



*Questerre
energy*

within reach

2005 ANNUAL REPORT



Questerre Energy Corporation is a Calgary-based petroleum and natural gas exploration and production company. The Company aims to create shareholder value through the development of scalable, high-impact projects.

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

president's message

HIGHLIGHTS

2005 was an exciting year for Questerre as we met or exceeded all of our goals for the year.

- Farm-in agreement and commencement of operations at Beaver River Field
- Farm-in agreement with Talisman in Quebec
- Drilled 17 (5.93 net) wells with an 88% success rate
- 466% increase in NPV-10 of our proved and probable reserves to \$22.1 million
- 29% increase in NPV-10 of our proved, probable and possible reserves to \$225 million
- 45% increase in our gross land base to 1.08 million acres
- Secondary listing on the Oslo Stock Exchange with daily trading volumes increasing from 71,000 shares to over 1.96 million shares

BEAVER RIVER FIELD, BRITISH COLUMBIA

Transeuro Energy made a farm-in commitment for Beaver River targeting the development of both prospective horizons at the Field, the shallow Mattson and the deeper Nahanni. We concluded our agreement in late May and operations commenced in early September.

The initial work program targeted the shallow Mattson sands with the re-entry of four existing wells. Three wells were re-entered and the first well, A-2, was placed on production at 2 mmcf/d late in the first quarter of 2006.

Positive results from this program have addressed one of the key risks of developing the Mattson – with proper stimulation techniques, wells in the Mattson are capable of commercial production. We believe the next well in the program, B-1, will provide more vital information – new well logs, reservoir core and optimal drilling and completion techniques – and further mitigate risk.

If the results from the B-1 well meet our expectations, the development of the Mattson sands could turn into a major resource play for us. Multiple wells will be required to recover over 100 Bcf in potential natural gas resource. We were pleased to learn that Transeuro shares our enthusiasm about this play – they have begun developing plans for an initial six well program for the Mattson and recently acquired a partner copy of the 3-D seismic survey from us.

While the Mattson holds significant potential, we believe the larger prize at Beaver River remains the Nahanni formation where remaining recoverable gas is expected to range between 120 Bcf of possible reserves and 540 Bcf of resource potential. Of interest, Talisman Energy recently spud a Nahanni well adjacent to the Beaver River Field in early 2006.

Our initial target for the Nahanni at the Field is an up-dip compartment that could contain up to 30 Bcf in potential reserves. We have also identified up to eight additional locations for new compartments and infill locations. Based on their review of the 3-D seismic data and results from the Mattson drilling program, we believe Transeuro could spud a well for this up-dip compartment as early as next year.

ST. LAWRENCE LOWLANDS, QUEBEC

Not without substantial risk, we believe the St. Lawrence Lowlands could be a home run opportunity for us.

The strategic land position we secured in early 2001, primarily for the Trenton Black River (“TBR”) play, is proving to be a valuable investment. In October 2005, we concluded a farm-in agreement with Talisman Energy Canada for this acreage. Recognized as North America’s expert in the TBR play, Talisman is currently producing approximately 100 mmcf per day in the Appalachian Basin from this formation.

Developments in the Appalachian Basin and an ongoing interpretation of our seismic database are confirming the multi horizon potential in the Lowlands. In addition to the primary zone of interest, our first target, Becancour, could be prospective for two additional zones – a shallow fractured Utica shale and a deeper Potsdam sandstone.

Of the over 40 potential locations we have identified, we believe the first to be drilled will be the Becancour structure. Covering twelve square miles, the structure could host several hundred Bcf in potential reserves. Pending review of the 2-D seismic data being acquired over two of our prospects, we anticipate Talisman spudding their first well on our acreage for Becancour by the fourth quarter of this year.

VULCAN, ALBERTA

Our efforts to develop a portfolio of conventional assets in Alberta met with exceptional success, particularly in the Vulcan area of southern Alberta.

Drilling results in Vulcan have exceeded our expectations with a 50% interest in a new Mannville pool discovery. Three wells were drilled in 2005 with the second well testing at a constrained rate of over 8 mmcf per day. Based on these results and a re-processed 3-D seismic survey, up to eight additional locations were identified for natural gas and ten for oil. We currently have 1,000 boe per day of gas production behind pipe in Vulcan from this new pool.

We expect further drilling and a reservoir simulation study will quantify the magnitude of this new pool discovery and whether the oil column encountered is associated with this gas pool. Under either an oil or gas development scenario, production from this pool will be significant to Questerre.

In the interim, we have been using advanced seismic modelling techniques to explore for similar pools in this relatively underexplored area. Despite a very competitive land position, we plan to actively expand our acreage through participation in Crown sales and farm-in opportunities.

WESTLOCK, ALBERTA

During the year we also began building a new core area in Westlock in Central Alberta. The area is prospective for natural gas in multiple horizons. Following an acquisition of producing properties and exploration acreage in Westlock and Hector, we acquired additional acreage and participated in the drilling of three wells in this area. Four more wells are planned for this area in 2006. We are also actively evaluating acquisition and farm-in opportunities in Westlock.

CORPORATE

Our financial results for 2005 do not reflect our discoveries in Vulcan nor any results from the farm-out of our major projects. These have started to be recognized in our proved and probable reserve additions for 2005. Nevertheless we did meet our goal of being breakeven cash flow from operations for the year.

We financed our capital expenditures of \$10.4 million through an initial public offering in Norway and a private placement completed in September.

We completed a \$10 million initial public offering in Norway and listed our Common Shares for trading on the Oslo Stock Exchange.

OUTLOOK FOR 2006

Our goals for 2006 are as follows:

- Obtain results from our partner funded new well at the Beaver River Field
- See our partner Talisman drill our first high impact exploration well in Quebec
- Complete development drilling at our new Vulcan pool
- Establish Westlock as a new core area
- Have in excess of 1,500 boe per day of production on stream or behind pipe

For 2006, our capital expenditure budget approved by our board of directors is \$20 million. This does not include spending by our partners on our properties. We expect this amount will be funded by existing working capital, cash flow and an equity placement.



Michael Binnion

President and Chief Executive Officer

areas of operations

BEAVER RIVER FIELD, BRITISH COLUMBIA

The Beaver River Field is located 100 miles northwest of Fort Nelson on the border of British Columbia and the Yukon. The Field is tied into the Duke Energy Gas Transmission pipeline and all gas produced is processed at the Duke Energy Fort Nelson Gas Plant. Gas is sold at the Station 2 Spot Price less applicable transportation and processing charges.

There are two primary zones of interest at the Field – the Nahanni formation at a depth of approximately 3,500 m and the shallower Mattson or Besa River formation at a depth of 1,300 to 2,000m.

Nahanni formation

Discovered in 1961, the Nahanni formation at the Field is estimated to hold 1.4 Tcf of original gas in place (“OGIP”). Recovery rates for the Nahanni were estimated at 90% of OGIP; however, production in the 1970s recovered only 12%, or 178 Bcf, due to unexpected water influx.

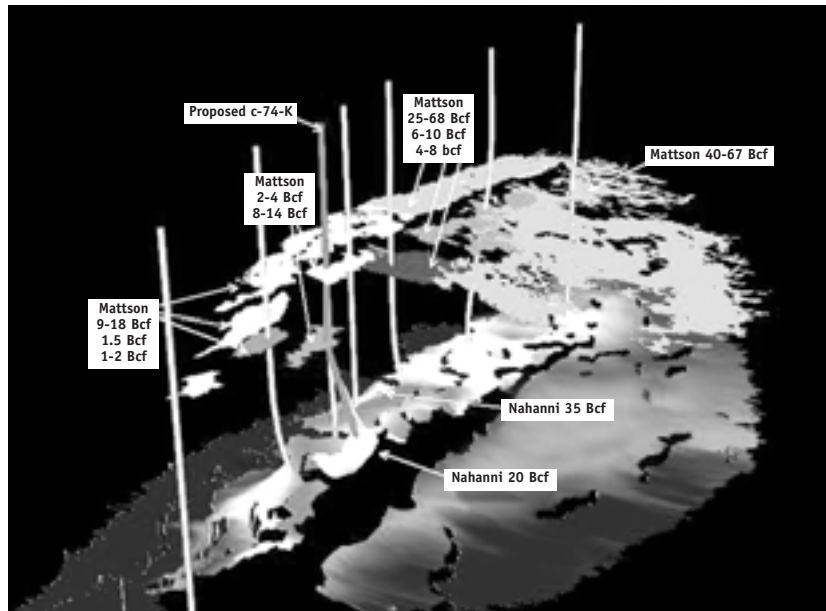
Assuming a range of recovery factors between 20% and 50% (based on active water drive gas reservoirs), ultimate remaining recoverable gas from Nahanni could range between 120 Bcf in possible reserves and 540 Bcf in resource potential, with individual wells averaging daily production of 25-50 mmcf. Questerre acquired a controlling interest in the Field in 2001.

Our interpretation of the Nahanni formation is based on compartmentalization and preferential flow of water in the fracture system (“coning”) – the majority of the recoverable reserves could be contained in undrilled fault blocks or compartments and the remainder behind water cones in existing compartments.

