TRITON ENERGY CORP.

Annual Information Form

Year Ended December 31, 2008

April 22, 2009

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, expected levels of activity, budgeted capital expenditures and the method of funding thereof, drilling, completion and tie-in plans, productive capacity of wells, expected royalty rates and changes to the Alberta royalty regime and the possible effect thereof on Triton may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, estimated drilling costs of test well at Limestone and the timing thereof, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates and estimated production rates, changes in royalty rates and expenses, environmental risks, partner risk and competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, changes in the regulatory and taxation environment, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Triton's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Triton believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements or information because Triton can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Triton operates; the timely receipt of any required regulatory approvals; the ability of Triton to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Triton has an interest in to operate the field in a safe, efficient and effective manner; the ability of Triton to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Triton to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Triton operates; and the ability of Triton to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect Triton's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at Triton's website (www.tritonenergy.ca). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

NON-GAAP MEASURES

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

GLOSSARY

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

"**971021 AB**" means 971021 Alberta Ltd., formerly Taylor Hill Resources Ltd., a corporation previously incorporated under the ABCA now amalgamated with Triton to form Triton Energy Corp.;

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

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

"**AJM**" means AJM Petroleum Consultants;

"**AJM Report**" means report of AJM dated March 5, 2009 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2008;

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

"**CRA**" means Canada Revenue Agency;

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

"**Corporation**" or "**Triton**" means Triton Energy Corp., a corporation amalgamated under the ABCA;

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

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

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

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

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

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

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

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

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

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

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

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

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

"**Tax Act**" means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5th Supp.), as amended including the regulations thereunder; and

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

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2008.

CONVENTIONS

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

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

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

Natural Gas

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

Other

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

Disclosure provided herein in respect of Boe may be misleading, particularly if used in isolation. The Boe conversion ratio of 6 Mcf of natural gas to 1 bbl of oil used throughout this document is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSION

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

THE CORPORATION

The Corporation was incorporated under the ABCA on February 4, 2004 under the name "Triton Energy Corp." The Corporation filed Articles of Amendment on September 28, 2004 to remove the private company provisions and share transfer restrictions. On April 28, 2005, the Corporation acquired 100% of the issued and outstanding shares of 971021 AB pursuant to a share purchase and sale agreement. Effective January 8, 2007, the Corporation amalgamated with 971021 AB by way of vertical short form amalgamation under the ABCA to form one company operating under the name Triton Energy Corp. The registered office of the Corporation is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9 and its head office is located at Suite 600, 734 – 7th Avenue SW, Calgary, Alberta T2P 3P8.

The Corporation does not have any subsidiaries.

The Corporation's Common Shares trade on the TSXV under the symbol "TEZ".

GENERAL DEVELOPMENT OF THE BUSINESS

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

Year Ended December 31, 2006

On July 26, 2006 the Corporation announced the appointment of Mr. Brian Cumming and Mr. Gord Bakarich to the positions of Vice President, Engineering and Vice President, Operations respectively. In conjunction with the appointments, the Corporation completed a non-brokered private placement for total gross proceeds of $240,000 by issuing 300,000 units at $0.80 per unit. Each unit consisted of 300,000 Common Shares and 300,000 non-transferable Common Share purchase warrants. Each warrant entitled the holder to purchase one Common Share at $0.80 per Common Share until July 31, 2007 or $0.90 per Common Share from August 1, 2007 to July 31, 2008. The warrants expired on July 31, 2008.

On November 1, 2006 the Corporation closed a bought deal private placement for gross proceeds of $4,000,001 by issuing 3,137,256 Common Shares on a "flow-through" basis under the Tax Act at $1.275 per share.

Operational highlights for the year ended December 31, 2006 included:

- The Corporation incurred $11.5 million in capital expenditures whereby $2.2 million was spent on land acquisitions, $2.2 million on geosciences and exploration activities, $4.2 million on drilling and completions, $2.8 million on plant and facilities and $0.1 million on office equipment.

- The Corporation drilled 9 (7.2 net) wells.

- Production averaged 516 Boe/d and 130 Boe/d for the three months and year ended December 31, 2006 respectively.

- The Corporation exited 2006 with 54,720 gross and 54,080 net acres of undeveloped land in Alberta.

Year Ended December 31, 2007

On March 13, 2007 the Corporation closed a bought deal private placement for total gross proceeds of $4,999,999 by issuing 2,439,024 Common Shares on a "flow-through" basis under the Tax Act at $2.05 per share.

On October 16, 2007 the Corporation closed a bought deal private placement for total gross proceeds of $4,812,840 by issuing 6,944,500 Common Shares on a "flow-through" basis under the Tax Act at $0.72 per share.

In November 2008 the Government of Alberta announced changes to the NRF whereby in some cases, wells drilled after January 1, 2009 would be eligible for transitional royalty rates. Due to the fact that these changes were not announced until November 2008, this announcement had very little impact on the Corporation's planned 2008/2009 drilling program.

Operational highlights for the year ended December 31, 2007 included:

- The Corporation incurred $17.5 million in capital expenditures whereby $1.2 million was spent on land acquisitions, $3.2 million on geosciences and exploration activities, $8.9 million on drilling and completions and $4.2 million on plant and facilities.

- The Corporation drilled 19 (15.3 net) wells.

- Production averaged 629 Boe/d and 130 Boe/d for the years ended December 31, 2007 and 2006 respectively.

- The Corporation exited 2007 with approximately 62,900 gross and 59,400 net acres of undeveloped land in Alberta.

