Management's Discussion and Analysis of Financial Condition and Results of Operations

The following Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") was prepared as of March 25, 2010. This MD&A is provided by Management of Questerre Energy Corporation ("Questerre" or the "Company") to review 2009 activities and results as compared to the previous year. This MD&A should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2009 and 2008. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. Additional information relating to Questerre, including Questerre's Annual Information Form is available on SEDAR at www.sedar.com.

Questerre is an independent energy company focused on shale gas in North America. The Company is concentrated on establishing commerciality of its Utica shale gas discovery in the St. Lawrence Lowlands, Québec. The Company also continues to develop a portfolio of conventional assets in Western Canada.

The Company's common shares are listed on the Toronto Stock Exchange and Oslo Stock Exchange under the symbol "QEC".

Forward Looking Statements

Certain statements contained within this MD&A, and in certain documents incorporated by reference into this document, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this MD&A, as the case may be.

This MD&A, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the performance of our oil and natural gas properties;
- the size of our oil, natural gas liquids and natural gas reserves and production levels;
- estimates of future cash flow;
- projections of prices and costs;
- drilling plans and timing of drilling, recompletion and tie-in of wells by the Company and its partners;
- weighting of production between different commodities;
- commodity prices, exchange rates and interest rates;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- capital expenditure programs and other expenditures and the timing and method of financing thereof;
- supply of and demand for oil, natural gas liquids and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions and development;
- our ability to grow or sustain production and reserves through prudent management;
- the emergence of accretive growth opportunities and continued access to capital markets;
- our future operating and financial results;
- schedules and timing of certain projects and our strategy for future growth; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

In particular, this MD&A contains the following forward-looking statements pertaining to the following:

- production volumes;
- timing of drilling programs and resulting cash flows;
- future oil and gas prices;
- operating costs;
- royalty rates;
- future development, exploration and acquisition activities and related expenditures;
- the amount of future asset retirement obligations; and
- future liquidity and future financial capacity.

With respect to forward-looking statements contained in this MD&A and the documents incorporated by reference herein, we have made assumptions regarding, among other things:

- future oil and natural gas prices;
- the continued availability of capital, undeveloped lands and skilled personnel;
- the costs of expanding our property holdings;
- the ability to obtain equipment in a timely manner to carry out exploration, development and exploitation activities;
- the ability to obtain financing on acceptable terms;
- the ability to add production and reserves through exploration, development and exploitation activities; and
- the continuation of the current tax and regulatory regime and other assumptions contained in this MD&A and the documents incorporated by reference herein.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A and the documents incorporated by reference into this document:

- volatility in market prices for oil, natural gas liquids and natural gas;
- counterparty credit risk;
- access to capital;
- changes or fluctuations in oil, natural gas liquids and natural gas production levels;
- liabilities inherent in oil and natural gas operations;
- adverse regulatory rulings, orders and decisions;
- attracting, retaining and motivating skilled personnel;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, and services;
- incorrect assessments of the value of acquisitions and targeted exploration and development assets;
- fluctuations in foreign exchange or interest rates;
- stock market volatility, market valuations and the market value of the securities of Questerre;
- failure to realize the anticipated benefits of acquisitions;
- actions by governmental or regulatory authorities including changes in royalty structures and programs and income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- limitations on insurance;
- changes in environmental or other legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; and
- geological, technical, drilling and processing problems and other difficulties in producing oil, natural gas liquids and natural gas reserves.

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

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities law.

BOE Conversions

Barrel of oil equivalent ("boe") amounts may be misleading, particularly if used in isolation. A boe conversion ratio has been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil and is based on an energy equivalent conversion method application at the burner tip and does not necessarily represent an economic value equivalency at the wellhead.

Non-GAAP Terms

This document contains the terms "cash flow from operations" and "netbacks" which are non-GAAP terms. The Company uses these measures to help evaluate its performance.

As an indicator of Questerre's performance, cash flow from operations should not be considered as an alternative to, or more meaningful than, cash flows from operating activities as determined in accordance with Canadian GAAP. Questerre's determination of cash flow from operations may not be comparable to that reported by other companies. Questerre considers cash flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund operations and future capital investment. It is also used by research analysts to value and compare oil and gas companies.

Cash Flow from Operations Reconciliation

	2009	2008
Cash flows from operating activities	**$ (26,529)**	$ 23,466,056
Net change in non-cash working capital	**2,905,105**	(6,176,758)
Cash flow from operations	**$ 2,878,576**	$ 17,289,298

The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices and its ability to generate cash flow to fund future growth through capital investment and repay any debt outstanding. Operating netbacks per boe equal total petroleum and natural gas revenue per boe adjusted for royalties per boe and operating expenses per boe. Cash netbacks per boe are calculated as operating netbacks less general and administrative expenses per boe. Operating and cash netbacks are a useful measure to compare the Company's operations with those of its peers.

Select Annual Information

As at/for the years ended December 31	**2009**	2008	2007
Financial ($, except common shares outstanding)			
Petroleum and Natural Gas Revenue	**12,933,267**	29,805,568	23,785,489
Cash Flow from Operations	**2,878,576**	17,289,298	10,229,020
Per share – Basic	**0.01**	0.09	0.07
Per share – Diluted	**0.01**	0.09	0.06
Net Loss	**(13,722,888)**	(9,212,614)	(1,281,674)
Per share – Basic	**(0.07)**	(0.05)	(0.01)
Per share – Diluted	**(0.07)**	(0.05)	(0.01)
Capital Expenditures, net of acquisitions and dispositions	**11,989,541**	42,490,941	15,462,461
Working Capital Surplus	**46,500,671**	54,307,989	10,007,846
Total Assets	**145,272,364**	165,531,133	93,074,767
Shareholders' Equity	**129,977,202**	137,189,444	71,627,841
Common Shares Outstanding	**199,722,143**	197,299,642	168,930,470
Weighted average – basic	**197,940,390**	186,447,776	157,078,211
Weighted average – diluted	**206,729,689**	196,593,333	163,260,612
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbl/d)	**378**	385	176
Natural Gas (Mcf/d)	**2,591**	4,761	7,282
Total (boe/d)	**810**	1,178	1,390
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**63.88**	99.42	71.42
Natural Gas ($/Mcf)	**4.34**	8.99	7.17
Total ($/boe)	**43.75**	69.13	46.88
Netback ($/boe)			
Petroleum and Natural Gas Revenue	**43.75**	69.13	46.88
Royalties Expense	**(3.32)**	(11.55)	(11.06)
Percentage	**8%**	17%	24%
Operating Expense	**(13.86)**	(14.05)	(12.07)
Operating Netback	**26.57**	43.53	23.75
General and Administrative Expense	**(15.94)**	(6.72)	(5.44)
Cash Netback	**10.63**	36.81	18.31
Wells Drilled			
Gross	**4.00**	19.00	17.00
Net	**1.71**	12.10	10.30

Highlights

- Consistent repeatable results from Utica pilot vertical well program in the St. Lawrence Lowlands, Québec
- Independent resource assessment of Utica shale estimates potential recoverable resource at 4.36 Tcf to Questerre's net working interest
- Horizontal well program underway in Lowlands to assess commerciality; first well tests at approximately 6 MMcf/d
- Evaluated new drilling and completion techniques in Antler, Saskatchewan with encouraging results
- Minimal capital investment and higher oil weighting generated cash flow of $2.88 million with average daily production of 810 boe/d
- Maintained financial strength with over $46 million in positive working capital and no debt

2009 Activities

St. Lawrence Lowlands, Québec

The appraisal of the Utica shale potential remained the focus for the Company in the St. Lawrence Lowlands.