This interpretation is based on comprehensive technical work we completed that includes hydrodynamic pressure studies, material balance analysis, pressure transient analysis and gas isotope analysis. We believe this interpretation was corroborated by a 3-D seismic survey acquired in 2002.

Based on an interpretation of the 3-D seismic data reprocessed in 2004, it appears that the Nahanni potentially has more undrilled compartments than originally expected. It is anticipated that this could translate into a higher recovery factor. The reprocessing has also identified a new compartment that appears to contain up-dip structure less than 500 meters away from the A-5 well. A new well into this compartment could test both the new compartment and up-dip hypothesis.

We have identified a drilling location targeting a new compartment based on the reprocessed seismic. Subject to Ampac electing to drill the Nahanni option well, we expect this location will be drilled in early 2008.



Prospectivity of Beaver River Field

Mattson formation

The shallow Mattson formation produced 6.6 Bcf during the 1970s from two wells. Individual wells that were not placed on production tested at daily rates ranging between 0.5 mmcf and 12 mmcf.

The reprocessing of the 3-D seismic survey in 2004 resulted in better imaging of this Mattson formation. An analysis of this horizon has indicated these could be tight gas zones, or non-conventional reservoir, where proper completion techniques play an important role in achieving commercial production. If we are successful in creating artificial fractures through modern stimulation techniques, we believe the Mattson could hold over 100 Bcf in potential natural gas resource.

The Mattson formation was the primary objective of the first phase of the Ampac Farmout Agreement. This commenced in September 2005 and operations on three of the four wells were finalized by March 2006.

The first well, A-2, was successfully re-entered, completed and stimulated. The well tested at 2 mmcf per day and was tied-in to the local gathering system in the first quarter of 2006. The re-entry of the second well, B-2, confirmed the integrity of the casing to the deeper Nahanni formation. This well will be preserved as a re-entry candidate for the Nahanni instead of the shallower Mattson. We have accepted the work completed on the B-2 well as satisfying the minimum work requirements for this well.

The third well, A-6, was fracture stimulated during the first quarter of 2006. The well initially flowed natural gas, but after the fracture stimulation it flowed at lower rates, which was unexpected. It is currently shut-in for an extended pressure buildup to support a detailed evaluation of the data and determine why the stimulation resulted in lower flow rates. Operations on the fourth well are scheduled for this summer. To this end, we granted our partner an extension until June 15, 2006 to complete the initial work program.



Testing of A-2 well

ST. LAWRENCE LOWLANDS, QUEBEC

The St. Lawrence Lowlands are located in Quebec south of the St. Lawrence River between Montreal and Quebec City.

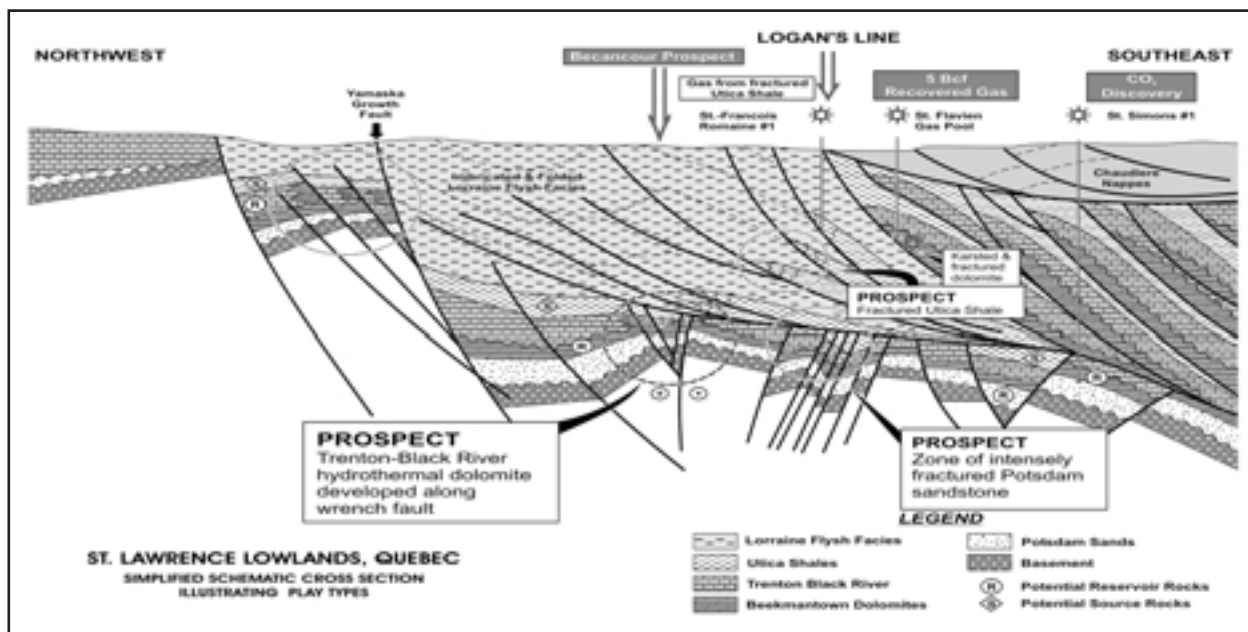
The St. Lawrence Lowlands have been sparsely explored with the exception of shallow drilling by Shell Canada in the 1970s. During the 1980s, exploration efforts focused on large deep tilted fault blocks. While these structures were proven to have poor porosity, the existence of a deep gas source to charge deeper structures and migration pathways was proven for the first time in this geological setting.

The recognition of significant wrench faulting in this basin, coupled with an understanding of the mechanism creating hydrothermal dolomitized reservoirs, led to a complete re-evaluation of the area in pursuit of a new exploration concept. This concept is based on areas where extensive wrench faulting creates conduits for hot high-pressure fluids to create hydrothermal dolomitized reservoirs.

Focusing specifically on this exploration concept, we completed an extensive regional geological and geophysical study of the St. Lawrence Lowlands. The study included the reprocessing and reinterpretation of over 3,000 km of 2-D seismic and a detailed review of the wells that have been drilled in the St. Lawrence Lowlands. The work is supported by the documented occurrence of hydrothermal dolomitized carbonates in outcrop and well bores in the Quebec. We believe that recent significant discoveries based on this exploration concept in the Appalachian Basin, directly south of the St. Lawrence Lowlands, further validate the proposed exploration concept.

In addition to the primary target in the Trenton-Black River, our acreage could be prospective for a shallower fractured shale target in the Utica and a deeper sandstone target known as the Potsdam.

Subject to the results of the 2-D seismic program currently underway by Talisman, we anticipate the first well will be drilled during the fourth quarter of 2006. The well will test our Becancour prospect that covers approximately 12 square miles.



Multiple play types in St. Lawrence Lowlands

SOUTHERN AND CENTRAL ALBERTA

Vulcan

The Vulcan area is located approximately 150 km south of Calgary. The area is prospective for natural gas in multiple horizons, with the primary target at a depth of approximately 1900m.

We participated for a 50% interest in a new Mannville pool discovery in this area in 2005.

Three wells, including the discovery well were drilled into the pool in 2005. The discovery well tested at 332 boe per day and the second well tested at a constrained rate of 740 boe per day. The third well did not encounter any commercial hydrocarbons in the target formation.

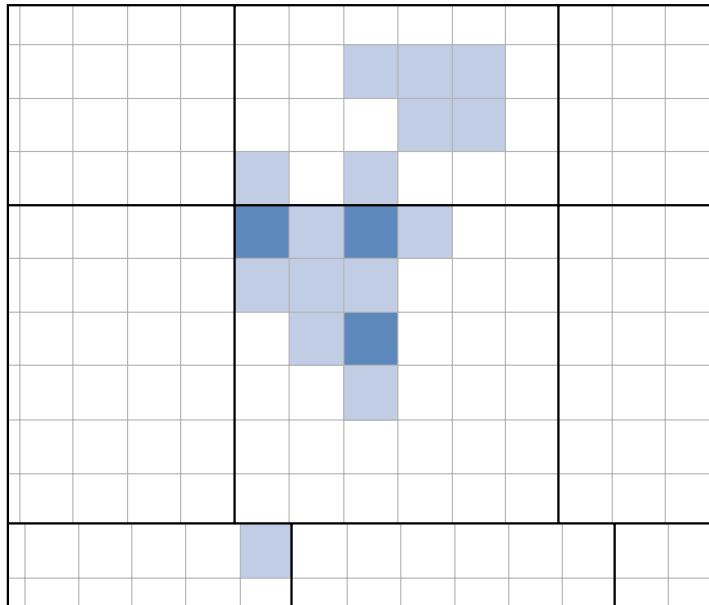
Based on test results and re-processing of the 3-D seismic survey, up to eight additional gas locations and ten additional oil locations were identified for this pool in 2006. To date, three locations were drilled in the first quarter of 2006 and all have encountered commercial hydrocarbons.

In conjunction with our partner, we are developing a reservoir simulation study to support the proposed development plan for the pool. It is expected this plan will be submitted to the Alberta Energy and Utilities Board (“EUB”) during the second quarter. Subject to EUB approval, the operator anticipates commercial production will begin early in the third quarter of 2006.

