Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") was prepared as of March 28, 2019 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, 2018 and 2017. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2018 dated March 28, 2019 ("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 and the weighting thereof;
- future commodity prices;
- legislative and regulatory developments in the Province of Quebec;
- the acquisition of assets in Quebec and the operatorship of such assets;
- the timing of the development of the Company's resources in Quebec;

- the Company's focus on engagement with the Government of Quebec for the passage of the final oil and gas regulations and social acceptability 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;
- moving to the next phase of contract engineering 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 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, 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 judicial rulings, 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)	**2018**	2017
Net cash from operating activities	**$ 13,091**	$ 14,661
Interest received	**(544)**	(154)
Interest paid	**593**	769
Change in non-cash working capital	**2,073**	(8,495)
Adjusted funds flow from operations	**$ 15,213**	$ 6,781

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,	**2018**	2017	2016
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Sales	**32,969**	21,361	17,120
Adjusted Funds Flow from Operations	**15,213**	6,780	7,045
Basic and Diluted ($/share)	**0.04**	0.02	0.03
Net Income (Loss)	**13,466**	(24,821)	169
Basic and Diluted ($/share)	**0.03**	(0.07)	–
Capital Expenditures, net of Acquisitions and Dispositions	**31,102**	27,746	14,218
Working Capital Surplus (Deficit)	**(9,078)**	9,648	(17,019)
Total Non-Current Financial Liabilities	**13,736**	15,952	8,726
Total Assets	**233,372**	217,215	177,761
Shareholders' Equity	**187,291**	170,739	139,660
Common Shares Outstanding (thousands)	**389,007**	385,331	308,274
Weighted average - basic (thousands)	**388,712**	350,055	278,662
Weighted average - diluted (thousands)	**395,715**	350,055	280,410
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	**1,263**	821	801
Natural Gas (Mcf/d)	**3,635**	3,350	3,436
Total (boe/d)	**1,869**	1,379	1,373
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**66.27**	61.28	47.51
Natural Gas ($/Mcf)	**1.82**	2.42	2.55
Total ($/boe)	**48.33**	42.44	34.06
Netback ($/boe)			
Petroleum and Natural Gas Revenue	**48.33**	42.44	34.06
Royalties Expense	**(2.76)**	(2.17)	(1.86)
Percentage	**6%**	5%	5%
Operating Expense	**(17.09)**	(19.93)	(15.23)
Operating Netback	**28.48**	20.34	16.98
General and Administrative Expense	**(6.50)**	(6.24)	(5.49)
Cash Netback	**21.99**	14.11	11.48
Wells Drilled			
Gross	**3.00**	7.00	3.00
Net	**0.71**	1.60	0.75

Highlights

- Total proved and probable reserves increased by 63% to 30 MMBoe with a before income tax NPV-10% of $229 million
- Kakwa North farm-in wells test at average rates of 2,800 boe/d including over 1,000 bbl/d of condensate
- Concludes agreement to acquire 753,000 net acres and regain operatorship in Quebec
- Feasibility study for Jordan oil shale project supports concession application
- Production averages 1,869 boe/d with adjusted funds flow from operations of $15 million during the year

2018 Activities

Western Canada

Kakwa, Alberta

With the farmout of its Kakwa North acreage during the year, development of the Company's condensate-rich Montney acreage is now underway with two joint venture partners.

In 2018, capital investment in Kakwa totaled $27.67 million (2017: $22.39 million) with daily production averaging 1,474 boe/d (2017: 1,123 boe/d). Total proved and probable reserves at December 31, 2018 were estimated at 27.85 MMBoe (2017: 16.09 MMBoe) with a before income tax NPV-10% of $183.79 million (2017: $121.59 million). The Company currently holds 40,160 (21,720 net) acres in the Kakwa area.

