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 August 12, 2009. This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and six months ended June 30, 2009 and the audited consolidated financial statements for the year ended December 31, 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 for December 31, 2008 is available on SEDAR at www.sedar.com.

Questerre is a junior oil and gas company involved in the exploration and development of scalable high-impact projects in Canada. To mitigate the risks associated with these projects, the Company has secured partners to assist in their development. To further diversify risk, the Company continues to develop a portfolio of conventional exploration and production 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.

Non-GAAP Terms

This document contains the terms "cash flow from operations", "netbacks" and "working capital" 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

	Three months ended June 30		*Six months ended June 30*	
	2009	2008	**2009**	2008
Cash flows from operating activities	**$ 461,941**	$ 8,279,521	**$ (1,553,863)**	$ 9,839,507
Net change in non-cash working capital	**255,210**	(3,140,693)	**3,334,365**	(761,555)
Cash flow from operations	**$ 717,151**	$ 5,138,828	**$ 1,780,502**	$ 9,077,952

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.

Working capital, which terms represent current assets less current liabilities is used to assess efficiency, liquidity and general financial strength. There is no GAAP measure that is reasonably comparable to working capital.

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.

Select Information

As at/for the period ended June 30	*Three months ended*		*Six months ended*	
	2009	2008	**2009**	2008
Financial ($)				
Petroleum and Natural Gas Sales	**2,974,761**	9,037,355	**6,699,760**	16,269,184
Cash Flow from Operations	**717,151**	5,138,828	**1,780,502**	9,077,952
Per share – Basic	**–**	0.03	**0.01**	0.05
Per share – Diluted	**–**	0.03	**0.01**	0.05
Net Loss	**(3,835,057)**	(2,670,086)	**(8,243,082)**	(2,017,885)
Per share – Basic	**(0.02)**	(0.01)	**(0.04)**	(0.01)
Per share – Diluted	**(0.02)**	(0.01)	**(0.04)**	(0.01)
Capital Expenditures, net of acquisitions and dispositions	**1,732,487**	3,066,281	**5,291,398**	20,761,135
Working Capital Surplus	**50,953,325**	68,450,058	**50,953,325**	68,450,058
Total Assets	**149,650,802**	160,395,379	**149,650,802**	160,395,379
Shareholders' Equity	**131,820,858**	143,603,481	**131,820,858**	143,603,481
Common Shares Outstanding	**197,618,809**	196,650,213	**197,618,809**	196,650,213
Weighted average – basic	**197,370,978**	181,275,421	**197,335,508**	175,504,676
Weighted average – diluted	**205,065,933**	194,380,878	**205,059,942**	187,525,387
Operations (units as noted)				
Average Production				
Crude Oil and Natural Gas Liquids (bbls/d)	**357**	310	**410**	307
Natural Gas (mcf/d)	**2,694**	5,590	**3,102**	5,708
Total (boe/d)	**806**	1,241	**927**	1,258
Average Sales Price				
Crude Oil and Natural Gas Liquids ($/bbl)	**63.98**	122.92	**55.62**	109.33
Natural Gas ($/mcf)	**3.64**	10.94	**4.58**	9.77
Total ($/boe)	**40.56**	80.03	**39.93**	71.06
Netback ($/boe)				
Total Revenue	**40.56**	80.03	**39.93**	71.06
Royalties	**1.40**	13.23	**3.41**	12.09
Percentage	**3%**	17%	**9%**	17%
Field Operating Expense	**12.19**	15.72	**12.67**	14.00
Operating Netback	**26.97**	51.08	**23.85**	44.97
Net Cash G&A	**17.83**	5.55	**14.49**	5.08
Cash Netback	**9.14**	45.53	**9.36**	39.89
Wells Drilled				
Gross	**–**	3.0	**1.0**	8.0
Net	**–**	1.5	**0.3**	4.5

Highlights

- Consistently positive results in the middle Utica
- Acquired significant acreage prospective for Horn River shale gas and deeper targets
- Positive cash flow of $0.72 million and production of 806 boe/d with minimal capital investment in producing assets, production shut-ins and lower prices
- Capital preservation efforts maintained working capital over $50 million and no debt

Second Quarter 2009 Activities

St. Lawrence Lowlands, Quebec

Questerre's activities in the Lowlands focused on the appraisal of test wells drilled with its partner, Talisman Energy Canada ("Talisman"). The Utica and Lorraine shales remained the primary zones of interest in addition to the deeper carbonate Trenton Black-River ("TBR") group.