During the year, Questerre finalized a joint vertical test well program with its partner, Talisman Energy Canada Inc. ("Talisman"). Targeting the Utica, this included the drilling and completion of St. Edouard No. 1 and the completion and testing of two wells drilled in 2008 – La Visitation No. 1 and St. David No. 1.

The drilling and completion of St. Edouard No. 1, the fourth and final well in the program, marked the end of the earn-in program by Talisman. Talisman currently holds a 75% working interest in approximately 720,000 joint acres. Questerre holds an approximate 25% working interest in this acreage and also retains a 4¼% gross overriding royalty on production from Talisman.

The stabilized initial rates from these wells ranged between 300 Mcf/d and 700 Mcf/d. Production logging indicates the majority of the flow is attributable to an interval within the middle Utica. These rates are in line with the middle Utica flow rates of over 800 Mcf/d from Gentilly No. 1, the first well in the program, and 900 Mcf/d from Leclercville No. 1, drilled offsetting the joint acreage.

Consistent results over a large geographic area provided the momentum to begin a pilot horizontal well program for the middle Utica to assess commerciality. Two horizontal wells were spud in the second half of 2009. The wells were located next to existing verticals for micro-seismic monitoring of frac effectiveness. The first, St. Edouard No. 1A, was successfully drilled and the horizontal leg was completed with eight stage fracture stimulations in early 2010. Initial flow rates were over 12 MMcf/d with an average stabilized rate of approximately 6 MMcf/d. The well is currently on a long-term test. Drilling operations on the second horizontal well, Gentilly No. 2, were completed in 2010 and the well will be fracture stimulated later this year.

Subject to results and partner participation, Questerre anticipates this pilot program could be expanded to include several other horizontal wells, a 3-D seismic survey and a pipeline tie-in to the local distribution system.

The evaluation of the Utica included the testing of other prospective intervals within this horizon. Targeting the upper Utica interval, Questerre's partner, Forest Oil Corporation ("Forest"), completed the testing of two prototype horizontal wells on the Yamaska permits earlier in the year. Stabilized rates of between 100 Mcf/d and 800 Mcf/d were achieved and reflect the slower than expected cleanup of the frac fluid. While the companies have identified alternative completion programs to address this issue, Questerre anticipates Forest will conduct this additional work in the future. In the interim, Forest plans to acquire 2-D seismic this year in advance of further drilling on these permits.

In early 2009, Questerre completed the St. Jean sur Richelieu No. 1 well to evaluate the shallower Utica shale south of the main fairway. Fracture stimulation yielded sustained gas flows at limited rates with frac efficiency less than expected. Additional work is ongoing to determine if gas fracturing can improve frac effectiveness and commerciality. The Company believes this acreage could be developed with vertical wells and multiple small fracs similar to other shallow tight gas projects.

The Company commissioned Netherland, Sewell & Associates, Inc., an independent reservoir engineering firm, to assess the Utica's potential. Utilizing the extensive technical data from the test wells, the report estimates prospective gas in place for the Utica shale in the deep fairway at 158 Bcf per square mile. Using a range of recovery factors based on more established shale plays, the report estimates prospective resources recoverable for Questerre's interest to range between 1.33 Tcf and 13.78 Tcf with a best estimate of 4.36 Tcf.

In addition to the Utica, Questerre and Talisman also tested two other zones of interest in the Lowlands.

Successful fracs were completed in the shallower Lorraine shale in La Visitation No. 1 and Gentilly No. 1. Sustained gas flows resulted at rates of approximately 100 Mcf/d. Results were affected by flow-back of the proppant and frac fluid. Further work, including fluid compatibility studies, is necessary to improve the effectiveness of the stimulation.

Testing of the deeper Trenton Black-River carbonate in the St. Edouard No. 1 well resulted in a final gas rate of approximately 2 MMcf/d over a three day test with no formation water. Pressure data indicates that the estimated reserves would be insufficient to support tie-in costs and the interval was suspended. With the focus on the Utica, further exploration for this zone has been deferred in the near term.

Northeast British Columbia

Beaver River Field

Testing of the Liard shale at Beaver River was setback with extended production shut-ins due to low natural gas prices, plant turnarounds, unusually cold weather and operational challenges.

The A-5 well, recompleted in late 2008, targeted a brittle dolomite interval above an organic rich shale sequence. The well tested at an initial gross rate of 10 MMcf/d and has been on production intermittently during the year most recently at the beginning of the fourth quarter with initial gross rates of over 2 MMcf/d. Results to date indicate minimal contribution from the deeper shale and further work will be required.

Testing during the winter was hampered by unexpected drilling mud from previous operations produced concurrently with the natural gas. This damaged surface facilities and required substantial rehabilitation and modification. Production was shut-in in the second quarter for a turnaround of the main processing plant. This was subsequently extended during a period of low natural gas prices. In the fourth quarter, unseasonably cold weather subsequently froze up facilities and shut-in production from this well.

Questerre continues to explore for joint venture opportunities to further assess and develop the Liard shale.

Greater Sierra

A planned drilling program with its partner, EnCana Corporation ("EnCana") was deferred with lower than expected natural gas prices in the year.

Through participation in a Crown land sale, Questerre acquired an additional 14,680 (11,680 net) acres south of its acreage with EnCana. The land is prospective for the primary Jean Marie formation in addition to the deeper Horn River shales and the Pine Point carbonates. Locations have been identified to test the deeper carbonate anomalies and assess the shale intervals. Questerre plans to work with an industry partner to pursue these locations and develop this acreage.

Antler, Saskatchewan

Low crude oil prices in the first quarter also impacted drilling in Antler with the suspension of a planned 20-well program.

A detailed review of the existing wells and drilling and completion practices was conducted during the year to improve recovery of the oil in place. Modified completion techniques were tested to confine the fracture stimulation within the target Bakken/Torquay interval and minimize water production from adjacent intervals. The Company also evaluated tubing conveyed fracture stimulation as an alternative to the Packers Plus system. Preliminary results are positive and Questerre plans to implement these in its current drilling program.

Field work in 2009 also focused on improving operating efficiencies with the installation of a pipeline to tie-in wells to the central battery facility and the electrification of the existing wells.

Southern Alberta

Minimal activity was conducted in Alberta in the current fiscal and regulatory environment.

Delayed regulatory approval for a minor compressor upgrade in Vulcan, Southern Alberta hindered production optimization from the Mannville I Pool. This in turn has setback plans for a proposed infill well into this oil pool. Subject to the timing of approvals, Questerre anticipates this well could be drilled towards the end of 2010.