Year Ended December 31, 2008

On April 23, 2008, the Corporation announced the appointments of Mr. Robert Pinckston and Mr. Frank Raffin to the positions of Manager, Exploration and Manager, Geophysics respectively. On May 9, 2008 the Corporation announced the appointment of Mr. Stephan D. Irish to the position of Vice President, Land. In conjunction with the appointments, the Corporation closed a non-brokered private placement to Messrs. Pinckston, Raffin and Irish for total gross proceeds of $540,000 by issuing a total of 900,000 units at a price of $0.60 per unit, each unit consisting of 900,000 Common Shares and 900,000 Common Share purchase warrants, each warrant entitling the holder to purchase one Common Share for a period of three years at $0.60 per share in the first year, $0.70 per share in the second year, and $0.80 per share in the final year.

On July 2, 2008 the Corporation closed the sale of 100% of its interests in three non-operated producing wells and associated land in the Falher area to an arm's length party for net proceeds of $1.0 million effective July 1, 2008. The proceeds from the sale have been allocated to Triton's ongoing exploration and development program.

Effective October 7, 2008 the Corporation received regulatory approval to commence a normal course issuer bid ("**NCIB**") to purchase for cancellation, from time to time, as the Corporation considers it advisable, up to a maximum of 3,192,000 Common Shares commencing October 9, 2008. In accordance with regulatory requirements, the maximum number of Common Shares approved for repurchase and cancellation under the NCIB represents approximately 10% of the public float of the Common Shares outstanding as of the date of the approval of the NCIB. Purchases of Common Shares are to be made on the open market through the facilities of the TSXV at a price consistent with the market pricing rules of the TSXV. To date, the Corporation has purchased and cancelled 2,588,944 Common Shares under the NCIB at an average price of $0.242 per share.

On November 20, 2008 the Corporation closed the sale of 100% of its interests in three producing wells and associated land in the Inland area to an arm's length party for net proceeds of $3.13 million effective October 1, 2008. The proceeds from the sale have been allocated to Triton's ongoing exploration and development program.

Effective December 19, 2008 Triton closed a bought deal private placement for total gross proceeds of $2,916,188 by issuing 7,856,500 Common Shares on a "flow-through basis" under the Tax Act at a price of $0.375 per share.

Operational highlights for the year ended December 31, 2008 included:

- The Corporation incurred $15.2 million in capital expenditures whereby $1.5 million was spent on land acquisitions, $2.9 million on geosciences and exploration activities, $7.9 million on drilling and completions and $2.9 million on plant and facilities.

- The Corporation drilled 9 (net) wells.

- The Corporation pooled and equalized in one (0.5 net) multi-zone petroleum and natural gas well.

- Production averaged 814 Boe/d and 629 Boe/d for the years ended December 31, 2008 and 2007 respectively.

- The Corporation exited 2008 with approximately 54,320 gross and 50,250 net acres of undeveloped land in Alberta.

DESCRIPTION OF THE BUSINESS

General

The Corporation is an Alberta-based petroleum and natural gas exploration and production company engaged in the acquisition of, exploration for, development and production of petroleum and natural gas primarily through internal generation of prospects within the Corporation's land base and in other strategically located areas currently within the province of Alberta. Emphasis is placed on exploration targets near established infrastructure that have the potential to be placed on production soon after drilling success. Triton's focus areas will characteristically have moderate drilling and operating costs and offer essentially year round access.

Exploration and Development Strategy

The short-term business plan of the Corporation is to continue growing Triton's production and reserves base through a combination of exploration, property development and acquisitions. To accomplish this, Triton continues to pursue an integrated growth strategy including exploration and development drilling focused in Alberta, acquisitions, farm-in opportunities, farm-out opportunities, further land acquisitions and trades.

The Corporation is currently concentrating its exploration activities in central Alberta areas generally characterized by multi-zone natural gas and light oil horizons at shallow to medium depths. As part of Triton's exploration strategy, management has targeted oil and gas companies with land holdings in Triton's prospect areas for potential farm-in, farm-out and/or joint venture opportunities to augment the Corporation's growth. Management of the Corporation has extensive experience in oil and gas exploration and development in Alberta. See "*Directors and Officers of the Corporation*".

Additionally, potential asset and/or corporate acquisitions will be considered to further supplement the growth strategy of the Corporation. It is anticipated that any future acquisitions would be financed through a combination of additional equity and/or debt. The Corporation will seek out, analyze and complete asset and/or corporate acquisitions where value creation opportunities have been identified that have the potential to increase shareholder value and returns, taking into account the Corporation's financial position, taxability and access to debt and equity financing.

The Corporation continues to follow its strategy in pursuing a reasonably balanced portfolio of petroleum and natural gas prospects. However, the Corporation is largely opportunity driven and will focus its expenditures in areas that provide the greatest economic return to the Corporation, recognizing that all drilling involves substantial risk and that a high degree of competition exists for prospects. No assurance can be given that drilling will prove successful in establishing commercially recoverable reserves. See "*Risk Factors*".

To achieve sustainable and profitable growth, the Corporation believes in controlling the timing, costs and future development of its projects whenever possible. Accordingly, the Corporation will seek to become the operator of its projects to the greatest extent possible.

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

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 5, 2009. The effective date of the Statement is December 31, 2008 and the preparation date of the Statement is March 5, 2009.