We are also evaluating secondary shallower targets on these lands, including Horseshoe Canyon coal bed methane (“CBM”) horizon. A minimum of four locations has been identified for these targets on the acreage in Vulcan. Two wells have been drilled during the first quarter of 2006 with completion and testing expected in the third quarter of this year.

Westlock, Hector, Parkland and Drumheller

We also developed an interest in the Westlock, Hector, Parkland and Drumheller areas of Southern and Central Alberta in 2005. We hold an interest in 24 sections of land in these areas. Production from this acreage is approximately 160 boe per day with over 50 boe per day behind pipe. Questerre expects to participate in the drilling of 4 wells in these areas in 2006.



Land holdings in Vulcan

management's discussion and analysis of financial condition and results of operations

The following Management Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") was prepared at, and is dated, March 27, 2006. This MD&A is provided by Management of Questerre Energy Corporation ("Questerre" or the "Company") to review 2005 activities and results as compared to the previous year and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2005 and 2004. Additional information relating to Questerre, including Questerre's Annual Information Form is available on SEDAR at www.sedar.com.

Questerre was incorporated in October 1971. The Company initially operated as an oil and gas exploration and production company with minority interests in several producing properties in Western Canada. In November 2000, a new management team was assembled and the Company changed its focus to pursuing what Management believes will be large-scale exploration and development projects. Management intends to leverage its specialized knowledge of naturally fractured and hydrothermally dolomitized reservoirs to develop these projects.

To mitigate the risks associated with these projects, the Company seeks industry partners to jointly participate in their development. The Company further seeks to temper risk through the development of a portfolio of conventional, lower risk projects in Alberta. It is expected the Alberta projects will provide near-term cash flow and growth.

As at March 24, 2006, the Company has two projects it believes hold the potential to create significant shareholder value – the Beaver River Field in British Columbia (the "Field") and the St. Lawrence Lowlands in Quebec. The lower risk Alberta project under development include assets in the areas of Westlock, Hector, Vulcan, Parkland and Drumheller.

The Company's Common Shares are listed on the Toronto Stock Exchange and Oslo Stock Exchange under the symbol QEC.

This MD&A contains forward-looking statements. Forward-looking statements are based on current expectations that involve a number of risks and uncertainties which could cause events or results to differ materially from those reflected in the MD&A. Forward-looking statements are based on the estimates and opinions of Questerre's management at the time the statements were made. Questerre assumes no obligation to update forward-looking statements should circumstances or management's estimates change.

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 and is based on an energy equivalent conversion method application at the burner tip and does not necessarily represent an economic value equivalent at the wellhead.

HIGHLIGHTS

- Proven and probable reserves on a NPV-10% basis increased from \$3.9 million at December 31, 2004 to \$22.1 million at December 31, 2005 on a constant dollar basis
- Proved, probable and possible reserves on a NPV-10% basis increased from \$174.8 million at December 31, 2004 to \$225.6 million at December 31, 2005 on a constant dollar basis
- Questerre participated in the drilling of 17 (5.93 net) wells in 2005 resulting in 14 gas wells, 1 oil well and 2 dry holes for an 88% success rate
- Questerre expanded its land holdings from 740,000 (603,000 net) acres in 2004 to 1,076,000 (770,000 net) acres in 2005
- The Company completed an initial public offering in Oslo, Norway and listed its Common Shares on the Oslo Stock Exchange, increasing average daily trading volumes from 70,940 shares in 2004 to 1,960,929 shares in 2005.

SELECTED ANNUAL INFORMATION

Item	For Year Ended		
	December 31, 2005	December 31, 2004	December 31, 2003
Total Revenues	\$ 1,734,477	\$ 1,636,096	\$ 2,788,701
Expenses	(4,740,039)	(2,768,162)	19,513,827
Net Income (Loss)			
Total	(3,005,562)	693,503	(16,725,126)
Per Share	(0.03)	0.02	(0.54)
Per Share (Diluted)	(0.03)	0.02	(0.54)
Total Assets	26,192,763	9,803,679	8,240,837
Total Capital Expenditures	10,307,805	7,475,182	13,287,416
Working Capital (Deficiency)	9,802,130	2,857,088	(4,457,846)
Total Long Term Debt	–	600,000	–
Total Liabilities	4,022,876	3,255,036	8,388,171
Shareholders' Equity	22,169,887	6,548,643	(147,334)
Cash Dividend per Share	0.00	0.00	0.00

QUARTERLY FINANCIAL INFORMATION

Period ended December 31, 2005	Q1	Q2	Q3	Q4	Total
Production revenue, net of royalties	\$ 461,249	\$ 520,965	\$ 282,696	\$ 469,567	\$ 1,734,477
Net income (loss)	(1,159,310)	(410,079)	(548,764)	(887,409)	(3,005,562)
Per share – basic	(0.02)	(0.01)	(0.01)	(0.01)	(0.03)
Per share – diluted	(0.02)	(0.01)	(0.01)	(0.01)	(0.03)
Period ended December 31, 2004	Q1	Q2	Q3	Q4	Total
Production revenue, net of royalties	\$ 64,555	\$ 903,601	\$ 286,365	\$ 381,575	\$ 1,636,096
Net loss	(5,523,293)	(909,815)	6,698,361	428,250	693,503
Per share – basic	(0.13)	(0.02)	0.15	0.01	0.02
Per share – diluted	(0.13)	(0.02)	0.15	0.01	0.02

OPERATIONAL INFORMATION

	2005	2004
Production (boe per day)	110	138
Average Sales price (\$/mcf)	\$ 8.28	\$ 6.25
Land Holdings (acres)		
Undeveloped		
Gross	1,059,403	731,743
Net	764,080	600,674
Developed		
Gross	16,414	8,254
Net	6,127	2,387
Reserves (mboe)		
Proved	506	-
Probable	402	382
Possible	9,094	14,163
Total	10,002	14,545
NPV 10% Based on constant pricing		
Proved	\$ 13,014,000	\$ (134,000)
Probable	\$ 9,129,000	\$ 4,044,000
Possible	\$ 203,411,000	\$ 170,864,000
Total	\$ 225,554,000	\$ 174,774,000

2005 ACTIVITIES

Beaver River Field

Farm-in agreement with Ampac Petroleum

In May 2005, Questerre Beaver River Inc. ("QBR"), a wholly owned subsidiary of the Company, entered into a definitive farmout agreement for the development of the Field with Ampac Petroleum Inc. ("Ampac"). Ampac is a private exploration and production company controlled by a director of Questerre. Ampac subsequently farmed out this agreement to Transeuro Energy Corp., an emerging international oil and gas company.

The development will target both the shallow Mattson and the deeper Nahanni formations. The first phase of the farmout involves the re-entry and re-completion of four existing wells for the Mattson. The agreement also includes two optional wells – one for a new Mattson sand and the second to target a new compartment in the Nahanni.

Ampac will fund and operate the initial phase to earn a 50% interest in the Mattson formation in the four re-entry wells. By drilling the first option well, Ampac will earn 50% of the remaining rights in the Mattson formation. Ampac will earn a 50% interest in the Nahanni formation and the facilities and infrastructure at the Field by drilling the second option well.

In February 2006, Transeuro acquired a copy of the 3-D seismic survey over the Field from QBR. In the event that Transeuro does not proceed with the Nahanni option well, it will pay QBR \$750,000 for the seismic survey.

2005 Work Program

The first phase of this development commenced in September 2005 and operations on three of the four wells were finalized by March 2006.

The first well, A-2, was successfully re-entered, completed and stimulated. The well tested at 2 mmcf per day and was tied-in to the local gathering system in the first quarter of 2006. The re-entry of the second well, B-2, confirmed the integrity of the casing to the deeper Nahanni formation. This well will be preserved as a re-entry candidate for the Nahanni instead of the shallower Mattson. QBR has accepted the work completed on the B-2 well as satisfying the minimum work requirements for this well.

The third well, A-6, was fracture stimulated during the first quarter of 2006. The well initially flowed natural gas, but after the fracture stimulation it flowed at lower rates, which was unexpected. It is currently shut-in for an extended pressure buildup to support a detailed evaluation of the data and determine why the stimulation resulted in lower flow rates. Operations on the fourth well are scheduled for this summer. To this end, the Company has granted its partner an extension until June 15, 2006 to complete the initial work program.

It is anticipated that the seismic data recently acquired from QBR will assist in the joint evaluation of additional drilling locations for the Mattson as well as the deeper Nahanni formation.

Fire Incident

In June 2005, a fire broke out in the workshop at the Field. Operations staff contained the fire following QBR's emergency response procedures and no injuries were sustained. For the second half of 2005, operations at the Field have focused on the reconstruction of the workshop and staff quarters. QBR has submitted its insurance claim and expects this will be settled in early 2006.

St. Lawrence Lowlands

Farm-in agreement with Talisman Energy

In early October 2005, Questerre executed a definitive agreement with Talisman Energy Canada for its existing 711,000 acres in the St. Lawrence Lowlands.