Drilling Activities

In 2009, Questerre participated in the drilling of four (1.71 net) wells, comprising of one (1.00 net) oil well in Antler and three (0.71 net) natural gas wells in Québec. In 2008, Questerre participated in the drilling of 19 (12.10 net) wells, comprising of 15 (10.00 net) oil wells and four (2.10 net) natural gas wells.

Production

Production volumes in 2009 reflect the focus on capital preservation with minimal investment by the Company in development drilling. Daily production averaged 810 boe/d during the year with oil and liquids representing 47% of total volumes. By comparison, in 2008, Questerre reported daily production of 1,178 boe/d with oil and liquids accounting for 33% of total volumes.

Lower natural gas production from Alberta and BC coupled with the completion of several oil wells in Antler, southeast Saskatchewan contributed to the improved oil weighting during the year. Light oil from Antler accounted for 73% of the oil and liquids volumes during the year (2008: 64%) with light oil and liquids from Vulcan, Southern Alberta making up the difference. Notwithstanding this increased production in Antler, total oil and liquids volumes decreased marginally to 378 bbl/d from 385 bbl/d in 2008 as a result of lower production in Vulcan.

Questerre's assets in Alberta remained the largest contributor to corporate production, adding 365 boe/d or 45% of total volumes down from 645 boe/d and 55% in the prior year. Unchanged from prior periods, Vulcan was the majority of these volumes at 312 boe/d or 85% during the year (2008: 476 boe/d and 74%). The decrease from the prior year mirrors the natural production profile of the Company's Mannville pools in Vulcan. Production from minor properties of 53 boe/d (2008: 169 boe/d) excludes assets acquired through the purchase of Stride Energy, a private E&P company, in 2006. These assets added approximately 120 boe/d in 2008 before being sold. Other than a proposed infill location at Vulcan, Questerre has no plans for additional drilling in Alberta in 2010.

Extended production shut-ins at the Beaver River Field significantly lowered volumes from British Columbia. Production averaged 170 boe/d (2008: 286 boe/d) or 21% of total volumes (2008: 24%). Production from Beaver River for the year of 130 boe/d (2008: 197 boe/d) was largely from the testing of the A-5 shale gas well which was hampered by operational challenges, cold weather and plant turnarounds. The higher flowing pressure of this well backed out production from the other two wells, A-2 and A-7, which accounted for the majority of production in the prior year. Questerre's interest in two gas wells at Greater Sierra, BC, was responsible for the other 40 boe/d (2008: 89 boe/d) of production from the province.

Light oil from Antler, Saskatchewan added the remaining 275 boe/d (2008: 247 boe/d). A deferred winter drilling program and reduced field activity during the year translated into minor production gains. Preliminary results from new drilling and completion approaches are positive and Questerre plans to implement these in a planned program in 2010.

Questerre anticipates its production in 2010 will continue to reflect prudent capital investment in the current financial market. Capital will be directed to establishing commerciality of the Utica shale in Québec and maximizing the value of its assets in Antler. In Antler, this will include the continued assessment of new completion ideas and early work for a water flood to improve recovery. Based on the timing of additional drilling in Antler, Questerre expects production to average between 400-600 boe/d.

2009 Financial Results

Revenue

Petroleum and natural gas revenue for the fiscal year declined to $12.93 million from $29.81 million in 2008. Materially higher production volumes and commodity prices in 2008 were responsible for the higher revenue compared to the current year. Total production volumes were 31% lower in 2009 with oil and natural gas prices lower by 36% and 52% respectively.

Crude oil prices recovered during the year on the expectation of a global economic recovery and as a financial hedge against the value of the US dollar and inflation. This was in spite of inventory levels above their five-year averages that illustrated weaker demand growth and potential oversupply largely by OPEC. Canadian crude prices experienced a similar increase as the appreciation of the Canadian dollar offset a decrease in the differential between the Canadian and US crude prices.

Realized prices mirrored the developments in the benchmark price during the year. The Edmonton Light price averaged $65.90/bbl with Questerre receiving a net price of $63.88/bbl in 2009. In the prior year, Questerre realized an average price of $99.42/bbl while the benchmark averaged $102.16/bbl.

Natural gas prices remained challenged for most of the year and staged a minor recovery in the fourth quarter on the back of colder than forecasted weather. A delayed supply side response from the significantly lower rig counts in 2009 and reduced industrial demand contributed to storage levels that approached maximum capacity. This was compounded by a cooler summer that tempered residential cooling demand and a less active hurricane season than anticipated.

Higher heat content gas production from Vulcan continued to positively impact realized natural gas prices. Consistent with prior years, Questerre received a premium to the reference AECO price. Sales prices averaged $4.34/Mcf (2008: $8.99/Mcf) in comparison to an AECO daily index price of $3.96/Mcf (2008: $8.16/Mcf).

Questerre did not enter into any risk management contracts in 2009 and all production was sold on the spot market.

Royalties

Royalty credits in Alberta and British Columbia along with lower prices and production volumes resulted in a significant decrease in royalties on an absolute and relative basis in 2009. Year over year, crown, freehold and overriding royalties declined 80% from $4.98 million to $0.98 million in 2009.

Royalties on production in Alberta averaged 13% of revenue during the year (2008: 22%). This takes into account a $0.47 million Alberta Royalty Tax Credit from 2006 received in the third quarter of the year. Excluding the credits, the effective royalty rate remained unchanged at 22% from the prior year. The Company expects the New Royalty Framework ("NRF") that came into effect in Alberta on January 1, 2009 to have a minimal effect on the Company's royalty rate. With limited drilling in Alberta, the Company does not expect to benefit from the incentive programs announced in March 2009. For the changes to the Alberta royalty structure announced in March 2010 see the risk management section of this MD&A.

Royalty credits on BC production during the year exceeded royalties payable by $0.12 million. This includes a credit of $0.18 million for 2008 production from the Company's wells in Greater Sierra that qualified under the Crown's ultra marginal gas well royalty program. The wells currently attract a royalty rate of approximately 3%. Questerre also benefits from a deep re-entry credit to offset any royalties payable on production from the A-5 well at the Beaver River Field during the year. Questerre incurred royalties of approximately 15% on production from the other two producing wells, A-2 and A-7, at Beaver River. With current natural gas prices, Questerre anticipates no further drilling in British Columbia in the near term. As such, the Company will not avail itself of the royalty incentives announced by the BC government in August 2009.

The realized royalty rate in Saskatchewan increased slightly from 6% in 2008 to 7% in 2009. This includes the Saskatchewan Capital Surcharge estimated at 1.7% of total revenue. Subject to the timing of additional drilling throughout the year, Questerre expects its royalty rate to increase as additional wells are drilled on freehold lands where the royalty rate averages 17%. By comparison, drilling on crown land benefits from an incentive program with a royalty rate of 2.5% on the first 100,000 barrels of production.