Disclosure of Reserves Data and Other Information

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by AJM with an effective date of December 31, 2008 contained in the AJM Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The AJM Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged AJM to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

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

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

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

	RESERVES (1)									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS(2)		NATURAL GAS LIQUIDS		BARRELS OF OIL EQUIVALENT(3)	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Developed										
Producing	86.1	67.0	0.0	0.0	5,155.9	3,678.7	13.4	8.1	958.8	688.2
Non-Producing	92.5	73.1	0.0	0.0	2,497.5	1,860.1	2.5	1.6	511.3	384.7
Proved Undeveloped	0.0	0	0.0	0.0	871.8	543.0	11.1	6.4	156.4	96.8
TOTAL PROVED	178.6	140.1	0.0	0.0	8,525.2	6,081.7	27.0	16.0	1,626.5	1,169.8
PROBABLE	89.5	68.1	0.0	0.0	3,961.9	2,793.2	11.2	6.7	760.9	540.4
TOTAL PROVED PLUS PROBABLE	268.1	208.2	0.0	0.0	12,487.1	8,874.9	38.2	22.8	2,387.4	1,710.1

Notes:

(1) Numbers in this table are subject to round off error.
(2) Natural gas volumes include solution gas volumes associated with the Corporation's light and medium crude oil reserves.
(3) Natural gas is converted Boe's at a ratio of six thousand standard cubic feet to one barrel of oil.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE[1][2][3] BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved Developed										
Producing	27,315.4	22,925.3	19,887.1	17,661.3	15,959.1	25,930.3	21,991.3	19,232.8	17,188.8	15,609.1
Non-Producing	16,140.4	11,753.6	8,921.4	6,992.8	5,622.4	11,784.1	8,585.0	6,527.2	5,129.7	4,138.3
Proved Undeveloped	3,449.3	2,715.4	2,176.8	1,771.4	1,459.6	2,517.7	1,949.7	1,538.0	1,231.4	997.9
TOTAL PROVED	46,905.0	37,394.3	30,985.3	26,425.5	23,041.0	40,232.2	32,526.0	27,298.0	23,549.9	20,745.3
PROBABLE	26,368.0	17,367.0	12,577.8	9,647.7	7,698.7	19,288.1	12,688.2	9,192.4	7,059.0	5,642.1
TOTAL PROVED PLUS PROBABLE	73,273.0	54,761.2	43,563.0	36,073.3	30,739.7	59,520.3	45,214.3	36,490.4	30,608.9	26,387.4

Notes:

(1) Utilizes AJM's price forecast as of December 31, 2008 as detailed below.
(2) Values are net of abandonment liabilities.
(3) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	98,150.0	26,033.2	21,299.9	3,003.4	908.5	46,905.0	6,672.9	40,232.2
Proved Plus Probable Reserves	152,246.3	40,863.3	32,993.0	4,201.4	915.5	73,273.0	13,752.8	59,520.3

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	3,041.7	$19.37/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	27,943.6	$3.39/Mcf
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	4,648.0	$19.60/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	38,915.0	$3.23/Mcf

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the AJM Report are based on the definitions and guidelines contained in NI 51-101 and the COGE Handbook. A summary of those definitions are set forth below.

   Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

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

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

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

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

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

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

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

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

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

3. Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing**,** inflation and exchange rates utilized by AJM in the AJM Report were AJM's forecasts, as at December 31, 2008, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL								
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Bow River 25° API Hardisty ($Cdn/Bbl)	Alberta AECO Average Gas Price ($Cdn/Mcf)	Pentanes Plus Edmonton ($Cdn/Bbl)	Butane Price Edmonton ($Cdn/Bbl)	Propane Price Edmonton ($Cdn/Bbl)	Inflation Rates[(1)] %/Year	Exchange Rate[(2)] ($US/$Cdn)
Forecast									
2009	$55.00	$65.40	$50.40	$7.00	$68.65	$52.30	$42.50	0.0%	0.820
2010	$76.50	$87.20	$65.20	$8.05	$91.55	$69.75	$56.70	2.0%	0.860
2011	$88.45	$96.50	$70.50	$8.20	$101.35	$77.20	$62.75	2.0%	0.900
2012	$100.80	$104.30	$76.30	$9.00	$109.50	$83.45	$67.80	2.0%	0.950
2013	$108.25	$112.05	$84.05	$9.75	$117.65	$89.65	$72.85	2.0%	0.950
2014	$110.40	$114.25	$86.25	$9.95	$119.95	$91.40	$74.25	2.0%	0.950
2015	$112.60	$116.55	$88.55	$10.15	$122.35	$93.25	$75.75	2.0%	0.950
2016	$114.85	$118.90	$90.90	$10.35	$124.85	$95.10	$77.30	2.0%	0.950
2017	$117.15	$121.25	$93.25	$10.55	$127.30	$97.00	$78.80	2.0%	0.950
2018	$119.50	$123.70	$95.70	$10.75	$129.90	$98.95	$80.40	2.0%	0.950
2019	$121.90	$126.15	$98.15	$10.95	$132.45	$100.90	$82.00	2.0%	0.950
2020	Escalated oil, gas and product prices at approximately 2% per year thereafter							2.0%	2.0%

Notes:

(1) Inflation rates for forecasting prices and costs. Cost inflation for 2010 forecast at 3%.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical price realized by Triton for the year ended December 31, 2008 was \$8.12/Mcf AECO for natural gas. Substantially all of Triton's production for the year ended December 31, 2008 was natural gas.

