at September 30, 2008.

	Natural Gas Wells				**Oil Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	130	28.9	32	9.5	62	5.5	20	3.1
British Columbia	46	9.7	27	6.8	6	0.3	4	0.8
Saskatchewan	-	-	-	-	3	1.1	6	2.2
Total	176	38.6	59	16.3	71	6.9	30	6.1

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as September 30, 2008.

	Undeveloped Acres	
	Gross	**Net**
Alberta	145,965	95,473
British Columbia	54,446	42,516
Total	200,411	137,989

Yoho has no work commitments on these lands. We expect that rights to explore, develop and exploit 14,144 net acres of our undeveloped land holdings, absent further action, will expire by September 30, 2009.

Forward Contracts

The material commitments related to the crude oil and natural gas properties that were outstanding at September 30, 2008 are disclosed in note 12 to the consolidated financial statements.

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment and reclamation costs related to well abandonment of existing and future reserve wells have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregated future net revenue there from. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any pipelines or facilities.

We will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

We estimate the costs to abandon and reclaim all of our producing and shut in wells (consisting of 68 net wells), facilities, and pipelines. Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

The additional Company liability associated with the wells not assigned reserves by GLJ, pipelines and facility reclamation costs, which was estimated to be $2.9 million ($1.5 million discounted at 10%), was not deducted in estimating future net revenue. We estimate over the next three years a total of $661,800 ($578,800 discounted at 10%) will be incurred on abandonment and reclamation costs.

Tax Horizon

Yoho was not required to pay any cash incomes taxes for the year ended September 30, 2008. The income taxes deducted in the calculation of future net revenue in the after tax table assumes a scenario whereby the Company produces out its existing reserves.

Based on current production and price assumptions and a continuing business model whereby the Company reinvests capital and incurs general and administrative and interest costs, the Company does not expect to pay cash income taxes until 2012 or later.

Capital Expenditures

The following table summarizes capital expenditures related to our activities for the year ended September 30, 2008.

Property acquisition costs:	
Proved properties	$ -
Unproved properties	2,183,506
Exploration costs	7,054,637
Development costs	8,927,109
Corporate acquisitions	7,942,165
Total	$ 26,107,417

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended September 30, 2008.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil	-		-		-	-
Natural Gas	3	2.5	7	4.6	10	7.1
Service	-	-	-	-	-	-
Dry	2	2.0	1	0.5	3	2.5
Total	5	4.5	8	5.1	13	9.6

Production Estimates

The following table discloses the estimated first year average daily production of Yoho by product type associated with the first year of the Gross (working interest) proved reserves and probable reserves reported in the GLJ Report. Boundary Lake is the only property that accounts for more that 20% of the total forecast production and is identified in the following table.

Total Proved	**LIGHT AND MEDIUM OIL** bbl/d	**HEAVY OIL** bbl/d	**NATURAL GAS** Mcf/d	**NATURAL GAS LIQUIDS** bbl/d	**TOTAL OIL EQUIVALENT** boe/d
Boundary Lake	-	-	3,958	10	669
Other	60	111	8,526	172	1,764
Total Proved Daily Production	60	111	12,484	182	2,433

Total Probable	**LIGHT AND MEDIUM OIL** bbl/d	**HEAVY OIL** bbl/d	**NATURAL GAS** Mcf/d	**NATURAL GAS LIQUIDS** bbl/d	**TOTAL OIL EQUIVALENT** boe/d
Boundary Lake	-	-	15	-	3
Other	1	2	206	6	43
Total Probable Daily Production	1	2	221	6	46

Total Proved and Probable	**LIGHT AND MEDIUM OIL** bbl/d	**HEAVY OIL** bbl/d	**NATURAL GAS** Mcf/d	**NATURAL GAS LIQUIDS** bbl/d	**TOTAL OIL EQUIVALENT** boe/d
Boundary Lake	--	-	3,972	10	672
Other	61	113	8,732	178	1,807
Total Proved and Probable Daily Production	61	113	12,705	188	2,479

Production History and Prices Received - Fiscal 2008

The following tables summarize certain information for our year ended September 30, 2008 in respect of production, product prices received, royalties paid, operating expenses, processing fees and resulting netback for the periods indicated below.

