Management's Discussion And Analysis

This Management's Discussion and Analysis ("MD&A") was prepared as of March 29, 2018 and should be read in conjunction with the audited consolidated financial statements of Questerre Energy Corporation ("Questerre" or the "Company") as at and for the years ended December 31, 2017 and 2016. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2017 ("AIF"), is available on SEDAR under Questerre's profile at www.sedar.com.

Questerre is actively involved in the acquisition, exploration and development of oil and gas projects, and, in specific, non-conventional projects such as tight oil, oil shale, shale oil and shale gas. Questerre is committed to the economic development of its resources in an environmentally conscious and socially responsible manner.

The Company's Class "A" common voting shares ("Common Shares") are listed on the Toronto Stock Exchange and the Oslo Stock Exchange under the symbol "QEC".

Basis of Presentation

Questerre presents figures in the MD&A using accounting policies within the framework of International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, representing generally accepted accounting principles ("GAAP"). All financial information is reported in Canadian dollars, unless otherwise noted.

Forward-Looking Statements

Certain statements contained within this MD&A 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 "anticipate", "assume", "believe", "budget", "can", "commitment", "continue", "could", "estimate", "expect", "forecast", "foreseeable", "future", "intend", "may", "might", "plan", "potential", "project", "will" 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. Management believes 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 this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A.

This MD&A contains forward-looking statements including, but not limited to, those pertaining to the following:

- drilling plans and the development and optimization of producing assets;
- future production of oil, natural gas and natural gas liquids;
- future commodity prices;
- legislative and regulatory developments in the Province of Quebec;
- the timing of the development of the Company's resources in Quebec;
- liquidity and capital resources;
- the assessment and report of the retorting processes and engineering studies of the Company's oil shale project in Jordan;
- the Company's plans to enter into negotiations for a concession agreement in Jordan;

- the Company's compliance with the terms of its credit facility;
- timing of the next review of the Company's credit facility by its lender;
- the efficiency of the re-designed EcoShale process and cost reductions associated therewith;
- ability of the Company to meet its foreseeable obligations;
- expectations regarding the Company's liquidity increasing over time;
- capital expenditures and the funding thereof;
- Questerre's reserves and resources;
- impacts of capital expenditures on the Company's reserves and resources;
- the benefits of the joint venture infrastructure in the Kakwa-Resthaven area;
- average royalty rates;
- commitments and Questerre's participation in future capital programs;
- risks and risk management;
- potential for equity and debt issuances and farm-out arrangements;
- counterparty creditworthiness;
- joint venture partner willingness to participate in capital programs;
- flow-through shares and use of proceeds and renunciation and indemnity obligations associated therewith;
- insurance;
- use of financial instruments;
- critical accounting estimates and;
- timing and type of economic feasibility studies.

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, the AIF, dated March 29, 2018, 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;
- the terms and availability of credit facilities;
- 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 and resources;
- competition for, cost and availability of, among other things, capital, acquisitions of reserves, undeveloped lands, equipment, skilled personnel 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;

- the passage of applicable hydrocarbon and environmental legislation and regulations and local acceptability;
- 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, tax, or other legislation applicable to the Company's operations, and its 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.

The discounted and undiscounted net present values of future net revenue attributable to reserves and resources do not represent the fair market value thereof.

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. Certain information set out herein with respect to forecasted results is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding the Company's reasonable expectations as to the anticipated results of its proposed business activities. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Non-GAAP Measures

This document contains certain financial measures, as described below, which do not have standardized meanings prescribed under GAAP. As these measures are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used.

This document contains the term "adjusted funds flow from operations", which is an additional non-GAAP measure. The Company uses this measure to help evaluate its performance.

As an indicator of the Company's performance, adjusted funds flow from operations should not be considered as an alternative to, or more meaningful than, net cash from operating activities as determined in accordance with GAAP. The Company's determination of adjusted funds flow from operations may not be comparable to that reported by other companies. Questerre considers adjusted funds flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund operations and support activities related to its major assets.

Adjusted Funds Flow from Operations Reconciliation

($ thousands)		2017		2016
Net cash from operating activities	$	14,661	$	6,719
Interest paid		615		912
Change in non-cash working capital		(8,495)		(586)
Adjusted funds flow from operations	$	6,781	$	7,045

This document also contains the terms "operating netbacks", "cash netbacks" and "working capital surplus (deficit)", which are non-GAAP measures.

The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices. Operating and cash netbacks, as presented, do not have any standardized meaning prescribed by GAAP and may not be comparable with the calculation of similar measures for other entities. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash netbacks have been defined as operating netbacks less general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.

The Company also uses the term "working capital surplus (deficit)". Working capital surplus (deficit), as presented, does not have any standardized meaning prescribed by GAAP, and may not be comparable with the calculation of similar measures for other entities. Working capital surplus (deficit), as used by the Company, is calculated as current assets less current liabilities excluding the risk management contracts.

Select Annual Information

As at/for the years ended December 31,	2017	2016	2015
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Sales	**21,361**	17,120	22,015
Adjusted Funds Flow from Operations	**6,781**	7,045	9,778
Basic and Diluted ($/share)	**0.02**	0.03	0.04
Net Income (loss)	**(24,821)**	169	(73,534)
Basic and Diluted ($/share)	**(0.07)**	-	(0.28)
Capital Expenditures, net of			
Acquisitions and Dispositions	**27,746**	14,218	20,524
Working Capital Surplus (Deficit)	**9,648**	(17,019)	(21,478)
Total Non-Current Financial Liabilities	**15,952**	8,726	9,370
Total Assets	**217,214**	177,761	161,894
Shareholders' Equity	**170,738**	139,660	127,453
Common Shares Outstanding (thousands)	**385,331**	308,274	264,932
Weighted average - basic (thousands)	**350,055**	278,662	264,932
Weighted average - diluted (thousands)	**350,055**	280,410	264,932
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	**821**	801	913
Natural Gas (Mcf/d)	**3,350**	3,436	4,012
Total (boe/d)	**1,379**	1,373	1,582
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**61.28**	47.51	51.75
Natural Gas ($/Mcf)	**2.42**	2.55	3.26
Total ($/boe)	**42.44**	34.06	38.13
Netback ($/boe)			
Petroleum and Natural Gas Revenue	**42.44**	34.06	38.13
Royalties Expense	**(2.17)**	(1.86)	(2.16)
Percentage	**5%**	5%	6%
Operating Expense	**(19.93)**	(15.23)	(13.97)
Operating Netback	**20.34**	16.98	22.00
General and Administrative Expense	**(6.24)**	(5.49)	(6.14)
Cash Netback	**14.11**	11.48	15.86
Wells Drilled			
Gross	**7.00**	3.00	1.00
Net	**1.60**	0.75	0.25

Highlights

- Kakwa development resumes with drilling of 7 (1.60 net) wells in 2017
- Quebec Government publishes draft hydrocarbon and environmental regulations for future development
- Internal feasibility study completed and supports concession application for Jordan oil shale project
- Total proved and probable reserves increased 20% to 27.11 MMboe with a before income tax NPV-10% of $174.69 million

2017 Activities

Western Canada

Kakwa-Resthaven, Alberta

Consistent with prior years, Kakwa accounted for the vast majority of the Company's capital spending and production in 2017. Development targeted the condensate-rich Montney formation.