Drilling of the fourth and final well of the Talisman farm-in, St. Edouard #1, was completed in the quarter. An open-hole test of the TBR formation was conducted based on gas shows while drilling. A final gas rate of 2.2 mmcf/d was achieved over a three day test with no formation water. Pressure data gathered during the test indicates that estimated reserves for this zone would be insufficient to support tie-in costs to the local gathering system and it was subsequently suspended.

Following the TBR test, a single zone within the Utica was identified and hydraulically fracture stimulated. The well is on initial cleanup and flow-back with results expected in the third quarter.

Testing of the third well of the Talisman program, St. David #1, was also finalized earlier in the quarter. Following the stimulation of two Utica intervals, the well flowed at 450 mcf/d over an extended test period. Production logging indicates the majority of the flow is from a single interval within the Utica.

The fracture stimulations conducted by Talisman on the joint wells have targeted a specific interval within the middle of the Utica formation. Test data has confirmed that the flow rates to date from all these wells are primarily attributable to this interval. These consistent results over a large geographic area have led the partners to commit to drilling two full-length horizontal wells with multi-stage fracs into this interval later this year.

Talisman recently acquired over 100 kms of 2-D seismic to identify locations for the pilot horizontal wells. Subject to the interpretation of this survey and final well results, the proposed horizontals will likely be located adjacent to the existing verticals for micro-seismic monitoring of stimulation effectiveness.

Questerre also completed its preliminary evaluation of the St. Jean sur Richelieu #1 well. The well was designed to evaluate the shallower Utica shale to the south of the main fairway. A successful fracture stimulation was conducted and yielded sustained gas flows of under 100 mcf/d. Frac efficiency was less than predicted. Based on the pressure data and depth, Questerre believes the Utica in this area can be developed with vertical wells and multiple small fracs similar to shallow tight gas projects in Alberta. Further work is ongoing to assess the application of gas fracturing to improve frac effectiveness and commerciality.

Northeast British Columbia

Beaver River Field

Production testing of the A-5 shale gas well was setback with a planned outage at the main processing plant during the quarter.

The A-5 well was shut-in for the entire month of June due to a turnaround of the Spectra Energy's Fort Nelson Gas plant. Prior thereto, the well produced at an average gross rate of 2.57 mmcf/d in the quarter consistent with Management's expectations. Fluid production, including drilling mud and other additives, continued to increase over this period with additional modifications made to the facilities to handle the increased volumes.

At current natural gas prices, Questerre realizes a sales price, net of gathering and processing charges, of approximately $2/mcf. The Company has since extended the shut-in until natural gas prices improve. In the meantime, field operators have been working on cleanup and restoration of leases along with the rehabilitation of the A-5 production facilities.

<u>Greater Sierra</u>

The turnaround at the Fort Nelson plant also shut-in production at Greater Sierra for the month of June.

Through participation in a Crown landsale, Questerre acquired an additional 14,680 acres (11,680 net) in the Greater Sierra area. Prospective intervals on this acreage include the primary Jean Marie as well as the deeper Horn River shale and Keg River and Pine Point carbonates. Subject to surface access and rig availability, Questerre is planning to drill a vertical well to test multiple targets during the winter of 2010.

Antler, Saskatchewan

With improving oil prices in the latter part of the quarter, operations at Antler recommenced with the fracture stimulation of two horizontal wells drilled in 2008.

The pilot stimulation tested a modified completion technique designed to confine the frac within the target Bakken/Torquay interval and minimize water production from adjacent intervals. The wells are on cleanup and initial results are encouraging. To further improve recovery, Questerre plans to drill a horizontal well this fall and assess the benefits of coiled tubing conveyed fracture stimulation. This could further improve frac efficiency by allowing a greater number of fracs over the length of the horizontal section.

Drilling Activities

Questerre did not participate in the drilling of any wells during the second quarter of 2009.

