ITERATION ENERGY LTD.

ANNUAL INFORMATION FORM

March 17, 2010

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ANNUAL INFORMATION FORM

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GLOSSARY OF TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

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

"**COGE Handbook**" means the "Canadian Oil and Gas Evaluation Handbook";

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

"**Cyries**" means Cyries Energy Inc., a corporation incorporated under and governed by the ABCA;

"**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;

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

"**developed 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;

"**Dry and Abandoned**" means a well which is not a productive well or a service well. A productive well is a well which is capable of producing oil and gas in commercial quantities or in quantities considered by the operator to be sufficient to justify the costs required to complete, equip and produce the well. A service well means a well such as a water or gas-injection, water-source or water-disposal well. Such wells do not have marketable reserves of crude oil or natural gas attributed to them but are essential to the production of the crude oil and natural gas reserves;

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

"**GLJ Report**" means the report prepared by GLJ dated January 29, 2010, effective as at December 31, 2009, setting forth pertinent information relating to the oil and gas reserves of certain of the Corporation's properties and the present value of the estimated future net reserves associated with such reserves;

"**gross reserves**" include working interest reserves before the deduction of royalties;

"**gross wells**" means the total number of wells in which the Corporation has an interest;

"**Hawker**" means Hawker Resources Inc., as the Corporation was named before it changed its name to Iteration Energy Ltd. on July 7, 2005;

"**Iteration**" or "**the Corporation**" means Iteration Energy Ltd., a corporation incorporated under and governed by the ABCA;

"**Iteration Energy**" or "**the Partnership**" means Iteration Energy, a general partnership formed on March 23, 2005;

"**Iteration Energy Partnership 2007**" means Iteration Energy Partnership 2007 (formerly named Peace River Arch Partnership);

"**LIBOR**" means London Interbank Offered Rate;

"**McDaniel**" means McDaniel and Associates Consultants Ltd., independent petroleum engineers, Calgary, Alberta;

"**McDaniel Report**" means the report prepared by McDaniel dated February 24, 2010, effective as at December 31, 2009, setting forth pertinent information relating to the oil and gas reserves of certain of the Corporation's properties and the present value of the estimated future net reserves associated with such reserves;

"**NEB**" means National Energy Board of Canada;

"**net reserves**" include working interest after royalty deductions plus royalty interest reserves;

"n**et wells**" means the number of gross wells multiplied by the Corporation's working interest therein;

"**NGLs**" means natural gas liquids;

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

"**Peace River Arch Partnership**" means the partnership holding certain oil and gas properties acquired by Iteration from an arms length oil and gas company on September 27, 2007;

"**Pointwest**" means Pointwest Energy Inc., a corporation incorporated under the ABCA;

"**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;

"**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;

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

"**royalties**" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling prices, the price forecasts for the individual properties in question have been employed;

"**Shut-in**" means wells which are capable of economic production or which the Corporation considers capable of production but which, for a variety of reasons, including but not limited to lack of markets or development, are not currently on production;

"**Southward**" means Southward Energy Ltd., a corporation incorporated under the ABCA;

"**Southward Properties**" means all of the petroleum and natural gas rights and related assets acquired from Southward;

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

"**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;

"**WCSB**" means Western Canada Sedimentary Basin;

"**working interest**" means the interest in a lease that carries with it the rights and obligations to develop and operate an oil or natural gas property;

"**WTI**" means West Texas Intermediate; and

"**Zorin**" means Zorin Exploration Ltd., a corporation incorporated under the ABCA.

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

ABBREVIATIONS

Crude Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	Barrel	mcf	thousand cubic feet
bbls/d	barrels per day	mmcf	million cubic feet
Mbbls	thousand barrels	bcf	billion cubic feet
Boe[(1)]	barrels of oil equivalent of natural gas and crude oil on the basis of 1 bbl of crude oil for 6 mcf of natural gas	mcf/d	thousand cubic feet per day
		mmcf/d	million cubic feet per day
		GJ	Gigajoules
Boed	barrels of oil equivalent per day	GJ/d	gigajoules per day
MBoe	thousand Boe		
NGLs	natural gas liquids		
Mmbtu	million British thermal units		
Stb	standard stock tank barrel		

Note:

(1) Natural gas is converted to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 mcf: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.

CONVERSION

In this Annual Information Form, certain measurements may be given in Standard Imperial or Metric Units only. The following table sets forth certain standard conversions:

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Barrels	Cubic metres	0.159
Cubic metres	Barrels	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains certain forward-looking statements and forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as "anticipate", "believe", "plan", "continuous", "estimate", "expect", "may", "will", "project", "should", or similar words suggesting future outcomes. In particular, this Annual Information Form contains forward-looking statements pertaining to the following:

- business plans and strategies;
- the strategic review process;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- the quantity of natural gas, oil, and NGL reserves;
- net present value of future net revenues from reserves;
- projections of market prices for natural gas, oil, and NGL commodities;
- projections of capital expenditure programs and other expenditures;

- oil and natural gas production levels;
- supply and demand for oil and natural gas;
- projections of foreign currency exchange rates and interest rates;
- treatment under governmental regulatory regimes and tax, environmental, and other laws;
- expected operating costs;
- Iteration's future operating and financial results; and
- expected abandonment and reclamation costs.

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

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Corporation and its shareholders.

Forward-looking statements and information are based on the Corporation's current beliefs as well as assumptions made by, and information currently available to, the Corporation concerning anticipated financial performance, business prospects, strategies, regulatory developments, future commodity prices, future production levels, the ability to obtain equipment in a timely manner to carry out development activities, the ability to market natural gas, oil, and NGLs successfully to current and new customers, the impact of increasing competition, the ability to obtain financing on acceptable terms, and the ability to add production and reserves through development and exploration activities. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that forward-looking statements will not be achieved. These factors include, but are not limited to, risks associated with oil and gas exploration, development and production, insurance, prices, financial risks, bank financing, substantial capital requirements, third party risk, competition, environment, reserves replacement, reliance on operators and key employees, changes to accounting policies (including the implementation of IFRS), corporate matters, permits and licenses, incorrect assessments of value, fluctuations in exchange rates, aboriginal claims, issuance of debt, availability of drilling equipment, title defects, uncertainty of reserve information and government regulation and taxation. Further information regarding these factors may be found under the heading "Risk Factors" in this Annual Information Form, and in the Corporation's most recent financial statements, management's discussion and analysis, management information circular, material change reports and news releases. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive.

The forward-looking statements contained in this Annual Information Form are made as of the date hereof and the Corporation does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

ITERATION ENERGY LTD.

Organization and Structure

The Corporation was incorporated as 599386 Alberta Ltd. under the ABCA on February 14, 1994 and changed its name to SYNSORB Biotech Inc. on March 31, 1994. Effective May 8, 2002: (i) each former holder of common shares of the Corporation received one new common share for each eight cancelled common shares previously held by such holder, (ii) the stated capital of the Corporation was reduced in respect of the common shares of the Corporation by $59,896,000, and (iii) 4,000,235 common shares of Oncolytics Biotech Inc. held by the Corporation were distributed to its shareholders. By articles of amendment filed on April 3, 2003, the name of the Corporation was changed to Hawker Resources Inc. and a new class of non-voting equity shares was created. On December 30, 2003, each of Pointwest and its wholly-owned subsidiary, Myriad Corporation, and the Corporation amalgamated pursuant to the provisions of the ABCA under the name Hawker Resources Inc. On December 31, 2003, 1053639 Alberta Ltd., a wholly-owned subsidiary of the Corporation, and the Corporation amalgamated pursuant to the provisions of the ABCA under the name Hawker Resources Inc. On March 17, 2004, Zorin Exploration Ltd., a wholly owned subsidiary of the Corporation, was dissolved into the Corporation. On April 28, 2004, the shareholders of the Corporation approved the reclassification of the class A shares into Common Shares and the removal of the class A shares from the authorized capital of the Corporation. By articles of amendment filed on July 7, 2005, the name of the Corporation was changed to Iteration Energy Ltd.

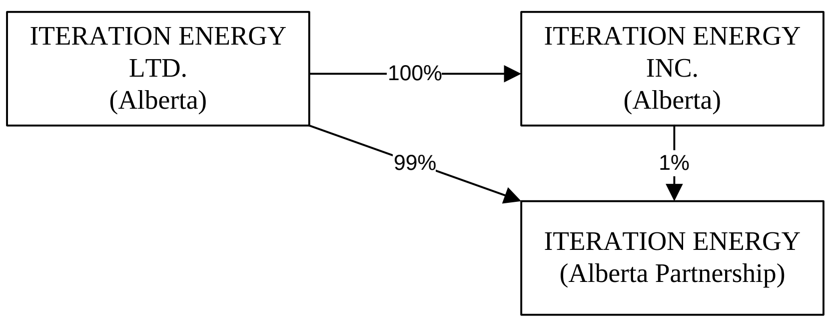
The head office and registered office of the Corporation is located at 700, 700 - 2nd Street S.W., Calgary, Alberta, T2P 2W1.

Inter-corporate Relationships

Iteration Energy is a general partnership formed under the laws of the Province of Alberta on March 23, 2007. The partners of Iteration Energy are the Corporation, which is also the managing partner, and Iteration Energy Inc. Iteration Energy Inc. is incorporated under the ABCA and is a wholly owned subsidiary of the Corporation. The principal business of Iteration Energy Inc. is holding the partnership interest of Iteration Energy. Iteration Energy holds substantially all of the oil and gas properties of the Corporation.

On January 1, 2010, Iteration completed an internal corporate reorganization, whereby, generally: (i) Iteration Energy Partnership 2007 transferred its assets, including its oil and gas properties, to its partners, Iteration Energy (99%) and Iteration Energy Inc. (1%), and was subsequently dissolved, and (ii) Cyries Energy Inc. was amalgamated into Iteration Energy Ltd.

The following chart illustrates the structure of the Corporation and its subsidiaries effective January 1, 2010 upon completion of Iteration's internal corporate reorganization.



Business Strategy

Subject to the outcome of the current process to investigate strategic alternatives (as described on Page 6), the Corporation has the following business strategy:

Vision. The Corporation's primary ongoing business objective is to continue as a full cycle oil and gas company with a dual focus on exploration and development activities and on an active acquisition strategy.

Drilling Program. Management intends to employ an active exploration program to seek out additional areas to add to the Corporation's production and opportunity inventory.

Responsible Fiscal Management. The Corporation strives to add value through its drilling and exploration activities and carefully manages its costs, thereby positioning itself to add to its inventory of opportunities and undeveloped land holdings.

Prudent Use of Equity. Management recognizes that equity must be used prudently, and it intends to rely heavily on operational revenues and, to the extent necessary, debt financing to satisfy liquidity requirements. The Corporation will attempt to minimize the dilution that would be caused to existing shareholders if large amounts of equity were issued.

GENERAL DEVELOPMENT OF THE BUSINESS

Business of the Corporation

Iteration is an Alberta based corporation engaged in the business of exploring for and developing oil and natural gas reserves in the WCSB and acquiring oil and natural gas properties. As at December 31, 2009, Iteration owned approximately 801,000 net acres of undeveloped land focused primarily in Alberta and British Columbia, with lesser properties in Saskatchewan, Texas and the Northwest Territories. As of December 31, 2009, the Corporation had approximately 13,200 Boed of production.

As at December 31, 2009, the Corporation employed 71 people, none of whom were unionized.