The majority of this capital investment and production was attributable to the Kakwa Central acreage where Questerre holds a 25% interest in 10,080 acres. On this acreage, 3 (0.71 net) wells were drilled and 5 (1.18 net) wells completed and tied-in during the year. These included the 102/04-09-63-6W6M Well and the 102/11-18-63-5W6M Well. During the first thirty days gross production from these two wells averaged 2.9 MMcf/d and 583 bbls/d of condensate and liquids (1,067 boe/d). Questerre holds a 25% interest in these wells. Though the initial rates from these wells is encouraging, they are not necessarily indicative of long-term performance. The operator also spud a third well, 100/01-29-63-05W5M, late in the fourth quarter which should be completed by mid-2019.

In addition, field infrastructure was expanded to accommodate for future growth. These expansions included the central water facility and central processing facility where capacity was effectively doubled as well as installation of ancillary pipelines and gas-lift facilities. Questerre holds a 25% interest in these facilities. The investment in infrastructure totaled $12.36 million or just under half of the total investment in Kakwa for the year (2017: $7.74 million). As a result of this significant investment over the last two years, Questerre anticipates a limited investment of approximately $2 million for infrastructure spending will be required over the next three years to further expand field capacity.

At Kakwa North, the Company's farm-in partner drilled, completed and tied-in two wells. During the first thirty days, gross production from these wells averaged 5.5 MMcf/d and 733 bbls/d of condensate (1,653 boe/d). Though the initial rates from these wells is encouraging, they are not necessarily indicative of long-term performance. The results from these wells contributed to the material increase in proved and probable reserves at Kakwa for 2018.

The operator also spud the third farm-in well early in 2019 with the potential for a fourth farm-in well to be drilled later this year. Questerre holds a royalty interest in all the farm-in wells converting to a 50% working interest after payout. Upon the completion of all contemplated farm-in wells at Kakwa North and Kakwa South, Questerre will hold a 50% interest in 8,360 gross acres in these areas.

In the fourth quarter of 2018, the Company acquired 21,760 (10,880 net) acres at Kakwa West, immediately offsetting its acreage at Kakwa North and Kakwa Central. The lands are subject to an industry standard gross overriding royalty. The Company is evaluating plans for development with the operator.

Based on realized commodity prices and continued results, the Company anticipates it will participate in the planned drilling program of up to 5 (1.25 net) wells at Kakwa Central in 2019. Subject to the results from the farm-in wells at Kakwa North and the operator's program, the Company may participate in additional drilling on this acreage.

Antler, Saskatchewan

Consistent with prior years, activities at Antler targeted optimizing existing production and expanding the pilot secondary recovery scheme to increase recovery of the oil in place.

Questerre invested $1.02 million (2017: $8.79 million) at Antler with daily production averaging 359 bbl/d (2017: 179 bbl/d). Total proved and probable reserves as at December 31, 2018 were estimated at 1.87 MMbbls (2017: 2.02 MMbbls) with a before income tax NPV-10% of $40.68 million (2017: $48.72 million). The Company currently holds 11,952 net acres in the Antler area.

In 2019, Questerre expects to continue its work on optimizing existing production and the pilot secondary recovery scheme.

St. Lawrence Lowlands, Quebec

In 2018, Questerre focused on engaging with the Government of Quebec for the passage of the final hydrocarbon regulations, securing social acceptability and regaining operatorship for its natural gas discovery in the Lowlands.

The Company will regain operatorship through the purchase and sale agreement executed with a senior exploration and production company to acquire joint assets in the Lowlands. This follows the letter of intent signed in early 2018.

Pursuant to the agreement, Questerre will acquire the exploration rights to 753,000 net acres in the Lowlands, associated wells and equipment, geological and geophysical data and other miscellaneous assets. Upon closing of the transaction, both parties will release each other from all claims related to outstanding litigation. Other consideration including cash and contingent payments and the security required for the assumption of abandonment and reclamation liabilities ("A&R Liabilities") is approximately $11 million in aggregate. Questerre may post a letter of credit as security for the A&R Liabilities. Closing of the transaction is subject to the approval by the Government of Quebec for the transfer of the exploration permits and licenses to Questerre and is scheduled before December 31, 2019. The Company intends to update the resource assessment of its Quebec assets following the closing of this transaction.