Operating Costs

Aggregate operating expenses fell 32% to $4.10 million from $6.06 million in 2008, mirroring the decline in production volumes. On a per unit basis, this resulted in a more muted decline from $14.05/boe to $13.86/boe.

Field operating expenses in Alberta decreased to $9.78/boe from $12.46/boe in the prior year. Operating costs in Vulcan remained relatively flat at $10.90/boe (2008: $10.86/boe) with reduced gathering and processing costs offsetting the higher proportion of fixed costs. The sale of its higher cost assets in Central Alberta in 2008 saw the operating costs on its other properties in Alberta decline to $3.20/boe in the current year from $16.99/boe in the prior year.

Operating expenses at Beaver River are also primarily fixed and the lower costs during the year of $1.29 million (2008: $1.54 million) reflect the lower gathering and processing charges for smaller production volumes. At Greater Sierra with a higher proportion of variable costs saw expenses fall to $0.20 million from $0.48 million in the prior year with the 55% decrease in production volumes.

Lifting costs in Antler saw a marginal increase to $12.84/bbl from $11.94/bbl in 2008. Questerre expects these costs on boe basis to improve in 2010 as a result of 2009 field work and additional anticipated 2010 volumes. The recent tie-in of several wells to the electrical grid is expected to eliminate the higher costs for generators and associated fuel. Furthermore, the installation of a pipeline to tie-in several wells to the central battery and expanded water disposal facilities should reduce trucking and disposal charges going forward.

General and Administrative Expenses

Gross general and administrative expenses ("G&A") saw a minor increase to $5.35 million from $5.20 million in the prior year.

With capital spending substantially lower in 2009, capitalized expenses and overhead recoveries totaled $0.64 million (2008: $2.30 million). This resulted in an increase in net G&A to $4.71 million from $2.90 million in 2009.

($ thousands)		**2009**		2008
General and administrative expenses	**$**	**5,354**	$	5,195
Capitalized expenses and overhead recoveries		**(642)**		(2,295)
General and administrative expenses, net	**$**	**4,712**	$	2,900

Stock-based Compensation

Stock-based compensation expense for the year ended December 31, 2009 totaled $5.23 million (2008: $4.08 million). As mandated by existing accounting standards, this represents the estimated fair value of stock options granted using the Black Scholes pricing model amortized over the vesting period.

The Black Scholes model calculates a theoretical value of the options based on the price of the Company's shares, its volatility, risk free rate and expected life. The higher expense is due to the increased volatility in Questerre's share price, higher exercise prices and the number of options granted in the last 18 months. The expense is a non-cash item, and, upon exercise of options in fact results in increased cash.

The weighted average fair value of the options granted in 2009 using the Black Scholes pricing model was $1.53 (2008: $1.27) and the weighted average exercise price was $2.26 (2008: $1.80).

Other Income and Expenses

In 2009, Questerre reported interest income of $0.48 million (2008: $1.50 million). The income was earned on the net proceeds of the $75 million equity issue completed by Questerre in the second quarter of 2008. Lower cash balances and declining interest rates account for the reduction in interest income in the current year. Cash is invested in Guaranteed Investment Certificates issued by Canadian chartered banks with a maturity of less than one year.

With no draw downs during the year, Questerre did not incur any interest expense under its term credit facility (2008: $0.12 million). As at December 31, 2009, Questerre did not have any amounts outstanding under this facility.

Questerre realized an immaterial gain on the disposition of marketable securities during 2009 compared to a realized loss of $0.71 million in 2008. The marketable securities held by the Company represent investments in junior exploration and production companies. In accordance with the financial instruments accounting guidelines, the Company has classified these securities as held for trading and marks these securities to market value at the end of each fiscal period. This 'mark to market' adjustment is recorded as an unrealized gain or loss on the statements of operations. In 2009, the Company recorded a $0.02 million unrealized gain compared to a $0.09 million unrealized loss in 2008. At December 31, 2009, Questerre holds marketable securities with a market value of $0.20 million (2008: $0.20 million).

In 2008, Questerre recorded an allowance for doubtful accounts of $1.73 million for amounts due from a joint venture partner. No allowance was recorded in 2009.

Depletion, Depreciation and Accretion

In 2009, Questerre's depletion and depreciation provision decreased 8% to $15.87 million, compared to $17.23 million in 2008. A 31% decrease in production volumes was offset by a 34% increase in the charge on a per boe basis from $39.97 in 2008 to $53.69 in 2009. Increased capital expenditures during the year without a corresponding increase in reserves accounts for this difference.

At December 31, 2009, Questerre excluded costs of $23.62 million (December 31, 2008: $19.89 million) relating to unproved properties and included $6.15 million (December 31, 2008: $5.36 million) of future development costs in the depletion calculation.

Questerre applies a two-stage ceiling test to determine if the value of its petroleum and natural gas properties is impaired. The carrying value of the Company's petroleum and natural gas properties at December 31, 2009 was determined to be in excess of the undiscounted net cash flow from the proved reserves. However, since the carrying value of these properties is less than the net cash flow from the proved and probable reserves using a risk free discount rate, as currently prescribed by accounting standards, no impairment loss is recognized in 2009. The Company also did not incur a writedown of its assets in 2008.

The net cash flow from reserves is based on future prices forecasted by the Company's independent reserve engineers as of December 31, 2009. These prices are incorporated by reference from Note 4 of the Company's audited consolidated financial statements for the year ended December 31, 2009.

For the year ended December 31, 2009, the non-cash accretion expense for asset retirement obligations is $0.42 million compared to $0.25 million in 2008. The increase is due to the obligations for wells drilled in 2009 and the second half of 2008 and revisions to the estimates used to determine the asset retirement obligations in the fourth quarter of 2008. Furthermore, the credit adjusted risk free rate was changed to 12% for obligations incurred post October 1, 2008. The estimated net present value of the total asset retirement obligation is $4.76 million as at December 31, 2009 based on a total future undiscounted liability of $9.58 million.

Income Taxes

The recovery of future taxes for 2009 was $4.19 million compared to an expense of $2.41 million in the prior year. The future tax recovery in the current year is due to an $11.15 million increase in the net loss before income taxes. It also includes a decrease in the potential future tax liability related to the Questerre common shares that were held by a wholly owned foreign subsidiary that was dissolved in 2009.

Net Loss

Questerre recorded a net loss of $13.72 million for the year (2008: $9.21 million). The loss in the current year was attributable to substantially lower commodity prices and reduced production volumes coupled with proportionately higher expenses. In the prior year, significantly higher revenue and comparatively lower expenses resulted in a smaller loss.

Capital Expenditures

Excluding acquisitions and dispositions, Questerre incurred capital expenditures of $11.99 million in 2009 a marked decrease from $43.96 million in 2008. The Company's significant 2009 capital expenditures consisted of the following:

- $6.28 million was invested in the St. Lawrence Lowlands, Québec where the Company participated in the drilling and completion of multiple wells to assess the Utica shale.
- In Saskatchewan $4.46 million was incurred in Antler primarily evaluating new drilling and completion techniques and tying-in and completing wells drilled in the prior year.
- In British Columbia the majority of the $0.84 million was spent acquiring acreage prospective for multiple horizons including the Horn River shale.