Production	**Q1**	**Q2**	**Q3**	**Q4**
Natural Gas (mcf/d)	9,381	9,325	10,514	12,626
Light oil and NGL (bbl/d)	152	166	184	213
Heavy oil (bbl/d)	134	119	105	109
BOE (boe/d)	1,850	1,840	2,041	2,427

Q1	**Natural Gas ($/Mcf)**	**Light Oil & NGLs ($/bbl)**	**Heavy Oil ($/bbl)**	**BOE ($/boe)**
Sales Price	6.31	62.01	33.66	39.56
Royalties	(1.32)	(5.75)	(5.05)	(7.54)
Operating Costs	(0.71)	(8.48)	(13.49)	(5.28)
Processing	(0.74)	-	-	(3.73)
Operating Netback	3.54	47.78	15.12	23.01

Q2	**Natural Gas ($/Mcf)**	**Light Oil & NGLs ($/bbl)**	**Heavy Oil ($/bbl)**	**BOE ($/boe)**
Sales Price	7.96	71.50	57.13	50.50
Royalties	(1.51)	(8.65)	(7.65)	(8.92)
Operating Costs	(0.87)	(10.91)	(13.73)	(6.31)
Processing	(0.65)	-	-	(3.27)
Operating Netback	4.93	51.94	35.75	32.00

Q3	**Natural Gas ($/Mcf)**	**Light Oil & NGLs ($/bbl)**	**Heavy Oil ($/bbl)**	**BOE ($/boe)**
Sales Price	10.63	95.08	85.97	67.71
Royalties	(2.22)	(6.48)	(16.19)	(12.88)
Operating Costs	(0.92)	(9.13)	(14.75)	(6.34)
Processing	(0.65)	-	-	(3.37)
Operating Netback	6.84	79.47	55.03	45.12

Q4	**Natural Gas ($/Mcf)**	**Light Oil & NGLs ($/bbl)**	**Heavy Oil ($/bbl)**	**BOE ($/boe)**
Sales Price	8.23	94.55	91.15	55.05
Royalties	(1.73)	(2.82)	(18.66)	(11.09)
Operating Costs	(0.77)	(13.01)	(10.87)	(5.23)
Processing	(0.45)	-	-	(2.70)
Operating Netback	5.28	78.72	61.62	36.03

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, Alberta, British Columbia, and Saskatchewan, 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 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 the approval of the Governor in Council.

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

Pipeline Capacity

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

The North American Free Trade Agreement

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

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

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 negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty like interests are, from time to time, carved out of the working interest owner's interest through non public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009; 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 2012.

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. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is 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. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2009, which, among other things, determines the Crown's share of crude and processed oil sands products.

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 ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (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 being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote 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 will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two year confidentiality period expires.

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 meters 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 meters (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per meter). These new programs are to be implemented along with the NRF.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime that is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources that is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government and be made available for resale. It appears that leaseholders will get a grace period before the shallower zones are reverted to the Crown, which is still to be determined. In addition to this, and in response to the drop in oil 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. Companies drilling new natural gas or conventional oil deep wells on or before November 19, 2008 (between 1000 and 3,500 meters) will be given a one-time option to adopt the new transitional royalty rates or those outlined in the NRF. On December 2, 2008 Bill 47 *Mines and Minerals (New Royalty Framework) Amendment Act* received royal assent and will come into force on various dates, with the rate adjustments contemplated by it coming into effect on January 1, 2009. See "*Risk Factors – New Alberta Royalty Regime*".