Recent Developments – Strategic Review Process

On February 4, 2010, Iteration announced that its board of directors had initiated a process to identify, examine and consider a range of strategic alternatives available to it, with a view to maximizing shareholder value, and that it had retained FirstEnergy Capital Corp. and Scotia Waterous Inc. to assist with this process. This process could result in a sale of the Corporation, a sale of a material portion of the Corporation's assets, or a corporate reorganization, among other alternatives. Iteration does not intend to disclose developments with respect to the strategic review process unless and until the board of directors has approved a definitive transaction or strategic option, unless otherwise required by law or disclosure of which is deemed appropriate. **The Corporation cautions that there are no guarantees that the strategic review will result in a transaction or if a transaction is undertaken, as to its terms or timing. In the event that no attractive business alternative is found, Iteration intends to continue building an asset base in its main focus areas in northeast British Columbia, northwest and western Alberta, east central Alberta and southeast Alberta by means of acquisitions, farm-ins and land sale opportunities.**

History

Financial Year Ended December 31, 2009

Completion of a Bought Deal Equity Financing - 44,965,000 Common Shares

Pursuant to a short term prospectus dated April 29, 2009, the Corporation issued 44,965,000 Common Shares through a bought deal equity financing on May 6, 2009, at a price of $1.28, for gross proceeds of $57,555,000. The net proceeds from the financing were used to reduce indebtedness under its credit facility, including the repayment in full of its $25 million supplemental facility, which was then cancelled.

New Credit Facility

On May 14, 2009, the Corporation secured a new syndicated bank credit facility with a borrowing base of $225 million, which matures on April 30, 2010, which facility replaced its then existing facility. For additional terms related to the credit facility please see "*Borrowings*".

2009 Disposition Program

Pursuant to its 2009 disposition program, Iteration has sold approximately $42 million of properties, prior to closing adjustments, through a series of transactions. The closing date for a majority of the transactions occurred on July 31, 2009. The largest property sold was Wilson Creek in central Alberta. Other properties sold include Wild River in western Alberta and three minor properties in northern Alberta.

Other

Effective January 17, 2010, Mr. Peter Scott resigned as Chief Financial Officer of the Corporation. Mr. Willie Dawidowski, the Vice President and Controller of Iteration agreed to provide ongoing continuity and leadership of Iteration's accounting and finance group. Mr. Scott joined Iteration on March 31, 2009 as Chief Financial Officer, and Mr. Sean Johnson resigned as Chief Financial Officer of Iteration at this time for personal reasons.

Effective August 12, 2009, Mr. Crone resigned as a director of Iteration.

Financial Year Ended December 31, 2008

Acquisition of Cyries Energy Inc.

On January 21, 2008, Iteration announced that it had entered into an arrangement agreement (the "**Arrangement Agreement**") with Cyries to acquire all of the securities of Cyries pursuant to an arrangement under section 193 of the ABCA (the "**Arrangement**"), pursuant to which Iteration would acquire each Cyries common share in exchange for 1.475 Common Shares and each Cyries warrant for that number of Common Shares that is equal to the result of the amount by which the Weighted Average Trading Price (as defined in the Arrangement Agreement) exceeds the exercise price of such Cyries warrant, which amount is then divided by the Weighted Average Trading Price multiplied by 1.475. The share exchange ratio of 1.475 was increased to 1.62 Common Shares pursuant to an amending agreement dated March 3, 2008. On March 7, 2008, the Arrangement was completed subsequent to receipt of the requisite approval of Cyries securityholders and of the Alberta Court of Queen's Bench. In connection with the Arrangement, Iteration issued an aggregate 93,990,604 Common Shares to former securityholders of Cyries such that, upon completion of the Arrangement, the current Iteration shareholders held approximately 47% and the former Cyries securityholders held approximately 53% of the outstanding Common Shares. The acquisition of Cyries was accounted for using the purchase method and the purchase equation was based on management's estimate of the fair values of the assets and liabilities of Cyries as at March 7, 2008. Iteration commenced reporting production from this acquisition on March 8, 2008.

In connection with the Arrangement, each of Don Archibald, Howard Crone and Garry Peddle were appointed as directors of Iteration.

Financial Year Ended December 31, 2007

Acquisition of Peace River Arch Partnership and Prospectus Offering

Pursuant to a purchase and sale agreement dated September 27, 2007 the Corporation purchased, with an effective date of June 1, 2007, the partnership interests of the Peace River Arch Partnership which held certain petroleum and natural gas properties and related assets in South East Alberta and the Peace River Arch area in North West Alberta from an unrelated oil and gas company. The gross purchase price was $52,375,000, subject to adjustments. The Corporation assumed an asset retirement obligation of $6,775,000 associated with this acquisition. The acquisition was initially funded by bank debt. The Corporation commenced reporting production from this acquisition on September 28, 2007.

Pursuant to a short form prospectus dated September 28, 2007, the Corporation closed the issuance of 5,210,000 subscription receipts through a bought deal equity financing on October 17, 2007, at a price of $4.80 per subscription receipt for gross proceeds of $25.0 million. Additionally, on November 13, 2007, the underwriters exercised their over-allotment option with respect to a further 767,400 subscription receipts at a price of $4.80 per subscription receipt for additional gross proceeds of $3.7 million. Each subscription receipt was exchanged for one Common Share at no additional charge in connection with closing of the acquisition of the Peace River Arch Partnership (which name was subsequently changed to Iteration Energy Partnership 2007). The net proceeds of this financing were used to reduce the bank debt incurred by the Corporation in respect of the acquisition.

PRINCIPAL PROPERTIES

Summary of Properties

The following is a description of the Corporation's principal properties on production or under development as at December 31, 2009.

Boundary Lake, British Columbia

Iteration has an average 92% working interest in and is operator of 55,039 gross acres (50,770 net acres) at North Boundary, which is located 55 kilometres northeast of Fort St. John in British Columbia. The Corporation also holds a 100% working interest in the gas processing facility that is able to process approximately 24 mmcf/d of gas. Compression can be added to expand the facility beyond this level. Hydrocarbons are produced from eight different Cretaceous and Triassic reservoir zones at depths of up to 1,400 metres. Production averaged approximately 2,040 Boed in 2009, with an exit rate of approximately 1,850 Boed. During 2009, 1.89 net gas wells were drilled.

Other British Columbia

Other significant properties in British Columbia include Monias, Umbach, and Rigel. Iteration has an average 66% working interest in this area and has an interest in 181,306 gross acres (120,794 net acres) of land in such properties. Hydrocarbons are produced from various Cretaceous and Triassic reservoir zones at depths of up to 1,400 metres. Production averaged 990 Boed in 2009, with an exit rate of approximately 970 Boed. During 2009, there were 0.5 net gas wells and 1.0 net oil well drilled.

Western Alberta

Significant properties in western Alberta include Knopcik, Gold Creek, Gordondale, and Valhalla. Iteration has an average 78% working interest in this area and has an interest in 622,960 gross acres (490,726 net acres) of land. The Corporation is operator for the Gordondale and Valhalla properties. Production averaged 7,050 Boed in 2009, with an exit rate of approximately 5,820 Boed. During 2009, there were 2.0 net gas wells drilled.

Eastern Alberta

Significant properties in eastern Alberta include Thornbury, Portage Algar, Atmore, Lac La Biche and Charron. This area also includes the Judy Creek, Big Bend and Lloydminster properties. Iteration has an average 73% working interest in these properties and has an interest in 575,326 gross acres (455,524 net acres) of land and is operator for the majority of its properties in the area. The Corporation also has significant interests in facilities in the area. Hydrocarbons are produced from several different Cretaceous sands and from the underlying Devonian carbonates at depths of up to 1,000 metres (Judy Creek up to 2,700 metres). Production averaged 3,160 Boed in 2009, with an exit rate of approximately 2,580 Boed. During 2009, there were 2.0 net gas wells, 2.0 net oil well, and 1.0 dry hole drilled.

Southern Alberta

The Corporation has significant properties at Manyberries, Grand Forks, Enchant and Hays in southern Alberta. Iteration has an average 67% working interest in this area and has an interest in 172,186 gross acres (117,058 net acres) of land. The Corporation is operator for almost all of this area and also has significant interests in facilities in the area. Hydrocarbons are produced from several formations at depths of up to 1,200 metres. Production averaged approximately 950 Boed in 2009, with an exit rate of approximately 940 Boed. During 2009, there were 2.1 net gas wells 10.48 net oil wells and 1.0 dry hole drilled.

Rainbow, Alberta

Significant properties in Rainbow include Black, Sousa, Rainbow and Zama. Iteration has an average 81% working interest in this area and has an interest in 151,036 gross acres (134,409 net acres) of land. The Company operates the Rainbow, Sousa and Black properties. Production averaged 710 Boed in 2009, with an exit rate of approximately 1,040 Boed. During 2009, there were 2.0 net oil wells drilled.

Drilling Activity

The following table sets forth the number of gross and net exploratory and development wells in which the Corporation has participated during the year ended December 31, 2009.

	Year Ended December 31	
	2009	
	Gross Wells	Net Wells
Exploratory		
Natural Gas	7.0	5.79
Crude Oil	3.0	3.00
Dry and Abandoned	1.0	0.50
Total Exploratory	11.0	9.29
Development		
Natural Gas	3.0	0.72
Crude Oil	16.0	12.52
Injector	-	-
Dry and Abandoned	2.0	2.00
Total Development	21.0	15.24
Total Drilling Activity	32.0	24.53

Location of Wells

The following table sets forth the Corporation's interest in producing wells and wells capable of production as at December 31, 2009.

	Wells			
	Producing		Shut-in(3)	
Property	Gross(1)	Net(2)	Gross(1)	Net(2)
Boundary Lake	39.0	38.3	14.0	14.0
Other British Columbia	61.0	30.6	26.0	12.6
Western Alberta	323.0	205.1	94.0	65.3
Eastern Alberta	317.0	244.7	111.0	66.3
Northwest Alberta	113.0	109.6	35.0	32.2
Southern Alberta	216.0	153.0	106.0	69.7
Other Alberta	128.0	30.6	12.0	4.8
Southwest Saskatchewan	-	-	11.0	9.9
Total	1,197.0	811.9	409.0	274.8

Notes:

(1) "Gross" means the total number of wells in which the Corporation has an interest.

(2) "Net" means the number of gross wells multiplied by the Corporation's working interest therein.

(3) "Shut-in" means wells which are capable of economic production or which the Corporation considers capable of production but which, for a variety of reasons, including but not limited to lack of markets or development, are not currently on production.

Land Holdings

The following table summarizes the undeveloped land of the Corporation as at December 31, 2009.

Property	Gross Acres[(1)]	Net Acres[(2)]
South Alberta	89,680	70,865
Northeast Alberta	276,309	225,460
Western Alberta	165,577	120,546
Peace River Arch and BC Block	180,164	159,156
Rainbow, Alberta	128,314	112,043
Saskatchewan	30,747	18,231
Northwest Territories	201,160	88,007
Texas	13,480	6,740
Total	1,085,431	801,048

Notes:

1. "Gross Acres" means the total acres in which the Corporation has an interest.
2. "Net Acres" means the total acres in which the Corporation has an interest multiplied by the working interest therein.