Production

With development drilling deferred in the present commodity price environment, Questerre's production volumes declined over prior periods. Daily production averaged 806 boe/d for the second quarter of 2009. This compares to 1,049 boe/d in first quarter and 1,241 boe/d for the same period in 2008. On a year-to-date basis, production was 927 boe/d in 2009 and 1,258 boe/d in 2008.

The Company's product mix remained relatively unchanged for the first two quarters of this year with oil and natural gas liquids accounting for 44% of production (2008: 25%). The increase from the previous year is largely due to the development of the Antler area in the second half of 2008 that currently accounts for two-thirds of Company oil volumes. Questerre's remaining oil and liquids are from its Mannville pools in Vulcan, southern Alberta.

Alberta production declined slightly to 379 boe/d in the second quarter of this year from 408 boe/d in the first. Proportionately, Vulcan contributed approximately 85% of these volumes in both periods with minor properties making up the remaining 15%. Production from Vulcan in the quarter decreased to 327 boe/d from 483 boe/d in the prior year. Higher volumes from this area in 2008 were credited to a horizontal oil well that came on test production in late June at rates in excess of 500 boe/d. For the same period, production from minor properties of 159 boe/d included assets in the Westlock area of Alberta that contributed 86 boe/d and were subsequently sold later in the year.

Production of 190 boe/d (2008: 396 boe/d) or 24% of Company volumes in the quarter was from Questerre's assets in British Columbia. This was lower than expected due to a turnaround at the primary processing plant that shut-in Questerre's BC production for one-third of the quarter. Beaver River continues to represent the majority of BC production with 152 boe/d or 80% of volumes from the A-5 shale gas well in 2009. By comparison, in 2008, 255 boe/d or 64% of volumes were from the lower pressure A-2 and A-7 wells that are currently backed out by the A-5 well. Questerre holds a 50% interest in two gas wells at Greater Sierra that added the other 38 boe/d of production from the province in the quarter (2008: 141 boe/d).

The Antler property in southeast Saskatchewan accounted for the residual volumes of 237 boe/d (2008: 203 boe/d). The decline from first quarter production of 336 boe/d reflects the flush production from horizontal wells that were placed on-stream in the preceding six months. Prior to resuming its drilling program, Questerre plans to drill one new well in Antler this year to assess a new drilling and completion technique.

Second Quarter 2009 Financial Results

Revenue

Petroleum and natural gas revenue for the second quarter mirrored the decline in production volumes. Prices had minimal impact as increases in oil prices were offset by decreases in gas prices for the period. For the three months ended June 30, 2009, Questerre reported revenue of $2.97 million as compared to $3.72 million for the three months ended March 31, 2009.

Significantly higher prices and volumes in 2008, mainly in the second quarter were responsible for increased revenue. While year to date revenues were $6.70 million in 2009, in 2008, revenue was $16.27 million and $9.04 million for the second quarter.

Crude oil prices improved materially over the prior quarter despite growing inventories and reduced demand. This has been partially attributed to financial interest in crude as a hedge against inflation and the value of the US dollar. This increase was tempered as lower demand contributed to a rising differential between the US and Canadian benchmark prices of approximately three to five times the normal. Furthermore, domestic prices also suffered from the increasing strength of the Canadian dollar.

The reference Edmonton Light price for the second quarter averaged $65.90/bbl up from $49.65/bbl in the first quarter. Questerre's realized price saw a similar improvement to $63.98/bbl from $49.11/bbl during the quarter.

Concerns about growing storage levels and reduced industrial and consumer demand continued to weigh on natural gas prices. Storage exceeds both prior year and five year averages and, based on recent estimates, could threaten capacity limits resulting in forced shut-ins and competing sales in the spot market. While the outlook for 2010 is strong based on markedly lower gas drilling activity this year, high storage is seen as the main driver in near-term prices.

Consistent with prior years, the higher heat content of gas production from Vulcan improved net gas prices. In the quarter, Questerre realized prices of $3.64/mcf (2008: $10.94/mcf) as compared to the AECO daily index average of $3.46/mcf (2008: $10.22/mcf).