Questerre invested $22.39 million at Kakwa (2016: $11.91 million) with daily production averaging 1,123 boe/d in 2017 (2016: 1,036 boe/d). Total proved and probable reserves at December 31, 2017 were estimated at 16.09 MMboe (2016: 14.21 MMboe) with a before income tax NPV-10% of $121.59 million (2016: $118.92 million). The Company currently holds 18,560 (10,880 net) acres, including a 100% working interest in 8,320 net acres.

During the year, activity focused on the drilling of 7 (1.60 net) wells and the expansion of field infrastructure on its joint venture acreage. The majority of the wells were completed and tied-in during the year. Questerre holds an average working interest of 23% in these wells.

The wells drilled during the year include the 100/09-29-63-5W6M (the "100/09-29 Well"), 102/09-29-63-5W6M (the "102/09-29 Well"), 100/01-20-63-6W6M Well ("01-20 Well") and the 102/06-18-63-5W6M Well ("06-18 Well"). Production over the first thirty days from the Montney for the 100/09-29 Well, 102/09-29 Well and the 100/01-20 Well averaged 2.7 MMcf/d and 827 bbls/d of condensate and other liquids (1,277 boe/d). Although the initial results from these wells are encouraging, they are not necessarily indicative of long-term performance or ultimate recovery.

An investment of $7.74 million (2016: $3.26 million) was made in field infrastructure to support future growth. These included a regenerative amine sweetening system, central water processing facility and gas lift facilities. The amine system has largely eliminated the operating costs associated with chemical sweetening. The first phase of the central water facility was completed in the fourth quarter and will temporarily store produced water for future completion operations. The gas lift facilities have improved uptime and are assisting with the lifting of produced liquids. Additional gas lift facilities are planned for 2018.

The Company is also participating in the planned expansion of the central processing facility from its current operating capacity of approximately 23 MMcf/d to 45 MMcf/d plus associated liquids. The plans contemplate a future expansion to 60 MMcf/d. Based on commodity prices and continued results Questerre plans to participate in the drilling of up to six (1.5 net) additional wells at its joint venture acreage during the year. The majority of these wells should be drilled in the second half of the year to coincide with the scheduled in-service date for the facility expansion.

To evaluate its operated acreage in the area, the Company entered into a farm-out agreement with an experienced Montney operator in the first quarter of 2018. Pursuant to the agreement, the partner has the right to drill, complete, equip and tie-in two horizontal wells targeting the Montney formation to earn a 50% interest in certain Kakwa operated acreage held by Questerre. The partner has the option to drill, complete, equip and tie-in additional wells to earn a similar interest in other Kakwa operated acreage held by Questerre. Questerre will hold a royalty interest in these initial wells and certain subsequent wells subject to standard payout provisions. The Company expects the first well to spud during the second quarter of 2018.

Antler, Saskatchewan

Activities at Antler focused on the optimization of existing production and the pilot waterflood to increase recovery of the oil in place. The Company also consolidated its interest in the area through an acquisition completed in the fourth quarter of 2017.

Including the acquisition for gross consideration of $7.25 million before customary adjustments, Questerre invested $8.79 million at Antler (2016: $0.54 million) with daily production averaging 179 bbl/d (2016: 209 bbl/d). Total proved and probable reserves at December 31, 2017 were estimated at 2.02 MMbbls (2016: 1.16 MMbbls) with a before income tax NPV-10% of $48.72 million (2016: $31.25 million). The Company currently holds 12,690 net acres in the Antler area.

The acquisition consisted of approximately 180 bbls/d of light oil production. Acquired assets include 3D seismic data over the producing acreage. The proved and probable reserves associated with these assets were assessed at 0.93 MMbbls at December 31, 2017.

In 2018, Questerre plans to continue work on production optimization and the pilot waterflood.

St. Lawrence Lowlands, Quebec

Following the introduction of the *Petroleum Resources Act* to govern the development of petroleum resources, including shale gas, in Quebec, the provincial government introduced draft hydrocarbon and environmental regulations during 2017. This follows almost six years of public consultations and extensive studies on the oil and natural gas industry in Quebec.

In March 2017, the Quebec Government passed into law Bill 102, *An Act to amend the Environment Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund*. One of the key features of Bill 102 is to establish a simplified and modulated authorization process based on the environmental risks associated with a project. Bill 102 also includes changes to various provisions of Quebec's *Environmental Quality Act* governing, in particular, contaminated lands, residual materials and hazardous materials. The majority of the changes introduced by Bill 102 entered into force on March 23, 2018. In February 2018, the Quebec Government published several draft regulations in the Gazette officielle du Québec to implement some of the changes introduced by Bill 102. The majority of such regulations will come into force by the end of 2018.

In September 2017, the Ministry of Natural Resources published the proposed regulations to govern oil and gas activities in the province. The draft regulations are required for the implementation of the *Petroleum Resources Act*.

The purpose of the *Petroleum Resources Act* is: (i) to replace the current oil & gas statutory framework set by the *Quebec Mining Act*; and (ii) to govern the development of petroleum resources while ensuring the safety of persons and property, environmental protection and optimal recovery of the resource, in compliance with the greenhouse gas emission reduction targets set by the Quebec Government. The *Petroleum Resources Act* will come into force on a date to be set by the Quebec Government, which is expected to be on or about the same time as the adoption of the final version of the draft regulations. The Company anticipates the final regulations could be released in early 2018.

Along with social acceptability, these hydrocarbon and environmental regulations are prerequisites to the resumption of field activities on the Company's acreage to assess its Utica gas discovery in the province.

In the first quarter of 2018, the Company published an update to the independent assessment of its Utica shale resources in Quebec (the "Quebec Resource Assessment"). The Quebec Resource Assessment was conducted by GLJ Petroleum Consultants, an independent qualified reserves evaluator, with an effective date of December 31, 2017. The Quebec Resource Assessment was prepared in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators* ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook Volume I ("COGE Handbook").

The best estimate by the Company's independent reserve engineers of risked Prospective Resources net to Questerre is 0.94 trillion cubic feet ("Tcf") (157 million barrels of oil equivalent ("boe")). Additionally, the Quebec Resource Assessment details the best estimate of risked Contingent Resources, net to Questerre, is 313 Bcf (52 million boe). The net present value of the risked Contingent Resources, including the development on hold and development unclarified sub categories, discounted at 10% before tax is estimated at $409 million.

An estimate of risked net present value of future revenue of Contingent Resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the investment. It involves Contingent Resources that are considered too uncertain with respect to development to be classified as reserves. There is no certainty that the estimate of risked net present value of future net revenue will be realized. Further, estimated values of future net revenue do not represent fair market value.