British Columbia

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m3 produced, whichever comes first; and the royalties for third tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the Province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits of up to $30 million annually towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil", or "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic meters of gas for every cubic meter of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic meters in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

- The elimination of the re entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/tax rates and new incentive volumes.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic meter incentive volume.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic meter incentive volume.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the federal government disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the federal government's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

In June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the Oil and Gas Conservation Act and the Oil and Gas Conservation Regulations, 1985. The program includes a security deposit, which has two purposes: (i) preventing the individual with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover for the decommissioning and reclaiming of orphan property. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

Land Tenure

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

Environmental Regulation

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

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007. 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. Industries can either choose one of these options or a combination thereof. The Corporation will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation also believes that 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 CO_2 from other emissions supporting carbon capture and storage.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO_{2e} of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government would receive otherwise.

In 2002, the Government of Canada ratified the Kyoto Protocol (the "**Protocol**") which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases.

On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products. The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

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

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

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facilities; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% 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 mentioned above.

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

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Protocol. 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 Mt 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.

Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or the new regulatory framework, could have a material impact on the nature of oil and natural gas operations. 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 at this time either the nature of those requirements or the impact on Yoho and its operations and financial condition.

Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy and the Organization of Petroleum Exporting Countries' ability to adjust supply to world demand and the weather. Recently crude oil prices have been kept high by political events causing disruptions in the supply of oil, and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

A second trend within the Canadian oil and gas industry is the fairly consistent "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. The Corporation must compete with these companies and others to attract qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Protocol, and other environmental initiatives, will have on the sector and, in more recent times, by the recent amendments to the *Income Tax Act* (Canada) (the "**Tax Act**") relating to income trusts and other "specified investment flow-through" entities ("**SIFTs**"). Pursuant to the changes to the Tax Act relating to SIFTs, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the changes to the Tax Act relating to SIFTs will not affect the method in which Yoho will be taxed, they may have an impact on the ability of a SIFT to purchase producing assets from junior oil and gas companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting exploration and production companies' ability to be sold to a SIFT which has been a key "exit strategy" in recent years for small to mid sized oil and gas companies. This may be a benefit for Yoho as it will compete with SIFTs for the acquisition of oil and gas properties from junior producers. However, it may also limit Yoho's ability to sell producing properties or pursue an exit strategy.

Yoho will compete with numerous new companies and their new management teams and development plans in its access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. Yoho may have to rely on internally generated funds to conduct its exploration and developmental programs.

RISK FACTORS

An investment in the Corporation is speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. An investor should consider carefully 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 Yoho depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, Yoho's existing reserves and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Yoho'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 Yoho will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of Yoho 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 Yoho.

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, Yoho 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 Yoho. In accordance with industry practice, Yoho not fully insured against all of these risks, nor are all such risks insurable. Although Yoho 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 Yoho could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on Yoho.

Operational Dependence

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

Project Risks

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

Yoho's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond Yoho's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;

- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Competition

The petroleum industry is competitive in all its phases. Yoho 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. Yoho's competitors will include oil and natural gas companies that have substantially greater financial resources, staff and facilities than Yoho. Yoho'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.

Regulatory

Oil and natural gas operations (exploration, production, 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 Yoho's costs, any of which may have a material adverse effect on Yoho's intended business, financial condition and results of operations. In order to conduct oil and gas operations, Yoho will require licenses from various governmental authorities. There can be no assurance that Yoho will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime that will be effective on January 1, 2009. The new regime would introduce new royalties for conventional oil, natural gas and bitumen, effective January 1, 2009, that are linked to price and production levels and would apply to both new and existing conventional oil and gas activities and oil sands projects.

Royalties payable pursuant to petroleum and natural gas leases with the Government of Alberta are *ad valorem* royalties, calculated using the oil or natural gas price and the level of production. Royalties payable to the Government of Alberta currently are 30 and 35 percent in the case of old and new conventional oil, respectively, 5 to 35 percent in the case of natural gas and 15 to 50 percent in the case of NGLs.

Under the NRF, the royalty formula for conventional oil will operate on a sliding rate formula containing separate elements that account for oil price and well production and specialty royalty programs will be eliminated along with "old" and "new" tiers. Royalty rates for conventional oil will range up to 50 percent, with rate caps once the price of conventional oil reaches Cdn. $120 per barrel.