All oil and natural gas production is sold on the spot market and Questerre does not hold any hedges, financial or physical, as at June 30, 2009.

Royalties

Royalty expense for the quarter was $0.10 million (2008: $1.49 million) and $0.57 million (2008: $2.77 million) for the first six months of the year. This represented an effective royalty rate of 3% (2008: 17%) for the quarter and 9% for the first half of the year (2008: 17%). The significant decrease is due to Crown royalty credits for incentive programs in British Columbia and a one-time adjustment for royalties in Saskatchewan.

Production from Alberta attracted a royalty rate of 21% (2008: 20%), from 24% in the first quarter. The rate in the second quarter reflects comparatively higher gas cost allowance credits for Vulcan production. The rate increased marginally from 20% in the second quarter of 2008 as Questerre disposed of a significant portion of its minor properties later in the year that attracted a royalty rate of 8%.

The New Royalty Framework ("NRF") which came into effect in Alberta on January 1, 2009 is anticipated to have a minimal impact on the Company's royalty rate. Lower production volumes and prices in 2009 are likely to result in an immaterial change to the Company's royalty rate under this new legislation.

In British Columbia, royalties for the quarter were a net credit of $0.18 million (2008: $0.50 million). This represents a credit for 2008 production from the Company's wells in Greater Sierra that qualify under the Crown's ultra marginal gas well royalty program. The wells now attract a royalty rate of 6%. Questerre benefits from a deep re-entry royalty credit on production from the A-5 well and as such does not anticipate paying any royalties for the remainder of this year.

New royalty incentives announced by the BC government on August 6, 2009 will have a minimal impact on royalties from the Company's existing wells. Subject to drilling in the Greater Sierra region in early 2010, Questerre anticipates it could benefit from these royalty incentive programs.

The royalty rate on Saskatchewan production was 2% (2008: 4%) and includes Crown, overriding and freehold royalties. The rate for the second quarter includes a credit amendment for Crown royalties relating to earlier periods based on an assessment received from the provincial government.

Operating Costs

Total operating expenses, including gathering and processing charges, for the quarter were $0.89 million (2008: $1.78 million) and $2.13 million (2008: $3.21 million) for the first half of the year. On a boe basis, operating costs averaged $12.19 for the quarter (2008: $15.72) and $12.67 (2008: $14.00) for the year to date.

Lifting costs in Alberta remained relatively stable, decreasing to $9.31/boe from $9.50/boe in the first quarter. During the second quarter of 2008, operating costs of $14.27/boe reflect higher cost properties in Central Alberta that were subsequently sold and the general cost inflation in the industry in the prior year.

Excluding third party gathering and processing charges that account for 25% of total operating costs at Beaver River this quarter, lower activity levels saw fixed expenses at the field decline over the previous quarter and the same period in 2008. With only one operational well and no boost compression, fixed costs for the quarter were $0.29 million as compared to $0.40 million in the prior quarter and $0.35 million for the same period in the prior year. Conversely, gathering and processing charges account for the majority of field costs at Greater Sierra. The lower production volumes reduced operating costs in this area to $0.04 million from $0.07 million in the prior quarter.

With improved operating efficiencies, costs in Antler decreased to $10.67/bbl from $12.73/bbl in the first quarter and $16.44/bbl in the second quarter of 2008. Questerre expects these to increase to approximately $13/bbl in the third quarter as additional wells that are not pipeline connected to the central battery are brought on stream.

General and Administrative Expenses

General and administrative expenses, net of capitalized overhead and recoveries ("G&A") were $1.31 million for the quarter (2008: $0.63 million) and $2.43 million for the year to date (2008: $1.16 million).

In line with first quarter gross expenses of $1.34 million, G&A for the quarter was $1.40 million. Lower capitalized expenses and overhead recoveries were responsible for the increase in net G&A to $1.31 million from $1.12 million in the first quarter. In the second quarter of 2008, lower gross expenses and higher deductions accounted for the G&A of $0.63 million.

The lower capitalization and overhead recoveries coupled with a 23% decrease in production volumes in the quarter saw a proportionate increase, on a boe basis, to $17.83 from $11.90 in the prior quarter.