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

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

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

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

Reconciliation of Changes in Reserves and Future Gross Revenue

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

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2007	86.0	64.2	150.2	163.0	100.3	263.3
Extensions	14.4	7.1	21.5	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	-36.0	-38.9	-74.7	0.1	0.0	0.1
Discoveries	116.4	57.0	173.3	0.0	0.0	0.0
Acquisitions	8.2	1.6	9.8	0.0	0.0	0.0
Dispositions	-3.9	-1.5	-5.5	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	-160.4	-100.3	-260.7
Production	-6.5	0.0	-6.5	-2.7	0.0	-2.7
December 31, 2008	178.6	89.5	268.1	0.0	0.0	0.0

FACTORS	NATURAL GAS LIQUIDS Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	ASSOCIATED AND NON-ASSOCIATED GAS Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved Plus Probable (Mmcf)
December 31, 2007	45.6	7.2	52.8	5,445.2	1,802.8	7,248.0
Extensions	11.6	7.4	19.0	4,507.4	2,448.2	6,955.5
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	-27.1	-3.2	-30.4	465.2	225.1	690.4
Discoveries	0.1	0.1	0.2	230.6	135.4	366.0
Acquisitions	0.2	0.0	0.3	461.6	92.3	553.9
Dispositions	-0.6	-0.3	-0.9	-869.0	-741.9	-1,610.9
Economic Factors	0.0	0.0	0.0	0.1	0.0	0.1
Production	-2.8	0.0	-2.8	-1,715.9	0.0	-1,715.9
December 31, 2008	27.0	11.2	38.2	8,525.2	3,961.9	12,487.1

Note:

(1) The Corporation has no unconventional reserves.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to Triton's assets for the years ended December 31, 2008, 2007 and 2006 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	61.1	61.1	0.0	0.0	884.5	884.5	11.1	11.1
2008	0.0	0.0	0.0	0.0	0.0	871.8	0	11.1

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	31.0	31.0	0.0	0.0	146.6	146.6	1.6	1.6
2008	0.0	0.0	0.0	0.0	0.0	136.0	0.0	1.6

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

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);

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

Significant Factors or Uncertainties

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

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

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

Future Development Costs

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

Year	Forecast Prices and Costs (M$)	
	Proved Reserves	Proved Plus Probable Reserves
2009	975.0	2,075.0
2010	1,288.6	1,288.6
2011	208.2	208.2
2012	0.0	0.0
2013	0.0	0.0
Thereafter	531.6	629.6
Total Undiscounted	3,003.4	4,201.4

The future development costs are capital expenditures required in the future for Triton to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $3.0 million for proved reserves and $4.2 million for proved plus probable reserves (in each case based on forecast prices and costs).

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

Other Oil and Gas Information

Principal Properties

The following is a description of Triton's principal oil and gas properties as at December 31, 2008. Unless otherwise stated, all production volumes in this section represent Triton's gross interest.

Newton

Newton is located in west central Alberta about 60 km northwest of Edmonton. Triton has 100% operated working interest in 14 sections of Crown land in the area. The target at Newton is sweet gas in multiple Mannville sandstone formations at drill depths under 1,200 meters. In 2008, Triton drilled four (4.0 net) wells at Newton resulting in three (3.0 net) natural gas wells and one dry hole. The Corporation exited 2008 with approximately 3,960 Mcf (660 Boe) per day of production from four (4.0 net) operated natural gas wells at Newton. Triton owns its own gathering system, which is tied into a third party gathering system and transports Triton's natural gas to the nearby Altagas Manola plant for processing. Triton has 6,400 (6,400 net) acres of undeveloped land at Newton and plans to drill one (1.0 net) additional 100% working interest well in the area in 2009.

Sullivan Lake

Sullivan Lake is located in east central Alberta approximately 150 km northeast of Calgary. Triton has an average 99.5% operated working interest in 11.75 sections of land in the area including seven sections of Crown land and 4.75 sections of freehold land. The Corporation is targeting sweet gas in the Lower Cretaceous Viking and Mannville sandstone formations at drill depths under 1,200 meters, as well as multiple shallow gas horizons in the Belly River formation at drill depths less than 450 meters. The Corporation exited 2008 with approximately 1,758 Mcf (293 Boe) per day of production from five (4.85 net) operated natural gas wells at Sullivan Lake, which are tied into Penn West and Apache gathering systems. Triton has 4,320 (4,320 net) acres of undeveloped land at Sullivan Lake and has two (2.0 net) additional drilling locations identified by geological mapping and 2-D seismic.

South Sullivan Lake

In 2008, Triton secured a series of options on an aggregate of 13 sections of freehold land in South Sullivan Lake. Here, the Corporation is targeting light oil and natural gas in the Mannville formation at drill depths under 1,200 meters. Triton drilled two (2.0 net) wells in this area in the fourth quarter of 2008 resulting in two (2.0 net) light oil wells. One (1.0 net) of these wells was tied in during December 2008 and the other in January 2009. The Corporation has 3,360 (3,360 net) acres of undeveloped land at South Sullivan Lake and plans to drill two to three additional 100% working interest wells in the area in 2009. Two of these wells are commitment wells. Triton drilled one of them in the first quarter of 2009 at an approximate cost of $450,000 and expects to drill the other one in the second quarter of 2009 at an estimated cost of $450,000.

Lanaway

Lanaway is located in west central Alberta about 120 km northwest of Calgary. Triton has a 50% working interest in one section of Crown land. The target at Lanaway is medium gravity oil in the Jurassic Rock Creek formation and natural gas in the Lower Mannville formation at a drill depth of 2,400 meters. In the summer of 2007 a well targeting natural gas in the Jurassic Rock Creek and Lower Mannville formations was drilled on the full section by another operator and tested commercial quantities of oil from the Jurassic Rock Creek formation and natural gas in the Lower Manville formation. Triton owned the petroleum rights in Rock Creek and Mannville formations and had 3-D seismic covering this section. During 2008 Triton and the well operator pooled their respective rights and the Corporation equalized in the well. The operator placed the well on limited production in December 2008. In order to enhance the production capability of the well, a short pipeline has been surveyed to a central oil battery owned by the operator. Construction of this pipeline is currently expected to be completed in the summer of 2009. The 3-D seismic survey suggests two to three additional drilling locations for Rock Creek oil.