Under the new royalty regime, natural gas royalties will be set by a sliding rate formula sensitive to price and well production rate. Vintages will be eliminated along with certain specialty royalty programs, though a form of deep gas royalty holiday will be retained and lower royalty rates will be applied over a wider price range for wells with less productivity. Royalty rates for natural gas will range from 5 to 50 percent with rate caps once the price of natural gas reaches $16.59/GJ (gigajoule). A shallow rights reversion program will also be implemented that will result in the reversion to the Government of Alberta of mineral rights to undeveloped geological formations above developed zones. Royalties for NGLs will be set at 40 percent for pentanes and 30 percent for butanes and propane.

In addition to this, and in response to the drop in oil 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. Companies drilling new natural gas or conventional oil deep wells on or before November 19, 2008 (between 1000 and 3,500 meters) will be given a one-time option per well to adopt the new transitional royalty rates or those outlined in the NRF.

On December 2, 2008 Bill 47 *Mines and Minerals (New Royalty Framework) Amendment Act* received royal assent and will come into force on various dates, with the rate adjustments contemplated by it coming into effect on January 1, 2009. The implementation of the recently enacted changes to the royalty regime in Alberta is subject to certain risks and uncertainties. The changes require legislation amendments, changes to existing legislation and regulations and development of proprietary software to support the calculation and collection of royalties. Additionally, there may be further modifications introduced to the royalty structure.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of Yoho. Current and future federal legislation, together with provincial emission reduction requirements, may require the reduction of emissions (or emissions intensity) produced by Yoho's expected operations and facilities. 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 either the nature of those requirements or the impact on Yoho and its operations and financial condition. The direct or indirect costs of these regulations may adversely affect the business of Yoho. See "*Industry Conditions – Environmental Regulation*".

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 Yoho to incur costs to remedy such discharge. Although Yoho believes that it is 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 adversely affect Yoho's financial condition, results of operations or prospects. See "*Industry Conditions – Environmental Regulation*".

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Yoho is and will continue to be affected by numerous factors beyond its control. Yoho's ability to market its oil and natural gas depends upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Yoho is also 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.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Yoho'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 Yoho's reserves. Yoho might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Yoho's net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. In addition, bank borrowings available to Yoho will be in part determined by Yoho's borrowing base. A sustained material decline in prices from historical average prices could reduce Yoho's borrowing base, therefore reducing the bank credit available to Yoho which could require that a portion, or all, of Yoho's bank debt be repaid and a liquidation of assets.

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. Such material increases in the value of the Canadian dollar may negatively impact Yoho's operating entities' production revenues. Further material increases in the value of the Canadian dollar would exacerbate this potential negative impact. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of Yoho's reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

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

Additional Funding Requirements

Yoho's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Yoho 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 Yoho to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Yoho's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, Yoho's ability to expend the necessary capital to replace its reserves or to maintain its production will be impaired. If Yoho's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on favourable terms.

Issuance of Debt

From time to time Yoho 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 Yoho's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, Yoho may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Yoho's articles nor its by laws limit the amount of indebtedness that Yoho may incur. The level of Yoho's indebtedness from time to time, could impair Yoho's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time Yoho 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, Yoho will not benefit from such increases. Similarly, from time to time Yoho 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, Yoho will not benefit from the fluctuating exchange rate.

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

Title to Assets

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 Yoho's claim which could result in a reduction of the revenue received by Yoho.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Yoho'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, GLJ has used both constant and forecast prices and costs in estimating the reserves and future net cash flows contained in the GLJ Report. 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 Yoho's oil and gas reserves will vary from the estimates contained in the GLJ Report and such variations could be material. The GLJ Report is based in part on the assumed success of activities Yoho intends to undertake in future years. The reserves and estimated cash flows set out in the GLJ Report will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Report.