For comparison, the company's 2008 capital program consisted of the following:

- $20.44 million in Antler with the majority incurred drilling and completing several horizontal wells and the associated facilities;
- $10.68 million in Greater Sierra that included $5.58 million for the acquisition of a 3-D seismic survey with the balance spent finishing the drilling and completion of two horizontal Jean Marie wells;
- $4.45 million at the Beaver River Field to finalize the drilling and completion of the A-8 Nahanni well and recompleting the A-5 well for shale gas potential;
- $4.80 million in Québec participating in the drilling of four wells and the recompletion of the Gentilly No. 1 well;
- $3.37 million in Alberta mainly in Vulcan to drill and complete one horizontal well, tie-in two others and the associated facilities.

($ thousands)		**2009**		2008
Expenditures on Property, Plant and Equipment				
Alberta	**$**	**376**	$	3,373
British Columbia		**837**		15,126
Saskatchewan		**4,457**		20,437
Québec		**6,279**		4,795
Corporate		**41**		226
		11,990		43,957
Dispositions		**–**		(2,146)
Acquisitions (cash portion)		**–**		680
Acquisitions (non-cash portion)		**–**		84
Asset Retirement Obligations		**56**		168
Total	**$**	**12,046**	$	42,743

Liquidity and Capital Resources

Questerre reported a working capital surplus of $46.50 million at December 31, 2009 as compared to a surplus of $54.31 million at December 31, 2008.

The Company's current assets consist of cash and cash equivalents of $51.40 million, $0.20 million of marketable securities, $4.51 million of accounts receivable, $0.30 million of inventory and $0.62 million in prepaids and deposits. Current liabilities of $10.53 million represent accounts payable and accrued liabilities.

In March 2010, Questerre closed an equity issuance of 30,000,000 Common Shares at a price of $4.30 per share for gross proceeds of approximately $129 million. This was comprised of 19,972,000 Common Shares on a private placement basis in Norway and 10,028,000 Common Shares by way of a short-form prospectus offering in Canada.

The Company believes it is sufficiently capitalized with the proceeds from the financing, a working capital surplus of $46.50 million at December 31, 2009, positive cash flow from operations and no debt. The majority of future planned capital spending will be incurred in Québec and is in part contingent upon the results of the pilot programs conducted by Questerre's partners. The Company does not anticipate utilizing its existing credit facility in the foreseeable future. The credit facility is believed to provide adequate contingency for unanticipated changes in capital spending or market conditions.

Cash Flow from Operations and Cash Flows from Operating Activities

Cash flow from operations for 2009 was $2.88 million or 83% lower than the 2008 cash flow from operations of $17.29 million. The decrease from the prior year is primarily due to lower realized prices for both oil and natural gas of 36% and 52%, respectively, and a 31% decrease in production volumes.

Cash flows from operating activities for 2009 was a negative $0.03 million compared to $23.47 million in 2008. The change in the non-cash working capital of $9.08 million represents the difference from the change in the cash flow from operations.

Share Capital

The Company is authorized to issue an unlimited number of Class A common voting shares. The Company is also authorized to issue an unlimited number of Class B common voting shares and an unlimited number of preferred shares, issuable in one or more series. At December 31, 2009, there were no Class B common voting shares or preferred shares outstanding.

The following table provides a summary of the outstanding common shares and options as at the date of the MD&A and the current and preceding year-ends.

	March 25 2010	December 31 2009	December 31 2008
Common shares	229,722,143	199,722,143	197,299,642
Stock options	18,528,753	18,618,753	17,655,421
Weighted average common shares			
Basic		197,940,390	186,447,776
Diluted		206,729,689	196,593,333

On September 30, 2009, 10,698,785 Questerre common shares that were acquired in the Terrenex acquisition were cancelled. The cancellation has been recorded as $10,315,647 being deducted from common shares and $12,793,729 as an increase to the deficit. Due to the pending cancellation of the 10,698,785 Questerre common shares at the time of acquisition in 2008, the cancellation has already been factored into the opening number of shares outstanding and therefore no outstanding share amounts need to be adjusted for in 2009.

A total of 2,422,501 common shares were issued pursuant to the exercise of stock options by directors, officers and employees during the year.

In March 2010, Questerre closed an equity issuance of 30,000,000 Common Shares at a price of $4.30 per share.

Off-Balance Sheet Arrangements

Questerre has no off-balance sheet arrangements.

Related Party Transactions

Questerre had no related party transactions in 2009.

Contractual Obligations and Commitments

Questerre has certain contractual obligations relating to the lease of office space and equipment rentals as set out in the table below:

	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Equipment rentals	$125,462	$115,811	$9,651	–	–
Office lease	333,241	333,241	–	–	–
	$458,703	$449,052	$9,651	–	–

Risk Management

Companies engaged in the petroleum and natural gas industry face a variety of risks. For Questerre, these include risks associated with exploration and development drilling as well as production operations, commodity prices, exchange rate and interest rate fluctuations. Unforeseen significant changes in such areas as markets, prices, royalties, interest rates and government regulations could have an impact on the Company's future operating results and/or financial condition. While management realizes that all the risks may not be controllable, they can be monitored and managed.

A significant risk for Questerre as a junior exploration company is access to capital. The Company attempts to secure both equity and debt financing on terms it believes are attractive in current markets. Management also endeavors to seek farm-in participants to participate in the development of its projects on favorable terms. However, there can be no assurance that the Company will be able to secure sufficient capital if required or that such capital will be available on terms satisfactory to the Company.

As a result of global economic conditions, the Corporation may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although the Corporation's business and asset base have not changed, the lending capacity of many financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash flow from operations, current cash balances, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Corporation's securities in particular. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. Based on current funds available and expected cash flow from operations, the Corporation believes it has sufficient funds available to fund its projected capital expenditures. However, if cash flow from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Corporation incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Questerre faces a number of financial risks over which it has no control, such as commodity prices, exchange rates, interest rates, access to credit and capital markets, as well as changes to government regulations and tax and royalty policies. The Company uses the following guidelines to address financial exposure:

- Internally generated cash flow provides the initial source of funding on which the Company's annual capital expenditure program is based.
- Debt may be utilized to expand capital programs, including acquisitions, when it is deemed appropriate and where debt retirement can be controlled.
- Equity, including flow-through shares, if available on acceptable terms, may be raised to fund acquisitions and capital expenditures.
- Farmouts of projects may be arranged if management considers that a project requires too much capital or where the project affects the Company's risk profile.

Credit risk arises from the potential loss resulting from a counterparty failing to meet its obligations in accordance with the agreed terms. The Company 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 Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner. Substantially all of the accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by entering into transactions with long-standing, reputable, counterparties and partners. In many cases, the Company has offsetting receivables and payables with its partners and makes use of these offsets to mitigate any payment risk. Wherever possible, the Company requires cash calls from its partners on capital projects before they commence.