The Quebec Resource Assessment assigned Economic Contingent Resources for approximately 16% of Questerre's acreage based on the results from several vertical and horizontal wells on its acreage that have all encountered pay in the Utica as reported by the Company in 2008 to 2010. Test data from these wells, in conjunction with offset development and studies of the analogous US Utica, supports the prospective commercial development of these resources.

Contingent Resource volumes have been classified as development on hold or development unclarified. Those areas classified as development on hold are primarily contingent on the passage of applicable hydrocarbon and environmental legislation and regulations as well as local acceptability. Remaining areas classified as development unclarified have additional contingency or risk associated with securing social license to operate and are thereby a lower priority for development. Additional contingencies include firm development plans, detailed cost estimates and corporate approvals and sanctioning. There is no certainty that any portion of the Contingent Resources will be economic to develop. Though pilot horizontal development plans have been proposed, the project evaluation scenario for the Contingent Resources is not sufficiently defined to make an investment decision to proceed to development.

The Contingent Resources have been risked for the chance of commerciality, or commercial development, defined as the product of the chance of discovery and the chance of development. For Contingent Resources, the chance of discovery is equal to one. The chance of development is the estimated probability that once discovered, a known accumulation will be commercially developed. Prospective Resources were also risked for chance of discovery. There is no certainty that any portion of Prospective Resources will be discovered. If discovered there is no certainty that it will be economically viable to produce any portion of the Prospective Resource.

Significant positive factors relevant to the estimate of Questerre's resources include the importation of all natural gas consumed in Quebec creating demand for local production, premium realized pricing due to the transportation costs associated with importing natural gas for consumption, production test data from Questerre's existing wells and the development of the analogous Utica shale in the United States. Significant negative factors include the limited number of wells on Questerre's acreage, lack of a developed service sector providing uncertainty regarding estimates of capital and operating costs, developing hydrocarbon regulations and environmental legislation and the requirement to obtain social acceptability for oil and natural gas operations.

While Questerre believes it will have sufficient financial capability to fund its share of costs associated with the development program in the Quebec Resource Assessment, it may not have access to the necessary capital when required. Conducting the development program is also dependent on the participation by Questerre's joint venture partners. There is no guarantee that they will elect to participate in the program to the extent required. Questerre retains the right to conduct activities without the operators' participation on an independent operations basis whereby it can fund 100% of the capital costs for certain well operations and facilities in return for net revenue equal to 400% of its capital investment before the operators can elect to either remain in a penalty position or hold a working interest.

For more information, please refer to the AIF and the press release dated March 12, 2018 available on the Company's website at www.questerre.com and on SEDAR at www.sedar.com.

Oil Shale Mining

Questerre's oil shale assets include its project in the Kingdom of Jordan ("Jordan") and its investment in Red Leaf Resources Inc. ("Red Leaf"). Red Leaf is a private Utah based company whose principal assets include the EcoShale process to produce oil and shale and oil shale leases in the state of Utah. Questerre currently owns approximately 30% of the common share capital of Red Leaf.

The Company acquired the Jordanian project in 2015 through a Memorandum of Understanding ("MOU") for the appraisal and development of oil shale with the Ministry of Energy and Mineral Resources in Jordan (the "MEMR"). The MOU covered an area of over 380 km^2 in the Isfir-Jafr area, approximately 200 km south of the capital Amman. The Company holds a 100% working interest in the MOU and the resources. The term of the

MOU was extended to May 22, 2018. Upon the completion of the MOU and the submission of the required documentation to the MEMR, the Company anticipates it will enter into negotiations with the MEMR for a concession agreement. The Company will continue to hold an exclusive right to the acreage under the MOU during the term of these negotiations. In 2017, the Company high graded its acreage and reduced the area under the MOU to 265 km^2.

Following an independent resource assessment prepared by Millcreek Mining Group ("Millcreek") in accordance with NI 51-101 and the COGE Handbook effective October 1, 2016, the Company's primary objective for 2017 was to evaluate the feasibility of commercial development. For more information on the resource assessment please refer to the Company's 2016 AIF dated March 24, 2017 and press release dated October 27, 2016 available on the Company's website at www.questerre.com and www.sedar.com.

The economic feasibility work involves assessing multiple retorting processes specifically for the Jordanian oil shale. This includes two processes that have been proven at commercial scale. Also under evaluation is the EcoShale process developed by Red Leaf. With Questerre, Red Leaf has been redesigning the EcoShale process to focus on reusable capsules. Red Leaf estimates that using large steel vessels similar to those used in coker facilities in refineries instead of the original single use earthen capsule could materially reduce costs.

In addition to assessing the retorting component of production, Questerre commissioned engineering studies to evaluate the three other components - mining and preparation of the ore, infrastructure, including power and other utilities, and upgrading of the produced oil including a marketing study.

Questerre recently completed an internal review of the retorting processes and the engineering studies. Based on the unique characteristics of the Jordanian shale, the Company believes the re-designed EcoShale process could be the most efficient. Early in 2018, the Company engaged a third party engineering firm to integrate all the studies and validate its work. Questerre anticipates this report will be completed in the third quarter of 2018.

During the year, Questerre acquired additional Red Leaf common shares for US$7.52 million. The Company currently holds 132,293 common shares, representing approximately 30% of the common share capital of Red Leaf. Questerre also acquired 288 Series A Preferred Shares, representing less than 0.5% of the issued and outstanding preferred share capital of Red Leaf, for US$0.16 million. For more information, see Note 7 to the Financial Statements.

In addition to its EcoShale process and its oil shale leases in Utah, Red Leaf holds US$104 million in cash and no debt as of December 31, 2017. In addition to common shares, Red Leaf's equity capital includes convertible preferred shares with dividends accruing at 8% per annum compounded annually. As at December 31, 2017, the Series A preferred shares are entitled to a priority amount of US$83.5 million on the occurrence of a defined liquidation event, including certain reorganizations, takeovers, the sale of all or substantially all the assets of the company and shareholder distributions.

Corporate

The Company completed a series of private placements during the year for gross proceeds of approximately $56 million.

In February 2017, the Company issued 30.8 million Common Shares at $0.79 per Common Share for gross proceeds of approximately $24.65 million and 1.41 million Common Shares at $0.49 per Common Share for gross proceeds of $0.69 million. The second issuance relates to a private placement completed in November 2016 for the same issue price. In October 2017, the Company issued 34.9 million Common Shares at $0.89 per Common Share for gross proceeds of approximately $31 million.

Following a review conducted in the fourth quarter of 2017, effective January 2018, the Company's credit facilities with a Canadian chartered bank were maintained at $18 million. The facilities consist primarily of a revolving operating demand loan. Any borrowings under the facilities, except letters of credit, are subject to interest at the Bank's prime interest rate and applicable basis point margins based on the ratio of debt to cash flow, measured quarterly. The facilities are secured by a revolving credit agreement, a debenture including a first floating charge over all assets of the Company and a general assignment of book debts. As at December 31, 2017, $13.90 million was drawn under the facility. The next scheduled review of these facilities is in the second quarter of 2018.