Production History

The following table describes the Corporation's average daily production volumes (before deduction of royalties payable to others), prices received, royalties paid, production costs and the resulting netbacks for each fiscal quarter in its most recently completed financial year and the year ended December 31, 2009.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	2009 Annual Average
Average Daily Production					
Natural gas (mcf/d)	79,000	74,650	64,176	59,362	69,289
Light and Medium Crude (bbls/d)	3,390	3,017	3,030	2,808	3,056
Heavy Crude (bbls/d)	186	203	136	43	140
NGLs (bbls/d)	1,423	1,474	1,357	1,415	1,408
Total (Boed)	18,165	17,137	15,219	14,160	16,153
Realized prices					
Natural gas ($/mcf)	5.39	3.46	3.02	4.81	4.20
Crude oil ($/bbl)	50.15	59.41	68.77	73.90	62.58
Heavy oil ($/bbl)	39.56	49.32	63.02	65.16	54.74
NGLs ($/bbl)	35.24	31.13	34.47	39.57	35.08
Total ($/Boe)	35.93	28.82	30.08	39.14	33.37
Netback ($/Boe)[(1)]					
Production revenue	35.93	28.82	30.08	39.14	33.37
Royalties	(7.43)	(4.18)	(4.80)	(6.59)	(5.76)
Operating expense	(15.23)	(15.23)	(12.36)	(12.51)	(13.95)
Transportation	(0.88)	(0.83)	(1.01)	(0.59)	(0.83)
Operating Netback – Corporate	12.39	8.58	11.91	19.45	12.83
General and admin expense	(1.92)	(1.96)	(2.64)	(2.72)	(2.28)
Corporate Netback	10.47	6.62	9.27	16.73	10.55
Operating Netback – Natural Gas and Associated Natural Gas Liquids ($/Boe)					
Production revenue	31.21	22.04	20.08	29.78	25.80
Royalties	(6.41)	(1.80)	(1.60)	(3.16)	(3.34)
Operating expense	(11.85)	(12.00)	(9.10)	(9.40)	(10.65)
Transportation	(1.07)	(0.98)	(0.90)	(0.82)	(0.96)
Operating Netback	11.88	7.26	8.48	16.40	10.85

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	2009 Annual Average
Operating Netback – Light and Medium Crude Oil and Associated Natural Gas Liquids ($/Boe)					
Production revenue	50.15	59.41	68.77	73.90	62.58
Royalties	(8.11)	(10.33)	(15.59)	(17.36)	(12.66)
Operating expense(2)	(14.25)	(14.10)	(12.75)	(12.45)	(13.50)
Transportation(2)	-	-	-	-	-
Operating Netback	27.79	34.98	40.43	44.09	36.42
Operating Netback – Heavy Crude Oil ($/Boe)					
Production revenue	39.56	49.32	63.02	65.16	54.74
Royalties	(1.50)	(3.62)	(8.61)	(5.83)	(4.63)
Operating expense(2)	(23.75)	(20.55)	(23.09)	(26.40)	(23.45)
Transportation(2)	-	-	-	-	-
Operating Netback	14.31	25.15	31.32	32.93	26.66

Note:

(1) Based on total corporate production for the year (i.e., natural gas, NGLs and crude oil combined).

(2) Transportation costs are included in operating expense.

STATEMENT OF RESERVE AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below has an effective date of December 31, 2009. The reserves data are derived from the McDaniel Report which was prepared on February 24, 2010, and the GLJ Report, which was prepared on January 29, 2010, both with an effective date of December 31, 2009, in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The reserves data conform with the requirements of NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Iteration believes is important to the readers of this information.

The McDaniel Report relates to Iteration's properties (excluding the historical Cyries properties) and the GLJ Report primarily relates to the historical Cyries properties. Historical Cyries properties refers to the oil and gas properties held by Cyries prior to the acquisition of Cyries by Iteration effective March 7, 2008. See "*General Development – History – 2008 Financial Year – Acquisition of Cyries Energy Inc.*"

The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation's properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2009. The information set forth below is derived from the McDaniel Report and the GLJ Report, which were prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. **All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Corporation's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.**

The information relating to the oil and gas reserves of the Corporation contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment costs. Refer to "*Forward-Looking Statements*" and "*Risk Factors*".

All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the estimates of future net revenues presented in the following tables represent the fair market value of the Corporation's reserves. There is no assurance that the McDaniel' price forecast (which was also applied to the GLJ Report) and cost assumptions contained in the McDaniel Report and GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the McDaniel Report and GLJ Report. The recovery and reserves estimates of the Corporation's properties described herein are estimates only. The actual reserves on the Corporation's properties may be greater or less than those calculated. For more information on the risks involved, see "*Forward-Looking Statements*" and "*Risk Factors*".

The Corporation has established a Reserves Committee, the majority of whom are independent directors, which reviews the qualifications and appointment of the independent qualified reserves evaluators. The Reserves Committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluation and review by the independent qualified reserves evaluators.

Disclosure provided in respect of Boe may be misleading, particularly if used in isolation. A Boe conversion rate of 6 mcf:1 bbl is based on an energy equivalency method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by an Independent Qualified Reserves Evaluator in Form 51-101 F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101 F3 are attached as Appendices "A" and "B" hereto, respectively.

All of the Corporation's reserves are on shore in Canada.

Information in the tables may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES

as of December 31, 2009
(Forecast Prices and Costs)

	RESERVES									
McDANIEL REPORT	**LIGHT AND MEDIUM OIL**		**HEAVY OIL**		**NATURAL GAS**		**NATURAL GAS LIQUIDS**		**TOTAL**	
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	1,407	1,267	453	425	26,976	22,164	702	525	7,059	5,911
Developed Non-Producing ...	247	194	55	48	6,613	5,178	93	64	1,496	1,169
Undeveloped	3,065	2,379	-	-	4,837	3,626	21	12	3,893	2,995
Total Proved...........................	4,720	3,840	508	473	38,426	30,968	816	602	12,448	10,075
Probable	1,989	1,517	332	298	29,563	23,548	513	377	7,761	6,117
Total Proved Plus Probable	6,709	5,357	840	771	67,989	54,516	1,329	979	20,209	16,193

SUMMARY OF OIL AND GAS RESERVES

as of December 31, 2009
(Forecast Prices and Costs)

GLJ REPORT	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
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	4,182	3,321	-	-	71,404	58,501	1,022	672	17,105	13,743
Developed Non-Producing	159	129	-	-	9,780	8,111	156	109	1,945	1,590
Undeveloped	515	458	-	-	6,749	5,769	191	139	1,831	1,559
Total Proved	4,856	3,908	-	-	87,933	72,381	1,369	920	20,881	16,892
Probable	2,746	2,165	-	-	38,450	31,205	652	440	9,806	7,806
Total Proved Plus Probable	7,602	6,073	-	-	126,383	103,586	2,021	1,360	30,687	24,697

SUMMARY OF OIL AND GAS RESERVES

as of December 31, 2009
(Forecast Prices and Costs)

COMBINED McDANIEL REPORT AND GLJ REPORT	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
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	5,589	4,588	453	425	98,380	80,665	1,724	1,197	24,163	19,654
Developed Non-Producing	406	323	55	48	16,393	13,289	249	173	3,441	2,759
Undeveloped	3,580	2,837	0	0	11,586	9,395	212	151	5,724	4,554
Total Proved	9,576	7,748	508	473	126,359	103,349	2,185	1,521	33,328	26,967
Probable	4,735	3,682	332	298	68,013	54,753	1,165	817	17,568	13,923
Total Proved Plus Probable	14,311	11,430	840	771	194,372	158,102	3,350	2,339	50,896	40,890

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE

as at December 31, 2009
(Forecast Prices and Costs)

McDANIEL REPORT	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					
Reserves Category	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	Unit Value ($/Boe)[1]
Proved						
Developed Producing	196,702	170,082	149,832	134,206	121,891	25.35
Developed Non-Producing	31,671	26,780	23,057	20,155	17,844	19.73
Undeveloped	166,759	121,963	92,216	71,548	56,618	30.79
Total Proved	395,132	318,825	265,104	225,909	196,352	26.31
Probable	253,180	171,658	125,444	96,609	77,215	20.51
Total Proved Plus Probable	648,312	490,484	390,548	322,518	273,568	24.12

Note:

(1) Unit values are before income taxes, per boe, discounted at 10%, based on the Corporation's net present values divided by net reserves.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE

as at December 31, 2009
(Forecast Prices and Costs)

GLJ REPORT	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**Unit Value ($/Boe)[1]**
Proved						
Developed Producing	537,217	419,710	345,930	295,463	258,818	25.17
Developed Non-Producing	51,680	39,850	32,010	26,518	22,495	20.13
Undeveloped	57,689	43,642	34,465	28,062	23,375	22.11
Total Proved	646,586	503,202	412,405	350,043	304,688	24.41
Probable	360,393	212,680	143,566	105,225	81,448	18.39
Total Proved Plus Probable	1,006,979	715,882	555,971	455,268	386,136	22.51

Note:

(1) Unit values are before income taxes, per Boe, discounted at 10%, based on the Corporation's net present values divided by net reserves.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE

as at December 31, 2009
(Forecast Prices and Costs)

COMBINED McDANIEL REPORT AND GLJ REPORT	BEFORE INCOME TAXES DISCOUNTED AT (%/year)						AFTER INCOME TAXES DISCOUNTED AT (%/year)				
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**Unit Value ($/Boe)[1]**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
Proved											
Developed Producing	733,919	589,792	495,762	429,669	380,709	25.22	704,451	570,563	482,657	420,379	373,872
Developed Non-Producing	83,351	66,630	55,067	46,673	40,339	19.96	62,479	50,833	42,832	37,024	32,618
Undeveloped	224,448	165,605	126,680	99,610	79,993	27.82	168,172	123,091	93,238	72,487	57,459
Total Proved	1,041,719	822,027	677,509	575,952	501,040	25.12	935,102	744,487	618,727	529,890	463,949
Probable	613,573	384,338	269,010	201,834	158,663	19.32	463,060	288,277	201,048	150,474	118,074
Total Proved Plus Probable	1,655,291	1,206,366	946,519	777,786	659,704	23.15	1,398,162	1,032,764	819,775	680,364	582,023

Note:

(1) Unit values are before income taxes, per boe, discounted at 10%, based on the Corporation's net present values divided by net reserves.

ADDITIONAL INFORMATION CONCERNING TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

as of December 31, 2009 (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$))1)	Future Net Revenue After Income Taxes (M$)
Proved Reserves								
McDaniel Report	787,176	132,154	201,163	35,894	22,834	395,132		
GLJ Report	1,272,417	213,135	373,662	24,817	14,217	646,586		
Total	**2,059,593**	**345,289**	**574,825**	**60,711**	**37,051**	**1,041,718**	**106,616**	**935,102**
Proved Plus Probable Reserves								
McDaniel Report	1,289,124	225,816	330,098	59,730	25,168	648,312		
GLJ Report	2,008,480	349,536	592,545	42,400	17,019	1,006,980		
Total	**3,297,604**	**575,352**	**922,643**	**102,130**	**42,187**	**1,655,292**	**257,130**	**1,398,161**

Note:

(1) Income taxes were calculated on combined revenues and costs and are not available in either the GLJ or McDaniel reports.

NET PRESENT VALUE OF FUTURE NET REVENUE
BY PRODUCTION GROUP

as of December 31, 2009
(Forecast Prices and Costs)

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAXES (discounted at 10%/year) ($/Boe) [1]
Total Proved Reserves			
McDaniel Report	Light and Medium Crude Oil (including solution gas and other by-products)	135,451	34.00
	Heavy Oil (including solution gas and other by-products)	11,034	23.33
	Natural Gas (including by-products but excluding solution gas from oil wells)	118,618	21.11
	Non-conventional Oil & Gas Activities	-	-
	Total	265,103	26.31
GLJ Report	Light and Medium Crude Oil (including solution gas and other by-products)	179,014	30.61
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	231,753	21.24
	Non-conventional Oil & Gas Activities	1,638	12.53
	Total	412,405	24.42
Combined	Light and Medium Crude Oil (including solution gas and other by-products)	314,465	31.98
	Heavy Oil (including solution gas and other by-products)	11,034	23.33
	Natural Gas (including by-products but excluding solution gas from oil wells)	350,371	21.20
	Non-conventional Oil & Gas Activities	1,638	12.53
	Total	**677,508**	**25.12**
Total Proved Plus Probable Reserves			
McDaniel Report	Light and Medium Crude Oil (including solution gas and other by-products)	183,526	32.55
	Heavy Oil (including solution gas and other by-products)	18,167	23.56
	Natural Gas (including by-products by excluding solution gas from oil wells)	188,855	19.31
	Non-conventional Oil & Gas Activities	-	-
	Total	390,548	24.12
GLJ Report	Light and Medium Crude Oil (including solution gas and other by-products)	256,289	28.02
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products by excluding solution gas from oil wells)	297,544	19.34
	Non-conventional Oil & Gas Activities	2,138	12.76
	Total	555,971	22.51
Combined	Light and Medium Crude Oil (including solution gas and other by-products)	439,815	29.75
	Heavy Oil (including solution gas and other by-products)	18,167	23.56
	Natural Gas (including by-products by excluding solution gas from oil wells)	486,399	19.33
	Non-conventional Oil & Gas Activities	2,138	12.76
	Total	**946,519**	**23.15**

Note:

(1) The Unit Value is prior to income taxes, discounted at 10%, and each product type includes associated by-products (NGLs). The Unit Values are based on the Corporation's net present values divided by net reserves.