Insurance

Yoho's involvement in the exploration for and development of oil and natural gas properties may result in Yoho becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Yoho will maintain 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, Yoho 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 Yoho. The occurrence of a significant event that Yoho is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Yoho.

Geo-Political Risks

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

In addition, Yoho's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. As the oil and gas industry in Canada is a key supplier of energy to the United States, certain terrorist groups may target Canadian oil and gas properties, wells and facilities in an effort to choke the United States economy. If any of Yoho's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Yoho. Yoho does not have insurance to protect against the risk from terrorism.

Dividends

Any decision to pay dividends on the Common Shares will be made by the board of directors of Yoho on the basis of Yoho's earnings, financial requirements and other conditions existing at such future time. See "Dividend Record".

Conflicts of Interest

Certain directors of Yoho 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 – Conflicts of Interest*".

Management of Growth

Yoho may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Yoho 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 Yoho to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licenses and Leases

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

Aboriginal Claims

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

On September 1, 2006, the Government of Alberta's First Nations Consultation Guidelines on Land Management and Resource Development were released. These guidelines support the previously issued First Nations Consultation Policy (May, 2005) and First Nations Framework for Consultation Guidelines. Under this policy certain procedural aspects of consultation with respect to specific projects will be delegated to the Corporation. These requirements may result in additional delays and costs which could have an adverse effect on the Corporation and its operations.

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 Yoho.

Third Party Credit Risk

Yoho 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 Yoho, such failures could have a material adverse effect on Yoho and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Yoho's ongoing capital program, potentially delaying the program and the results of such program until Yoho finds a suitable alternative partner.

Reliance on Key Personnel

Yoho's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on Yoho. Yoho does not have any key person insurance in effect for management. The contributions of the existing management team to the immediate and near term operations of Yoho 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 Yoho 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 Yoho.

Dilution

Yoho may take future acquisitions or enter into financing or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of oil and natural gas to Yoho or to the operators, and the delays by operators in remitting payment to the Corporation, 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 the Corporation in a given period and expose the Corporation to additional third party credit risks.

Changes in Legislation

The return on an investment in securities of Yoho is subject to changes in Canadian federal and provincial tax laws and government incentive programs and there can be no assurance that such laws or programs will not be changed in a manner that adversely affects the Corporation or the holding and disposing of the securities of the Corporation.

Income Taxes

As the Corporation is engaged in the oil and natural gas business its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation relating to characterization of costs incurred in their businesses which affects whether such costs are deductible and, if deductible, the rate at which they may be ducted for the purposes of calculating taxable income. Yoho will file all required income tax returns and believes that it will be in full compliance with the provisions of the *Income Tax Act* (Canada) and all applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of costs or otherwise, such reassessment may have an impact on current and future taxes payable.

Accounting Write-Downs as a Result of GAAP

Canadian generally accepted accounting principles ("**GAAP**") require that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the financial statements of Yoho. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the Corporation's Common Shares.

Under GAAP, the net amount at which petroleum and natural gas properties are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flow from oil and natural gas reserves. If net capitalized costs exceed the future discounted cash flows, Yoho will have to charge the amounts of the excess to earnings. A decline in the estimated future net cash flow from oil and natural gas reserves could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

GAAP requires that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to net income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the trading price of the common shares of the Corporation may indicate a goodwill impairment. An impairment would result in a write-down of the goodwill value and a non-cash charge against net income. The calculation of impairment value is subject to management estimates and assumptions.