($ thousands)	*Three months ended June 30*		*Six months ended June 30*	
	2009	2008	**2009**	2008
General and administrative expenses	**$ 1,398**	$ 1,135	**$ 2,735**	$ 2,284
Capitalized expenses and overhead recoveries	**(90)**	(508)	**(303)**	(1,122)
General and administrative expenses, net	**$ 1,308**	$ 627	**$ 2,432**	$ 1,162

Stock-Based Compensation

Stock-based compensation expense was $1.28 million for the quarter ended June 30, 2009 (2008: $0.53 million) and $2.69 million for the first half of 2009 (2008: $0.86 million). This represents the estimated fair value of stock options granted using the Black Scholes pricing model amortized over the vesting period.

The appreciation and increased volatility in Questerre's share price, higher exercise prices coupled with the number of options granted in the last twelve months resulted in significantly higher expense during the period. The weighted average fair value of the options granted in the first half of 2009 using the Black Scholes pricing model was $1.21 (2008: $1.25) and the weighted average exercise price was $1.80 (2008: $1.78).

Other Income and Expenses

For the first six months of the year, Questerrre reported interest income of $0.29 million (2008: $0.39 million) and $0.09 million (2008: $0.31 million) for the three months ended June 30, 2009. The income was earned on the net proceeds of the $75 million equity issue completed by Questerre in the second quarter of 2008. The decreases in the interest income amounts in 2009 are due to lower interest rates realized and the smaller balances invested. The proceeds are invested in Guaranteed Investment Certificates issued by Canadian chartered banks with a maturity of less than one year.

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. For the first six months of 2009, the Company recorded an unrealized loss of $0.03 million. At June 30, 2009, Questerre holds marketable securities with a market value of $0.16 million.

Depletion, Depreciation and Accretion

Depletion and depreciation expense for the second quarter of 2009 decreased 21% to $3.83 million from $4.83 million in the prior quarter. On a per boe basis, these translated into rates of $52.20 and $51.16 respectively. With minimal additions to the depletable base in the second quarter, the decrease in gross expense is due to the lower production volumes.

The higher finding and development costs in 2008 explain the 37% increase on a unit of production basis from $38.12/boe in the second quarter of the prior year. A similar decrease in production volumes from the prior year had a more material impact and reduced the gross expense from $4.31 million.

At June 30, 2009, property, plant and equipment included $22.12 million (December 31, 2008: $19.89 million) relating to seismic expenditures and unproved properties which have been excluded from the depletion calculation. Included in the depletion calculation are future development costs of $5.36 million (December 31, 2008: $5.36 million).

Questerre recognized $0.11 million in accretion expense for the three months ended June 30, 2009 (2008: $0.04 million) and $0.21 million for the first six months of 2009 (2008: $0.10 million). The increases are due to the obligations for wells drilled in 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 $5.19 million as at June 30, 2009 based on a total future undiscounted liability of $9.86 million.

Net Loss

Questerre realized a loss, before income taxes, of $4.44 million for the three months ended June 30, 2009 (2008: $0.23 million) and a loss of $9.74 million for the six months ended June 30, 2009 (2008: $1.66 million). The loss in the current year was attributable to substantially lower commodity prices and reduced production volumes coupled with higher expenses. In the prior year, significantly higher revenue and comparatively lower expenses resulted in a smaller loss.

Income Taxes

The recovery of future taxes for the second quarter of 2009 was $0.64 million when compared to a recovery of $0.89 million in the prior quarter and an expense of $2.43 million in the second quarter of 2008. The 2009 second quarter decrease in the future tax recovery, when compared to the 2009 first quarter recovery, is primarily related to a decrease in the net loss before income taxes.

Capital Expenditures

Questerre incurred capital expenditures of $1.73 million in the second quarter of 2009 and $5.29 million for the first half of the year.

These expenditures largely focused on the shale gas appraisal program in Quebec where the Company incurred $2.73 million participating in the drilling and completion of several shale gas wells. The Company invested $0.78 million to acquire additional exploration acreage in the Greater Sierra region of British Columbia. Excluding minor capital commitments in Alberta for $0.12 million, the remainder was spent in Antler to tie-in existing wells to the central battery, expand water disposal facilities and finalize the drilling and completion of wells spud in the fourth quarter of 2008.