In early 2006, at its sole cost, Talisman commenced a 2-D seismic program over two Questerre prospects. Based on the results of the program Talisman has the right to drill up to four wells to earn on all the acreage.

Questerre and its partners may retain a 25% working interest in the acreage and receive a 5% gross overriding royalty from Talisman. The Company and its partners will be responsible for 15% of the drilling costs with Talisman funding the remainder of the drilling and all land, geological and geophysical costs.

Farm-in agreement with Gastem Inc.

The Company expanded its land holdings in Quebec through a farm-in agreement with Gastem Inc., a junior exploration and production company. Pursuant to this agreement, Questerre will earn a 50% interest in over 311,000 acres held by Gastem by funding a prescribed work program. In January 2006, Questerre acquired a 10% interest in Gastem by subscribing, on a private placement basis, for 1.46 million units of Gastem at \$0.10 per unit. Each unit consists of 1 common share and one unit. Each unit entitles the holder to acquire one additional common share of Gastem at \$0.10 per share for two years.

Vulcan

Questerre participated in a new Mannville pool discovery in the Vulcan area of Southern Alberta. Questerre has a 50% interest in this discovery.

Three wells including the discovery well were drilled into the pool in 2005. The discovery well tested at 332 boe per day and the second well tested at a constrained rate of 740 boe per day. The third well did not encounter any commercial hydrocarbons in the target formation.

Based on test results and re-processing of the 3-D seismic survey, Questerre and its partner identified up to eight additional gas locations and ten additional oil locations for this pool in 2006. To date, three locations were drilled in the first quarter of 2006 and all have encountered commercial hydrocarbons.

In conjunction with Questerre, the operator is developing a reservoir simulation study to support its development plan for the pool. It is expected this plan will be submitted to the Alberta Energy and Utilities Board ("EUB") during the second quarter. Subject to EUB approval, the operator anticipates commercial production will begin early in the third quarter of 2006.

Questerre and its partner are also evaluating secondary shallower targets on these lands, including the Horseshoe Canyon coal bed methane ("CBM") horizon. A minimum of four locations has been identified for these targets on the Vulcan acreage. Two wells have been drilled during the first quarter of 2006 with completion and testing expected in the third quarter of this year.

Westlock, Hector and Drumheller

Purchase and Sale Agreement with Rupert's Crossing

The Company entered into an agreement with Rupert's Crossing, an Investment Corporation ("Rupert's") to acquire Rupert's interest in certain producing properties and acreage in the Westlock and Hector areas of Central Alberta. Rupert's is a private investment holding company controlled by the President and Chief Executive Officer of Questerre.

The purchase price for this acquisition of \$2.1 million was based on an evaluation of the assets prepared by an independent reservoir engineering firm. The acquisition closed during the second quarter of 2005 with an effective date of April 1, 2005.

During 2005, the Company expanded its landholdings in the area through participation at Crown land sales. The Company participated in the drilling of three gross wells (1.6 net) resulting in two gas wells and one oil well.

In Drumheller, Questerre participated for a 20% interest in an 8 well development program with EOG Resources Canada, Inc., a US based independent. The program yielded eight gas wells. Subject to receipt of regulatory approval and tie-in, these wells are scheduled to be on production by July 2006.

Current production from these areas is approximately 160 boe per day with an additional 50 boe per day of production behind pipe.

Other Areas

Parkland

Questerre participated in the completion and stimulation of a well in the Parkland area of Alberta in early 2005. The well was targeting natural gas in multiple horizons. Based on an analysis of the test results, it appears that the original completion and stimulation was not optimized for the target formations. The Company proposes to recomplete and stimulate the well during the first quarter of 2006.

Simonette

The Company participated in the drilling of a well in the Simonette area of Alberta during the first quarter of 2005 with Cabot Petroleum Canada Corporation. The well was testing a Swan Hills reef play adjacent to two fields that produced in excess of 15 million barrels each from the Swan Hills formation. The well did not encounter reservoir in the Swan Hills formation and was subsequently abandoned. Questerre farmed out a 26.7% interest (20% after payout) in this well to Devon Canada and retained a 23.3% interest (30% after payout) in this well.

Drilling Activities

In 2005, Questerre participated in the drilling of 17 gross wells (5.93 net wells) resulting in 14 gas wells, 1 oil well and 2 dry holes for an 88% success rate.

Corporate

Listing on Oslo Stock Exchange

Questerre completed a \$10 million public offering and listed its Common Shares for trading on the Oslo Stock Exchange in Norway during the second quarter of 2005. A total of 30,000,000 Common Shares were issued at \$0.33 per Common Share under the offering primarily to retail and institutional investors in Norway.

Equity Offerings

Including the initial public offering in Norway, the Company completed a total of three placements for gross proceeds of \$19.19 million through the issuance of 43,112,690 Common Shares.

PRODUCTION

The Company's production in 2005 was primarily natural gas from its interests in non-operated producing properties in Alberta and the Beaver River Field (the "Field").

Production for the year ended December 31, 2005 averaged 110 boe per day as compared to 138 boe per day for the year ended December 31, 2004. The 20% decline in production is attributable to the lower production from the Field in 2005 offset by increased production from its properties in Alberta.

Field production averaged 39 boe per day in 2005 as compared to 113 boe per day in 2004. The sole producing well at the Field, the A-5 well, was shut-in at the beginning of the third quarter due to a downhole obstruction. A workover of this well is planned for 2006.

The Company has recently tied-in the A-2 well at the Field. QBR will have a 50% interest in this well.

The acquisition of producing properties in Central Alberta effective April 2005 and subsequent drilling increased production from Alberta from 25 boe per day in 2004 to 72 boe per day in 2005. The Company has identified several additional drilling locations on these new lands and plan to participate in the drilling of four wells in this area in 2006.

Based on the drilling success in early 2006, the Company believes it has 1,000 boe per day of natural gas production behind pipe in Vulcan. Subject to the results from the 2006 winter drilling program in Vulcan, the Company plans to participate in up to five additional gas wells and ten potential oil wells in 2006.

2005 FINANCIAL RESULTS

Revenue

Questerre reported petroleum and natural gas revenues of \$2.10 million in 2005 (2004 - \$1.94 million). 2005 revenues include \$0.57 million (2004: \$1.53 million) in natural gas sales from the Field and \$1.53 million (2004: \$0.41 million) from its interests in producing properties in Central and Southern Alberta. Questerre's realized natural gas prices increased by 32% to \$8.28 per mcf in 2005 from \$6.25 per mcf in 2004. These higher prices offset the decrease in production and accounted for the 8% increase in gross revenue over the year.

Royalties

Questerre recorded royalty expense of \$0.36 million for the year ended December 31, 2005 (2004 –\$0.31 million).

Crown and overriding royalties in 2005 include a recovery of Crown royalties of \$0.14 million accrued on Field production in 2004. The recovery reflects the Company's qualification during the year for a \$0.75 million royalty credit for the A-5 well. The Company did not record Crown royalties on production from the Field in 2005 and offsets them against this royalty credit. To date, the Company has utilized \$0.23 million of this credit.

Excluding the royalty credit, crown and overriding royalties on production from Alberta were \$0.51 million (2004 – \$0.1 million). The significant increase can be attributed to higher production from Alberta in 2005 as compared to the previous year. On a percentage basis, the royalty rate increased by 17% to 33% in 2005 from 28% in 2004.

Operating Costs

Total operating expenses for the year ended December 31, 2005 decreased substantially to \$0.71 million from \$1.72 million in 2004. The majority of the decrease is due to the lower operating expenditures at the Field in 2005.

The Company recorded minimal operating expenses for the Beaver River Field during the second half of 2005. With the A-5 well shut-in in July, operations at the Field were directed towards the reconstruction of the operators' quarters and workshop after the fire in June 2005. The Company expects to be reimbursed for these specific expenses under its insurance policy.

General & Administrative Expenses

General and administrative expenses of \$1.03 million in 2005 reflect the increased corporate activity securing farm-in partners for the Company's projects and the development of a portfolio of assets in Alberta. Overhead capitalization of \$0.42 million associated with this increased capital expenditures in Alberta offset a significant portion of 2005 expenses.

(\$ thousands)	2005	2004
General & administrative expenses	\$ 1,450	\$ 1,010
Bad debt expense	–	139
Overhead recoveries	(416)	(411)
General & administrative expenses, net	\$ 1,034	\$ 738

Other Income and Expenses

Questerre incurred restructuring charges of \$80,500 in 2005 representing the issuance of Common Shares in connection with the corporate restructuring completed in 2004. During the year ended December 31, 2004, Questerre recorded restructuring expenses of \$0.43 million representing professional services associated with the Company's filings under the CCAA.

Questerre recorded a gain of \$7.63 million in 2004 representing the net forgiveness of outstanding amounts owing by the Company to its unsecured trade creditors. \$7.30 million related to amounts settled under the Plans. See Note 3 to the audited consolidated financial statements.