Drilling Activities

In 2017, Questerre participated in the drilling of 7 (1.60 net) wells in the Kakwa area. 4 (0.92 net) wells were placed on production in 2017 and 3 (0.68 net) wells will be completed and placed on production in 2018.

Production

	2017			2016		
	Oil and Liquids (bbls/d)	**Natural Gas (Mcf/d)**	**Total (boe/d)**	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Total (boe/d)
Alberta	**600**	**3,278**	**1,146**	547	3,360	1,107
Saskatchewan	**179**	**-**	**179**	209	-	209
Manitoba	**42**	**-**	**42**	45	-	45
British Columbia	**-**	**72**	**12**	-	76	12
	821	**3,350**	**1,379**	801	3,436	1,373

Note: Oil and liquids includes light & medium crude oil and natural gas liquids. Natural gas includes conventional and shale gas.

With the majority of the Kakwa joint venture wells coming on stream in the latter half of the year, production on average remained relatively unchanged over the prior year.

Representing over 80% of corporate volumes, production from the area increased from 673 boe/d in the first quarter (2016: 1,159 boe/d) to 1,358 boe/d (2016: 967 boe/d) in the fourth quarter with an average of 1,123 boe/d (2016: 1,036 boe/d). During the year, Questerre participated in the drilling of all seven (1.60 net) wells spud on the joint venture acreage. By comparison, in 2016, to preserve financial liquidity, the Company participated in the drilling of only three (0.75 net) out of the seven wells spud.

Questerre's oil and liquids production represents light crude oil and natural gas liquids and natural gas production represents primarily shale gas. Consistent with prior years, the oil and liquids weighting remained unchanged at about 60%. This generally approximates the relative weighting of natural gas liquids, primarily condensate, to natural gas from Kakwa.

Liquids production also includes volumes from Antler, Saskatchewan and Pierson, Manitoba. These volumes decreased over the prior year due to natural declines. At Antler, these declines were partially offset by a workover and optimization program as well as an acquisition of approximately 180 bbls/d completed in the fourth quarter of the year.

Based on its planned participation in up to six gross wells on the Kakwa joint venture acreage largely in the second half of this year, the Company anticipates its production to increase in 2018.

2017 Financial Results

Petroleum and Natural Gas Sales

	2017			2016		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Alberta	$ 13,267	$ 2,913	$ 16,180	$ 9,148	$ 3,152	$ 12,300
Saskatchewan	4,218	-	4,218	3,968	-	3,968
Manitoba	911	-	911	796	-	796
British Columbia	4	48	52	7	49	56
	$ 18,400	$ 2,961	$ 21,361	$ 13,919	$ 3,201	$ 17,120

Note: Oil and liquids includes light & medium crude oil and natural gas liquids. Natural gas includes conventional and shale gas.

Year over year, petroleum and natural gas sales increased by 25% or $4.24 million due to materially higher crude oil and liquids prices. This was marginally offset by the lower natural gas revenue due to lower natural gas prices.

Pricing

	2017	2016
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	2.26	2.16
Crude Oil - Canadian Light Sweet Blend ($/bbl)	65.86	54.28
Realized prices:		
Natural Gas ($/Mcf)	2.42	2.55
Crude Oil and Natural Gas Liquids ($/bbl)	61.28	47.51

Note: Oil and liquids includes light & medium crude oil and natural gas liquids. Natural gas includes conventional and shale gas.

Crude oil prices improved materially over the prior year with the benchmark West Texas Intermediate ("WTI") averaging US$52/bbl in 2017 compared to US$43/bbl in 2016.

Prices in the first quarter remained relatively strong following OPEC's decision to cut oil production in late 2016. Throughout the next two quarters, prices were negatively impacted by concerns of growing rig counts and increasing oil production in the United States, particularly from the Permian Basin. Prices improved materially in the fourth quarter partly due to the extension of the OPEC/Russia production cuts, reducing inventories, and signs of growing global demand. In Canada, prices were affected by an improving exchange rate and a volatile differential. On average, the differential between WTI and the benchmark Canadian Light Sweet blend ("MSW") decreased from a premium US$0.25/bbl to a discount of US$0.77/bbl. Questerre anticipates this discount will remain volatile during the coming year.

Realized prices for Questerre's oil and liquids track the MSW benchmark with condensate often receiving a premium to this price. This is offset by the lower prices for other liquids, particularly propane.

Natural gas prices increased over the year with the benchmark Henry Hub averaging US$2.99/MMBtu compared to an average price of US$2.48/MMBtu in 2016.

Dry natural gas production in the US continued to increase in 2017, driven in part by growth in the Marcellus and Utica shale in the northeast US. Expected demand growth for industrial and power usage was slower than expected, due to the increase in the use of renewables for power generation. This was partially offset by exports primarily to Mexico. In Alberta, high storage levels, maintenance issues on the main pipeline and limited access to markets outside the province increased the differential materially and resulted in negative gas prices in the province in the third quarter of the year.

Higher heat content production from Kakwa contributed to a realized price of $2.42/Mcf in 2017 (2016: $2.55/Mcf) compared to an AECO average price of C$2.26/Mcf (2016: $2.16/Mcf).

Royalties

($ thousands)		2017		2016
Alberta	$	676	$	546
Saskatchewan		257		294
Manitoba		160		97
	$	1,093	$	936
% of Revenue:				
Alberta		4%		4%
Saskatchewan		6%		7%
Manitoba		18%		12%
Total Company		5%		5%

Consistent with the increase in oil and gas revenue over the prior year, gross royalties increased from $0.94 million to $1.09 million. As a percentage of the revenue this remained constant at 5%.

The royalties in Alberta, specifically at Kakwa, include gross overriding royalties and Crown royalties net of credits for processing the Crown's share of production through the Company's joint facilities and incentive programs.

Production in Kakwa benefits from several legacy incentive programs including the New Well Royalty Rate and the Natural Gas Deep Drilling Program that provides for royalties of up to 5%. These will remain in effect for a period of 10 years from the commencement of the Modernized Royalty Framework ("MRF"). Under the MRF, that took effect on January 1, 2017, Crown incentive programs will be replaced with a capital cost allowance, with initial royalty rates of 5% of gross revenue until cumulative revenue reaches a certain threshold that reflects the total vertical depth, the total lateral length and the total proppant placed for the well. Thereafter, the well will move to post payout status with sliding scale royalties based on product type and commodity price. Once the well's production rate drops to a mature rate, the royalty rate will decrease to mitigate higher fixed costs.

The increase on production from Manitoba reflects the higher proportion of volumes from freehold lands that attract a higher rate compared to Crown lands.

Operating Costs

($ thousands)		2017		2016
Alberta	$	7,754	$	6,142
Saskatchewan		1,938		1,105
Manitoba		248		301
British Columbia		90		104
	$	10,030	$	7,652
$/boe:				
Alberta		18.51		15.16
Saskatchewan		29.66		14.44
Manitoba		16.16		18.26
British Columbia		24.56		23.67
Total Company		19.93		15.23

Operating costs increased by just over 30% to $10.03 million from $7.65 million in 2016 due to higher costs at Kakwa and Antler.