In the third quarter of 2018, the Government of Quebec enacted the *Petroleum Resources Act* to govern the development of hydrocarbons in the province. It also enacted the associated regulations (the “Regulations”) which includes restrictions on oil and gas activities, specifically the prohibition of hydraulic fracturing of shale and a prohibition of activities within 1,000m from urbanized areas and bodies of water. These restrictions would prevent Questerre from developing its assets in Quebec. Questerre believes the remaining Regulations while stricter than other jurisdictions, are generally workable.

Following the enactment of the Regulations, Questerre filed a legal brief with the Superior Court of Quebec challenging the validity of the specific Regulations relating to the hydraulic fracturing restrictions. The brief requested a stay and ultimately a judicial hearing to have them set aside. The Company’s motion was made on the basis that the Regulations are ultra vires, or beyond the legal authority granted to the Government by the *Petroleum Resources Act*, contrary to the independent scientific studies, and moreover they do not comply with the consultation requirements detailed in Quebec legislation with respect to the enactment of regulations. The Company was granted a fast track hearing for the judicial review in the first quarter of 2019.

At the request of the Ministry of Justice, Questerre has agreed to temporarily defer the judicial review hearing. To address concerns about the potential environmental impacts of development, Questerre has recently submitted for review by the Ministry of Environment a conceptual engineering plan to test its Clean Tech Energy pilot program. The Company recently retained a senior Quebec engineering firm to prepare a detailed plan and permit application which is expected to be an eight month project. Discussions with the Government are on going. These actions are to allow the parties to resolve the issues raised in the Company’s legal brief in a constructive manner.

During the year, the Company continued to advance its clean tech energy pilot as part of its goal to secure social acceptability for its project. This pilot is designed to test the technologies and processes needed to produce natural gas while substantially eliminating greenhouse gas emissions, drinking water usage and toxic fluids below ground as well as materially reduce noise pollution. The Company also introduced a revenue sharing initiative with local communities to further improve social acceptability.

In 2019, the Company plans to continue its work on social acceptability while engaging with the Government to resolve the regulatory situation. Should Questerre be unsuccessful in its negotiations with the Government or receive an unfavorable ruling for its judicial review, the value of its Quebec assets could be materially impaired.

Oil Shale Mining

Questerre advanced the technical and economic feasibility assessment of its oil shale project in Jordan during the year.

In June 2018, the Company finalized a feasibility study for this project. Conducted by Hatch Ltd. (“Hatch”), a global engineering firm, the design basis for the study is an initial project capable of sustaining production of 50,000 bbl/d.

The study estimates capital costs, including a 20% contingency, of US$18 $20/bbl and operating costs of US$18/bbl. These costs include the upgrading of the produced oil to low sulphur diesel and gasoline, that based on a regional marketing study, typically realize a US$10 $12/bbl premium to the Brent benchmark pricing. These costs are AACE Class 5 cost estimates with an average accuracy of +100%/-50%.

Based on these results, the Company is moving to the next phase of contract engineering with Hatch. This is designed to identify opportunities to optimize the processes and potentially improve economic returns. It is also designed to improve the accuracy of cost estimates from Class 5 to Class 4 which have an average accuracy of +30%/-20%.

This study and other requisite documentation required under the Memorandum of Understanding ("MOU") with the Kingdom of Jordan for its oil shale acreage were submitted in the second quarter of the year. Upon acceptance of these documents, the Company anticipates it will enter negotiations for a concession agreement to include the fiscal and other terms essential to the overall project economics. The Company continues to hold the exclusive exploration rights to the acreage under the MOU following its expiry on May 22, 2018 and during the term of the negotiations.

Corporate

After a review conducted in the third quarter of 2018, effective November 2018, the Company's credit facilities with a Canadian chartered bank remained unchanged 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 effective interest rate in 2018 was 4.14%. 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, 2018, $13.84 million was drawn under the facility. The next scheduled review of these facilities is in the second quarter of 2019.