PRICING ASSUMPTIONS

Forecast Prices used in Estimates

The forecast price and cost assumptions assume the continuance of current laws and regulations and changes in wellhead selling prices, and take into account with respect to future operating and capital costs. The forecast prices as at December 31, 2009 are provided in the table below and reflect McDaniel standard price forecast as referred to in the McDaniel Report. These same forecast price and cost assumptions were used by GLJ in the preparation of the GLJ Report.

FORECAST PRICES AND COSTS

	OIL				NATURAL GAS			
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40^0 API ($Cdn/bbl)**	**Hardisty Heavy Crude 12^0 API ($Cdn/bbl)**	**Cromer Medium 29.0^0 API ($Cdn/bbl)**	**AECO Gas Price ($Cdn/MMBtu)**	**Edmonton Cond. & Natural Gasolines ($Cdn/bbl)**	**INFLATION RATES %/Year**	**EXCHANGE RATE ($US/Cdn)**
Historical								
2001	25.97	39.60	18.05	32.22	6.30	42.42	2.6	0.646
2002	26.10	39.95	27.60	34.93	4.07	40.65	2.2	0.637
2003	31.05	43.15	27.40	37.57	6.66	44.10	2.0	0.716
2004	41.40	52.54	30.40	45.94	6.87	55.77	2.0	0.770
2005	56.56	68.72	34.35	57.47	8.58	77.30	2.1	0.826
2006	66.23	72.80	43.14	61.25	7.16	78.05	2.2	0.880
2007	72.30	76.35	44.63	65.40	6.65	84.05	2.0	0.935
2008	99.60	102.20	75.57	93.20	8.15	110.40	2.4	0.943
2009	61.80	65.90	55.65	62.85	4.15	67.85	2.0	0.880
Forecast								
2010	80.00	83.20	68.10	76.50	6.05	85.20	2.0	0.950
2011	83.60	87.00	67.60	79.10	6.75	89.00	2.0	0.950
2012	87.40	91.00	68.00	81.80	7.15	93.10	2.0	0.950
2013	91.30	95.00	68.10	85.40	7.45	97.10	2.0	0.950
2014	95.30	99.20	71.10	89.20	7.80	101.40	2.0	0.950
2015	99.40	103.50	74.20	93.10	8.15	105.70	2.0	0.950
2016	101.40	105.60	75.70	94.90	8.40	107.90	2.0	0.950
2017	103.40	107.70	77.20	96.80	8.55	110.00	2.0	0.950
2018	105.40	109.80	78.70	98.70	8.70	112.10	2.0	0.950
2019	107.60	112.10	80.40	100.70	8.90	114.50	2.0	0.950
2020	109.70	114.30	81.90	102.70	9.05	116.70	2.0	0.950
2021	111.90	116.50	83.60	104.80	9.25	119.00	2.0	0.950
2022	114.10	118.80	85.20	106.80	9.45	121.30	2.0	0.950
2023	116.40	121.20	86.90	109.00	9.65	123.80	2.0	0.950
2024	118.80	123.70	88.70	111.20	9.85	126.30	2.0	0.950
Thereafter	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	2.0	0.950

Reconciliation of Gross Reserves by Primary Product Type

The following table summarizes the changes in gross reserves from December 31, 2008 to December 31, 2009.

Future Prices and Costs

Factors	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Proved (mbbl)	Probable (mbbl)	Proved Plus Probable (mbbl)	Proved (mbbl)	Probable (mbbl)	Proved Plus Probable (mbbl)	Proved (mmcf)	Probable (mmcf)	Proved Plus Probable (mmcf)	Proved (mbbl)	Probable (mmbl)	Proved Plus Probable (mbbl)
December 31, 2008	9,691	3,903	13,593	784	456	1,240	155,842	75,540	231,382	2,863	1,178	4,042
Extensions and Improved Recovery	627	640	1,267	10	10	20	5,337	2,740	8,077	100	32	132
Technical Revisions	384	(59)	325	(194)	(112)	(306)	(192)	(6,887)	(7,079)	32	39	70
Discoveries	-	-	-	-	-	-	710	563	1,273	34	27	61
Infill Drilling	146	320	466	-	-	-	368	324	692	12	18	30
Acquisitions	4	1	5	-	-	-	1	-	1	-	-	-
Dispositions	(161)	(70)	(230)	(41)	(22)	(63)	(10,417)	(4,266)	(14,683)	(343)	(129)	(472)
Production	(1,115)	-	(1,115)	(51)	-	(51)	(25,290)	-	(25,290)	(514)	-	(514)
Other[1]	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2009	9,576	4,735	14,311	508	332	840	126,359	68,013	194,372	2,185	1,165	3,350

Note:
(1) "Other" includes revisions due to economic factors, pricing, costs, etc.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table summarizes the gross volumes of undeveloped reserves as at December 31, 2009, and reflects the year that those reserves were first attributed during each of the three most recent financial years.

McDaniel Report	Proved Undeveloped Reserves At Forecast Costs and Prices					Probable Undeveloped Reserves At Forecast Costs and Prices				
	Prior	2007	2008	2009	Total	Prior	2007	2008	2009	Total
Natural Gas (mmcf)	-	984	3,801	52	4,837	343	1,038	7,727	1,257	10,365
Light and Medium Crude (mbbls)	-	942	1,743	381	3,065	-	410	522	307	1,273
Heavy Crude (mbbls)	-	-	-	-	-	60	-	38	-	98
NGLs (mbbls)	-	2	19	0	21	11	1	58	3	74
Total (MBoe)	-	1,108	2,396	390	3,893	128	584	1,943	517	3,172

GLJ Report	Proved Undeveloped Reserves At Forecast Costs and Prices					Probable Undeveloped Reserves At Forecast Costs and Prices				
	Prior	2007	2008	2009	Total	Prior	2007	2008	2009	Total
Natural Gas (mmcf)	-	-	6,008	742	6,750	-	-	6,822	1,741	8,563
Light and Medium Crude (mbbls)	-	-	243	272	515	-	-	558	469	1,027
Heavy Crude (mbbls)	-	-	-	-	-	-	-	-	-	-
NGLs (mbbls)	-	-	164	27	191	-	-	128	55	183
Total (MBoe)	-	-	1,408	423	1,831	-	-	1,823	814	2,637

Combined McDaniel Report and GLJ Report	Proved Undeveloped Reserves At Forecast Costs and Prices					Probable Undeveloped Reserves At Forecast Costs and Prices				
	Prior	2007	2008	2009	Total	Prior	2007	2008	2009	Total
Natural Gas (mmcf)	-	984	9,809	794	11,587	343	1,038	14,549	2,998	18,928
Light and Medium Crude (mbbls)..........	-	942	1,986	653	3,581	-	410	1,117	773	2,299
Heavy Crude (mbbls)..........	-	-	-	-	-	60	-	38	-	98
NGLs (mbbls)..........	-	2	183	27	212	11	1	186	58	257
Total (MBoe) ...	-	1,108	3,804	813	5,724	128	584	3,766	1,331	5,809

The Corporation attributes proved and probable undeveloped reserves based on the accepted engineering and geological practices as defined under NI 51-101. The practices include the determination of reserves based on the presence of commercial test rate from either production tests or drill stem tests, or extensions of know accumulations supported by a combination of geological, geophysical and engineering data.

The majority of the proven and probable undeveloped reserves are scheduled to be developed within the next two years.

Significant Factors or Uncertainties

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

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

For additional details of significant economic factors and uncertainties affecting the reserves of Iteration, see "*Risk Factors*" and "*Industry Conditions*".

Future Development Costs

The following table outlines future development costs (undiscounted) deducted in the estimation of Iteration's future net revenue, attributable to the following reserves categories.

	2010 ($M)	2011 ($M)	2012 ($M)	2013 ($M)	2014 ($M)	Thereafter ($ M)
Reserve Category						
Proved Reserves (Forecast Prices and Costs)						
McDaniel Report	21,709	12,090	1,237	-	574	284
GLJ Report.........................	12,448	10,325	62	626	308	1,048
Total	**34,157**	**22,415**	**1,299**	**626**	**882**	**1,332**
Proved plus Probable Reserves (Forecast Prices and Costs)						
McDaniel Report	32,587	22,149	1,237	135	1,319	2,303
GLJ Report.........................	19,657	19,872	257	657	308	1,649
Total	**52,244**	**42,021**	**1,494**	**792**	**1,627**	**3,952**

Future development costs are expected to be funded out of a combination of existing cash on hand, funds from operations and the Corporation's credit facility.

NET ASSET VALUE

The following table is an estimate of the pre-tax value of the petroleum and natural gas assets of the Company including non-producing land and proprietary seismic, net of debt:

	Present value discounted at 10% ($millions)	per share
Proved producing	396.0	$ 1.87
Total proved	577.7	$ 2.73
Proved plus probable	846.7	$ 4.01

The values above are based on:

-Pre-tax PV 10% values of the year end reserves reports using the McDaniel 1/1/2010 price deck
-Deduction of year end net debt of $196.8 million

Included in the above are management's estimates of:

-Undeveloped land: $84 million
-Proprietary seismic: $13 million

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

As at December 31, 2009, the Corporation had an interest in the following producing and non-producing oil and natural gas wells:

	PRODUCING		SUSPENDED		STANDING		NON-PETROLEUM	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wells								
Gas	740.0	491.68	103.0	53.11	132.0	96.19	81.0	44.91
Oil	456.0	320.22	119.0	84.74	56.0	41.23	35.0	19.24
TOTAL	1196.0	811.90	222.0	137.85	188.0	137.42	116.0	64.15

Properties with No Attributed Reserves

The following table sets forth, as at December 31, 2009, the gross and net acres of unproved properties held by the Corporation and the net area of unproved properties for which the Corporation expects its rights to explore, develop and exploit to expire during the next year:

	UNPROVED PROPERTIES (acres)		
LOCATION	**Gross**	**Net**	**Net Area to Expire in 2010**
Saskatchewan	30,747	18,231	14,070
Alberta	747,934	622,224	50,473
British Columbia	92,110	65,846	3,727
Northwest Territories	201,160	88,007	88,007
Texas	13,480	6,740	100
	1,085,431	801,048	156,377

Forward Contracts

The following is a summary of Iteration's forward contracts which were in effect as at December 31, 2009.