On a unit of production basis, with similar production volumes in both years, operating costs were also 30% higher this year at $19.93/boe from $15.23/boe last year. In Alberta, Kakwa costs were higher primarily for chemical treatment and unutilized processing and transportation commitments. While the installation of the regenerative amine system reduced chemical costs, additional costs were incurred for further treating. Unutilized demand charges averaged approximately $2.3 million or just under 30% of operating costs at Kakwa. The Company anticipates these will decrease as additional volumes are brought on production in the second half of 2018.

At Antler, $0.40 million was spent to workover wells that restored production but did not result in an increase in proved and probable reserves. Additionally, higher costs were incurred in 2017 for maintenance of the battery as well as rehabilitation costs associated with a spill. With the vast majority of costs at Antler as fixed, Questerre believes these costs on a boe basis will decline in 2018 with the increased production volumes attributable to the acquisition completed late last year.

General and Administrative Expenses

($ thousands)		2017		2016
General and administrative expenses, gross	$	4,119	$	3,735
Capitalized expenses and overhead recoveries		(976)		(974)
General and administrative expenses, net	$	3,143	$	2,761

Gross general and administrative expenses ("G&A") in 2017 increased by approximately 10% due to higher legal, transfer agent and consulting fees. This was offset by a 5% decrease in salaries and directors' fees over the prior year. Capitalized expenses and overhead recoveries remain unchanged and reflect the administrative costs associated directly with the Company's assets, particularly in Quebec and Jordan.

Depletion, Depreciation, Impairment and Lease Expiries

For the year ended December 31, 2017, the Company reported depletion and depreciation expense of $9.72

million compared to $8.86 million in 2016. The higher expense reflects the increased capital costs and marginally higher production in the current year. On a per unit basis, depletion increased slightly to $17.95/boe from $17.62/boe in 2016 with increased production volumes in the current year from cash generating units ("CGUs") with higher finding and development costs.

At December 31, 2017, the Company reviewed the carrying amounts of its property, plant and equipment and exploration and evaluation assets for indicators of impairment such as changes in future prices, future costs, reserves and discount rates.

Based on this review, the Company's Montney and Other Alberta CGUs were tested for impairment in accordance with the Company's accounting policy. The recoverable amount of the CGUs was estimated based on the fair value less costs of disposal ("FVLCD") using a discounted cash flow model. As a result of lower commodity prices and an increase in the discount rate used for the Montney CGU due to higher expected equity returns for Montney producers, the Company recorded an impairment charge of $12.30 million. Of this amount $11.98 million relates to the Montney CGU and $0.32 million related to its Other Alberta CGU. In 2016, due the introduction of new hydrocarbon legislation and the updated resource assessment in Quebec, the Company recognized a reversal of the impairment loss of $23.50 million recorded in 2015 for these assets.

The Company also recorded an expense of $7.12 million (2016: $17.84 million) primarily related to expired acreage in the Wapiti area of Alberta where the Company has no future plans for development. During the year, the Company also recorded a gain of $3.66 million (2016: nil) on the disposition of shallow exploration rights in the Kakwa area.

With respect to its investment in Red Leaf, during the year, the Company reversed a previously recorded impairment charge of $2.34 million (2016: nil). The reversal relates to the increase in fair value of the Red Leaf common shares held by Questerre prior to the acquisition. The Company also recorded an expense of $3.40 million for the year (2016: nil) representing its proportionate share of the net loss realized by Red Leaf during the period commencing from its initial acquisition to the end of the year. The expense recorded also reflects the impact of the Red Leaf preferred share dividends on the carrying value of the Red Leaf common shares.

Share Based Compensation

Pursuant to the Company's stock option plan, an optionee may request that the Company purchase all or any part of the then vested options of the optionee for an amount equal to the market price of the Common Shares less the exercise price of the option shares. Notwithstanding the foregoing, the Company may, at its sole discretion, decline to accept and, accordingly, has no obligations with respect to the exercise of this put right at any time. Once the options are cash settled, the options are cancelled.

In December 2015, the Company changed the accounting for its stock based compensation awards to assume that options will be equity settled instead of cash settled. The change was made to reflect the settlement history of the options and the Company's intent to only settle options in equity in the future. Under the equity settled method, compensation costs attributable to stock options granted to employees, officers or directors are measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. The exercise of stock options is recorded as an increase in Common Shares with a corresponding reduction in contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

The Company recorded stock based compensation expense of $0.41 million for the year ended December 31, 2017 (2016: $0.12 million).

Deferred Taxes

The Company reported a deferred tax expense of $5.53 million for 2017 compared to an expense of $0.45 million for the prior year.

The expense reflects the increase in its valuation allowance for its deferred tax asset at year end. In 2017, the Company assessed the recoverability of this asset using the estimate of before tax cash flows associated with its proved reserves using escalating pricing and future development costs as outlined in its independent reserve report, including an estimate of applicable G&A costs associated with these reserves. Questerre had sufficient tax pools to offset taxable income in 2017.

Other Income and Expenses

Changes to the fair value of the Company's risk management contracts are recorded through net profit or loss.

The Company recorded an unrealized gain of $1.12 million (2016: loss of $1.53 million) and a realized loss of $0.07 million (2016: gain of $1.33 million) for its risk management contracts. No contracts were outstanding as of December 31, 2017.

Questerre reported interest expense of $0.62 million for the year ended December 31, 2017 and $0.91 million for the prior year. The expense primarily relates to the interest on its credit facilities with a Canadian chartered bank.

The Company recorded a loss on foreign exchange, net of deferred tax, through other comprehensive income (loss) of $0.86 million for the year ended December 31, 2017 (2016: $0.07 million). The changes are due to fluctuations in the exchange rate relating to its US dollar investments, primarily Red Leaf.

Total Comprehensive Income (Loss)

Questerre's total comprehensive loss was $25.68 million for 2017 compared to income of $0.10 million in 2016. The Company's change in total comprehensive income is attributable mainly to the higher operating costs, impairment and loss on equity investment compared to the prior year. Furthermore, in 2016 the Company recorded the reversal of an impairment charge of $22.9 million primarily related to its assets in Quebec.

Net Income (Loss) Per Share

Questerre's basic net loss per share of $0.07 compared to nil per share in 2016. Questerre's net loss was $24.82 million in 2017 and the Company reported net income of $0.17 million in 2016.

Capital Expenditures

($ thousands)		2017		2016
Alberta	$	22,158	$	11,909
Saskatchewan		1,541		540
Manitoba		89		39
Jordan		833		1,260
Quebec		640		470
		25,261		14,218
Acquisitions (Saskatchewan)		6,935		-
Proceeds from disposition		(4,450)		-
Total	$	27,746	$	14,218

In 2017, Questerre incurred net capital expenditures of $27.75 million as follows:

- $22.16 million was invested in Alberta to participate in the drilling and completion of wells targeting condensate-rich natural gas from the Montney and related infrastructure costs;
- $1.54 million was invested in Saskatchewan to optimize production from wells that resulted in increased reserves; and
- $0.83 million was invested in Jordan to assess the Company's oil shale acreage.