Stock Based Compensation

Stock based compensation expense for the year ended December 31, 2005 totaled \$0.70 million as compared to a credit of \$0.03 million in 2004. The higher expense in 2005 can be attributed to the issuance of 6.02 million options at a weighted average price of \$0.58 per Common Share. The fair value of these options using the Black-Scholes option-pricing model is \$0.34 per option. By comparison, the Company issued a total of 3.68 million options at a weighted average price of \$0.27 per Common Share in 2004. The fair value of these options was \$0.13 per option.

Interest Expense

Interest expense of \$0.07 million in 2005 was unchanged from 2004. In both years, this comprised of interest payable on the term bank loan and the promissory note to Rupert's. See Related Party Transactions. The expense in 2005 was offset by interest earned of \$0.04 million during the year (2004 – \$0.03 million).

Depletion, Depreciation and Site Restoration

Questerre recognized \$2.07 million in depletion and depreciation in 2005 compared to \$7.4 million in 2004. Included in 2005 depletion is a \$1.31 writedown to reflect the costs of an unsuccessful well in the Simonette area of Alberta.

Included in 2004 depletion is a \$7.0 million ceiling test write-down and depletion charge recorded by the Company on its Field petroleum and natural gas assets. The write-down reflected the majority of the costs incurred to finish the drilling, completion and tie-in of the A-5 re-entry in 2004. Depletion for 2004 also includes \$0.2 million relating to the Company's costs of an unsuccessful well in the Gaspe Peninsula, Quebec.

Questerre does not include costs of \$1.81 million associated with its St. Lawrence Lowlands acreage in Quebec in the calculation of depletion or in costs subject to the ceiling test calculation. The Company also does not include costs of \$1.37 million related to its exploration project in the Parkland area in Alberta in its calculation of depletion or in costs subject to the ceiling test calculation. The projects in Parkland and in Quebec remain unproved at December 31, 2005.

The Company's estimated undiscounted asset retirement cost for the Beaver River Field at December 31, 2005 was \$1.78 million, unchanged from 2004. Questerre acquired four wells and participated in the drilling of 17 wells in 2005, resulting in an increased asset retirement obligation of \$0.27 million. Questerre estimates its total undiscounted asset retirement obligations to be \$2.38 million at December 31, 2005.

Taxes

Consistent with prior years, Questerre had sufficient tax pool deductions to offset taxable income in 2005 resulting in no income taxes payable for the current year. In addition, the Company's tax assets continue to significantly exceed tax liabilities. No tax asset is recognized at December 31, 2005 as there is no certainty that the Company will be able to realize the value of the tax assets in the future.

Net Loss and Cash Flow

Questerre recorded a net loss of \$3.01 million (\$0.03 per share) in 2005 compared to net income of \$0.07 million (\$0.02/share) in 2004. The net loss for the year is due primarily to the depletion expense that includes a writedown of the unsuccessful well in the Simonette area of Alberta. The net income in 2004 is primarily due to the gain on settlement of all outstanding obligations and the recovery due to future tax on flow-through shares offset by higher depletion.

liquidity and capital resources

CAPITAL EXPENDITURES

Questerre incurred capital expenditures of \$10.31 million in 2005 compared to \$7.48 million in 2004.

The vast majority of these expenditures relate to the development of its portfolio of assets in Central and Southern Alberta

- \$4.20 million was incurred developing the new pool discovery in Vulcan, including \$0.37 million on land acquisition and \$0.47 million on seismic data acquisition, processing and interpretation
- \$3.50 million was spent on acquired lands in the Hector and Westlock areas and includes \$2.1 million for the acquisition of production properties from Rupert's
- Participation in the Simonette well totaled \$1.23 million with the balance spent in Drumheller and in Parkland

The majority of capital spending in 2004 at the Field related to the drilling, completion and tie-in of the A-5 re-entry. In Quebec, approximately \$0.2 million was spent on the drilling of the Miguasha #1 well with the remainder incurred in the St. Lawrence Lowlands. In Alberta, Questerre incurred approximately \$0.8 million in drilling costs in the Parkland area with the remainder spent on land acquisition in the Vulcan and Simonette areas.

(\$ thousands)	2005	2004
Capital Expenditures		
Beaver River Field, British Columbia	\$ 227	\$ 6,271
St. Lawrence Lowlands, Quebec	21	287
Alberta Properties	10,060	917
Total	\$ 10,308	\$ 7,475

WORKING CAPITAL POSITION

Questerre reported a working capital surplus of \$9.80 million at December 31, 2005 compared to a working capital surplus of \$2.86 million as of December 31, 2004. The improved working capital position primarily reflects the equity placements completed by the Company in 2005.

The Company's current assets at December 31, 2005 primarily consist of cash of \$9.30 million, accounts receivable of \$1.53 million and field inventory of \$0.09 million. \$1.0 million of the receivables represent amounts due under the insurance claim for the Field. The Company expects this claim will be settled early in 2006.

Questerre's current liabilities consist of trade payables of \$1.60 million and \$0.15 million representing the term bank loan that has been classified as a current liability.

A significant portion of the Company's working capital will finance its projected capital expenditures of approximately \$5.24 million for the first quarter of 2006. Approximately three quarters of these expenditures relate to the development of the new pool in Vulcan. To augment its working capital position, the Company completed a \$7.2 million placement in early February. The Company anticipates these funds will finance potential acquisitions and farm-in opportunities.

Subject to commercial production commencing from Vulcan, Questerre believes that future capital expenditures will continue to be financed by existing working capital, cash flow and equity placements.

SHARE CAPITAL

The Company is authorized to issue an unlimited number of Class A common voting shares (the "Common Share"), an unlimited number of Class B common voting shares and an unlimited number of preferred shares, issuable in one or more series.

In April 2005, the Company completed a private placement of 3,125,000 Common Shares at \$0.32 per Common Share for gross proceeds of \$1.0 million.

In June 2005, the Company completed an offering of 30,000,000 Common Shares at \$0.33 per Common Share for gross proceeds of \$10 million. Concurrent with this offering, the Company listed its Common Shares for trading on the Oslo Stock Exchange.

In September 2005, Questerre completed a private placement of 9,987,690 Common Shares at \$0.82 per Common Shares for gross proceeds of \$8.19 million.

A total of 3,125,000 Common Shares were issued in November 2005 in connection with the corporate restructuring transactions completed in 2004. (See "Related Party Transactions")

At December 31, 2005, there were no Class B common voting shares or preferred shares outstanding, a total of 113,014,594 Common Shares outstanding and 9,205,000 stock options outstanding.

CONTRACTUAL OBLIGATIONS

Questerre is party to an Office Rental Agreement with a related party for the provision of offices, office equipment and support personnel. Either party may terminate the agreement with six months' written notice. Questerre's annual commitment under this agreement is \$126,000 for 2006.

The Company is responsible for principal payments on its bank loan in the amount of \$80,400 in 2006 and \$73,700 in 2007.

OFF-BALANCE SHEET ARRANGEMENTS

Questerre has no off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

Questerre incurred fees of \$126,000 for the years ended December 31, 2005 and 2004 to a company with common directors and officers. The transactions were in the normal course of business paid pursuant to an Office Rental Agreement for the provision of office space, office equipment and support personnel. The agreement may be terminated by either party with six months' written notice.

In April 2005, the Company completed a private placement of 3,000,000 Common Shares at \$0.32 per Common Share. Terrenex Acquisition Corporation ("Terrenex") subscribed for 2,812,500 Common Shares and Rupert's subscribed for 312,500 Common Shares. Terrenex currently holds approximately 9% of the issued and outstanding share capital of Questerre. All of the Directors of Terrenex serve as directors or officers of Questerre.

In April 2005, the Company executed a purchase and sale agreement with Rupert's to acquire its interest in producing properties and exploration acreage in Central Alberta. Rupert's is a private investment holding company controlled by the President and Chief Executive Officer of Questerre. See "Purchase and Sale Agreement with Rupert's Crossing."

In May 2005, QBR entered into a farm-in agreement with Ampac Petroleum (“Ampac”), a private exploration and production company for the development of the Field. A director of the Company is the sole shareholder and director of Ampac. See “Farm-in agreement with Ampac Petroleum.”

In November 2005, the Company issued a total of 3,150,000 Common Shares as follows

- 2,000,000 Common Shares were issued on the conversion of the \$0.6 million promissory note due to Rupert’s at a conversion rate of \$0.30 per Common Share. See Note 6 to the Audited Consolidated Financial Statements.
- 300,000 Common Shares were issued to Terrenex pursuant to the Liquidity Option Agreement. See Note 3 to the Audited Consolidated Financial Statements.
- 850,000 Common Shares were issued to employees of the Company and QBR pursuant to the Employee Retention Plan established in May 2004. No additional shares are to be issued pursuant to this retention plan.

FINANCIAL INSTRUMENTS

The Company’s financial instruments included in the balance sheet are comprised of accounts receivable, accounts payable, accrued liabilities, marketable securities and the bank loan. The fair value of financial instruments classified as current assets approximate their carrying amounts due to the short-term maturity of these instruments. The fair value of bank loan approximates its carrying amount as the interest rate approximates market.

Excluding the amounts due under the insurance claim, the remainders of the Company’s accounts receivable are for revenue due on production from the Company’s interest in non-operated properties in Alberta. The Company is exposed to credit risks normal for the oil and gas industry.