Drilling Activities

Three (0.71 net) wells were spud during 2018 at Kakwa. Questerre holds an average 23.6% working interest in the three wells drilled at Kakwa Central. Two additional wells were drilled at Kakwa North, where Questerre holds an overriding royalty convertible to a working interest after payout.

Production

	2018			2017		
	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	**879**	**3,635**	**1,485**	600	3,350	1,158
Saskatchewan	**359**	**–**	**359**	179	–	179
Manitoba	**25**	**–**	**25**	42	–	42
	1,263	**3,635**	**1,869**	821	3,350	1,379

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

The increased capital investment in Kakwa in the last two years contributed to materially higher production over the prior year.

Representing approximately 80% of corporate volumes, Kakwa production increased from 1,123 boe/d to 1,474 boe/d. Nine (2.1 net) wells were brought on production in the last two years compared to 4 (1 net) well(s) in the prior two years. The well count increased because Questerre participated in the entire drilling program in these years compared to 2016 when the Company limited its participation to only one third of the wells drilled to preserve financial liquidity.

Questerre's oil and liquids production is comprised primarily of light crude oil and condensate and nominal volumes of other natural gas liquids. Natural gas production is shale gas from Kakwa. The liquids weighting increased from 60% to 68% in 2018 due to higher volumes from Antler, Saskatchewan where the Company acquired 180 bbl/d of light oil production in December 2017. Over time, the Company anticipates its liquids weighting to average approximately 60% reflecting the relative weighting of natural gas liquids to natural gas at Kakwa.

In 2019, the Company plans to participate in up to five (1.25 net) wells on the Kakwa Central acreage subject to commodity prices and results. With the majority of these wells scheduled to be tied in the second half of this year, Questerre anticipates its production to decline marginally over the year with an increase by year-end. Pending the results from Kakwa North, Questerre could participate in additional drilling on this acreage in the fourth quarter of this year.

2018 Financial Results

Petroleum and Natural Gas Sales

	2018			2017		
($ thousands)	**Oil and Liquids**	**Natural Gas**	**Total**	Oil and Liquids	Natural Gas	Total
Alberta	**$ 20,201**	**$ 2,414**	**$ 22,615**	$ 13,271	$ 2,961	$ 16,232
Saskatchewan	**9,706**	**–**	**9,706**	4,218	–	4,218
Manitoba	**648**	**–**	**648**	911	–	911
	$ 30,555	**$ 2,414**	**$ 32,969**	$ 18,400	$ 2,961	$ 21,361

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 over 50% due to higher production volumes and liquids prices. In spite of lower natural gas prices, higher crude oil prices accounted for40% of this increase with higher volumes accounting for the balance.

Pricing

	2018	2017
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	**1.34**	2.26
Crude Oil - Canadian Light Sweet Blend ($/bbl)	**69.07**	65.86
Realized prices:		
Natural Gas ($/Mcf)	**1.82**	2.42
Crude Oil and Natural Gas Liquids ($/bbl)	**66.27**	61.28

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

While average crude oil prices increased over the prior year, they ended 2018 materially lower. The benchmark West Texas Intermediate ("WTI") averaged US$65/bbl compared to US$52/bbl last year with prices in December closing at US$49/bbl compared to US$58/bbl in 2017.

A bullish outlook on prices in the first three quarters of the year was supported by concerns about supply disruptions from Venezuela, Iran and Libya. In the last quarter, the outlook turned bearish with rising trade tensions between the US and China, weakening sentiment for demand growth and more importantly, the consistent growth in US oil production, driven by the Permian. Coupled with a lack of access to international markets, increasing domestic storage levels and Midwest refinery outages in the fourth quarter, differentials between WTI and the Canadian benchmark Light Sweet Blend ("MSW") and condensate prices increased to record levels in the last quarter.