Accounts receivable related to the sale of the Company's petroleum and natural gas production is paid in the following month from major marketing companies and the Company has not experienced any credit loss relating to these revenues.

The Company has issued and may continue to issue flow through shares to investors. The Company uses its best efforts to ensure that qualifying expenditures of Canadian Exploration Expenditures ("CEE") are incurred in order to meet its flow through obligations. However, in the event that the Company incurs qualifying expenditures of Canadian Development Expenditures ("CDE") or has CEE expenditures reclassified under audit by the Canada Revenue Agency, the Corporation may be required to liquidate certain of its assets in order to meet the indemnity obligations under the flow through share subscription agreements.

Exploration and development drilling risks are managed through the use of geological and geophysical interpretation technology, employing technical professionals and working in areas where those individuals have experience. For its non-operated properties, the Company strives to develop a good working relationship with the operator and monitors the operational activity on the property. The Company also carries appropriate insurance coverage for risks associated with its operations.

Although Questerre has no formal hedging policy, the Company may use financial instruments to reduce corporate risk in certain situations. Questerre currently has no hedges or other financial instruments in place.

Environmental Regulation and Risk

Potential risks to the environment are inherent in some of the business activities of the Company. Questerre endeavors to conduct its operations in a manner consistent with environmental regulations as stipulated in provincial and federal legislation. The Company mitigates the potential financial exposure of environmental risks by maintaining adequate insurance.

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 Government of Canada is in the process of developing future regulatory requirements that are expected to set greenhouse gas emission reduction requirements for various industrial activities, including oil and gas exploration and production. Questerre's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which will likely subject Questerre to federal law regulating emissions of greenhouse gases if and when such requirements come into force. Future federal legislation, together with provincial emission reduction requirements, such as those contained in Alberta's Climate Change and Emissions Management Act, British Columbia's Greenhouse Gas Reduction (Cap and Trade) Act, and proposed in Saskatchewan's Bill 126: Management and Reduction of Greenhouse Gases Act, may require the reduction of emissions or emissions intensity with Questerre's operations and facilities.

Although Questerre is not a large emitter of greenhouse gases, the Company continues to monitor developments in this area. Although environmental legislation is evolving in a manner which could result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs, at this time it is not possible to predict the impact of these requirements on the Company and its operations and financial condition.

Alberta Royalty and Tax Regime

On February 16, 2007, the Alberta Government announced that a review of the Province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane, would be conducted by a panel of experts with the assistance of individual Albertans and key stakeholders. On September 18, 2007, the Royalty Review Panel delivered its final report and recommendations to the Government of Alberta. The report titled "Our Fair Share", recommended significant increases to royalties levied on natural gas, conventional oil and oil sands produced in Alberta. On October 25, 2007, the Alberta Government released details of its planned implementation of the final Royalty Review Panel report, titled "The New Royalty Framework" ("NRF").

Questerre reviewed the modifications by the Government of Alberta to its royalty program, which took effect on January 1, 2009, and provides the following observations:

- In 2009, approximately 55% of Questerre's production is from properties located outside Alberta and is therefore not affected by the NRF.
- Royalties determined under the NRF will be determined based on commodity prices, well productivity and depth of wells. A significant portion of Questerre's wells are lower productivity wells that, on a relative basis, are less impacted by the NRF than higher productivity wells.
- The NRF will have a negative impact on the economics of any future drilling.

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. The new well incentive program applies to wells commencing production of conventional oil and natural gas between April 1, 2009 and March 31, 2011 and provides for a maximum 5% royalty rate for the first twelve months of production, up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. Questerre has not drilled any wells in Alberta to take advantage of this incentive.

On March 11, 2010, the government of Alberta announced that the following will become permanent features of the royalty structure, effective with the January 2011 production month:

Permanent 5% Front-end Royalty

- The current incentive program rate of 5% on new natural gas and conventional oil wells will become a permanent feature of the royalty system, with the current time and volume limits.

Lower Maximum Rates

- The maximum royalty rate for conventional oil will be reduced at higher price levels from 50% to 40% to provide better risk-reward balance to investors.
- Recognizing the fundamental changes to the North American supply/demand balance and increased competition from other jurisdictions, the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%.

Implementation/Transition

- All royalty curves will be finalized and announced by May 31, 2010 and be effective for all production January 1, 2011.
- The transitional royalty framework for oil and gas introduced in November 2008 will continue until its original announced expiration on December 31, 2013. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.
- The drilling royalty credit will continue until expiry on March 31, 2011 and all other programs will continue as designed.

As part of the recognition of the significant changes in the North American natural gas market, the government will continue to analyze various components of natural gas royalties. The conclusion of this analysis will be included in the final royalty curve revisions to be announced on May 31st. Once Questerre receives the final royalty curves then the impact of the changes can be analyzed at that time.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion outlines the accounting estimates that are critical to determining Questerre's financial results.

Petroleum and Natural Gas Reserves

All of Questerre's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

Full Cost Accounting

Questerre follows the full cost method of accounting for petroleum and natural gas operations as outlined in the Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting – Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit-of-production method based on estimated proved petroleum and natural gas reserves.

In applying the full cost method, Questerre calculates a ceiling test at each annual balance sheet date, or earlier if circumstances or events indicate impairment may have occurred. This is done to ensure that the net carrying value of petroleum and natural gas assets does not exceed the estimated undiscounted future net cash flow from production of proved reserves. Accordingly, the Company must base this calculation of future net cash flow on estimated forecasted sales prices, costs and regulations in effect at the period end. AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flow from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

Asset Retirement Obligations

Questerre follows CICA Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Company's property, plant and equipment. Determination of the asset retirement obligations is based on internal estimates using current costs and technology in accordance with existing legislation and industry practice and must also estimate timing, a credit adjusted risk-free rate and inflation rate in the calculation. These estimates are subject to change over time and, as such, may impact the charge against earnings. The liability is recorded at fair value and is adjusted to its present value in subsequent periods and the amount of the accretion is charged to earnings in the period. The associated asset retirement costs are capitalized as part of the carrying amount of the related asset. The capitalized amount is depleted on a unit of production basis in accordance with the Company's depletion policy. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost also result in an increase or decrease to the asset retirement obligation and asset.

Goodwill

Goodwill of $2.47 million represents the excess purchase price over the fair value of identifiable assets and liabilities acquired from Stride Energy Ltd. in 2006. Goodwill is not amortized. However, in accordance with accounting standards, goodwill impairment is assessed annually at December 31, or more frequently as economic events dictate. Impairment is determined by comparing the fair value of the reporting unit to its carrying value, including goodwill. If it is determined that the fair value of the reporting units assets and liabilities is less than its carrying value, an impairment amount is determined. The impairment is charged to earnings.

Stock-based Compensation

The Company has a stock-based compensation plan enabling employees, officers and directors to purchase common shares at exercise prices equal to the market price or above on the date the option is granted. The Company uses the fair value method for valuing stock option grants. Compensation costs attributable to share options granted are measured at their fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon exercise of the stock options, the consideration paid by the option holder, together with the amount previously recognized in contributed surplus, is credited to share capital. The assumptions used in calculating its stock based compensation expense are: the volatility of the stock price, risk-free rates of return and the expected lives of the options.