DIRECTORS AND OFFICERS

The name, jurisdiction of residence, principal occupation for the prior five years of each of the directors and officers of Yoho are as follows:

Name and Jurisdiction of Residence	Offices Held and Time as Director	Principal Occupation During the Last Five Years
Terry Svarich (1)(3) Alberta, Canada	Chairman of the Board since February 17, 2005	Mr. Svarich is currently the President of DevSun Ltd., a private investment company. Mr Svarich is also currently a director of ProEx Energy Ltd., a TSX listed company. Mr. Svarich was a director of Progress Energy Ltd. from 2001 through 2004.
Bruce Allford (2) Alberta, Canada	Director since December 20, 2004	Mr. Allford is a partner with the Calgary law firm, Burnet, Duckworth & Palmer LLP.
Brian McLachlan Alberta, Canada	President, CEO and a Director since January 5, 2005	Mr. McLachlan has been the President and Chief Executive Officer of Yoho since January of 2005. Mr. McLachlan has been consulting in the oil and gas industry since December of 2003. Mr. McLachlan was the President and Chief Executive Officer of Taurus Exploration Ltd. from October of 1998 to December of 2003. Prior thereto Mr. McLachlan was the President and Chief Executive Officer of Paragon Petroleum Ltd.
Peter Kurceba (2)(3)(4) Alberta, Canada	Director since February 9, 2006	Mr. Kurceba is an oil and gas industry advisor at J.F. Mackie & Company Ltd., an independent equity investment firm. Prior thereto, from August 2004 to October 2005, Mr. Kurceba was an oil and gas industry consultant. From 2000 to August 2004, Mr. Kurceba was a founder and the Vice President, Exploration of Profico Energy Management Ltd.
Kevin Olson (1)(2) Alberta, Canada	Director since December 20, 2004	Mr. Olson is the President of EnergyX Equity Inc., being the manager of two private investment funds, and has held this position since October, 2001. Prior thereto Mr. Olson was the Vice President, Corporate Development of Northrock Resources Ltd.
Gary Perron (1) Alberta, Canada	Director since December 20, 2004	Mr. Perron is the Managing Director and Senior Vice President of BMO Nesbitt Burns Inc.
John Brussa Alberta, Canada	Director since March 11, 2008	Mr. Brussa is a partner (since 1987) of Calgary law firm, Burnet, Duckworth & Palmer LLP, specialising in taxation. Mr. Brussa is also a director of several energy and energy-related corporations and income funds.
Clark Drader Alberta, Canada	Vice President, Land since May 1, 2005	Mr. Drader has been the Vice President, Land of Yoho since May 1, 2005. From January 2003 until May 1, 2005 Mr. Drader was a Consulting Senior Land Negotiator with Northrock Resources Ltd. Prior thereto Mr. Drader was a Land Manager with BP Canada. Mr. Drader has also been the President of Drader Resources Ltd. since January of 2003.
Barry Stobo Alberta, Canada	Vice President, Engineering and Chief Operating Officer since February 1, 2005	Mr. Stobo has been the Vice President, Engineering and Chief Operating Officer of Yoho since February of 2005. Prior thereto, Mr. Stobo was the Vice President, Operations of Vintage Petroleum Canada Inc. and its predecessor Genesis Exploration Ltd.
Wendy Woolsey Alberta, Canada	Vice President, Finance and Chief Financial Officer since March 1, 2005	Ms. Woolsey has been the Vice President, Finance and Chief Financial Officer of Yoho since March of 2005. Prior thereto Ms. Woolsey was the Manager, Finance of Baytex Energy Trust.

Notes:

(1) Member of our Audit Committee.
(2) Member of our Compensation Committee.
(3) Member of our Reserves Committee.
(4) Prior to February 9, 2006, Mr. Kurceba served as a Special Advisor to the Board of Directors.

All directors of the Corporation are elected by the shareholders of the Corporation at each annual general meeting of the Shareholders to serve a term until the subsequent annual general meeting of the shareholders. As at December 10, 2008 the directors and executive officers of Yoho, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 4,149,818 Common Shares, or approximately 22.1% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as set forth below, no director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within 10 years before the date of this Annual Information Form, has been, a director or executive officer of any company that, while that person was acting in that capacity:

(a) was the subject of a cease trade or similar order, or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days;

(b) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(c) within a year of that person ceasing to act in such 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.