Transaction Type	Daily Volume	Units	Contract Price	Term
WTI Oil Collar	200	Bbl/day	$70.00-$91.00	Jan 1/10 to Dec 31/10
WTI Oil Collar	200	Bbl/day	$70.00-$97.00	Jan 1/10 to Dec 31/10
AECO Gas Swap	3,500	GJ/day	$4.98	Nov 1/09 to Oct 31/10
AECO Gas Swap	2,000	GJ/day	$6.00	Nov 1/10 to Oct 31/11
WTI Oil Swap	400	Bbl/day	$85.00	Jan 1/10 to Mar 31/10
WTI Oil Swap	400	Bbl/day	$85.50	Apr 1/10 to Jun 30/10
WTI Oil Swap	400	Bbl/day	$87.50	Apr 1/10 to Jun 30/10
WTI Oil Swap	400	Bbl/day	$88.00	Apr 1/10 to Jun 30/10
AECO Gas Swap	7,900	GJ/day	$5.20	Jan 1/10 to Jun 30/10
AECO Gas Swap	7,900	GJ/day	$5.21	Apr 1/10 to Jun 30/10
AECO Gas Swap	7,900	GJ/day	$5.20	Jan 1/10 to Mar 31/10
AECO Gas Swap	15,800	GJ/day	$5.54	Jul 1/10 to Sept 30/10
WTI Oil Swap	800	Bbl/day	$85.10	Jul 1/10 to Sept 30/10

Abandonment and Reclamation Costs

The Corporation estimates the costs associated with abandonment and reclamation for surface leases, wells and facilities based on a review of engineering studies, industry guidelines, and management's estimate on a site by site basis. The Corporation expects to incur abandonment and downhole reclamation costs for approximately 1,151 net wells.

Based on total proved reserves, the following table summarizes the expected net present value of abandonment and downhole reclamation costs to be incurred by the Corporation.

	Net Present Value (undiscounted) $('000)	Net Present Value (discounted at 10%) $('000)
Total abandonment and downhole reclamation costs, net of estimated salvage value	37,051	15,035
Abandonment and downhole reclamation costs not deducted in estimating future net revenue	-	-
Portion forecast to be paid during the next three years	4,698	4,061

Tax Horizon

The income taxes deducted in the calculation of future after tax net revenue assumes a blow down scenario whereby the Corporation produces out its existing reserves.

The Corporation forecasts its tax horizon, assuming current commodity prices, and a continuing business model whereby it reinvests capital at historic capital efficiencies and incurs general and administrative costs and interest costs. Under this scenario, the Corporation does not forecast being in a taxable position until 2014.

Costs Incurred

During the year ended December 31, 2009, the Corporation incurred the following costs:

Nature of Costs	2009 ($'000)
Property Acquisition Costs	
Proved properties	-
Unproved properties	5,114
Exploration costs	6,853
Development costs	42,191
Plant and equipment costs	11,312
Other	715
Total	66,185

Tax Pools

The Corporation's estimated consolidated tax pools at December 31, 2009 are as follows:

	$('000')
Undepreciated capital cost (UCC)	117,750
Canadian Oil and Gas Property Expense (COGPE)	168,963
Canadian Development Expense (CDE)	162,880
Canadian Exploration Expense (CEE)	96,871
Non Capital Loss Carryforwards	6,660
Share issue costs	12,666
Total	565,790

Exploration and Development Activities

The following table summarizes the results of exploration and development activities for the year ended December 31, 2009.

	Gross	Net
Development Wells		
Gas	3.0	0.72
Oil	16.0	12.52
Service	-	-
Dry	2.0	2.00

	Gross	Net
Total Development	21.0	15.24
Exploratory Wells		
Gas	7.0	5.79
Oil	3.0	3.00
Dry	1.0	0.50
Total Exploration	11.0	9.29
Total Wells	32.0	24.53

The Corporation intends to continue to develop its principal properties as well as continue its grassroots exploration program to establish new core areas in Alberta and British Columbia. The Corporation will continue to target oil and natural gas properties with multiple horizons in the WCSB.

Production Estimates

The following tables summarize the volume of total proved and total proved plus probable production of the Corporation as estimated by McDaniel and GLJ for the year ended December 31, 2010, using forecast prices and costs.

	Forecast Prices and Costs	
	Total Proved	**Total Proved plus Probable**
Natural Gas (mmcf)		
McDaniel Report	8,125	9,410
GLJ Report	13,572	14,359
Total	21,697	23,769
Natural gas liquids (mbbls)		
McDaniel Report	200	221
GLJ Report	194	206
Total	394	427
Light, Medium and Heavy Crude Oil (mbbls)		
McDaniel Report	503	549
GLJ Report	884	971
Total	1,387	1,520
Total production (MBoe)		
McDaniel Report	2,057	2,337
GLJ Report	3,340	3,570
Total	5,397	5,907

BORROWINGS

On May 14, 2009, Iteration secured a credit facility with a syndicate of lenders, consisting of Canadian Imperial Bank of Commerce, Bank of Nova Scotia, Bank of Montreal and Alberta Treasury Branch. The borrowing base of the credit facility is $225 million, and consists of a $12.5 million operating facility and a $212.5 million extendible revolving term facility. This facility will mature April 30, 2010, and, at the Corporation's request, such credit facility may be renewed for a period of not more than 364 days on agreement of the lenders. The pricing on this facility is as follows:

(a) for Canadian prime based loans or US base rate loans, at applicable prime plus a margin ranging from 175 to 325 basis points, depending on the ratio of consolidated debt to earnings before interest, taxes and depletion/depreciation/accretion for the preceding four quarters;

(b) for borrowings by way of Bankers' Acceptances or LIBOR loans, at the Bankers' Acceptance or LIBOR rate plus a stamping fee ranging from 275 to 425 basis points, depending on the ratio of consolidated debt to earnings before interest, taxes and depletion/depreciation/accretion for the preceding four quarters; and

(c) a standby fee on the unutilized portion of the facility of between 82.5 and 127.5 basis points depending on the ratio of consolidated debt to earnings before interest, taxes and depletion/depreciation/accretion for the preceding four quarters.

This facility is secured by a $500 million floating charge demand debenture.

As at December 31, 2009, bank indebtedness was $190.0 million. Iteration's bank indebtedness represents the drawn portion of a syndicated facility. The effective interest rate in respect of indebtedness under its credit facility for the year ended December 31, 2009 was 4.2%.

INDUSTRY CONDITIONS

Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. In western Canada, the various provincial governments have legislation and regulations that govern land tenure, royalties, production rates, environmental protection, the prevention of waste and other matters. Although it is not expected that any of these controls and regulations will affect the operations of Iteration in a manner materially different than they would affect other oil and natural gas producers of similar size, the controls and regulations should be considered carefully by investors in the oil and natural gas industry. Outlined below are some of the principal aspects of legislation and regulations governing the oil and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing – Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price received by the Corporation depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance and other contractual terms. Oil exports from Canada may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB, which requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

In Canada, producers of natural gas also negotiate sales contracts directly with natural gas purchasers. The price received by the Corporation depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. 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 continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years or for a term of 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 exports to be made pursuant to a contract of longer duration or in larger quantities requires an exporter to obtain an export licence from the NEB, which requires the approval of the Governor in Council.

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

Pricing and Marketing — Natural Gas Liquids

In Canada, the price of NGLs sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGLs exported from Canada are subject to regulation by the National Energy Board and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the National Energy Board and the Government of Canada. NGLs may be exported for a term of no more than one year in respect to propane and butane, and no more than two years in respect to ethane, all exports requiring an order of the National Energy Board.

Pipeline Capacity

As a result of recent pipeline additions and expansions, an excess of natural gas pipeline capacity exists in western Canada, which provides for the ability to deliver all current production to natural gas sales markets.

Land Tenure

Oil and natural gas located in western Canada 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, usually from two to five years, and on conditions set forth in provincial legislation, which may include 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 generally granted by lease on such terms and conditions as may be negotiated.

Provincial Royalties and Incentives

For crude oil, natural gas and related production from federal or provincial Crown lands, the royalty regime is a significant factor in the profitability of production operations. 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 well productivity, geographical location and field discovery date.

From time to time, the provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, 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. The trend in recent years has been for provincial governments to reduce the benefits under such programs and to allow them to expire without renewal, and consequently few such programs are currently operative.

Alberta

On March 11, 2010 the Alberta government released the outcome of a Competitiveness Review for the petroleum and natural gas industry along with their policy response. The policy calls for, among other things, the reduction of royalty rates and speeding up regulatory processes. Final details are expected to be announced at the end of May 2010.

The Alberta Government implemented a new oil and gas royalty framework effective January 2009. The new framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%.

In November 2008, the Alberta Government announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 and 3,500 metres, which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The election must be made prior to the end of the first calendar month in which the leased substance is produced. All wells using the transitional royalty rates must shift to the new royalty framework rates on January 1, 2014.

The Deep Oil Exploration Program ("**DOEP**") and the Natural Gas Deep Drilling Program ("**NGDDP**") are new programs that began January 1, 2009. These programs provide upfront royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 metres with a Crown interest and must be spudded after January 1, 2009. These oil wells qualify for a royalty exemption on either the first $1,000,000 of royalty or the first 12 months of production. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 metres. The NGDDP will have an escalating royalty credit in line with progressively deeper wells from $625 per metre to a maximum of $3,750 per metre. There are additional benefits for the deepest wells. Both the DOEP and the NGDDP are five year programs. Any wells spud after December 31, 2013, or any wells that choose the transition option, will not qualify under either program. No royalty adjustments will be granted under either the DOEP or the NGDDP after December 31, 2018.

On March 3, 2009, the Alberta government announced a three-point incentive program. This incentive program includes a drilling royalty credit for new oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, providing a $200-per-metre-drilled royalty credit to companies on a sliding scale based on their production levels from last year. There is also a new well incentive program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and March 31, 2010 to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. As of June 25, 2009, the Alberta government has extended these two programs to March 31, 2011. The province of Alberta will also invest $30 million in a fund committed to abandonment and reclamation projects where there is no legally responsible or financially able party to deal with the clean-up of inactive wells.

British Columbia

The Province of British Columbia announced an Oil and Gas Stimulus Package on August 6, 2009. This stimulus package included a one year, two percent royalty rate for all wells drilled from September 2009 through June 2010, an increase in deductions for natural gas deep drilling and the inclusion of 1,900 to 2,300 meter horizontal well in the Deep Royalty Program.

In May 2008, the Government of British Columbia introduced the Net Profit Royalty Program to stimulate development of high risk and high cost natural gas and oil resources in British Columbia that are not economic under other royalty programs. The program allows for the calculation of royalties based on the net profits of a particular project and is governed under the Net Profit Royalty Regulation, which came into effect in May, 2008.

Natural Gas

The British Columbia natural gas royalty regime is price-sensitive, using a "select price" as a parameter in the royalty rate formula. When the reference price, being the greater of the producer price or the Crown set posted minimum price ("**PMP**"), is below the select price, the royalty rate is fixed. The rate increases as prices increase above the select price. The Government of British Columbia determines the producer prices by averaging the actual selling prices for gas sales with shared characteristics for each company minus applicable costs. If this price is below the PMP, the PMP will be the price of the gas for royalty purposes.

Natural gas is classified as either "conservation gas" or "non-conservation gas". There are three royalty categories applicable to non-conservation gas, which are dependent on the date on which title was acquired from the Crown and on the date on which the well was drilled. The base royalty rate for non-conservation gas ranges from 9% to 15%. A lower base royalty rate of 8% is applied to conservation gas. However, the royalty rate may be reduced for low productivity wells.

Oil

The royalty regime for oil is dependent on age and production. Oil is classified as "old", "new" or "third tier" and a separate formula is used to determine the royalty rate depending on the classification. The rates are further varied depending on production. Lower royalty rates apply to low productivity wells and third tier oil to reflect the increased cost of exploration and extraction. There is no minimum royalty rate for oil.