Financial Instruments

Handbook Section 3855 sets out comprehensive requirements for recognition and measurement of financial instruments. Under this standard, an entity would recognize a financial asset or liability only when the entity becomes a party to the contractual provisions of the financial instrument. Financial assets and financial liabilities would, with certain exceptions, be initially measured at fair value.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Other Estimates

The accrual method of accounting will require management to incorporate certain estimates of revenues, royalties, production costs and other costs as at a specific reporting date. In addition, the Company must estimate capital expenditures on capital projects that are in progress or recently completed where actual costs have not been received as of the reporting date.

Accounting Standards Changes

On January 1, 2009, the Company adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064, "Goodwill and Intangible Assets". The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard was applied retroactively and has had no material impact on Questerre's consolidated financial statements.

In June 2009, the CICA issued amendments to CICA Handbook Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009 and are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards (IFRS). The adoption of this section required enhanced disclosures on Questerre's consolidated financial statements.

This section was amended to require disclosures about the inputs to fair value measurements, including their classification within a hierarchy that prioritizes the inputs to fair value measurement.

The three levels of the fair value hierarchy are:

- Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 – Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly; and
- Level 3 – Inputs that are not based on observable market data.

Questerre's marketable securities are recorded at fair value using quoted market prices and are classified as level 1 in the fair value hierarchy.

Future Accounting Pronouncements

International Financial Reporting Standards ("IFRS")

Questerre's IFRS Changeover Plan

In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. Questerre will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of 2010 required comparative information.

The key elements of Questerre's changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

During 2009, Questerre made significant progress on its changeover plan. The Company analyzed accounting policy alternatives and preliminarily drafted its IFRS accounting policies. Process and system changes have been designed for significant areas of impact, with internal control requirements taken into account. IFRS education sessions have been held with internal stakeholders.

Process and system changes will be implemented in early 2010 to ensure IFRS comparative data is captured. Questerre's IFRS accounting policies are expected to be finalized mid-2010. Quantification of IFRS impacts will then be determined utilizing previously captured data. Communication of impacts to external stakeholders is expected to occur in the latter half of 2010.

Questerre will continue to update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board.

Expected Accounting Policy Impacts

Questerre's significant areas of impact continue to include property, plant and equipment ("PP&E"), asset retirement obligations ("ARO"), impairment testing and income taxes. These areas of impact have the greatest potential impact to the Company's financial statements. The following discussion provides an overview of these areas, as well as the exemptions available under IFRS 1, First-time Adoption of International Financial Reporting Standards. In general, IFRS 1 requires first time adopters to retrospectively apply IFRS, although it does provide optional and mandatory exemptions to these requirements.

Property, Plant and Equipment

Under Canadian GAAP, Questerre follows the CICA's guideline on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Questerre will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs.

Pre-exploration costs are those expenditures incurred prior to obtaining the legal right to explore and must be expensed under IFRS. Currently, Questerre capitalizes and depletes pre-exploration costs within the country cost centre. In 2008 and 2009, these costs were not material to Questerre.

Exploration and evaluation costs are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. Under IFRS, Questerre will initially capitalize these costs as Exploration and Evaluation assets on the balance sheet. When the area or project is determined to be technically feasible and commercially viable, the costs will be transferred to PP&E. Unrecoverable exploration and evaluation costs associated with an area or project will be expensed.

Development costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under IFRS, Questerre will continue to capitalize these costs within PP&E on the balance sheet. However, the costs will be depleted on a unit-of-production basis over an area level (unit of account) instead of the country cost centre level currently utilized under Canadian GAAP. Questerre has not finalized the areas or the inputs to be utilized in the unit-of-production depletion calculation.

Under IFRS, upstream divestures will generally result in a gain or loss recognized in net earnings. Under Canadian GAAP, proceeds of divestitures are normally deducted from the full cost pool without recognition of a gain or loss unless the deduction would result in a change to the depletion rate of 20% or greater, in which case a gain or loss is recorded.

Questerre expects to adopt the IFRS 1 exemption, which allows the Company to deem its January 1, 2010 IFRS upstream asset costs to be equal to its Canadian GAAP historical upstream net book value. On January 1, 2010, the IFRS exploration and evaluation costs will be equal to the Canadian GAAP unproved properties balance and the IFRS development costs will be equal to the full cost pool balance. Questerre will allocate this upstream full cost pool over reserves to establish the area level depletion units.

Asset Retirement Obligation

Under Canadian GAAP, ARO is measured as the estimated fair value of the retirement and decommissioning expenditures expected to be incurred. Existing liabilities are not re-measured using current discount rates. Under IFRS, ARO is measured as the best estimate of the expenditure to be incurred and requires the use of current discount rates at each remeasurement date. Generally, the change in discount rates results in a balance being added to or deducted from PP&E.

As a result of Questerre's intended use of the IFRS 1 upstream assets exemption, the Company is required to revalue its January 1, 2010 ARO balance and recognize the adjustment in retained earnings.

Impairment

Under Canadian GAAP, Questerre is required to recognize an upstream impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the country cost centre. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the fair value of the proved and probable reserves and the costs of unproved properties.

Under IFRS, Questerre is required to recognize and measure an upstream impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit. Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. Impairment losses, other than goodwill, are reversed under IFRS when there is an increase in the recoverable amount. Questerre will group its upstream assets into cash-generating units based on the independence of cash inflows from other assets or other groups of assets.

Income Taxes

In transitioning to IFRS, the Company's future tax liability will be impacted by the tax effects resulting from the IFRS changes discussed above. Questerre continues to assess the impact that the IFRS income tax principles may have on the Company.

Other IFRS 1 Considerations

Business combinations and joint ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles.

Other Recent Accounting Pronouncements

As of January 1, 2011, Questerre will be required to adopt the following CICA Handbook sections:

"Business Combinations", Section 1582, which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of operations. The adoption of this standard will impact the accounting treatment of future business combinations.

"Consolidated Financial Statements", Section 1601, which, together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on Questerre's Consolidated Financial Statements.

"Non-controlling Interests", Section 1602, which establishes the accounting for a non-controlling interest in a subsidiary in the consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on Questerre's Consolidated Financial Statements.

Design and Evaluation of Internal Control Over Financial Reporting and Disclosure Controls and Procedures

Questerre is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings" and is required to make specific disclosures with respect to NI 52-109 as follows:

- The Company has designed and evaluated the effectiveness of Disclosure Control and Procedures ("DC&P"). The President and Chief Executive Officer and the Chief Financial Officer have concluded that DC&P are designed appropriately and are operating effectively as at December 31, 2009.

- The Company has designed and evaluated the effectiveness of Internal Controls over Financial Reporting ("ICFR"). The President and Chief Executive Officer and the Chief Financial Officer have concluded that the ICFR are designed appropriately and are operating effectively as at December 31, 2009.
- The Company reports that no changes were made to ICFR during 2009 that have materially affected, or are reasonably likely to materially affect the Company's ICFR.