Mr. Allford was (and remains) a director and the Corporate Secretary of Indo Pacific Resources Ltd. (a non-operating, internationally based mining exploration company) at the time this company became the subject of a cease trade order issued (in July, 2000) by the Alberta and British Columbia Securities Commissions by reason of that company's failure to file financial statements, which cease trade orders remain in effect. Mr. Stobo, the Vice-President, Engineering of the Corporation, was the interim President, Chief Executive Officer and a Director of Merit Energy Ltd. during the period from November of 1999 to March of 2000, following the resignation of the President of the company. Merit Energy Ltd. sought and received creditor protection under the *Companies' Creditors Arrangement Act* (Canada), and subsequently became the subject of receivership proceedings. Mr. Stobo resigned as acting President of that company prior to receivership proceedings being implemented.

No director, officer or promoter of Yoho, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver, receiver manager or trustee appointed to hold his or her assets.

No director, officer, Insider or Promoter of the Corporation, or any shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in deciding whether to make an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Yoho will be subject in connection with the operations of Yoho. In particular, certain of the directors and officers of Yoho are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Yoho or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Yoho. 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 will disclose his interest in such contract or agreement and will refrain from voting on any matter in respect of such contract or agreement unless otherwise provided in the ABCA.

Personnel

As at September 30, 2008, the Corporation employed 12 full-time employees. Yoho intends to add additional professional and administrative staff as the need arises.

YOHO SHARE CAPITAL

As of the date of this Annual Information Form, the authorized share capital of the Corporation consists of an unlimited number of Common Shares of which there are 18,752,613 shares are issued and outstanding and an unlimited number of Class C Non-Voting Common Shares of which there are 1,871,273 shares are issued and outstanding.

Common Shares

The holders of Common Shares are entitled to dividends as and when declared by the Board of Directors of the Corporation, to one vote per share at meetings of shareholders of the Corporation and, upon liquidation, to receive such assets of the Corporation as are distributable to the holders of the Common Shares, to be shared rateably with the holders of the Class C Non-Voting Common Shares.

Class C Non-Voting Common Shares

The holders of Class C Non-Voting Common Shares are entitled to dividends as and when declared by the Board of Directors of the Corporation and, upon liquidation, to receive such assets of the Corporation as are distributable to the holders of the Class C Non-Voting Common Shares, to be shared rateably with the holders of the Common Shares. In addition, the holders of Class C Non-Voting Common Shares are entitled to receive notice of and to attend any meeting of the shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation, other than the Class C Non-Voting Shares) provided that, except as required by law, the holders of Class C Non-Voting Common Shares shall not be entitled to vote at any meeting of the shareholders of the Corporation.

DIVIDEND POLICY

Yoho has not paid any dividends. The Board of Directors of Yoho will determine the actual timing, payment and amount of dividends, if any, that may be paid by us from time to time based upon, among other things, the cash flow, results of operations and financial conditions of Yoho, the need for funds to finance ongoing operations and other business considerations as our board of directors considers relevant.

MARKET FOR SECURITIES

The Common Shares are listed for trading on the TSXV under the symbol "YO". The following table sets forth the high and low closing trading prices and the aggregate volume of trading of the Common Shares (as reported by the TSXV) for the periods indicated. The Common Shares commenced trading on the TSXV on October 18, 2005.

	Price Range		
	High ($)	**Low ($)**	**Volume Traded**
2007			
September	3.58	2.85	109,221
October	2.90	2.50	199,334
November	2.85	1.67	179,494
December	2.16	1.60	170,379
2008			
January	2.40	1.65	215,900
February	3.02	1.80	1,868,450
March	3.25	2.30	336,223
April	4.30	2.50	334,169
May	3.90	3.17	130,349
June	4.17	3.30	751,022
July	3.95	3.30	210,633
August	3.40	2.78	187,121
September	2.90	2.32	102,117
October	2.75	1.49	447,367
November	1.75	1.01	518,930
December (to December 9)	1.25	1.07	474,611

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

LEGAL PROCEEDINGS

To the knowledge of the Corporation, there are no outstanding legal proceedings material to the Corporation to which the Corporation is or was a party to, or in respect of which any of its properties are or were subject of during the year ended September 30, 2008, nor are there any such proceedings known to be contemplated.