Limestone

Limestone is located in the foothills of southwest Alberta approximately 110 km northwest of Calgary. Triton is participating in the drilling of a non-operated test well which is licensed to a depth of 5,462 metres. The well spud on January 6, 2009 and is expected to take 145 days to complete drilling operations. Upon completion of its earning obligations, Triton will earn a 12.5% working interest in the test well and 11 sections of contiguous Crown land in the area. Triton's anticipated share of drilling cost is approximately $4.0 million. The target at Limestone is natural gas in a Leduc carbonate reef identified using geological mapping and 3-D seismic.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2008:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing(1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	2.00	1.75	3.00	3.00	10.00	9.35	6.00	5.50

Note:

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

Properties with No Attributable Reserves

At December 31, 2008 the Corporation had 54,320 gross (50,250 net) acres of undeveloped land holdings in the Province of Alberta. The Corporation expects that rights to 16,896 net acres of its undeveloped land holdings will expire by December 31, 2009. Triton is considering whether or not to drill or submit an application to continue, sell, swap or farm-out selected portions of the above acreage.

Forward Contracts and Marketing

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

Additional Information Concerning Abandonment Costs

Triton estimates well abandonment costs on an area by area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The Corporation has 24.0 net well events for which it expects to incur abandonment costs.

Estimated costs of abandonment were included in the AJM Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices is $0.9 million undiscounted ($0.4 million using a 10% discount rate). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Corporation in respect of proved reserves as disclosed above. No allowance for salvage value was included in these costs. The total proved plus probable abandonment and reclamation costs are $0.9 million (undiscounted) and $0.3 million (discounted at 10%). The table below indicates the expected timing of well abandonment costs for the Corporation.

The following table sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue:

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

Year	Abandonment Costs (Undiscounted)
2009	70.0
2010	37.6
2011	38.3
Thereafter	762.6
Total Undiscounted	908.5
Total Discounted @ 10%	376.5

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

Year	Abandonment Costs (Undiscounted)
2009	70.0
2010	37.6
2011	38.3
Thereafter	769.6
Total Undiscounted	915.5
Total Discounted @ 10%	338.7

Tax Horizon

Based on the Corporation's available tax pools, expected capital expenditures and forecast net income for 2009, the Corporation does not anticipate paying current income taxes in 2009. Depending on levels of production, commodity prices, acquisitions and capital expenditures, Triton may begin paying current income taxes in 2010 or beyond.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2008 ($000s):

Property acquisition costs	
Proved properties	$ 140
Undeveloped properties	1,315
Exploration costs	10,376
Development costs	3,335
Total	$15,166

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2008:

	Exploration		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	2.0	2.0	0.0	0.0
Heavy Oil	0.0	0.0	0.0	0.0
Natural Gas	3.0	3.0	1.0	1.0
Service	0.0	0.0	0.0	0.0
Dry	3.0	3.0	0.0	0.0
Total:	8.0	8.0	1.0	1.0

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

Production Estimates

The following table sets out the volume of the Corporation's gross working interest production estimated for the year ended December 31, 2009 as evaluated by AJM which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Information*":

Forecast Prices and Costs

Total Proved

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	Boe *(Boe/d)*
Newton	9.3	2,877.8	9.5	498.4
Sullivan	45.7	1,390.6	0.7	278.2
Lanaway	35.9	73.1	0.0	48.1
Other Properties	7.1	0.0	0.0	7.1
Total Proved	**98.0**	**4,341.6**	**10.2**	**831.8**

Total Proved Plus Probable

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	Boe *(Boe/d)*
Newton	10.3	3,261.1	10.8	564.6
Sullivan	47.0	1,477.8	0.7	294.0
Lanaway	38.5	78.1	0.0	51.5
Other Properties	7.2	0.0	0.0	7.2
Total Proved plus Probable	**103.0**	**4,817.0**	**11.5**	**917.3**

Production History

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

	Quarter Ended			
	2008			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (Bbls/d)	35	9	12	15
Heavy Oil (Bbls/d)	0	1	8	19
Gas (Mcf/d)	5,021	4,645	3,994	5,091
NGLs (Bbls/d)	12	10	4	5
Combined (Boe/d)	884	795	689	888
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	59.74	80.32	128.91	85.61
Heavy Oil ($/Bbls)	0.00	80.00	82.79	60.05
Gas ($/Mcf)	7.27	8.19	9.10	8.13
NGLs ($/Bbls)	57.79	105.67	91.25	77.76
Combined ($/Boe)	44.16	50.61	56.39	49.80

	Quarter Ended 2008			
	Dec. 31	Sept. 30	June 30	Mar. 31
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	5.79	4.24	12.55	6.57
Heavy Oil ($/Bbls)	0.00	12.52	7.60	7.28
Gas ($/Mcf)	1.52	1.70	1.59	1.96
NGLs ($/Bbls)	16.68	16.92	25.84	20.11
Combined ($/Boe)	9.08	10.20	9.66	11.63
Operating & Transportation Expenses ($/Boe)				
Light and Medium Crude Oil ($/Bbls)	41.56	75.74	66.28	34.99
Heavy Oil ($/Bbls)	0.00	422.33	92.00	130.83
Gas ($/Mcf)	1.35	1.39	1.54	1.42
NGLs ($/Bbls)	8.07	8.35	9.25	8.49
Combined ($/Boe)	9.40	9.60	11.20	11.61
Netback Received ($/Boe)(2)				
Light and Medium Crude Oil ($/Bbls)	12.39	0.34	50.08	44.05
Heavy Oil ($/Bbls)	0.00	-354.85	-16.81	-78.06
Gas ($/Mcf)	4.40	5.10	5.97	4.75
NGLs ($/Bbls)	33.04	80.40	56.16	49.16
Combined ($/Boe)	25.68	30.81	35.53	26.56

Notes:

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

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2008:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLS (Bbls/d)	Boe (Boe/d)
Inland	0	0	1,206	0	201
Sullivan	3	0	1,868	1	315
Newton	4	0	1,520	6	263
Other Alberta	12	7	94	0	35
Total Alberta	19	7	4,688	7	814

The Corporation's production for the year ended December 31, 2008 was 96.8% natural gas and natural gas liquids, 2.3% light and medium crude oil and 0.9% heavy oil.