In 2018, the MSW differential increased to US$11.11/bbl from US$2.50/bbl with an average discount of US$26.30/bbl (2017: US$1.11/bbl) in the fourth quarter. Condensate differentials also increased materially to a US$3.77/bbl discount in 2018 from a US$0.60/bbl premium in 2017 and a fourth quarter average of US$13.50/bbl (2017: US$2.57 premium). These differentials improved materially in the first quarter of 2019 in part due to the mandated production curtailment announced by the Government of Alberta.

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 lower prices for other natural gas liquids, particularly propane.

Natural gas prices increased nominally during the year with the benchmark Henry Hub averaging US$3.12/MMBtu compared to US$2.99/MMBtu in 2017.

Growth in supply was more than offset by higher demand resulting in storage levels reaching 15-year lows in the United States. Dry natural gas production increased to a new record of over 80 Bcf/d this summer, driven by the Marcellus and Utica in the northeast United States and associated gas primarily from the Permian. Consumption increased with higher weather-related demand for power generation, liquified natural gas exports and exports to Mexico. In Canada, production also grew to multi-year highs but declining exports to the United States have resulted in differentials substantially exceeding the AECO reference price for natural gas in Alberta.

Higher heat content production from Kakwa contributed to a realized price of $1.82/Mcf (2017: $2.42/Mcf) compared to an AECO average $1.34/Mcf (2017: $2.26/Mcf).

Royalties

($ thousands)	**2018**	2017
Alberta	**$ 1,223**	$ 676
Saskatchewan	**568**	257
Manitoba	**94**	160
	$ 1,885	$ 1,093
% of Revenue:		
Alberta	**5%**	4%
Saskatchewan	**6%**	6%
Manitoba	**15%**	18%
Total Company	**6%**	5%

Mirroring the increase in petroleum and natural gas revenue, royalties increases from $1.09 million to $1.89 million in 2018. As a percentage of revenue, this increased marginally to 6% from 5%.

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

These incentive programs include the legacy 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 for new wells 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 is determined by 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.

Operating Costs

($ thousands)	**2018**	2017
Alberta	**$ 8,324**	$ 7,844
Saskatchewan	**3,129**	1,938
Manitoba	**206**	248
	$ 11,659	$ 10,030
$/boe:		
Alberta	**15.36**	18.56
Saskatchewan	**23.88**	29.66
Manitoba	**22.56**	16.16
Total Company	**$ 17.09**	$ 19.93

Operating costs in 2018 increased by just over 15% to $11.66 million from $10.03 million last year.

On a unit of production basis, this decreased to $17.09/boe from $19.93/boe with the higher production volumes in 2018. With approximately 80% of the Kakwa operating costs, including firm transportation and processing commitments, as fixed, the allocation of these costs over higher volumes resulted in lower costs on a boe basis. Similarly, at Antler, over 85% of the operating costs are fixed and the higher volumes also translated into a lower expense on a boe basis.

General and Administrative Expenses

($ thousands)	**2018**	2017
General and administrative expenses, gross	**$ 5,742**	$ 4,119
Capitalized expenses and overhead recoveries	**(1,310)**	(976)
General and administrative expenses, net	**$ 4,432**	$ 3,143

Gross general and administrative expenses ("G&A") increased by 39% to $5.74 million from $4.12 million in 2018. The increase is primarily attributable to payments under the bonus plan and the reversal of salary and fee reductions implemented in 2015 and 2016 to preserve financial liquidity. Additionally, higher consulting and legal costs were incurred in the current year. Capitalized expenses are the administrative costs associated with its exploration projects in Quebec and Jordan and these amounts increased over the prior year due to the higher government and public relations activity in Quebec.

Depletion, Depreciation, Impairment and Lease Expiries

For the year ended December 31, 2018, Questerre reported depletion, depreciation and accretion expense of $12.01 million (2017: $9.90 million). The higher expense reflects the higher production volumes in the current year. On a per unit basis, depletion expense decreased to $15.71/boe from $17.95/boe with increased volumes from cash generating units ("CGUs") with lower finding and development costs.