In 2008, a total of $21.05 million was invested in the Company's core areas. A winter intensive capital program in northeast British Columbia saw $17.70 million invested in the first quarter alone with the balance spent in the second quarter mainly in Alberta and Saskatchewan.

($ thousands)	*Three months ended June 30*		*Six months ended June 30*	
	2009	2008	**2009**	2008
Expenditures on Property, Plant and Equipment				
Alberta	**59**	1,295	**116**	1,752
British Columbia	**680**	(213)	**775**	13,978
Saskatchewan	**445**	2,248	**1,667**	5,289
Quebec	**548**	24	**2,733**	30
	1,732	3,354	**5,291**	21,049
Dispositions	**–**	(890)	**–**	(890)
Acquisitions (cash portion)	**–**	602	**–**	602
Acquisitions (non-cash portion)	**–**	162	**–**	162
Asset Retirement Obligations	**–**	(275)	**17**	(106)
Total	**1,732**	2,953	**5,308**	20,817

Liquidity and Capital Resources

Questerre reported a working capital surplus of $50.95 million at June 30, 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 $56.59 million, $0.16 million of marketable securities, $4.91 million of accounts receivable, $0.19 million of inventory and $0.58 million in prepaids and deposits. Current liabilities of $11.47 million represent accounts payable and accrued liabilities.

The Company believes it is sufficiently capitalized with positive cash flow from operations, no debt and a working capital surplus of approximately $51 million, consisting mainly of cash and cash equivalents to weather current commodity prices and financial markets.

The majority of planned capital spending in 2009 will be incurred in Quebec and is in part contingent upon the results of the pilot programs conducted by Questerre's partners. The Company does not currently anticipate using its credit facility to fund capital expenditures in 2009 or 2010. The line of credit 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 in the 2009 second quarter of $0.72 million was $0.35 million, or 33% lower than the preceding quarter and $4.42 million or 86% lower than the prior year second quarter. The decrease in the cash flow from operations from the preceding quarter was primarily due to lower production volumes. Compared to the prior year, lower realized prices for both oil and natural gas of 48% and 67%, respectively, and lower volumes account for the significant decrease.

Cash flows from operating activities for the second quarter of 2009 were $0.46 million compared to $8.28 million in the same period in 2008. The cash flow from operations change of $4.42 million and the change in the non-cash working capital of $3.40 million represents the change in the cash flows from operating activities.

Share Capital

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

	August 12 2009	June 30 2009	December 31 2008
Common shares	197,631,310	197,618,809	197,299,642
Stock Options	18,274,586	18,332,087	17,655,421
Weighted average common shares			
Basic		197,335,508	186,447,776
Diluted		205,059,942	196,593,333

Risk Management

Except as detailed below, there were no changes to Questerre's risk management policies during the period from those detailed in the MD&A for the year ended December 31, 2008.

British Columbia's Royalty Incentives

On August 6, 2009, the BC government announced an oil and gas stimulus package to attract investment and produce immediate economic benefits to the province. The package included royalty and regulatory initiatives to enhance the province's competitiveness. Royalty initiatives include a one year 2% royalty for all wells drilled between September 2009 and June 2010, an increase of 15% in the existing royalty deductions for natural gas drilling, qualification of horizontal wells drilled between 1900 and 2300m into the Deep Royalty Credit Program and an additional $50 million allocation for the Infrastructure Royalty Credit Program to stimulate investment in oil and gas roads and pipelines. Regulatory initiatives are the commingling of production in the plains area and amendments to the drilling license regulation to create flexibility allowing industry to move wells to production while not losing the privileges to convert drilling licenses to leases.

Questerre is evaluating additional capital investment in British Columbia as a result of this announcement. Subject to drilling in the Greater Sierra region in early 2010, Questerre anticipates it could benefit from these royalty incentive programs.