Saskatchewan

Natural Gas

Crown royalty rates are sensitive to the individual productivity of each well. The rates are applied to the respective portions of each classification of gas ("fourth tier gas", "third tier gas", "new gas" and "old gas") produced from a well.

Each month, the royalty rates are adjusted based on the level of the Provincial Average Gas Price ("**PGP**") established by the Province monthly. The PGP represents the weighted average fieldgate price (expressed in $\$/10^3m^3$) received by producers during the month for the sale of all gas subject to royalty. Crown royalty of the production volume is calculated on each individual well using the applicable royalty rate to the volume of gas produced by each well on a monthly basis.

The operator must elect to use either the PGP or the Operator Average Gas Price ("**OGP**") for purposes of valuing the Crown's royalty share of the production volume from each well. The OGP is determined each month by the operator and represents the weighted average fieldgate price ($\$/10^3m^3$) received by the operator for sales of gas during the month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the gas for the month.

Conventional Oil

Crown royalty rates are sensitive to the individual productivity of each well and the type of oil produced from the well. Each month, royalty rates are adjusted based on the level of the reference price established by the Province for each type of oil.

For Crown royalty purposes, crude oil is classified as "heavy oil", "southwest designed oil" or "non-heavy oil other than southwest designated oil". There are separate reference prices established for each type of oil which represent the average wellhead price (in $\$/m^3$) received by producers during the month for sales of that oil type in Saskatchewan.

The Crown royalty share of production volume is calculated on each individual well using the applicable royalty rate to the volume of oil produced from the well each month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the oil for the month.

A separate cost sensitive royalty structure applies to incremental production from enhanced oil recovery projects, which incorporates lower royalty and freehold production tax rates before the project reaches payout of investment and operating expenditures.

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

Climate Change

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change. The Canadian federal government previously released the *Regulatory Framework for Air Emissions*, updated March 10, 2008 by *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (collectively, the "**Regulatory Framework**"), for regulating greenhouse gas ("**GHG**") emissions by proposing mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place this year, but the federal government has delayed the release of any such legislation and potential federal requirements in respect of GHG emissions are unclear. On January 30, 2010, the Canadian federal government announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, to align itself with U.S. policy. In 2009, the Canadian federal government announced its commitment to work with the provincial governments to implement a North American-wide cap and trade system for GHG emissions, in cooperation with the United States. Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits.

The Canadian federal government currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether either federal GHG regulations or an integrated North American cap and trade system will or will not be implemented, or what obligations might be imposed under any such system.

As the details of the implementation of any federal legislation for GHGs have not been announced, the effect on the Corporation's operations cannot be determined at this time.

Alberta

Alberta regulates GHG emissions under the *Climate Change and Emissions Management Act*, the *Specified Gas Reporting Regulation* (the "**SGRR**"), which imposes GHG emissions reporting requirements, and the *Specified Gas Emitters Regulation* (the "**SGER**") which imposes GHG emissions limits. Under the SGRR, the Corporation must report if it has GHG emissions of 100,000 tonnes or more from a facility in any year. Under the SGER, GHG emission limits apply once a facility has direct GHG emissions in a year of 100,000 tonnes or more. Under the SGER, any facility coming into commercial production after 2000 will be considered a new facility and will be required to reduce its emission intensity (e.g., tonnes of GHGs emitted per unit of production) by 2% per year beginning in its fourth year of commercial operation. The SGER permits the Corporation to meet the applicable emission limits by making emissions intensity improvements at facilities, offsetting GHG emissions by purchasing offset credits or emission performance credits in the open market, or acquiring 'fund credits' by making payments of $15/per tonne to the Alberta Climate Change and Management Fund. The Alberta government recently announced its intention to raise the price of fund credits and increase the required reductions in GHG emissions intensity to unspecified levels. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations.

British Columbia

The Province of British Columbia intends to reduce its GHG emissions to 33% below 2007 levels by 2020 and has set interim targets of 6% below 2007 levels by 2012 and 18% below 2007 levels by 2016 and, accordingly, has implemented the *Greenhouse Gas Reduction Targets Act.* The Crown is obliged to report every second year on the amount of reductions achieved in the province, although there is no mechanism in place to measure compliance nor is there any consequence for failing to reach the target. A carbon tax was implemented on the purchase or use of fossil fuels within the Province of British Columbia, starting at $10/ton on July 1, 2008 and rising by $5 per year to $30/ton in 2012. Fuel sellers are required to pay a security equal to the tax payable on the final sale to end purchasers, and end purchasers are required to pay the tax. Fuel sellers collect carbon tax at the time fuel is sold at retail to the end purchaser. Carbon capture and storage is required for all new coal-fired electricity generation facilities and a 0.4% levy tax has been implemented at the consumer level on electricity, natural gas, grid propane and heating oil that goes towards establishing the Innovative Clean Energy Fund.

Saskatchewan

On May 11, 2009, the Province of Saskatchewan introduced Bill 95 *An Act Respecting the Management and Reduction of Greenhouse Gases and Adaptation to Climate Change.* The new legislation will establish a provincial plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Province has indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes under provincial regulation.

Environment

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect our business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations requirements may materially adversely affect Iteration's business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by the Corporation or by consumers of the Corporation's products. The imposition of such measures might negatively affect the Corporation's costs and prices for the Corporation's products and have an adverse effect on earnings and results of operations.

Future federal legislation, including potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from the Company's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Company is unable to predict the impact of emissions reduction legislation on the Company and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

We believe that we are in material compliance with applicable environmental legislation and are committed to continued compliance. We believe that it is reasonably likely that a trend towards stricter standards in environmental legislation will continue and we anticipate making increased expenditures of both a capital and an expense nature as a result of increasingly stringent environmental laws.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed after their useful life to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of material fines and penalties, the revocation of necessary licences and authorizations and civil liability for pollution damage.

In Alberta, environmental compliance is governed by the *Alberta Environmental Protection and Enhancement Act*. In British Columbia, environmental compliance is governed by the *Environmental Assessment Act*.

The operations of the Corporation are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. It is impossible to predict the full impact of these laws and regulations on the Corporation's operations. However, it is not anticipated that the Corporation's competitive position will be adversely affected by current or future environmental laws and regulations governing their current oil and natural gas operations. The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to environmental protection. The Corporation also believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

RISK FACTORS

Exploration, Development and Production Risks

Oil and gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or to participate in other ventures or be able to identify and reach agreement with suitable partners. Moreover, if such acquisitions or partners are identified, the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such opportunities uneconomic. There is no assurance that commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

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

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

Insurance

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

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on North American supply, demand, foreign exchange rates of the Canadian dollar relative to other world currencies, and other factors, all of which are beyond the control of the Corporation. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of the Corporation's oil and gas reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's future net production revenue, causing a reduction in its oil and gas acquisition and development activities.

The level of bank borrowings available to the Corporation is, in part determined by the borrowing base of the Corporation. A sustained material decline in prices from historical average prices could limit or reduce the Corporation's borrowing base, thereby reducing the debt financing available to the Corporation.

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

Financial Risks

As a result of the weakened global economic situation, the Corporation, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although the Corporation's business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Corporation's securities in particular.

In 2007 through 2009, the U.S. credit markets experienced serious disruption due to a deterioration in residential property values, defaults and delinquencies in the residential mortgage market (particularly, subprime and non-prime mortgages) and a decline in credit quality of mortgage backed securities. These problems led to a slow-down in residential housing market transactions, declining housing prices, delinquencies in non-mortgage consumer credit and a general decline in consumer confidence. These conditions continued and worsened in 2008, causing a loss of confidence in the broader U.S. and global credit and financial markets, resulting in the collapse of and intervention in major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by the U.S. and foreign governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially.

The significant decline in energy commodity prices, and in particular, natural gas prices, associated with the recession impacted Iteration's operations in the latter part of 2008 and 2009 resulting in reductions to cash flow, and forecast capital spending, and heightened risks on financial instruments, among other things.

Positive economic indicators are suggesting a cessation of the economic recession in North America in 2010. However, the effects of the recession are still being felt in Canada as evidenced by cautious investor confidence, commodity and market volatility, an increased cost of debt, tight credit controls, higher unemployment rates and lower natural gas commodity prices, among other factors.

Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions and, as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to the Corporation.

Bank Financing

The Corporation has a credit facility with a syndicate of Canadian chartered banks pursuant to which the banks have agreed to provide $225 million to the Corporation. See "*Borrowings*". At December 31, 2009, the Corporation had drawn $190 million by way of bankers' acceptances.

The credit facility is next due for review on April 30, 2010. Reviews focus on the borrowing base supporting lending limits and are influenced by the lenders' willingness to lend in general, commodity price forecasts used to determine the lending base, reserves, lenders' interest in particular business sectors, such as energy, and the relative strength of the borrower. There can be no assurance that the Corporation will be able to maintain its current borrowing base under its facility or that financing will be available or sufficient to meet the requirements of the

Corporation or, if financing is available, that it will be on terms appropriate and acceptable to the Corporation. In such a case, the Company may seek to supplement its cash from operations by equity or debt financings, negotiate incremental borrowings with subordinated lenders, sell certain of its oil and gas properties and assets, or reduce its planned capital expenditures

The facility is secured by a $500 million floating charge demand debenture.

Substantial Capital Requirements

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

Third Party Risk

In the normal course of our business, the Corporation has entered into contractual arrangements with third parties which subject the Corporation to the risk that such parties may default on their obligations. The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations.

Competition

The Corporation competes for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than the Corporation. The Corporation's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies, individual producers and operators. The Corporation's ability to increase reserves in the future will depend not only on its ability to explore and develop the properties to be acquired, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

The Corporation's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators, its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions, federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and 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 may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects (see "*Industry Conditions – Environmental Regulation*").

Reserves Replacement

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

Reliance on Operators and Key Employees

To the extent the Corporation is not the operator of its oil and gas properties, the Corporation is dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Corporation will be largely dependent upon the performance of its management and key employees. The Corporation does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Corporation. In assessing the risk of an investment in the Common Shares, potential investors should recognize that they are relying on the ability and integrity of the management of the Corporation.

Changes to accounting policies, including the implementation of IFRS

In January 2006, the CICA Accounting Standards Board ("**AcSB**") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that IFRS will replace Canadian GAAP in 2011 for Canadian publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that must be evaluated. The implementation of IFRS may result in significant adjustments to our financial results, which could negatively impact our business. At this time, we cannot reasonably quantify the full impact that adopting IFRS will have on our financial position and future results.

Corporate Matters

To date, the Corporation has not paid any dividends to its outstanding common shareholders. However, the board of directors of the Corporation may decide to pay dividends in the future if circumstances permit. Any decision to pay dividends will be made by the board of directors of the Corporation on the basis of the Corporation's earnings, financial requirements and other conditions existing at the time.

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

Permits and Licenses

The operations of the Corporation may require licenses and permits from various governmental authorities. The time required to obtain these licenses and permits can be impacted by various area stakeholders. There can be no assurance that the Corporation will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development of its projects.

Incorrect Assessments of Value

Acquisitions of oil and gas properties or companies, including the acquisition of Cyries, are and will be based in large part on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated.

Fluctuations in Foreign Currency Exchange Rates

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rate which fluctuates over time. A material increase in the value of the Canadian dollar may negatively impact the Corporation's net production revenue and cash flow. The exchange rate of the Canadian dollar relative to the United States dollar varied between 1.0206 and 1.3063 in 2009. There can be no assurance that this range of volatility will not continue in the future. To the extent that the Corporation has engaged, or in the future engage, in risk management activities related to commodity prices and foreign exchange rates, through entry into oil or natural gas price commodity contracts and foreign exchange contracts or otherwise, we may be subject to unfavorable price changes and credit risks associated with the counterparties with which the Corporation contracts.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

Aboriginal Claims

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

Issuance of Debt

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

Availability of Drilling Equipment, Access Restrictions and Cost Inflation

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. Demand for this equipment will also result in inflationary pressures with respect to the costs of acquiring these services.