During the year, the Company completed an acquisition in the Antler area of Saskatchewan for $6.94 million. The Company also disposed of exploration and evaluation assets in the Kakwa area for gross proceeds of $4.45 million.

In 2016, Questerre reduced its capital investment to preserve liquidity. It incurred net capital expenditures of $14.22 million as detailed below:

- $11.91 million was invested in Alberta to participate in the drilling and completion of three (0.75 net) wells targeting condensate-rich natural gas from the Montney and related infrastructure costs;
- $0.54 million was invested in Saskatchewan to optimize production from wells that resulted in increased reserves; and
- $1.26 million was invested in Jordan to assess the Company's oil shale acreage.

Liquidity and Capital Resources

The Company's objectives when managing its capital are firstly to maintain financial liquidity, and secondly to optimize the cost of capital at an acceptable risk to sustain the future development of the business.

In January 2018 following a review, the Company's credit facilities remained at $18 million from the last scheduled review. At December 31, 2017, $13.90 million (December 31, 2016: $22.89 million) was drawn on the credit facility and the Company is in compliance with all of its covenants under the credit facilities. As a consequence of the foregoing, Management does not believe there is a reasonably foreseeable risk of non-compliance with its credit facilities. Under the terms of the credit facility, the Company has provided a covenant that it will maintain an Adjusted Working Capital Ratio greater than 1.0. The ratio is defined as current assets (excluding unrealized hedging gains and including undrawn Credit Facility A availability (See Note 13 to the Financial Statements) to current liabilities (excluding bank debt outstanding and unrealized hedging losses). The Adjusted Working Capital Ratio at December 31, 2017 was 2.66 and the covenant was met.

The size of the credit facilities is determined by, among other things, the Company's current reserve report, results of operations and forecasted commodity prices. The next scheduled review is expected to be completed in the second quarter of 2018.

The credit facilities are a demand facility and can be reduced, amended or eliminated by the lender for reasons beyond the Company's control. Should the credit facilities be reduced or eliminated, the Company would need to seek alternative credit facilities or consider the issuance of equity to enhance its liquidity.

Questerre had a working capital surplus, including amounts due under its credit facilities, of $9.65 million at December 31, 2017, as compared to a deficit of $17.02 million at December 31, 2016. Management believes that with its private placements completed in the year for gross proceeds of approximately $56 million, expected positive operating cash flows from operations and current credit facilities, the Company should generate sufficient cash flows and have access to sufficient financial liquidity to meet its foreseeable obligations in the normal course of operations.

Questerre anticipates an improvement in commodity prices, which should improve cash flow and reduce the working capital deficit to the extent adjusted funds flow from operations, exceeds planned capital expenditures. On an ongoing basis, the Company will manage where possible future capital expenditures to maintain liquidity (See "Commitments"). However, it cannot provide any assurance that sufficient cash flows will be generated from operating activities to reduce its working capital deficiency and to carry out its planned capital expenditure program. The Company intends to invest up to 90% of the 2017 future development costs associated with proved reserves in its independent reserves assessment as of December 31, 2017. It anticipates that, as a result, reserves associated with wells not drilled in 2017 will remain in the proved undeveloped category.

For a detailed discussion of the risks and uncertainties associated with the Company's business and operations, see the Risk Management section of the MD&A and the AIF.

Cash Flow from Operating Activities

Net cash from operating activities for the year ended December 31, 2017 and 2016 was $14.66 million and $6.72 million, respectively. While adjusted funds flow from operations decreased in 2017, a significant increase in non-cash working capital in the current year contributed to the higher net cash from operating activities in 2017 compared to the prior year.

Cash Flow used in Investing Activities

Cash flow used in investing activities increased to $33.18 million in 2017 from $19.68 million in 2016. For the year ended December 31, 2017, the Company incurred capital expenditures of $25.26 million compared to $14.22 million for the same period in 2016. Additionally, the Company concluded an acquisition of producing properties at Antler for $6.94 million and increased its investment in Red Leaf by $10.33 million. This was partially offset by an asset disposition in the Kakwa area for gross proceeds of $4.45 million and an increase in related non-cash working capital of $4.89 million compared to a decrease of $5.46 million in the prior year.

Cash Flow provided by Financing Activities

Cash flow provided by financing activities increased from $20.89 million in 2016 to $46.08 million in 2017. The increase reflects the private placements completed by the Company for gross proceeds of approximately $56 million and drawdowns under the Company's credit facilities, net of repayments. In 2016, the Company realized gross proceeds of $13.22 million from the issuance of equity and a net increase of $8.35 million from drawdowns under its credit facilities.

Share Capital

The Company is authorized to issue an unlimited number of Common 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, 2017, there were no Class "B" common voting shares or preferred shares outstanding.

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

(thousands)	**March 29, 2018**	**December 31, 2017**	December 31, 2016
Common Shares	**388,956**	**385,331**	308,274
Stock Options	**21,327**	**21,387**	14,856
Warrants	**-**	**3,566**	13,124
Weighted average Common Shares			
Basic		**350,055**	278,662
Diluted		**350,055**	280,410

A summary of the Company's stock option activity during the years ended December 31, 2017 and 2016 follows:

	December 31, 2017		December 31, 2016	
	Number of Options *(thousands)*	**Weighted Average Exercise Price**	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	**14,856**	**$0.41**	19,982	$0.72
Granted	**6,900**	**0.69**	4,100	0.18
Forfeited	**(232)**	**0.52**	(4,289)	0.47
Expired	**(90)**	**0.70**	(3,260)	1.85
Exercised	**(47)**	**0.62**	(1,677)	0.60
Outstanding, end of period	**21,387**	**$0.50**	14,856	$0.41
Exercisable, end of period	**9,180**	**$0.50**	5,939	$0.55

Commitments

A summary of the Company's net commitments at December 31, 2017 follows:

($ thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation, Marketing and Processing	$ 4,728	$ 3,990	$ 3,990	$ 3,990	$ 3,990	$ 15,962	$ 36,650
Office Leases	116	99	90	-	-	-	305
	$ 4,844	$ 4,089	$ 4,080	$ 3,990	$ 3,990	$ 15,962	$ 36,955

Questerre has no capital commitments in 2018. In order to maintain its capacity to execute its business strategy, the Company expects that it will need to continue the development of its producing assets. There will also be expenditures in relation to G&A and other operational expenses. These expenditures are not yet commitments, but Questerre expects to fund such amounts primarily out of adjusted funds flow from operations and its existing credit facilities.

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 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, Questerre believes that they can be monitored and managed. For more information, please refer to the "Risk Factors" and "Industry Conditions" sections of the AIF and Note 6 to the audited consolidated financial statements for the year ended December 31, 2017.

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 participants to farm-in on the development of its projects on favorable terms. However, there can be no assurance that the Company will be able to secure sufficient capital if required or that such capital will be available on terms satisfactory to the Company.