At December 31, 2018, 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 CGU was 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. Due to the increase in the reserves assigned to the Kakwa area, the Company recorded a reversal of $28 million of impairment expense incurred in 2017 and 2015. No impairment or impairment reversals were recorded for any of the Company's other CGUs. In 2017, the Company incurred an impairment expense of $12.30 million for its Montney and Other Alberta CGUs due to the lower commodity prices and an increase in the discount rate for the Montney CGU as a result of higher expected returns for Montney producers.

The Company also recorded an expense of $1.56 million primarily related to acreage in Quebec that has been relinquished as the Company has no future plans for development. By comparison, in 2017, the Company incurred $7.12 million for land expiries in Alberta.

Loss on Equity Investment

Questerre currently holds approximately 30% of the common share capital of Red Leaf Resources Inc. ("Red Leaf"). The Company uses the equity method of accounting for its ownership in Red Leaf. Under the equity method, the Company's investment is recognized at cost with any changes to fair value being recognized through the income statement. The Company also records its proportionate share of Red Leaf's income or loss.

Questerre recorded a loss of $7.63 million (2017: $3.4 million) representing its share of the net loss realized by Red Leaf for the period and an impairment expense of $1.70 million. In 2017, the Company reversed a previously recorded impairment charge of $2.34 million relating to the increase in the fair value of Red Leaf common shares held prior to the acquisition completed in the second quarter of 2017. For more information, please see Note 7 to the Financial Statements.

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.

The Company recorded stock based compensation expense of $0.71 million for the year ended December 31, 2018 (2017: $0.41 million).

Other Income and Expenses

Questerre reported interest expense of $0.59 million for the year ended December 31, 2018 and $0.77 million for the prior year. The expense primarily relates to the interest on its credit facilities with a Canadian chartered bank. The Company also reported interest income of $0.54 million for the year (2017: $0.15 million). The interest was earned on term deposits held with Canadian chartered institutions.

The Company recorded a gain on foreign exchange, net of deferred tax, through other comprehensive income (loss) of $0.74 million for the year ended December 31, 2018 (2017: loss $0.86 million). The income is due to an increase in the exchange rate relating to its US dollar denominated investment in Red Leaf.

Deferred Taxes

The Company reported a deferred tax expense of $6.12 million for 2018 (2017: $5.53 million).

The expense is due to the net income in the current year and resulted in a reduction in the deferred tax asset at year end. In 2018, 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 2018.

Total Comprehensive Income (Loss)

Questerre's total comprehensive income was $14.20 million for 2018 compared to a loss of $25.68 million in 2017. The Company's change in total comprehensive income is attributable mainly to the reversal of previous impairment expense and higher revenue offset by the higher loss on its investment in Red Leaf in the current year. In 2017, Questerre total comprehensive loss also included a gain of $3.66 million on the sale of exploration and evaluation assets and a gain of $1.05 million on risk management contracts.

Net Income (Loss) Per Share

Questerre's basic net income was $0.03 per share compared to a loss of $0.07 per share in 2017. Questerre reported net income was $13.47 million in 2018 and a net loss of $24.82 million in 2017.

Cash Flow from Operating Activities

Net cash from operating activities for the years ended December 31, 2018 and 2017 was $13.09 million and $14.66 million, respectively. While adjusted funds flow from operations increased in 2018, a decrease in non-cash working capital in the current year contributed to the lower net cash from operating activities in 2018 compared to the prior year.

Cash Flow used in Investing Activities

Cash flow used in investing activities decreased to $30.41 million in 2018 from $33.18 million in 2017. For the year ended December 31, 2018, the Company incurred capital expenditures of $30.97 million compared to $25.26 million for the same period in 2017. In 2017, expenditures included $10.33 million to increase its investment in Red Leaf and $6.94 million to acquire producing assets in Antler offset by an asset disposition of $4.45 million in Kakwa.

Cash Flow provided by Financing Activities

Cash flow provided by financing activities decreased materially to $0.69 million from $46.08 million in 2017. In 2017, the Company completed private placements for gross proceeds of $57.9 million and made a net repayment under its credit facilities of $9 million. In 2018, the Company raised $0.76 million through the exercise of warrants and stock options and made no net change in the amount outstanding under its credit facilities.