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.

FULL COST ACCOUNTING

Questerre follows the Canadian Institute of Chartered Accountants’ (“CICA”) guideline on full cost accounting to account for its oil and natural gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of natural gas and crude oil reserves are capitalized and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depreciation, depletion and amortization (“DD&A”). A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates, the excess must be written off as an expense charged against earnings.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned or if impairment has occurred. If reserves can be assigned, the cost of the properties would be included in the depletion calculation. If impairment has occurred, any write-down would be included in depletion and depreciation expense for the period.

OIL AND GAS RESERVES

Questerre's proved oil and gas reserves are evaluated and reported on by an independent reservoir engineering firm. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. These estimates are the basis for the determination of the fair market value and the estimated net revenue stream of these reserves. The Company expects that its estimate 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 economics of recovery based on cash flow forecasts. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation. A revision to the reserve estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test.

ASSET RETIREMENT OBLIGATION

The Company recognizes asset retirement obligations in the period in which they are incurred if a reasonable estimate of fair value can be determined. 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 policies.

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.

Actual costs incurred upon settlement of the obligation are charged against the liability to the extent the liability is recorded. Any difference between actual costs incurred upon settlement of the asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which settlement occurs. The Company has recorded a \$1.78 million obligation on the Field and \$0.49 million on its assets in Southern and Central Alberta.

Determination of the original undiscounted retirement obligations and timing of these obligations are based on internal estimates using current costs and technology in accordance with existing legislation and industry practice. These estimates are subject to change over time and, as such, may impact the charge against income for asset retirement obligations.

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.

The Company has issued and will continue to issue flow through shares to investors. The Company uses its best efforts to ensure that qualifying expenditures of CEE are incurred in order to meet its flow through obligations. However, in the event that the Company incurs qualifying expenditures of 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 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.

Interest rates on long-term debt float with the Bank of Canada rate. The Company does not have any US\$ denominated debt. If strong indications arise that interest rates would be increasing significantly, steps would be taken where possible to fix the rate for a period of time.

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

control environment

Based on their evaluation as of December 31, 2005, the Company's President and the Chief Financial Officer concluded, pursuant to Canadian Multilateral Instrument 52-109 Part 2.1, that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings is recorded, processed, summarized and reported within the time periods that meet the regulatory requirements. In addition, as of December 31, 2005, there were no changes in the Company's internal controls over financial reporting that occurred during 2005 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting. The Company will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

TO THE SHAREHOLDERS OF QUESTERRE ENERGY CORPORATION

The accompanying consolidated financial statements of Questerre Energy Corporation and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management has established systems of internal controls, which are designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the Audit Committee, which is comprised of non-management directors. The Audit Committee has reviewed the consolidated financial statements with management and the auditors and has reported to the Board of Directors which have approved the consolidated financial statements.

The consolidated financial statements have been audited by Pricewaterhouse Coopers LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.



Michael Binnion
President and Chief Executive Officer



Jason D'Silva
Vice President, Finance

Calgary, Alberta, Canada
March 27, 2006

auditors' report

TO THE SHAREHOLDERS OF QUESTERRE ENERGY CORPORATION

We have audited the consolidated balance sheets of Questerre Energy Corporation as at December 31, 2005 and 2004 and the consolidated statements of income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada

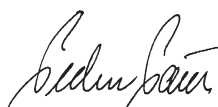
March 24, 2006

consolidated balance sheets

	December 31 2005	December 31 2004
Assets		
Current assets		
Cash	\$ 9,296,160	\$ 2,701,477
Marketable securities (market value: \$546,120)	499,311	-
Accounts receivable	1,533,354	218,249
Inventory	92,925	141,373
Deposits and cash calls paid	32,064	502,522
	11,453,814	3,563,621
Restricted Cash (note 5)	100,000	100,000
Petroleum and natural gas properties (note 4)	50,383,321	40,075,517
Less: accumulated depletion and depreciation	(35,744,372)	(33,935,459)
	14,638,949	6,140,058
	\$ 26,192,763	\$ 9,803,679
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	\$ 1,597,584	\$ 572,033
Bank loan (note 5)	154,100	234,500
	1,751,684	806,533
Promissory note payable (note 6)	-	600,000
Asset retirement obligation (note 7)	2,271,192	1,848,503
	4,022,876	3,255,036
Shareholders' Equity		
Common shares (note 8)	49,268,507	31,339,389
Contributed surplus (note 8)	739,640	41,952
Deficit	(27,838,260)	(24,832,698)
	22,169,887	6,548,643
	\$ 26,192,763	\$ 9,803,679

See accompanying notes to consolidated financial statements.

Approved by the Board of Directors



Director



Director

consolidated statements of income (loss) and deficit

	For the years ended December 31	
	2005	2004
Revenue		
Petroleum and natural gas revenue	\$ 2,097,422	\$ 1,942,523
Royalties	(362,945)	(306,427)
	1,734,477	1,636,096
Expenses		
Operating	714,783	1,718,803
General and administrative	1,034,429	737,600
Restructuring costs	80,500	430,219
Stock-based compensation (note 8 (e))	697,688	(28,575)
Interest expense	67,832	69,984
Interest income	(40,194)	(25,033)
Gain on settlement of obligations (note 3)	–	(7,630,778)
Foreign exchange gain (loss)	(46,603)	1,803
Depletion and depreciation	2,074,544	7,402,949
Accretion on asset retirement obligation (note 7)	157,060	91,190
	4,740,039	2,768,162
Net (loss) before income taxes	(3,005,562)	(1,132,066)
Taxes		
Future tax recovery	–	1,825,569
	–	1,825,569
Net (Loss) income	(3,005,562)	693,503
Deficit, beginning of period	(24,832,698)	(25,526,201)
Deficit, end of period	\$ (27,838,260)	\$ (24,832,698)
Net (loss) income per share		
Basic and diluted (note 8 (c))	\$ (0.03)	\$ 0.02

See accompanying notes to consolidated financial statements.

consolidated statements of cash flows

For the years ended December 31
2005 2004

Cash provided by (used in):

Operating Activities

Net loss (income)	\$ (3,005,562)	\$ 693,503
Items not affecting cash		
Depletion and depreciation	2,074,544	7,402,949
Accretion on asset retirement obligation	157,060	91,190
Non cash corporate restructuring costs	80,500	–
Gain on settlement of obligations	–	(7,630,778)
Stock-based compensation expense	697,688	(28,575)
Future tax recovery	–	(1,825,569)
	4,230	(1,297,280)
Net change in non-cash working capital	(779,302)	377,459
	(775,072)	(919,821)

Financing Activities

Issue of common shares	19,189,908	8,238,452
Share issue and listing costs	(1,941,290)	(353,234)
Promissory note	–	600,000
Repayment of bank loan	(80,400)	(80,400)
Net change in non-cash working capital	–	7,602,180
	17,168,218	16,006,998

Investing Activities

Expenditures on petroleum and natural gas properties	(10,307,805)	(7,475,182)
Net change in non-cash working capital	1,008,653	(6,589,129)
	(9,299,152)	(14,064,311)

Increase in cash	7,093,994	1,022,866
Cash, beginning of period	2,701,477	1,678,611
Cash, end of period	\$ 9,795,471	\$ 2,701,477

See accompanying notes to consolidated financial statements.

During the year ended December 31, 2005, the Company paid \$67,832 (2004 – \$69,984) of cash interests and \$Nil in cash taxes (2004 – \$Nil).

notes to the consolidated financial statements

For the years ended December 31, 2005 and 2004

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Questerre Energy Corporation (“Questerre” or the “Company”) is primarily involved in the exploration and development of naturally fractured and hydrothermally dolomitized reservoirs. The Company has two primary projects – the Beaver River Field in British Columbia (the “Field”) and the St. Lawrence Lowlands in Quebec (note 4). To mitigate the risks associated with these primary projects, the Company has secured partners to assist in the development of these projects.

The Company has also developed a portfolio of conventional exploration and production assets in five areas in Central and Southern Alberta – Westlock, Hector, Vulcan, Parkland and Drumheller.

2. SIGNIFICANT ACCOUNTING POLICIES

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that effect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accordingly, actual results could differ from estimated amounts.

a) Principles of consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, Questerre Beaver River Inc. (“QBR”) and 6058931 Canada Inc.

b) Cash

Cash consists of cash in the bank, less outstanding cheques and short term deposits with a maturity of less than three months.

c) Marketable securities

Marketable securities are carried at the lower of weighted average cost and market value.

d) Measurement uncertainty

Depletion and depreciation, amounts used for ceiling test calculations and asset retirement obligations are estimates. The ceiling test is based on estimates of oil and natural gas reserves and commodity prices, production expenses and capital costs required to develop and produce those reserves. By their nature, these estimates are subject to measurement uncertainty, and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

e) Inventory

Inventory is recorded at the lower of weighted average cost and market, measured by replacement cost.

f) Revenue recognition

Revenue from the sale of petroleum and natural gas are recorded when the title passes to a third party.

g) Oil and natural gas properties

The Company follows the full cost method of accounting whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical expenses, carrying charges of non-producing property, costs of drilling both productive and non-productive wells, petroleum and natural gas production equipment and overhead charges related to exploration and development activities. Proceeds received from the disposition of oil and gas properties and equipment are credited against the capitalized costs unless the disposition would significantly alter the rate of depletion and depreciation, in which case a gain or loss on disposal would be recorded.