As future capital expenditures will be financed out of adjusted funds flow from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry, and the Company's securities in particular. To the extent that external sources of capital become limited or unavailable, or available but on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected. Based on current funds available and expected adjusted funds flow from operations, the Company believes it has sufficient funds available to fund its projected capital expenditures. However, if adjusted funds flow from operations is lower than expected, or capital costs for these projects exceed current estimates, or if the Company incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties. The Company anticipates that future development of its Quebec assets will require significant additional capital to be financed through among other sources, future equity issuances or asset dispositions.

Questerre faces a number of financial risks over which it has no control, such as commodity prices, exchange rates, interest rates, access to credit and capital markets, as well as changes to government regulations and tax and royalty policies.

The Company uses the following guidelines to address financial exposure:

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

Credit risk represents the potential financial loss to the Company if a customer or counterparty to a financial instrument fails to meet or discharge their obligation to the Company. Credit risk arises from the Company's receivables from joint venture partners and oil and gas marketers. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Credit risk also arises from the Company's cash and cash equivalents. In the past, the Company manages credit risk exposure by investing in Canadian banks and credit unions. Management does not expect any counterparty to fail to meet its obligations.

Poor credit conditions in the industry may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner if possible.

Substantially all of the accounts receivable are with oil and natural gas marketers and joint venture partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by entering into transactions with long-standing, reputable counterparties and partners.

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

Receivables from joint venture partners are typically collected within one to three months after the joint venture bill is issued. The Company mitigates this risk by obtaining pre-approval of significant capital expenditures.

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

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

The Company may use financial instruments to reduce corporate risk in certain situations. Questerre's hedging policy is up to a maximum of 40% of total production at management's discretion.

As at December 31, 2017, the Company had no outstanding commodity risk management contract in place.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases of emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and natural gas industry operations, which can affect the location and operation of wells and facilities, and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures, and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders. The Company mitigates the potential financial exposure of environmental risks by complying with the existing regulations and maintaining adequate insurance. For more information, please refer to the "Risk Factors" and "Industry Conditions" sections of the AIF.

Critical Accounting Estimates

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. These estimates and judgments have risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Petroleum and Natural Gas Reserves and Resources

All of Questerre's petroleum and natural gas reserves and resources are evaluated and reported on by independent petroleum engineering consultants in accordance with NI 51-101 and the COGE Handbook. For further information, please refer to "Statement of Reserves Data and Other Oil and Gas Information" in the AIF.

The estimation of reserves and resources is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves and resources will change to reflect updated information. Reserve and resource estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices. These estimates are evaluated by independent reserve engineers at least annually.

Proven and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. If probabilistic methods are used, there should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves and there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Reserve and resource estimates impact a number of the areas, in particular, the valuation of property, plant and equipment, exploration and evaluation assets and the calculation of depletion.

Cash Generating Units

A CGU is defined as the lowest grouping of assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include geography and the manner in which management monitors and makes decisions about its operations.

Impairment of Property, Plant and Equipment, Exploration and Evaluation and Goodwill

The Company assesses its oil and natural gas properties, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable. Determining if there are facts and circumstances present that indicate that carrying values of the assets may not be recoverable requires management's judgment and analysis of the facts and circumstances.

The recoverable amounts of CGUs have been determined based on the higher of value in use ("VIU") and the FVLCD. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, the discount rate, future operating and development costs and recent land transactions. Changes to these assumptions will affect the recoverable amounts of the CGUs and may require a material adjustment to their related carrying value.

Goodwill is the excess of the purchase price paid over the fair value of the net assets acquired. Since goodwill results from purchase accounting, it is imprecise and requires judgment in the determination of the fair value of assets and liabilities. Goodwill is assessed for impairment on an operating segment level based on the recoverable amount for each CGU of the Company. Therefore, impairment of goodwill uses the same key judgments and assumptions noted above for impairment of assets.

Asset Retirement Obligation

Determination of the Company's asset retirement obligation is based on internal estimates using current costs and technology in accordance with existing legislation and industry practice and must also estimate timing, a risk-free rate and inflation rate in the calculation. These estimates are subject to change over time and, as such, may impact the charge against profit or loss. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a risk-free rate. The associated abandonment and retirement costs are capitalized as part of the carrying amount of the related asset. The capitalized amount is depleted on a unit of production basis in accordance with the Company's depletion policy. Changes to assumptions related to future expected costs, risk-free rates and timing may have a material impact on the amounts presented.

Share Based Compensation

The Company has a stock option plan enabling employees, officers and directors to receive Common Shares or cash at exercise prices equal to the market price or above on the date the option is granted. Under the equity settled method, compensation costs attributable to stock options granted to employees, officers or directors are measured at fair value using the Black-Scholes option pricing model. The assumptions used in the calculation are: the volatility of the stock price, risk-free rates of return and the expected lives of the options. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Changes to assumptions may have a material impact on the amounts presented.

Income Tax Accounting

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the Company's estimate, the ability of the Company to realize the deferred tax assets could be impacted.

The Company has revised its estimate related to deferred tax assets in the year. Since December 31, 2016, the recoverability of deferred tax assets is assessed using proved reserves including an estimate of G&A associated with the assets.

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

Investment in Red Leaf

Questerre has investments in certain private companies, including Red Leaf, which it classifies as an equity investment and assesses for indicators of impairment at each period end. For the purposes of impairment testing, the Company measures the fair value of Red Leaf by valuation techniques such as the net asset value approach.

Accounting Standards Changes

Changes in Accounting Policies for 2017

The Company adopted amendments to IAS 7, Statement of Cash Flows, which provide disclosures on evaluating changes in the liabilities arising from financing activities during the year ended December 31, 2017. See Note 13 on IAS 7 adoption.

Future Accounting Pronouncements

The following standards and interpretations have not been illustrated as they will only be applied for the first time in future periods. They may result in consequential changes to the accounting policies and other note disclosures. The Company is currently evaluating the impact of adopting these standards on its consolidated financial statements.

<u>IFRS 16 Leases</u>

On January 13, 2016, the IASB issued IFRS 16 Leases ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded. IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 Revenue From Contracts With Customers has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting this standard on its consolidated financial statements.

<u>IFRS 15 Revenue From Contracts With Customers</u>

In May 2014, the IASB published IFRS 15 Revenue From Contracts With Customers ("IFRS 15") replacing IAS 11 Construction Contracts, IAS 18 Revenue and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser.

The new standard is effective for annual periods beginning on or after January 1, 2018. The standard may be applied retrospectively or using a modified retrospective approach. The Company has performed an initial assessment of IFRS 15 and plans to adopt the standard under the modified retrospective approach on January 1, 2018. Under this method, comparative figures are not restated and the cumulative effect of initially applying the standard (if any) would be recognized at the date of adoption. The Company will be required to disclose additional information regarding the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, including a disaggregation of revenue by product type. The Company's initial assessment that adoption of IFRS 15 will not have a material impact on the Company’s Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) is made as of the date of these annual financial statements and may change as new publications or interpretations of the new standard become available. The evaluation of all potential measurement and disclosure impacts is ongoing.