For the twelve months ended December 31, 2008 approximately 95.3% of the Corporation's gross revenue was derived from natural gas and natural gas liquids production and the remaining 4.7% of the Corporation's gross revenue was derived from light, medium and heavy oil production.

DIRECTORS AND OFFICERS OF THE CORPORATION

The name, municipality of residence, and position held with the Corporation of each of the directors and officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held
Michael S. Zuber(2)(3)(4) Calgary, Alberta, Canada	President, Chief Executive Officer and a Director (since February 2004)
Daryl H. Connolly(1)(2)(3)(4) Calgary, Alberta, Canada	Director (since February 2004) and Chairman
Reginald J. LaBonte(1) West Vancouver, British Columbia, Canada	Director (since May 2004)
W. C. (Mike) Seth(1)(4) Calgary, Alberta, Canada	Director (since June 2005)
Scott M.B. Hunt (2)(3) Calgary, Alberta, Canada	Director (since October 2004)
Dean J. Schultz Calgary, Alberta, Canada	Vice President, Finance and Chief Financial Officer
Robert J. Mepham Calgary, Alberta, Canada	Vice President, Exploration
Brian R. Cumming Calgary, Alberta, Canada	Vice President, Engineering
Gordon S. Bakarich Cochrane, Alberta, Canada	Vice President, Operations
Steve D. Irish Calgary, Alberta, Canada	Vice President, Land
C. Steven Cohen Calgary, Alberta, Canada	Corporate Secretary

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Corporate Governance Committee
(4) Member of the Reserves Committee
(5) The Corporation does not have an Executive Committee.

As at the date hereof, the directors and officers of the Corporation, and associates and affiliates, as a group own or control, directly or indirectly, 3,782,001 Common Shares or 9.3% of the issued and outstanding Common Shares.

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

Messrs. Zuber, Schultz, Mepham, Cumming, Bakarich, and Irish devote their full time and attention to the business and affairs of the Corporation. The other directors and officers of the Corporation will devote time and attention to the affairs of the Corporation as required.

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

Michael S. Zuber – President, Chief Executive Officer and a Director

Mr. Zuber has over 27 years' experience in the formation, financing and management of publicly traded junior resource companies. He has been President, Chief Executive Officer and a Director of the Corporation since founding it in February 2004. From April 2002 to February 2004, he was co-founder, Director and President of Aquest Explorations Ltd. His experience in the petroleum industry began in 1981 and for the past 26 years he has been involved with junior resource companies with exploration and development projects in Canada, the United States and internationally. Mr. Zuber is a member of Triton's Compensation Committee, Corporate Governance Committee and Reserves Committee.

Dean J. Schultz, C.A. – Vice President, Finance and Chief Financial Officer

Mr. Schultz has over 15 years' management and business experience and joined the Corporation in January 2005 as Vice President, Finance and Chief Financial Officer. He is a Chartered Accountant and holds a B.Sc. degree in Mathematical Sciences from the University of Alberta (1993) and is a member of the Canadian Institute of Chartered Accountants. From January 2001 to December 2004, Mr. Schultz was at Collins Barrow, Calgary LLP where he provided audit, assurance, accounting and compliance services for public and private corporations. In addition, he was involved in providing value added services including financial performance review and recommendations, pro forma cash flow analysis/preparation, business plan review, accounting policy recommendations and general business advice.

Robert J. Mepham, P.Geol. – Vice President, Exploration

Mr. Mepham has over 30 years' experience in the oil and gas industry in Western Canada. He obtained an Honours B.Sc. degree in Geology from McMaster University in 1978 and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("**APEGGA**"). Mr. Mepham joined Triton in September 2004 as Vice President, Exploration. From September 1997 to August 2004, he was Senior Exploration Geologist at Thunder Energy Inc. Mr. Mepham has extensive experience with shallow Edmonton and Belly River sand plays as well as medium depth Lower Cretaceous sand plays in east central and west central Alberta.

Brian R. Cumming, P.Eng. - Vice President, Engineering

Mr. Cumming has over 30 years' experience in the oil and gas industry in Western Canada. Mr. Cumming joined Triton in August 2006. Prior to joining Triton, from September 2003 to July 2006, he consulted to a variety of clients in the oil and gas industry, conducting property evaluations, exploitation, and reserves management as well as directing operations. He was Vice President Operations for Resolute Energy Ltd. from December 2001 until September 2003. Before joining Resolute, he was Engineering Manager for Maxwell Oil & Gas Ltd, and previously has held senior engineering positions with a number of senior and intermediate producers. Mr. Cumming is a graduate of Queens University (Kingston) with a BSc. Honours in Geological Engineering in 1978 and is a member of APEGGA and the Petroleum Society of C.I.M.