Alberta's New Royalty Programs

The Alberta Government's New Royalty Framework ("NRF") and Transitional Royalty Program ("TRP") came into effect on January 1, 2009. The NRF established new royalties for conventional oil and natural gas that are linked to commodity prices, well production volumes and well depths for gas wells and oil quality for oil wells. These new rates apply to both new and existing conventional oil and gas activities in Alberta. The TRP allows for a one time option of selecting between transitional rates and the NRF rates on new natural gas or conventional oil wells drilled between 1,000 metres to 3,500 metres in depth. The TRP rates would apply until January 1, 2014, at which time all wells would be moved to the NRF.

On March 3, 2009, the Alberta Government announced an energy incentive program that focuses on keeping drilling and service crews at work. There are two components of this program that could potentially affect Questerre; the Drilling Royalty Credit and the New Well Incentive. The Drilling Royalty Credit is a depth related credit for the drilling of new conventional oil and natural gas wells between April 1, 2009 and March 31, 2011. The New Well Incentive provides a five percent royalty rate for new natural gas and conventional oil wells that come on production between April 1, 2009 and March 31, 2011 for a period of 12 months or 0.5 billion cubic feet equivalent for gas wells or 50,000 barrels of oil equivalent for oil wells, whichever comes first.

It is envisaged for the remainder of 2009 that both the NRF, in combination with low natural gas prices plus the new incentive programs will have a negligible impact on Questerre's Crown royalty rates. Future capital plans are being evaluated as a result of the NRF, TRP and Energy Incentive Programs which have changed the economics of operating in Alberta.

Accounting Standards Changes

On January 1, 2009, the Company adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook Section:

"Goodwill and Intangible Assets", Section 3064. 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.

Future Accounting Pronouncements

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("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 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.

The Company is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes, with a focus on the areas that have been identified as having the most significant impact. The significant impact areas are those identified as having the greatest potential impact to the Company's consolidated financial statements or the greatest risk in terms of complexity to implement. Such areas identified to date include property, plant & equipment ("PP&E"), impairment testing, asset retirement obligations, stock-based compensation and income taxes.

The Company expects one of the most significant impacts of the IFRS changeover will be in the area of accounting for exploration and development costs. Questerre currently follows the CICA's guidelines on full cost accounting. In moving 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. Depletion will be calculated at a lower unit of account level than the current country cost centre basis. In addition, impairment testing will be performed at a lower level than the current country cost centre basis and the impairment test is a one step rather than a two step process.

In July 2009, the International Accounting Standards Board ("IASB") issued a document outlining additional exemptions for first-time adopters of IFRS. Included in the document is an exemption which permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) over reserves to the unit of account level upon transition to IFRS. This exemption relieves the Company from retrospective application of IFRS for upstream PP&E. Questerre intends to adopt this exemption and the Company is also evaluating the impact of other first-time adoption exemptions available upon initial transition to IFRS.

Questerre will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company's consolidated financial statements is not reasonably determinable at this time.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Company is accumulated and communicated to Questerre's management as appropriate to allow timely decisions regarding required disclosure. Questerre's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the Company, including its consolidated subsidiaries, is made known to them by others within those entities, particularly during the period in which the interim filings are being prepared.

Internal controls have been designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements together with the other financial information for external purposes in accordance with Canadian GAAP. The Company's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision internal controls over financial reporting related to the Company, including its consolidated subsidiaries.

There have been no significant changes in Questerre's internal control over financial reporting during the quarter ended June 30, 2009 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Quarterly Financial Information

	June 30 2009	March 31 2009
Production (boe/d)	**806**	1,049
Average Realized Price ($/boe)	**40.56**	39.46
Petroleum and Natural Gas Sales	**2,974,761**	3,724,999
Cash Flow from Operations	**717,151**	1,063,351
Per share – Basic	**–**	0.01
Per share – Diluted	**–**	0.01
Net Loss	**(3,835,057)**	(4,408,025)
Per share – Basic	**(0.02)**	(0.02)
Per share – Diluted	**(0.02)**	(0.02)
Capital Expenditures, net of acquisitions and dispositions	**1,732,487**	3,558,911
Working Capital Surplus	**50,953,325**	51,756,719
Total Assets	**149,650,802**	154,599,633
Shareholders' Equity	**131,820,858**	134,190,125
Weighted Average Common Shares Outstanding		
Basic	**197,370,978**	197,299,642
Diluted	**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