IFRS 9 *Financial Instruments*

In July 2014, the IASB completed the final elements of IFRS 9 Financial Instruments ("IFRS 9"). The standard supersedes earlier versions of IFRS 9 and completes the IASB’s project to replace IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39"). IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity’s own credit risk is recorded in other comprehensive income rather than the statement of income. The Company has determined that adoption of IFRS 9 will result in changes to the classification of the Company’s financial assets but will not change the classification of the Company’s financial liabilities. The Company has also determined there will not be any material changes in the measurement and carrying values of the Company’s financial instruments as a result of the adoption of IFRS 9. In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. Questerre has determined that the new impairment model will not result in material changes to the valuation of its financial assets on adoption of IFRS 9.

Design and Evaluation of Internal Controls over Financial Reporting and Disclosure Controls and Procedures

Questerre is required to comply with National Instrument 52-109 “*Certification of Disclosure in Issuers’ Annual and Interim Filings*” (“NI 52-109”) and is required to make specific disclosures with respect to NI 52-109 as follows:

- The Company has designed and evaluated the effectiveness of Disclosure Controls and Procedures (“DC&P”). The President and Chief Executive Officer and the Chief Financial Officer have concluded that DC&P are designed appropriately and are operating effectively as at December 31, 2017.
- The Chief Executive Officer and the Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting (“ICFR”), in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of the Company’s ICFR as at December 31, 2017 and have concluded that such ICFR have been designed appropriately and are operating effectively.
- The Company reports that no changes were made to ICFR during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect the Company’s ICFR.

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.

Fourth Quarter 2017 Results

Questerre's cash from operating activities decreased to $1.27 million for the quarter ended December 31, 2017 from $2.70 million for the same period in 2016. This is attributable to the decrease in non-cash working capital, which offsets the higher petroleum and natural gas revenue in the last quarter of 2017. The increase in adjusted funds flow from operations to $2.55 million from $1.94 million is due to higher petroleum and natural gas revenue in the period compared to the prior year.

Petroleum and natural gas revenue increased materially from $4.57 million for the three months ended December 31, 2016 to $7.30 million for the same period in 2017 due to higher production volumes and prices. Production volumes increased by over 35% to 1,714 boe/d from 1,261 boe/d due to Company's full participation in the 2017 joint venture drilling program at Kakwa. The Company also completed an acquisition of producing assets in the Antler area during the fourth quarter. By comparison in 2016, the Company selectively participated in the joint venture program at Kakwa. The Company's realized price for oil and natural gas liquids was $66.98/bbl for the fourth quarter of 2017 and $51.12/bbl for the same period in 2016.

Operating costs were $3.46 million or $21.96/boe for the three months ended December 31, 2017 compared to $1.67 million or $14.38/boe for the same period last year. The increase in operating costs is due to the higher production in the current year and higher costs specifically in the Kakwa area for chemical and unutilized take or pay commitments. Additionally during the quarter, the Company incurred $0.4 million in operating costs at Antler to restore wells to production that did not increase reserves.

During the quarter, the Company realized a loss of $1.05 million related to its investment in Red Leaf (2016: nil).

Total comprehensive loss for the three months ended December 31, 2017 was $17.96 million compared to income of $3.67 million for the same period in 2016. The Company's change in total comprehensive income is attributable mainly to the higher operating costs, impairment and loss on equity investment compared to the prior year. The income in the prior year was largely due to the reversal of prior impairment charge of $22.93 million related to the Company's assets in Quebec.

Quarterly Financial Information

($ thousands, except as noted)	December 31, 2017	September 30, 2017	June 30, 2017	March 31, 2017
Production (boe/d)	**1,714**	1,643	1,037	1,123
Average Realized Price ($/boe)	**46.30**	36.03	44.34	43.82
Petroleum and Natural Gas Sales	**7,302**	5,446	4,184	4,429
Adjusted Funds Flow from Operations	**2,552**	1,938	880	1,411
Basic and Diluted ($/share)	**-**	-	-	-
Net Profit (Loss)	**(18,036)**	(2,641)	(3,621)	(523)
Basic and Diluted ($/share)	**(0.05)**	(0.01)	(0.01)	(0.01)
Capital Expenditures, net of acquisitions and dispositions	**14,976**	4,906	2,544	5,320
Working Capital Surplus (Deficit)	**9,648**	(7,559)	(3,184)	3,274
Total Assets	**217,214**	198,904	205,672	205,640
Shareholders' Equity	**170,738**	158,204	160,069	163,888
Weighted Average Common Shares Outstanding				
Basic (thousands)	**383,093**	346,685	345,408	324,426
Diluted (thousands)	**383,093**	346,685	345,408	324,426

($ thousands, except as noted)	December 31, 2016	September 30, 2016	June 30, 2016	March 31, 2016
Production (boe/d)	1,261	1,275	1,422	1,538
Average Realized Price ($/boe)	39.43	34.91	34.17	28.79
Petroleum and Natural Gas Sales	4,574	4,095	4,423	4,029
Adjusted Funds Flow from Operations (1	1,943	1,447	1,916	1,740
Basic and Diluted ($/share)	0.01	0.01	0.01	0.01
Net Profit (Loss)	3,674	(1,007)	(2,173)	(325)
Basic and Diluted ($/share)	0.01	-	(0.01)	-
Capital Expenditures, net of acquisitions and dispositions	5,260	4,060	741	4,158
Working Capital Surplus (Deficit)	(17,019)	(21,250)	(23,075)	(24,044)
Total Assets	177,761	165,109	161,721	163,547
Shareholders' Equity	139,660	127,895	125,028	127,134
Weighted Average Common Shares Outstanding				
Basic (thousands)	293,470	283,494	264,932	264,932
Diluted (thousands)	308,017	283,494	264,932	264,932

The general trends over the last eight quarters are as follows:

- Petroleum and natural gas revenues and adjusted funds flow from operations have fluctuated with production volumes and realized commodity prices.
- Production volumes reflect the capital investment in drilling and completing wells at Kakwa in preceding quarters. Following increased investment in Kakwa in 2017, production has grown to 1,714 boe/d in the most recent quarter. The Company plans to continue to invest at Kakwa, subject to commodity prices and results, and expects a commensurate increase in production. Additionally, the Company expects production to increase following the acquisition of producing assets in the Antler area in the fourth quarter of 2017.
- The level of capital expenditure over the quarter has varied largely due to the timing and number of wells drilled and completed for the Kakwa asset as well as the timing of the infrastructure investment.
- The working capital deficit has generally increased when capital expenditures and other investments have been higher than adjusted funds flow from operations and cash from financing activities.
- Shareholders' equity increased in the quarters ended December 31, 2016, March 31, 2017 and December 31, 2017 as a result of the equity issuances completed by the Company during those periods.

Off-Balance Sheet Transactions

The Company did not engage in any off-balance sheet transactions during the year ended December 31, 2017, other than commitments as disclosed.

Related Party Transactions

The Company did not engage in any related party transactions during the year ended December 31, 2017, other than key management compensation as disclosed.