Gordon S. Bakarich, P.Eng. - Vice President, Operations

Mr. Bakarich has over 15 years' experience in the petroleum and natural gas industry in Western Canada. He obtained a B.Sc. (Honours) Degree in Chemical Engineering from Queens University (Kingston) in 1993 and is a member of APEGGA. Prior to joining Triton in August 2006, Mr. Bakarich was Manager, Operations at Blue Mountain Energy Ltd. from October 2004 to July 2006 where he was responsible for the management of all drilling, completions, tie-ins and production as well as the corporate health, safety and environment programs. Prior to Blue Mountain, Mr. Bakarich held various senior engineering and consulting positions with a number of senior oil and gas producers.

Steve D. Irish, P.Land – Vice President, Land

Mr. Irish has over 28 years of professional negotiation and general land and contract expertise. He obtained a B.A. Degree in Geography (Geomorphology) from the University of Calgary in 1978 and is an active member of the Canadian Association of Professional Landmen. Mr. Irish began his career in 1978 as a District Landman with Dome Petroleum and went on to hold positions of increasing responsibility with Rupertsland Resources, Westburne Petroleum and Anderson Exploration. From 1989 to 2002 he was Land Manager, Deep Basin Exploration and Production at Canadian Hunter Exploration and from 2002 to 2004 he was Land Manager at Lightning Energy. Mr. Irish co-founded Greenbank Energy in 2004 where he was Vice President, Land until the company was sold to Rock Energy in 2007. Mr. Irish joined Triton on June 1, 2008 as Vice President, Land.

C. Steven Cohen, B.Sc., LL.B. – Corporate Secretary

Mr. Cohen has over 26 years' experience in corporate and securities law. He is currently a partner in the law firm of Burnet, Duckworth & Palmer LLP in Calgary, Alberta. He graduated from the University of Alberta with a B.Sc. degree in Engineering in 1977 and a received a Bachelor of Laws degree from the University of Toronto in 1981. Mr. Cohen was called to the Bar in Alberta in 1982 and in Ontario in 1988. Mr. Cohen acts as Corporate Secretary for several public oil and gas companies headquartered in Calgary, Alberta.

Daryl H. Connolly, P.Eng. – Chairman and Director

Mr. Connolly has over 38 years' experience in the oil and gas industry in Canada, the United States, Australia and the North Sea. He is a registered Professional Engineer as well as a member of the Canadian Institute of Mining and Metallurgy and the Society of Petroleum Engineers. From May 2006 to present, Mr. Connolly is Chairman, President and Chief Executive Officer of Redcliffe Exploration Inc. and from September 2005 to December 2007, Chairman, President and Chief Executive Officer of Redcliffe Energy Ltd. From February 2004 until August 2005 he was a Director, President and Chief Executive Officer of Aquest Energy Ltd. and from April 2002 to February 2004 he was Chairman and Chief Executive Officer of Aquest Explorations Ltd. Mr. Connolly was co-founder and Chairman of Rock Creek Resources Inc. from January 2002 until July 2005. Mr. Connolly is a member of Triton's Audit Committee and Reserves Committee. Mr. Connolly is also the Chairman of the Compensation Committee, Corporate Governance Committee and Board of Directors of the Corporation.

W.C. (Mike) Seth, P.Eng. – Director

Mr. Seth has over 40 years' experience in all aspects of oil and gas reserve evaluations. Currently, he is the President of Seth Consultants Ltd. Prior to founding his own consulting company, he was Chairman of McDaniel & Associates Consultants Ltd., a Calgary, Alberta based petroleum engineering firm from July 2005 to February 2006, and was the President and Managing Director of McDaniel & Associates Consultants Ltd. from 1989 until July 2005. Mr. Seth speaks regularly to the oil and gas industry and financial groups on related topics and has also appeared as an expert witness before various regulatory authorities and Court of Queen's Bench of Alberta. He is a current member of the Petroleum Society of C.I.M. and APEGGA. Mr. Seth is a member of Triton's Audit Committee and Chairman of Triton's Reserves Committee.

Reginald J. LaBonte, C.A. – Director

Mr. LaBonte has over 30 years' experience as a Chartered Accountant providing assurance and related advisory services to publicly traded companies in Canada and the United States. Mr. LaBonte is currently a Partner with Dale Matheson Carr-Hilton LaBonte LLP (DMCL), Chartered Accountants, headquartered in Vancouver, British Columbia. Prior to that, Mr. LaBonte was a Partner with LaBonte & Co., a Vancouver firm which he started in 1983, which merged to form DMCL in 2004. He has been a board and audit committee member for a number of public companies in his career. Mr. LaBonte is a member of the Institute of Chartered Accountants of British Columbia and is Chairman of Triton's Audit Committee.

Scott M.B. Hunt – Director

Mr. Hunt has over 20 years' experience in corporate finance and business development, and has held senior management positions in both private and publicly traded companies. He is currently President and Chief Executive Officer of Koda Capital Corp. since 1990, a Calgary-based private venture capital company and from 2002 to 2005 he served as Chairman of the Board for the Calgary Stampede Foundation. Mr. Hunt provides expertise and advice on the Corporation's corporate policies and procedures and is a member of Triton's Compensation Committee and Corporate Governance Committee.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

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

Conflicts of Interest

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

DESCRIPTION OF SHARE CAPITAL

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

Common Shares

The Corporation has an unlimited number of Common Shares authorized. At April 22, 2009, there were 40,707,637 Common Shares of the Corporation issued and outstanding. All Common Shares have been issued as fully paid and non-assessable. The holders of Common Shares are entitled to dividends if, as and when declared by the board of directors, to one vote per Common Share at any meeting of the shareholders of the Corporation and, upon liquidation, to receive all assets of the Corporation as are distributable to the holders of Common Shares.