Title Defects

Although title reviews will generally be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews may not discover unforeseen title defects that could adversely affect Iteration's title to the property or entitlement to revenue from the property.

Uncertainty of Reserve Information

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived from exploration and production activities, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth in this Annual Information Form represent estimates only. The reserves and estimated future net cash flow from the Corporation's properties have been independently evaluated effective December 31, 2009 in the McDaniel and GLJ reports. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the evaluations.

Government Regulation and Taxation

Oil and gas operations are subject to extensive Canadian federal, provincial and local laws and regulations governing exploration, development, transportation, production, exports, labour standards, occupational health, waste disposal, protection and redemption of the environment, hazardous materials, toxic substances, taxation and other matters. It is believed that the Corporation is in substantial compliance with all applicable laws and regulations. Amendments to current laws and regulations governing oil and gas operations and the more stringent implementation thereof are actively considered from time to time and the implementation thereof could have a material adverse impact on the Corporation. In addition, taxation laws and regulations as well as the current administrative practices of both the federal and provincial tax authorities may be amended or construed in such a way that is detrimental to the Corporation or its activities.

MARKET FOR SECURITIES

Common Shares are listed and posted for trading on the TSX under the symbol "ITX".

The following table sets forth the monthly price ranges and volumes of trading of the Common Shares on the TSX during 2009.

Period 2009	High $	Low $	Volume
January	1.80	0.93	14,218,000
February	0.96	0.65	10,793,000
March	1.10	0.63	34,736,000
April	1.43	0.98	24,046,000
May	1.63	1.09	53,780,000
June	1.52	1.12	24,000,000
July	1.22	0.90	16,015,000
August	1.17	0.93	14,732,000
September	1.58	0.88	60,850,000
October	1.42	1.11	13,300,000
November	1.22	1.05	13,074,000
December	1.27	1.10	17,671,000

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred Shares, issuable in series ("**Preferred Shares**"), of which 211,039,023 Common Shares and no Preferred Shares are issued and outstanding as at the date hereof. The following is a summary of the rights, privileges and restrictions of the Common Shares and Preferred Shares.

Common Shares

The holders of Common Shares shall be entitled to receive notice of, and to one vote per share at, every meeting of the shareholders of the Corporation, receive such dividends as the directors may from time to time declare and to share equally in the assets of the Corporation remaining upon liquidation of the Corporation, after the creditors of the Corporation have been satisfied.

Preferred Shares

The Preferred Shares, which are issuable in one or more series, have such rights, privileges, restrictions and conditions as the board of directors of the Corporation may by resolution determine. The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding-up of the Corporation, be entitled to preference over the Common Shares, and over any other shares of the Corporation ranking, by their terms, junior to the Preferred Shares. If any cumulative dividend or amount payable on the return of capital, in respect of a series of Preferred Shares is not paid in full, all series of Preferred Shares shall participate ratably in respect of accumulated dividends and return of capital.

DIVIDENDS

The Corporation has not paid any dividends to date. Any decision to pay dividends in the future will depend upon the earnings and financial position of the Corporation and such other factors which the board of directors may consider appropriate in the circumstances.

DIRECTORS AND EXECUTIVE OFFICERS

The name, municipality of residence, position with the Corporation and principal occupation of each of the directors and executive officers of the Corporation as at December 31, 2009 are as follows:

Name and Municipality of Residence	Position with the Corporation	Director or Officer Since	Present Occupation and Positions Held During the Last Five Years
Donald Archibald *Calgary, Alberta*	Chairman and Director	March 7, 2008	Former Chairman and Chief Executive Officer of Cyries from May 2004 until March 7, 2009; prior thereto the President and Chief Executive Officer of Cequel, a public oil and gas company, from January 2002 to June 2004.
Pat Breen, P. Eng.(3)(4) *Calgary, Alberta*	Director	July 5, 2005	President, Foremost Income Fund since October 2003. President, Universal Industries Ltd., from November 2000 to August 2003. Prior thereto, Mr. Breen was District Manager, Lloydminster for Husky Energy Inc.
Dallas Droppo, Q.C.(1)(2) *Calgary, Alberta*	Director	July 5, 2005	Partner, Blake, Cassels and Graydon LLP, Barristers and Solicitors.
James T. Grenon(2)(3) *Calgary, Alberta*	Lead Director	July 5, 2005	President, TOM Capital Associates Inc. (Private investment company).

Name and Municipality of Residence	Position with the Corporation	Director or Officer Since	Present Occupation and Positions Held During the Last Five Years
Michael J. Hibberd[(1)(2)(4)] *Calgary, Alberta*	Director	July 5, 2005	President, MJH Services Inc. since 1995 (corporate finance advisors).
Gary Peddle[(3)(4)]	Director	May 22, 2008	Former Vice President, Operations, Cyries Energy Inc.
Robert Waters, C.A.[(1)] *Calgary, Alberta*	Director	July 5, 2005	Senior Vice-President and Chief Financial Officer, Enerplus Resources Fund since December, 2001.
Brian Illing, P. Geol. *Airdrie, Alberta*	President and Chief Executive Officer and Director	March 21, 2005	President and Chief Executive Officer, Iteration Energy Ltd. since March 2005. Prior thereto President and Chief Executive Officer, Iteration Energy Inc. from September 2004 to March 2005. Mr. Illing held various positions with Canadian Natural Resources Ltd. ("**CNRL**") from August 1993 to September 2003, including Executive Vice-President Exploration.
Willie Dawidowski, C.A. *Calgary, Alberta*	Vice President & Controller	January 1, 2010	Vice President & Controller, Iteration since January 1, 2010. Prior thereto, Controller, Iteration, from June 2009 to December 2009, Vice President Finance and CFO Mahalo Energy Ltd (Peregrine Energy Ltd.) from October 2004 to June 2009, Vice President Finance Wiser Oil Company of Canada June 2002 to September 2004.
Mark Ariss *Calgary, Alberta*	Vice President Exploration East	March 21, 2005	Vice President Exploration, Iteration Energy Ltd. since March 2005. Vice President Exploration, Iteration Energy Inc. March 2005. Prior thereto, Mr. Ariss was an Exploration Manager with CNRL from 1998 to February 2005.
Jane Mactaggart *Calgary, Alberta*	Vice President Exploitation	March 21, 2005	Vice President Exploitation, Iteration Energy Ltd. since March 2005. Vice President Exploitation, Iteration Energy Inc. from February 2005 to March 2005. Prior thereto, Ms. Mactaggart held various positions, including Exploitation Manager with CNRL from June 1999 to February 2005.
Carmen McKay-Illing *Airdrie, Alberta*	Vice President Corporate Affairs	March 21, 2005	Vice President Corporate Affairs, Iteration Energy Ltd. since March 2005. Vice President Corporate Affairs, Iteration Energy Inc. from September 2004 to March 2005. Prior thereto, from January 2004 to July 2004, Ms. McKay-Illing was a consultant to CNRL. From March 1992 to January 2004, Ms. McKay-Illing held various positions in the Exploration and Operations Planning departments of CNRL.

Name and Municipality of Residence	Position with the Corporation	Director or Officer Since	Present Occupation and Positions Held During the Last Five Years
Myron Rak *Calgary, Alberta*	Vice President Production	September 2007	Vice President Production, Iteration Energy Ltd. since September 2007. Prior thereto, Mr. Rak was Production Manager at Iteration Energy Ltd. from May 2005, and a Production Engineer at Canadian Natural Resources Ltd. from 1998 until May 2005.
Kevin Stromquist *Calgary, Alberta*	Vice President Exploration West	March 21, 2005	Vice President Exploration, Iteration Energy Ltd. Since March 2005. Vice President Exploration, Iteration Energy Inc. from November 2004 to March 2005. Senior Vice President of Exploration CNRL from September 2003 to October 2004. Prior thereto, Mr. Stromquist was Exploration Manager for northeast British Columbia for CNRL.
Anthony F.W. Grenon *Calgary, Alberta*	Corporate Secretary	March 21, 2005	President, A.F.W. Grenon Professional Corporation and a Managing Director, TOM Capital Associates Inc. (private investment company).

Notes:
(1) Member of Audit Committee.
(2) Member of Corporate Governance Committee.
(3) Member of Reserves Committee.
(4) Member of Compensation Committee.

As at December 31, 2009 the directors and executive officers of the Corporation beneficially owned, directly or indirectly controlled or directed, an aggregate of 28.1 million Common Shares, representing 13.3% of the issued and outstanding Common Shares.

AUDIT COMMITTEE INFORMATION

The disclosure regarding the Corporation's Audit Committee, required under Multilateral Instrument 52-110 - *Audit Committee*, is contained in Appendix "C" to this Annual Information Form.

CONFLICTS OF INTEREST

Certain of the directors and officers of the Corporation are directors and officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the ABCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of the Corporation.

LEGAL PROCEEDINGS

Management is not aware of any material litigation outstanding, threatened or pending by or against the Corporation. Pursuant to a purchase and sale agreement, the Corporation has indemnified the purchaser of a former subsidiary company for up to $1,000,000 of income tax and legal expenses incurred with respect to specifically identified income tax returns. The Corporation recently received a letter from the purchaser advising that Canada Revenue Agency has proposed adjustments to the corporate income tax returns of April 30, 2003 and June 30, 2003, the periods to which the indemnity relates, and requested the Corporation participate in responding to the proposal from Canada Revenue Agency. The Corporation has agreed to fund up to $50,000 towards the cost of preparing the response to Canada Revenue Agency but considers its financial exposure to the indemnified obligations to be immaterial.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed elsewhere in this Annual Information Form, none of the directors, officers or principal shareholders of the Corporation, and no associate or affiliate of any of them, has or has had any material interest in any transaction which materially affects the Corporation.

REGISTRAR AND TRANSFER AGENT

The registrar and transfer agent for the Common Shares of the Corporation is Alliance Trust Company, with offices in Calgary, Alberta, with sub-agency offices in Toronto, New York and London England.

MATERIAL CONTRACTS

The Corporation has not entered into any material contracts during the year ended December 31, 2009 or entered into before this time which are still in effect, other than material contracts entered into in the ordinary course of business.

INTERESTS OF EXPERTS

Ernst & Young LLP Chartered Accountants Calgary, Alberta has prepared the auditor's report on the consolidated financial statements of the Corporation for the year ended December 31, 2009. Ernst & Young LLP has confirmed it is independent in accordance with the rules of professional conduct of the Institute of Chartered Accountants of Alberta.

McDaniel has prepared the McDaniel Report with an effective date of December 31, 2009. McDaniel has confirmed it is an Independent Qualified Reserves Evaluator. GLJ has prepared the GLJ Report with an effective date of December 31, 2009. GLJ has confirmed it is an Independent Qualified Reserves Evaluator.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issue under equity compensation plans, is contained in the Corporation's management information circular for the most recent annual meeting of shareholders. Additional financial information is provided in the Corporation's comparative audited consolidated financial statements and management's discussion and analysis for the year ended December 31, 2009. Additional information relating to the Corporation is available at SEDAR at www.sedar.com.

APPENDIX "A"

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATORS

Report on Reserves Data

McDaniel
& Associates Consultants Ltd.

February 24, 2010

Iteration Energy Ltd.
700, 700 – 2nd Street SW
Calgary, Alberta
T2P 2W1

Attention: The Board of Directors of Iteration Energy Ltd.