During the year ended September 30, 2008 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

A company controlled by Mr. McLachlan, 358949 Alberta Ltd., has a one percent overriding royalty on certain lands held by the Corporation. This arrangement is the result of consulting work that 358949 Alberta Ltd. performed on these properties previous to Yoho acquiring these lands in February 2005. The lands to which the overriding royalty is applicable are fixed by defined prospect boundaries.

The Corporation entered into a short-term loan facility with a private lender controlled by a director of the Corporation for the principal amount of $6,000,000 on December 29, 2006 which loan facility was originally to become due and payable on June 29, 2007. As partial consideration for the loan, the Corporation issued to the lender 240,000 Common Share purchase warrants. Each warrant was exercisable into one Common Share of the Corporation at a price of $5.25 at any time up to June 29, 2007, which warrants expired unexercised. The loan was further extended on June 29, 2007 to become due and payable on January 3, 2008. As partial consideration for the extension, the Corporation issued 210,500 Common Shares on a "flow through" basis, priced at $4.75 per share, for gross proceeds of $1,000,000 to the lender. On December 31, 2007, $1,000,000 of the facility was repaid. The loan facility was further extended on January 2, 2008 to become due and payable on January 3, 2009. In connection with this extension, the Corporation issued 500,000 Common Share purchase warrants to the lender. Each warrant is exercisable at a price of $2.75 into Common Share issued on a "flow-through" basis up to June 30, 2008 which warrants were fully exercised prior to their expiry. This loan has now been fully repaid.

Other than set out above, there were other no material interests, direct or indirect, of directors and senior officers of the Corporation, nominees for director, any shareholder who beneficially owns more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction since the beginning of the Corporation's last completed financial year or in any proposed transaction which has materially affected or would materially affect the Corporation.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our independent registered Chartered Accountants are KPMG LLP, Chartered Accountants, Calgary, Alberta.

Valiant Trust Company, at its principal office in Calgary, Alberta and through its co-agent, Equity Transfer Services Inc., at its principal office in Toronto, Ontario is the transfer agent and registrar for the Common Shares.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator. None of the principals of GLJ have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the GLJ Report, at any time thereafter or that are to be received by them. KPMG LLP, our

Auditors, are independent of the Corporation in accordance with the auditor's rules of professional conduct in the Province of Alberta.

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 Yoho or of any associate or affiliate of Yoho, except for Bruce Allford and John Brussa, directors of Yoho, who are partners at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business or as otherwise disclosed herein, there have been no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

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 the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for its most recently completed financial year.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph, any interim financial statements which have been issued by the Corporation are available on the foregoing basis and upon request by contacting the Corporation at:

Yoho Resources Inc.
750, 736 – 6th Avenue SW
Calgary, Alberta T2P 3T7

Phone: (403) 537-1771
Fax: (403) 537-1775
www.yohoresources.ca

APPENDIX A

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

To the Board of Directors of Yoho Resources Inc. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at September 30, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at September 30, 2008, estimated using forecast prices and costs.

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

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions 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 September 30, 2008, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County 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	November 17, 2008	Canada	-	$101,430	-	$101,430

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

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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, December 8, 2008

(signed) "*Doug R. Sutton*"
Doug R. Sutton, P. Eng
Vice-President

APPENDIX B

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

Management of Yoho Resources Inc. (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 September 30, 2008, 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, on the recommendation of the Reserves Committee, approved:

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves 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 reserves are categorized according to the probability of their recovery.

(signed) "*Brian A. McLachlan*"
Brian A. McLachlan
President and Chief Executive Officer

(signed) "*Barry J. Stobo*"
Barry J. Stobo
Vice President, Engineering and Chief Operating Officer

(signed) "*Terry Svarich*"
Terry Svarich
Director

(signed) "*Peter Kurceba*"
Peter Kurceba
Director

December 8, 2008