All costs of acquisition, exploration and development of oil and gas reserves, associated tangible plant and equipment costs, and estimated costs of future development of proven undeveloped reserves are depleted and depreciated using the unit of production method based on estimated proven reserves before royalties as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content.

Depreciation of capital assets not related to oil and gas properties is provided using the straight line method over periods ranging from five to ten years.

Costs of unproved properties are initially excluded from oil and gas properties for the purpose of calculating depletion. These properties are assessed periodically to determine whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

The Company reviews the carrying amount of its oil and natural gas properties (“the properties”) relative to their recoverable amount (“the ceiling test”) at each annual balance sheet date, or earlier if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, then an impairment loss, equal to the amount by which the carrying amount of the properties exceeds the discounted cash flow from those properties using proved and probable reserves and expected future prices and costs, is recognized in depletion.

h) Asset retirement obligation

The fair value of asset retirement obligations related to long-term assets are recognized as a liability in the period in which they are incurred. The fair value of the asset retirement obligation is estimated by discounting the expected future cash flows to settle the asset retirement obligation at the Company’s credit adjusted risk free rate. Asset retirement costs equal to the discounted asset retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows.

i) Joint operations

Significant portions of the Company’s exploration and production activities are conducted jointly with others and accordingly, the financial statements reflect only the Company’s proportionate interest in such activities.

j) Foreign currency translation

Monetary assets and liabilities, denominated in foreign currencies, are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. Other assets and revenue and expense items are translated at rates prevailing when they were acquired or incurred. Foreign exchange gains and losses are included in income.

k) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deductions at the date of renouncement.

l) Stock based compensation plan

The company has a stock option plan for directors and employees. The stock option plan is described in note 8(d). The compensation cost attributable to share options granted is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase in contributed surplus.

m) Per share information

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated based on the treasury-stock method, which assumes that any proceeds obtained on exercise of options would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

3. CORPORATE RESTRUCTURING

On April 1, 2004, QBR was granted an Order by the Court of Queen's Bench of Alberta providing for creditor protection under the *Companies' Creditors Arrangement Act* ("CCAA"). On June 22, 2004, Questerre also applied for and was granted an Order by the Court of Queen's Bench of Alberta providing for creditor protection under CCAA.

QBR's financial difficulty was the result of significant problems and cost overruns associated with a re-entry operation undertaken at the Field. QBR held a 100% working interest in the operation as a result of joint venture partners choosing to forego participation under penalty. The CCAA filing by Questerre was necessary due to claims advanced or threatened by certain parties that provided goods and services in connection with the re-entry operation and was intended to allow the Company to restructure its affairs while continuing operations on a normalized basis.

On August 9, 2004, the Company filed Plans of Compromise or Arrangement (the "Plans") under the CCAA for the settlement of all outstanding claims. The Plans were approved by the requisite majority of unsecured creditors at meetings of creditors held on August 31, 2004 and sanctioned by the Court of Queen's Bench of Alberta on September 9, 2004. Questerre and QBR subsequently emerged from Court protection under the CCAA on October 8, 2004.

Pursuant to the Plans proposed by Questerre and QBR, unsecured creditors received either the lesser of the amount of their claim or \$2,000. Alternatively, unsecured creditors elected to receive a cash dividend of \$0.05 plus one Common Share of Questerre for each dollar of their claims. The Common Shares of Questerre issued under the Plans were subject to a contractual escrow and released in two equal instalments on the fourth and eighth month anniversary of the date the Plans received final Court approval.

In addition to the proposed settlement, Questerre arranged for a liquidity option. Under this liquidity option, unsecured creditors received \$0.05 for each dollar of their claims, and also received an additional \$0.07 for each dollar of their claim in exchange for foregoing each Common Share they would have otherwise received. This resulted in a cash settlement of \$0.12 per dollar of claim outstanding.

The Common Shares that would otherwise have been issued to these unsecured creditors were issued to Terrenex Acquisition Corporation ("Terrenex"), a related party, pursuant to the terms of the Liquidity Option Agreement. In consideration, Terrenex established a fund to finance the liquidity option up to a maximum of \$668,500 and was issued 300,000 Common Shares.

A total of \$0.56 million in cash and 9,623,012 Common Shares were issued on the implementation of these Plans. 6,756,102 Common Shares were issued to Terrenex pursuant to the Liquidity Option Agreement.

4. PETROLEUM AND NATURAL GAS PROPERTIES

	December 31 2005	December 31 2004
Petroleum and natural gas properties (net of accumulated depletion and depreciation)		
Alberta	\$ 9,374,442	\$ 1,024,584
British Columbia	3,458,224	3,346,186
Quebec	1,806,283	1,769,288
	\$ 14,638,949	\$ 6,140,058

During the year ended December 31, 2005, the Company capitalized administrative overhead charges of \$415,957 (2004 – \$326,619) relating to exploration and development activities.

The Company incurred a writedown of \$1.31 million for the year ended December 31, 2005. This amount relates to the Company's share of costs of an unsuccessful well in the Simonette area of Alberta during the first quarter of the year. This amount is included in the depletion and depreciation provision on the income statement.

At December 31, 2005, the Company used the following prices in its ceiling test calculation (C\$/GJ):

2006	2007	2008	2009	2010
10.05	9.05	8.05	7.00	6.55

(a) Alberta

The Company does not include costs of \$1.37 million related to its exploration project in the Parkland area in Alberta in its calculation of depletion or in costs subject to the ceiling test calculation. This project remains unproved at December 31, 2005.

(b) British Columbia

In May 2005, QBR entered into a Royalty and Quitclaim agreement with its partners at the Field (the "Farmors") and Ampac Petroleum Inc. ("Ampac") ("Quitclaim Agreement"). Ampac is a private exploration and production company controlled by a Director of Questerre. Pursuant to the Quitclaim Agreement, the Farmors quitclaimed their interest in the Field to Ampac and QBR in consideration of a royalty and a release by QBR of any amounts owed under the original farmout agreement dated January 12, 2001 (the "Beaver River Agreement"). QBR and Ampac would assume all liabilities associated with the Farmors' interest in the Field. The respective interests of QBR and Ampac in the Field post the quitclaim are 66.67% and 33.33%. Upon the execution of this Quitclaim Agreement, QBR and the Farmors agreed to terminate their existing farm-in agreement.

In May 2005, QBR and Ampac entered into a Farmout and Operating Agreement ("Farmout Agreement") for the Field. Pursuant to the Farmout Agreement, Ampac would conduct an initial work program ("Initial Work Program") involving the re-entry of four wells to earn a 50% interest in the drilling spacing units of the wells for a shallow horizon only. The second phase will involve two optional wells. Upon the completion of the Initial Work Program and the two optional wells, Ampac will hold a 50% interest in the Field, including all horizons, infrastructure and equipment. Should Ampac not complete the two optional wells, it will transfer its interest in the Field, excluding the interest earned under the Initial Work Program to QBR.

In prior years, all costs associated with the Field, net of estimated salvage values, were written down except \$2.95 million of seismic costs. These costs primarily relate to the 3-D seismic survey acquired over the Field in 2002 and have continuing value to QBR.

(c) Quebec

Questaerre does not include costs of \$1.81 million associated with its St. Lawrence Lowlands acreage in Quebec in the calculation of depletion or in costs subject to the ceiling test calculation. The Company's assets in Quebec remain unproved at December 31, 2005.

5. BANK LOAN

In July 2002, the Company obtained a five-year, \$400,000 term loan with a Canadian bank. Under the terms of the loan, the Company must make monthly payments of \$6,700 principal plus interest until the loan is paid out. The interest rate under the loan is the bank's floating base rate plus 2.0% and the Company may fix the rate at any time. The loan is secured by the first assignment to the bank of a \$100,000 Guaranteed Investment Certificate and by a General Security Agreement over the assets of the Company and its subsidiary, QBR. Financial covenants include maintaining a minimum long term debt to tangible equity ratio of 0.8 to 1.0 and maintaining a working capital ratio of at least 1.0 to 1.0.

While Questaerre currently meets this financial covenant, the Company has not been in compliance with this covenant in the past and, therefore, the bank loan has been classified as a current liability.

6. PROMISSORY NOTE PAYABLE

The Company issued a promissory note for \$0.6 million to Rupert's Crossing, an Investment Corporation ("Rupert's"). Rupert's is a private investment holding company controlled by the President and Chief Executive Officer of Questaerre. The promissory note was issued in 2004 on the receipt of \$0.6 million in cash from Rupert's.

The promissory note was due November 14, 2006 and bore interest at 8% per annum, payable monthly. It was secured by a General Security Agreement over the assets of the Company and the hypothecation of the Company's exploration licenses in the St. Lawrence Lowlands in Quebec.