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator of Iteration Energy Ltd. (the "Company")

To the Board of Directors of Iteration Energy Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009 estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2009, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
February 24, 2010	Canada	-	390,548	-	390,548

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

7. Because the reserves data are based on 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.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

C. B. Kowalski, P. Eng.
Vice President

Calgary, Alberta

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

To the board of directors of Iteration Energy Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, 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 December 31, 2009, 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 (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	January 21, 2010	Canada	-	555,971	-	**555,971**

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, January 29, 2010

"ORIGINALLY SIGNED BY"
Bryan M. Joa, P. Eng.
Vice-President

APPENDIX "B"

FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

Management of Iteration Energy Ltd. (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 and proved plus probable reserves and related future net revenue and using forecast prices and costs as at December 31, 2009.

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

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

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;
(b) met with the independent qualified reserves evaluators 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 evaluators.

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 reserves data and other oil and gas information;
(b) the filing of Form 51-101F1 which is the report of the independent qualified reserves evaluators on the reserves data; and
(c) the content and filing of the 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) "*Jane Mactaggart*"
Jane Mactaggart
Vice President Exploitation

(signed) "*Brian Illing*"
Brian Illing
President and Chief Executive Officer

(signed) "*Pat Breen*"
Pat Breen
Chairman of the Reserves Committee

(signed) "*James T. Grenon*"
James T. Grenon
Director

March 17, 2010.

APPENDIX "C"

ITERATION ENERGY LTD. (the "Corporation")

AUDIT COMMITTEE DISCLOSURE
PURSUANT TO MULTILATERAL INSTRUMENT 52-110

1) The Audit Committee's Charter

Set forth below is the charter of the Audit Committee (the "Committee") of the board of directors of the Corporation.

(a) Authority

The Committee shall be comprised of no less than three directors of the Corporation, none of whom will be officers or employees of the Corporation or its affiliates. All of the members of the Committee shall be independent directors. The length of term to be served by directors on the Committee will be determined by the board of directors of the Corporation, giving consideration to the benefits of periodic rotation of Committee membership. One of the members of the Committee shall be appointed Chairman by the board of directors. The Chairman of the Committee will appoint a Secretary to the Committee. The Secretary of the Committee may or may not be a member of the Committee. The Committee may retain independent counsel or other persons having special expertise to assist the Committee in fulfilling its responsibilities and set the remuneration and pay of any such advisors. All actions of the Committee will require a vote of a majority of its members present at a meeting of the Committee at which a quorum is present.

(b) Purpose of the Committee

The Committee is responsible for meeting with the auditor of the Corporation and reviewing the quarterly and annual financial reports before the reports are approved by the board of directors. The responsibilities of the Committee are to satisfy, on behalf of the board of directors that:

i) The Corporation's quarterly and annual financial statements are fairly presented in accordance with generally accepted accounting principles and to recommend to the board of directors whether the quarterly and annual financial statements should be approved.

ii) The information contained in the following financial publications is not significantly incomplete, misleading or erroneous:

- Annual Report to Shareholders, if prepared;
- Management's Discussion and Analysis;
- Annual Information Form;
- Quarterly Financial Information; and
- Prospectuses.

iii) The Corporation has implemented appropriate systems of internal control over financial reporting, and appropriate systems of internal control to ensure compliance with legal, regulatory and ethical requirements.

iv) The external audit function has been effectively carried out and any matter that the independent auditor wishes to bring to the attention of the board of directors has been addressed. The Committee will also recommend to the board of directors the reappointment or appointment of the auditor.

v) If required, review the Corporation's expense policy and the expense reports of management.

vi) The internal control policies within the Corporation were unchanged from the previous reporting period.

vii) The external auditor of the Corporation is required to report directly to the Audit Committee.

(c) Composition and Competency of the Committee

Each member of the Committee shall be an independent director and, as such, shall be free from any relationship that may interfere with the exercise of his or her independent judgment as a member of the Committee. All members of the Committee will be financially literate, as determined by the board of directors, in the exercise of business judgment which shall include a working familiarity with basic finance and accounting practices and an ability to read and understand financial statements. At least one member of the Committee shall have an accounting designation or related financial management expertise.

(d) Meetings of the Committee

The Committee shall meet with such frequency and of such intervals, as it shall determine is necessary to carry out its duties and responsibilities. At a minimum, the Committee shall meet at least quarterly with management and the Corporation's external auditor in separate executive sessions to discuss any matters that the Committee or each of these groups or persons believes should be discussed privately. The Committee, in its discretion, may ask members or management or others to attend its meetings, or portions thereof, and to provide pertinent information as necessary. The Committee shall maintain minutes of its meetings and records relating to those meetings and the Committee's activities and provide copies of such minutes to the board of directors.

(e) Duties and Activities of the Committee

The duties and activities of the Committee shall include:

i) Make recommendations to the board of directors on the appointment of the external auditor of the Corporation.

ii) Review and approve the Corporation's external auditor's annual engagement letter and audit plans, including the proposed fees contained therein, and pre-approve all non-audit services to be provided to the Corporation by the external auditor.

iii) Review the performance of the external auditor and make recommendations to the board of directors regarding their replacement when circumstances warrant. The review shall take into consideration the evaluation made by management of the external auditor's performance. Approve payment of audit fees and pre-approve audit related and other authorized work fees.

iv) Oversee the independence of the external auditor.

v) Review and approve, if appropriate, the annual audit plan of the external auditor, including the scope of audit activities, and monitor such plan's progress and results during the year.

vi) Confirm, through private discussions with the external auditor and management, that no restrictions are being placed on the scope of the external auditor's work.

vii) Review and ensure adequacy of financial statements and disclosure in the Management Discussion and Analysis prior to public disclosure of the information.

viii) Establish the Corporation's whistleblower policy for the confidential submission, receipt, retention and treatment of complaints and concerns regarding accounting and auditing matters, and review of any developments and responses on reports received thereunder.

ix) Review the adequacy and effectiveness of financial reporting systems and internal control policies and procedures with the external auditor and management. Ensure that the Corporation complies with all new regulations in this regard.

x) Review with management that the Corporation's administrative, operational and accounting internal controls, including controls and security of computerized information systems are operating in accordance with prescribed policies, procedures and codes of conduct.

xi) Review with management and the external auditor any material weaknesses affecting internal controls.

xii) Receive periodic reports from the external auditor and management to assess the impact of significant accounting or financial reporting documents proposed by the CICA, the relevant Canadian Securities commissions, stock exchanges or other regulatory bodies, or any other significant accounting or financial reporting related matters that may have a bearing on the Corporation.

xiii) Establish and maintain free and open means of communication between the board of directors, the Committee, the external auditor and management.

xiv) Review with management the list of risks that they have identified and ensure that management has implement the appropriate systems to monitor, mitigate and report such business risks.

xv) Review the adequacy of the Corporation's insurance coverage with respect to Directors and Officers Liability, general liability, pollution, business interruption, and well control.

xvi) Review the disclosure of identified risks in the annual disclosure documents sent to shareholders to ensure that such disclosure meets with regulatory requirements and adequately addresses risks to shareholders.

xvii) Conduct or authorize investigations into any matters within the Committee's scope of responsibilities including retaining outside counsel or other consultants or experts for this purpose.

xviii) Review annual and interim press releases regarding earnings and other financial information prior to public disclosure of such information.

xix) Review the disclosure made in the Corporation's Annual Report, if prepared, Annual Information Form, and Management's Discussion and Analysis.

xx) Review and satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information and periodically assess the adequacy of those procedures.

xxi) Perform such additional activities, and consider such other matters, within the scope of its responsibilities, as the Committee or board of directors deems necessary or appropriate.

(f) Oversight of Various Financial External Reports

The Committee shall oversee the adequacy of the financial reporting contained in the Annual Report, if prepared, Annual Information Form, Management's Discussion and Analysis, prospectuses and any other document of the same nature.

(g) Internal Functioning of the Committee

Once a year, the Committee shall review the adequacy of its Charter and bring to the attention of the board of directors any required changes. On an annual basis the Committee will also make a critical review of its past performance to ensure that it has assumed its responsibilities and executed all required tasks and will suggest changes if it failed to do so. This review will also cover the performance of individual members.

While the Committee has the duties and responsibilities set forth in this Charter, the Committee is not responsible for planning or conducting the audit, or for determining whether the Corporation's financial statements are complete and accurate and are in accordance with generally accepted accounting principles. Similarly, it is not the responsibility of the Committee to resolve disagreements, if any, between management and the external auditor. While it is acknowledged that the Committee is not legally obligated to ensure that the Corporation comply with all of the laws and regulations, the spirit and intent of this Charter is that the Committee shall take reasonable steps to encourage the Corporation to act in full compliance therewith.

2) Composition of the Audit Committee

The members of the Committee are Mr. Robert Waters (Chair), Mr. Michael Hibberd and Mr. Dallas Droppo. Each member of the Committee is independent and financially literate within the meaning of Multilateral Instrument 52-110.

3) Relevant Education and Experience

Name (Director Since)	**Principal Occupation and Biography**
Mr. Robert Waters, BBA, MBA, CA (July 2005) <u>Other Public Directorships</u> None	Senior Vice-President and Chief Financial Officer, Enerplus Resources Fund since December, 2001. Prior thereto, Vice-President Finance and Chief Financial Officer, Pengrowth Energy Trust since June 1998.
Mr. Michael Hibberd, BA, MBA, LLB (July 2005) <u>Other Public Directorships</u> AltaCanada Energy Avalite Inc. Canacol Energy Heritage Oil PLC and Heritage Oil Corporation Pan Orient Energy Zapata Energy	President, MJH Services Inc. since 1995. (corporate finance advisors). Prior to 1995, Director and Senior V.P. Corporate Finance at ScotiaMcLeod.
Mr. Dallas Droppo, BSc, LLB (July 2005) <u>Other Public Directorships</u> Norex Exploration Services Inc. Mart Resources, Ltd.	Partner/Lawyer, Blake, Cassels and Graydon LLP. Financially literate by virtue of many years of experience in the corporate finance and securities areas of law and as result of attendance at various industry seminars on topics relating to financial statements and audit committees.

4) **Pre-Approval Policies and Procedures**

The Committee has implemented a policy restricting the services that may be provided by the Corporation's auditor and the fees paid to the Corporation's auditor. Prior to the engagement of the Corporation's auditor to perform both audit and non-audit services, the Committee pre-approves the provision of the services. In making their determination regarding non-audit services, the Committee considers the compliance with the policy and the provision of non-audit services in the context of avoiding impact on auditor independence. All audit and non-audit fees paid to Ernst & Young LLP in 2009 and 2008 were approved by the Committee. Based on the Committee's discussions with management and the independent auditor, the Committee is of the view that the provision of the non-audit services by Ernst & Young LLP described above is compatible with maintaining the firm's independence from the Corporation.

5) **External Auditor Service Fees**

The aggregate fees paid by the Corporation to Ernst & Young LLP, the auditor for the Corporation, for professional services rendered during the Corporation's last two fiscal years are as follows:

	2009 ($)	**2008 ($)**
Audit fees[(1)]	392,108	338,750
Audit related fees[(2)]	65,650	160,500
Tax fees[(3)]	56,369	20,205
All other fees[(4)]	24,150	-
Total	538,277	519,455

Notes:

(1) Audit fees were for professional services rendered by Ernst & Young LLP for the audit of the Corporation's annual financial statements and reviews of the Corporation's quarterly financial statements, and accounting consultations related thereto.

(2) Audit related fees are for services provided by the Corporation's auditor relating to offerings and related regulator filings.

(3) Tax fees were for tax compliance, tax advice and tax planning. The fees were for services provided by the Corporation's auditor's tax division.

(4) All other fees are fees billed for products and services provided by the Corporation's auditor, other than Audit fees, Audit related fees and Tax fees. Such other fees in 2009 were for assistance with the adoption of IFRS.