Capital Expenditures

($ thousands)	**2018**	2017
Alberta	**$ 27,753**	$ 22,158
Saskatchewan & Manitoba	**1,020**	1,630
Jordan	**1,335**	833
Quebec	**869**	640
	30,977	25,261
Acquisitions (Saskatchewan)	**125**	6,935
Proceeds from disposition	–	(4,450)
Total	**$ 31,102**	$ 27,746

In 2018, Questerre incurred capital expenditures of $30.97 million as follows:

- In Alberta, $27.75 million was primarily invested to drill, complete and equip wells and expand infrastructure on the Kakwa Central joint venture acreage;
- In Jordan, the Company invested $1.33 million in the technical and economic feasibility assessment of its oil shale project;
- In Saskatchewan, $1.02 million was invested to workover wells and expand the secondary recovery pilot; and
- In Quebec, $0.87 million was invested to secure social acceptability.

In 2017, Questerre incurred capital expenditures, excluding dispositions and acquisitions, of $25.26 million as follows:

- $22.16 million was invested in Alberta to participate in the drilling and completion of wells and related infrastructure costs on the Kakwa Central joint venture acreage;
- $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.

In 2017, the Company completed an acquisition of producing assets in 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.

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.

At December 31, 2018, $13.84 million (December 31, 2017: $13.90 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) to to current liabilities (excluding bank debt outstanding and unrealized hedging losses). The Adjusted Working Capital Ratio at December 31, 2018 was 1.48 and the covenant was met. See Note 13 to the Financial Statements.

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 2019.

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 deficit, including amounts due under its credit facilities, of $9.08 million at December 31, 2018, as compared to a surplus of $9.65 million at December 31, 2017.

Management believes that with its 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. To execute its business plan including the full participation in the current and future drilling programs and Kakwa Central and Kakwa North, the Company anticipates it will need to improve its financial liquidity through potential asset sales, equity issuances or securing additional credit facilities. However, it cannot provide any assurance that sufficient financing will be available on acceptable terms or that cash flows will be generated from operating activities to reduce its working capital deficiency and to carry out its planned capital expenditure program.

An improvement in commodity prices should improve cash flow and reduce the working capital deficit. This will likely result in additional adjusted funds flow from operations being available to finance planned capital expenditures. On an ongoing basis, the Company will manage where possible future capital expenditures to maintain liquidity (See “Commitments”). The Company intends to invest up to 85% of the 2019 future development costs associated with proved reserves in its independent reserves assessment as of December 31, 2018. It anticipates that, as a result, reserves associated with wells not drilled in 2019 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.

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, 2018, 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 28, 2019**	**December 31, 2018**	December 31, 2017
Common Shares	**389,007**	**389,007**	385,331
Stock Options	**27,512**	**21,412**	21,387
Warrants	–	–	3,566
Weighted average Common Shares			
Basic		**388,712**	350,055
Diluted		**395,715**	350,055

A summary of the Company's stock option activity during the years ended December 31, 2018 and 2017 follows:

	December 31, 2018			December 31, 2017		
	Number of Options *(thousands)*		**Weighted Average Exercise Price**	Number of Options *(thousands)*		Weighted Average Exercise Price
Outstanding, beginning of period	**21,387**	**$**	**0.50**	14,856	$	0.41
Granted	**3,288**		**0.48**	6,900		0.69
Forfeited	**(150)**		**0.52**	(232)		0.52
Expired	**(3,003)**		**0.88**	(90)		0.70
Exercised	**(110)**		**0.42**	(47)		0.62
Outstanding, end of period	**21,412**	**$**	**0.44**	21,387	$	0.50
Exercisable, end of period	**10,403**	**$**	**0.34**	9,180	$	0.50

Commitments

A summary of the Company's net commitments at December 31, 2018 follows:

($ thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Transportation, Marketing and Processing	$ 3,654	$ 4,084	$ 4,728	$ 3,990	$ 3,990	$ 11,972	$ 32,418
Office Leases	139	117	–	–	–	–	256
	$ 3,793	$ 4,201	$ 4,728	$ 3,990	$ 3,990	$ 11,972	$ 32,674

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, 2018.