Pursuant to the terms of the note, the Company had the right to prepay the entire amount or any portion thereof with 30 days' notice in writing to Rupert's. Rupert's was granted an option to convert the entire amount into Common Shares of the Company at a conversion rate of \$0.30 per Common Share.

In November 2005, Rupert's elected to convert its \$0.6 million promissory note. A total of 2,000,000 Common Shares were issued at a conversion price of \$0.30 per Common Share.

7. ASSET RETIREMENT OBLIGATION

The total future asset retirement obligation was estimated by management based on Questerre's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company estimates its total undiscounted asset retirement obligations to be \$2,382,942 at December 31, 2005. Questerre used a credit adjusted risk free rate of seven per cent and an inflation rate of three per cent over the varying lives of the assets to calculate the present value of the asset retirement obligation.

The following table provides a reconciliation of the Company's total asset retirement obligation:

	December 31 2005	December 31 2004
Balance, beginning of period	\$ 1,848,503	\$ 848,134
Increase in estimate of obligation	265,629	909,179
Accretion expense	157,060	91,190
Balance, end of period	\$ 2,271,192	\$ 1,848,503

8. SHARE CAPITAL

a) Authorized

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, 2005, there were no Class B common voting shares or preferred shares outstanding.

b) Issued and outstanding -- Class A common shares and common share warrants

	Number	Amount
Common Shares		
Balance, December 31, 2003	42,112,246	\$ 25,279,580
Issued for cash	3,280,860	1,373,075
Flow through shares issued for cash	11,703,791	5,389,928
Issued for cash on exercise of warrants	31,995	32,155
Issued under Plans	9,623,012	1,443,454
Tax effect of flow-through share issue		(1,825,569)
Share issue costs	-	(353,234)
Balance, December 31, 2004	66,751,904	\$ 31,339,389
Issued for cash	43,112,690	19,189,908
Issued on conversion of promissory note	2,000,000	600,000
Issued for corporate restructuring (note 3)	1,150,000	80,500
Share issue costs	-	(1,941,290)
Balance, December 31, 2005	113,014,594	49,268,507
Total Common Share Capital		\$ 49,268,507

Common Shares

In April 2005, the Company completed a private placement of 3,125,000 Common Shares at \$0.32 per Common Share for gross proceeds of \$1.0 million.

In June 2005, the Company completed an offering of 30,000,000 Common Shares at \$0.33 per Common Share for gross proceeds of \$10 million. Concurrent with this offering, the Company listed its Common Shares for trading on the Oslo Stock Exchange.

In September 2005, the Company completed a private placement of 9,987,690 Common Shares at \$0.82 per Common Shares for gross proceeds of \$8.19 million.

c) Per share amounts

The following table summarizes the weighted average common shares used in calculating net income (loss) per common share:

	2005	2004
Basic	91,308,441	48,273,347
Diluted	93,742,194	48,817,849

The reconciling item between the basic and diluted average common shares is stock options.

d) Stock options

The Company has a stock option plan that provides for the issuance of options to its directors, officers and employees at or above market prices. The stock options granted under the plan vest evenly over a three year period and expire five years from the date of grant. The following table sets forth a reconciliation of the stock option plan activity for the year ended December 31, 2005:

	Number of Options	Weighted Avg Exercise Price
Outstanding, December 31, 2003	3,643,500	\$ 1.28
Granted		
January 2004	313,000	1.41
September 2004	2,315,000	0.10
November 2004	50,000	0.25
December 2004	1,000,000	0.30
Cancelled	(3,956,000)	1.29
Outstanding, December 31, 2004	3,365,000	\$ 0.16
Granted		
March 2005	250,000	\$ 0.72
June 2005	3,000,000	0.40
September 2005	2,220,000	0.82
November 2005	550,000	0.53
Cancelled	(180,000)	(0.14)
Outstanding, December 31, 2005	9,205,000	0.44
Exercisable, December 31, 2005	2,062,083	\$ 0.29

The outstanding options have a range of exercise prices from \$0.10 to \$1.00, and a weighted average number of years to expiry of 4.2 (2004 – 5.0 years). The exercisable options have a range of exercise prices from \$0.10 to \$1.00 and 4.0 years to expiry (2004 – 5.0 years).

e) Stock-based compensation costs

The Company accounts for its stock based compensation plan using the fair value method. Under this method, compensation cost attributable to share options granted to employees or directors is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. The fair value of each option granted is estimated at the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2005	2004
Weighted average fair value per option	\$ 0.26	\$ 0.13
Risk free interest rate (%)	3.0	3.0
Expected life (years)	3.0	3.0
Expected volatility (%)	105	173

f) Contributed surplus

The following table sets forth a reconciliation of contributed surplus for the year ended December 31, 2005:

Balance, December 31, 2003	-
Adoption of Stock based compensation	\$ 70,527
Stock based compensation expense	136,350
Forfeit of options	(164,925)
Balance, December 31, 2004	\$ 41,952
Stock based compensation expense	717,641
Forfeit of options	(19,953)
Balance, December 31, 2005	\$ 739,640

9. FUTURE INCOME TAXES

The provision for income taxes in the financial statements differs from the result, which would have been obtained in applying the combined federal and provincial tax rate to the Company's earnings before income taxes. The difference results from the following items:

	Year ended December 31	
	2005	2004
Net loss before income taxes	\$ (3,005,562)	\$ (1,132,066)
Combined federal and provincial tax rate	33.69%	38.66%
Computed "expected" income tax recovery	(1,009,869)	(437,657)
Increase in income taxes resulting from:		
Non-deductible crown charges and recoveries	404,371	73,541
Tax rate reduction	-	45,208
Unrecognized tax benefit of accounting losses	605,498	318,908
Recognition of future income tax in recognition of tax on flow-through shares	-	(1,825,569)
Future income tax recovery	\$ -	\$ (1,825,569)

The components of the Company's future income tax liability are as follows:

	December 31 2005	December 31 2004
Future income tax assets:		
Property, plant and equipment	\$ 3,061,927	\$ 5,214,245
Asset retirement obligation	712,721	626,088
Share issue expenses	652,273	401,459
Non-capital loss carryforwards	771,526	276,024
Valuation adjustment	(5,198,447)	(4,692,247)
	-	-
Future income tax liabilities:		
Flow through share renouncements to be incurred	-	(1,825,569)
	-	(1,825,569)
Net future income tax liability	\$ -	\$ -

Non-capital loss carryforwards at December 31, 2005 represent non-capital losses and expire in 2011.

10. FINANCIAL INSTRUMENTS

The company's financial instruments included in the balance sheet are comprised of accounts receivable, accounts payable, accrued liabilities and bank loan. The fair value of financial instruments classified as current assets approximate their carrying amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its carrying amount as the interest rate approximates market.

Virtually all of the Company's accounts receivable are for revenue on its non-operated properties in Alberta. The Company is exposed to credit risks normal for the oil and gas industry.

11. RELATED PARTY TRANSACTIONS

At December 31, 2005, Questerre had amounts owing to Terrenex totaling \$754 (December 31, 2004 – \$5,040). All of the directors of Terrenex serve as directors or officers of Questerre.

Questerre incurred fees of \$126,000 for the year ended December 31, 2005 (2004 – \$126,000) to a company with common directors and officers. The transactions were in the normal course of business paid pursuant to an Office Rental Agreement for the provision of office space, office equipment and support personnel. The agreement may be terminated by either party with six months' written notice.

In April 2005, the Company completed a private placement of 3,000,000 Common Shares at \$0.32 per Common Share. Terrenex subscribed for 2,812,500 Common Shares and Rupert's subscribed for 312,500 Common Shares.

In April 2005, the Company executed a purchase and sale agreement with Rupert's to acquire its interest in producing properties and exploration acreage in Central Alberta. The purchase price of \$2.1 million was based on an evaluation of the assets prepared by an independent reservoir engineering firm.

In May 2005, QBR entered into the Farmout Agreement with Ampac Petroleum ("Ampac"), a private exploration and production company. A director of the Company is the sole shareholder and director of Ampac. See Note 4 (b).

In November 2005, the Company issued a total of 3,150,000 Common Shares as follows:

- 2,000,000 Common Shares were issued on the conversion of the \$0.6 million promissory note due to Rupert's at a conversion rate of \$0.30 per Common Share. See Note 6.
- 300,000 Common Shares were issued to Terrenex pursuant to the Liquidity Option Agreement. See Note 3.
- 850,000 Common Shares were issued to employees of the Company and QBR pursuant to the Employee Retention Plan established in May 2004.

12. SUBSEQUENT EVENTS

In February 2006, the Company completed a private placement of 11,000,000 Common shares at \$0.65 per Common Share for gross proceeds of \$7.15 million.

In February 2006, QBR granted Ampac an extension from March 1, 2006 to June 15, 2006 to complete the Initial Work Program under the Farmout Agreement.

corporate information

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Michael Binnion
Russ Hammond
Tom Landry, Jr.
David Mallory
Peder Paus
Jed Wood

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*President and Chief
Executive Officer*

John Brodylo
VP Exploration

Peter Coldham
*VP Engineering
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Stock Information

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