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

Fourth Quarter 2009 Results

In the St. Lawrence Lowlands, operations in the quarter focused on the pilot horizontal well program to assess commerciality of the Utica shale. The first well, St. Edouard No. 1A, was successfully drilled and cased to a measured depth of 3181m with a 1000m horizontal leg in the target middle Utica interval. The horizontal well was successfully completed with 8 stage fracture stimulations. Clean-up and flow back commenced January 29, 2010. Initial rates were over 12 MMcf/d. During the test, the well flowed natural gas at an average rate of over 6 MMcf/d. The well is currently still flowing on an extended production test. The second well, Gentilly No. 2, spud in December. Operations were completed on schedule and budget in January 2010. Total measured depth for the well was 2693m with an approximate 700m horizontal leg. Completion operations are expected to commence after spring break-up.

Improving commodity prices and test production from Beaver River strengthened our financial and operating performance in the fourth quarter of the year. The focus on capital preservation resulted in a strong working capital position of $46.50 million at year end with cash and cash equivalents of $51.40 million.

Production for the period averaged 759 boe/d as compared to 632 boe/d in the preceding quarter and 907 boe/d for the fourth quarter of 2008.

New drilling and completion techniques at Antler, Saskatchewan continued to show promise during the quarter. Based on these results, Questerre and its partners finalized plans to implement these in a winter drilling program consisting of three (1.50 net) wells. Production from Beaver River, northeast British Columbia, resumed early in the quarter at initial rates of up to 3 MMcf/d (gross) from three wells – A-5, A-7 and A-2. Extended periods of unseasonably cold weather subsequently froze production facilities at two of the wells. Current production is approximately 500 Mcf/d (gross) from the A-2 well.

Crude oil prices in the quarter reflected the growing optimism about the economic recovery and the weakness in the US dollar. Late in the quarter, natural gas prices staged a recovery with colder than expected weather positively impacting the record storage levels. As a result, oil and liquids prices increased 8% to $76.30/bbl and natural gas prices increased by 41% to $4.53/Mcf from $3.21/Mcf in the previous quarter. The improved prices and higher volumes translated into petroleum and natural gas revenue of $3.45 million or 24% higher than third quarter revenue of $2.79 million.

With the cash flow from operations largely unchanged compared to the prior quarter, Questerre's net loss for the period increased with higher non-cash expenses, particularly stock based compensation and depletion and depreciation and a smaller future tax recovery. For the quarter, Questerre reported a net loss of $3.90 million and positive cash flow from operations of $0.60 million. This compares to a net loss of $1.58 million and positive cash flow from operations of $0.50 million in the preceding quarter.

Capital expenditures of $3.44 million in the quarter focused on the pilot horizontal program in Québec. Of this amount, $2.54 million was spent drilling two (0.46 net) horizontal wells in the Lowlands and $0.71 million in Antler completing and tying in one (1.00 net) horizontal well.

Quarterly Financial Information

	December 31 2009	**September 30 2009**	**June 30 2009**	**March 31 2009**
Production (boe/d)	**759**	**632**	**806**	**1,049**
Average Realized Price ($/boe)	**49.37**	**47.92**	**40.56**	**39.46**
Petroleum and Natural Gas Sales	**3,447,123**	**2,786,384**	**2,974,761**	**3,724,999**
Cash Flow from Operations	**595,717**	**502,357**	**717,151**	**1,063,351**
Per share – Basic	**–**	**–**	**–**	**0.01**
Per share – Diluted	**–**	**–**	**–**	**0.01**
Net Loss	**(3,898,088)**	**(1,581,718)**	**(3,835,057)**	**(4,408,025)**
Per share – Basic	**(0.02)**	**(0.01)**	**(0.02)**	**(0.02)**
Per share – Diluted	**(0.02)**	**(0.01)**	**(0.02)**	**(0.02)**
Capital Expenditures, net of acquisitions and dispositions	**3,438,205**	**3,259,938**	**1,732,487**	**3,558,911**
Working Capital Surplus	**46,500,671**	**49,016,405**	**50,953,325**	**51,756,719**
Total Assets	**145,272,364**	**149,304,238**	**149,650,802**	**154,599,633**
Shareholders' Equity	**129,977,202**	**132,216,221**	**131,820,858**	**134,190,125**
Weighted Average Common Shares Outstanding				
Basic	**199,243,068**	**197,827,758**	**197,370,978**	**197,299,642**
Diluted	**208,653,009**	**206,723,239**	**205,065,933**	**205,069,693**

	December 31 2008	September 30 2008	June 30 2008	March 31 2008
Production (boe/d)	907	1,292	1,241	1,274
Average Realized Price ($/boe)	55.65	74.81	80.03	62.38
Petroleum and Natural Gas Sales	4,644,224	8,892,160	9,037,355	7,231,829
Cash Flow from Operations	2,799,792	5,411,554	5,138,828	3,939,125
Per share – Basic	0.01	0.03	0.03	0.02
Per share – Diluted	0.01	0.03	0.03	0.02
Net Earnings (Loss)	(7,487,376)	292,647	(2,670,086)	652,201
Per share – Basic	(0.04)	–	(0.01)	–
Per share – Diluted	(0.04)	–	(0.01)	–
Capital Expenditures, net of acquisitions and dispositions	14,377,062	7,352,744	3,066,281	17,694,854
Working Capital Surplus (Deficiency)	54,307,989	67,826,776	68,450,058	(4,506,141)
Total Assets	165,531,133	162,756,977	160,395,379	102,606,756
Shareholders' Equity	137,189,444	145,328,700	143,603,481	72,783,296
Weighted Average Common Shares Outstanding				
Basic	197,293,327	197,250,522	181,275,421	169,733,932
Diluted	206,230,961	208,686,342	194,380,878	172,902,492

	December 31 2007	September 30 2007	June 30 2007	March 31 2007
Production (boe/d)	1,216	1,206	1,443	1,702
Average Realized Price ($/boe)	48.16	39.11	49.93	48.98
Petroleum and Natural Gas Sales	5,387,928	4,339,265	6,555,860	7,502,436
Cash Flow from Operations	1,584,590	2,414,613	3,183,088	3,046,729
Per share – Basic	0.01	0.02	0.02	0.02
Per share – Diluted	0.01	0.02	0.02	0.02
Net Earnings (Loss)	(2,066,084)	(676,499)	980,543	480,366
Per share – Basic	(0.01)	–	0.01	–
Per share – Diluted	(0.01)	–	0.01	–
Capital Expenditures, net of acquisitions and dispositions	9,355,590	5,646,625	(6,702,933)	7,163,179
Working Capital Surplus	10,007,846	26,476,203	29,911,344	20,427,261
Total Assets	93,074,767	77,241,283	80,758,475	77,279,174
Shareholders' Equity	71,627,841	62,100,834	62,412,993	60,688,283
Weighted Average Common Shares Outstanding				
Basic	162,650,245	155,211,741	155,198,536	155,190,861
Diluted	166,729,098	160,919,586	161,897,966	162,242,898