Preferred Shares

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

PRICE RANGE AND TRADING VOLUME OF THE COMMON SHARES

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

Period	High	Low	Volume
2007			
January	1.86	1.45	818,717
February	1.80	1.53	617,220

Period	High	Low	Volume
March	2.08	1.10	3,251,269
April	1.30	1.00	842,100
May	1.17	0.95	415,388
June	1.10	0.73	881,538
July	0.93	0.70	454,375
August	0.75	0.52	815,600
September	0.70	0.55	490,650
October	0.68	0.52	798,096
November	0.60	0.46	734,166
December	0.51	0.41	1,206,855
2008			
January	0.63	0.48	483,044
February	0.61	0.40	2,251,230
March	0.60	0.50	156,375
April	0.55	0.54	526,200
May	0.60	0.58	1,475,000
June	0.58	0.55	2,041,400
July	0.50	0.48	440,700
August	0.42	0.41	1,984,900
September	0.37	0.34	974,100
October	0.25	0.23	2,277,400
November	0.23	0.21	3,350,200
December	0.28	0.26	956,300
2009			
January	0.35	0.26	394,813
February	0.28	0.25	552,847
March	0.27	0.18	1,046,954
April 1 - 21	0.34	0.25	227,700

DIVIDENDS

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

HUMAN RESOURCES

As at December 31, 2008, the Corporation had 9 full time employees (6 officers, a manager of exploration, a manager of geophysics and an office manager), and 5 other part time consultants. See "*Directors and Officers of the Corporation*".

PRIOR SALES

Date of Issuance	Number and Type of Securities	Issue Price per Security	Aggregate Funds Received
May 9, 2008	250,000 Units	$0.60[(1)]	$150,000[(1)]
April 23, 2008	650,000 Units	$0.60[(1)]	$390,000[(1)]

Note:

(1) Issuances consisted of non-brokered private placements of units ("**Units**") at a price of $0.60 per Unit, each unit consisting of one (1) Common Share and one (1) Common Share purchase warrant, with each warrant entitling the holder to acquire an additional Common Share for a period of three (3) years at an exercise price of $0.60 per common share in the first year, $0.70 per common share in the second year and $0.80 per common share in the third year.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation is a party, or was a party to in 2008, or that any of its properties is or was the subject matter of in 2008, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2008 there were: (i) no penalties or sanctions imposed against the Corporation or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Corporation entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

MATERIAL CONTRACTS

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

RISK FACTORS

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

Exploration, Development and Production Risks

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

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

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

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government 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 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. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

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

Prices, Markets and Marketing

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

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle-East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

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

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

New Alberta Royalty Regime

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime effective January 1, 2009. The Corporation anticipates a potential increase in the royalty rate effective January 1, 2009 due to the implementation of the Alberta royalty framework. The calculation of the royalties payable to the Government of Alberta under the NRF is dependent on many factors including commodity prices, well production, as well as total depths of the producing wells. The royalties payable can change significantly depending on these factors and as such can be difficult to predict. As commodity prices increase, the Corporation's royalty rate will also increase with a maximum royalty rate of 50% on high producing wells in Alberta.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There has been much public debate with respect to Canada's ability to meet these targets and the government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

Operational Dependence

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

Substantial Capital Requirements

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

Reserve Estimates

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

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

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

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

Additional Funding Requirements

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

Third Party Credit Risk

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

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which will require the Corporation to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "Industry Conditions – Environmental Regulation".

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

Management of Growth

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

Availability of Drilling Equipment and Access

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Competition

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

Issuance of Debt

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

Hedging

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

Title to Assets

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

Insurance

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

Geo-Political Risks

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

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

Dilution

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

Expiration of Licences and Leases

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

Dividends

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

Aboriginal Claims

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

Seasonality

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

Conflicts of Interest

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

Reliance on Key Personnel

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

INDUSTRY CONDITIONS

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

Pricing and Marketing - Oil and Natural Gas

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

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

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

Pipeline Capacity

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

The North American Free Trade Agreement

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

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

Provincial Royalties and Incentives

General

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

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

Alberta

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

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

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

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

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Government of Alberta announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

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

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

Land Tenure

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

Environmental Regulation

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

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Government of Alberta enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

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

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

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

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

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

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

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

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

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

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

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition at this time.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of the Corporation are Collins Barrow Calgary LLP, Chartered Accountants, 1400, 777 – 8th Avenue S.W., Calgary, Alberta, T2P 3R5.

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

INTEREST OF EXPERTS

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

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

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's information circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided for in our financial statements and management's discussion and analysis for the year ended December 31, 2008.

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

Management of Triton Energy Corp. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

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

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

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

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

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

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

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

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

(c) the content and filing of this report.

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

DATED as of this 22nd day of April, 2009.

(signed) "*Michael S. Zuber*"
Michael S. Zuber
President and Chief Executive Officer

(signed) "*Brian R. Cumming*"
Brian R. Cumming
Vice-President, Engineering

(signed) "*Daryl H. Connolly*"
Daryl H. Connolly
Director

(signed) "*W.C. (Mike) Seth*"
W.C. (Mike) Seth
Director

SCHEDULE "B"

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

To the Board of Directors of Triton Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs

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

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions 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 end December 31, 2008 and identifies the respective portions thereof that we have evaluated and reported on to the Company's management/Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Triton Energy Corp. Reserve Estimation and Economic Evaluation	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue ($M, before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
AJM Petroleum Consultants	March 5, 2009	Canada	-	$43,563.0	-	$43,563.0

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 reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual events will vary and the variations may be material. However, any variation 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:

AJM Petroleum Consultants
Fifth Avenue Place, East Tower
6th Floor, 425 – 1st Street S.W.
Calgary, Alberta
T2P 3P8

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