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. Pursuant to IFRS 9, the Company made a provision of $0.17 million at December 31, 2018 for its expected credit losses related to its accounts receivable.

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 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, 2018, 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 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 or reversal of previously recognized impairments if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable or indications that previously recognized losses should be reversed. 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 2018

The Company adopted IFRS 9 *Financial Instruments* and IFRS 15 *Revenue from Contracts with Customers*. See Note 4 to the Financial Statements.

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.

IFRS 16 Leases

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.

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, 2018.
- 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, 2018 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, 2018 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 2018 Results

Petroleum and natural gas revenue decreased by 12% to $6.46 million for the last quarter of 2018 from $7.30 million in the same period last year. Although production volumes increased by 19%, realized prices declined by over 31%. Production increased over the prior year with additional wells brought on stream at the Kakwa Central area over the last two years. The decline in realized liquids prices in the fourth quarter this year to $45.96/bbl from $66.98/bbl last year reflects the decrease in the benchmark WTI as well as a material increase in differentials to Canadian condensate and light oil.

Operating costs increased nominally to $3.52 million from $3.46 million last year. On a boe basis this declined from $21.96 to $18.75. With approximately 80% of operating costs at Kakwa and Antler as fixed, the allocation of these costs over higher production volumes in the current year results in a lower expense per unit of production. During the quarter, the Company realized a loss of $4.24 million related to its investment in Red Leaf (2017: $1.05 million). Based on the review of the carrying amount of its assets at December 31, 2018 and as a result of the increase in reserves at Kakwa, the Company recorded a reversal of previously incurred impairment expense of $28 million in the fourth quarter (2017: $12.30 million expense).

Total comprehensive income for the three months ended December 31, 2018 was $15.17 million compared to a loss of $17.96 million for the same period in 2017. The change in the Company's total comprehensive income is attributable to the reversal of the previously recorded impairment expenses offset by the higher loss on its investment in Red Leaf.

Questerre's net cash from operating activities was $1.84 million for the quarter ended December 31, 2018 compared to $1.27 million for the same period in 2017. This is attributable to the increase in interest income and the lower petroleum and natural gas revenue in the current year. During the quarter, capital expenditures including the acquisition of additional acreage at Kakwa totaled $8.8 million (2017: $8.04 million).

Quarterly Financial Information

($ thousands, except as noted)	**December 31, 2018**	September 30, 2018	June 30, 2018	March 31, 2018
Production (boe/d)	**2,033**	1,414	2,016	2,013
Average Realized Price ($/boe)	**34.35**	52.98	54.91	52.66
Petroleum and Natural Gas Sales	**6,462**	6,892	10,074	9,541
Adjusted Funds Flow from Operations	**1,929**	2,620	6,012	4,652
Net Profit (Loss)	**14,858**	(2,023)	572	59
Basic and Diluted ($/share)	**(0.01)**	(0.01)	–	–
Capital Expenditures, net of acquisitions and dispositions	**8,785**	6,077	7,452	8,663
Working Capital Surplus (Deficit)	**(9,077)**	(2,374)	1,239	2,804
Total Assets	**233,372**	218,630	220,043	218,346
Shareholders' Equity	**187,291**	171,648	173,464	172,123
Weighted Average Common Shares Outstanding				
Basic (thousands)	**388,412**	388,412	387,862	387,848
Diluted (thousands)	**392,612**	388,412	395,552	396,285

($ 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 ($/boe)	46.30	36.03	44.34	43.82
Petroleum and Natural Gas Sales	7,302	5,446	4,184	4,429
Adjusted Funds Flow from Operations (1)	2,552	1,938	880	1,411
Basic and Diluted ($/share)	–	–	–	–
Net 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

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

2,033 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.

- 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 March 31, 2017, December 31, 2017, as a result of the equity issuances completed by the Company during those periods and in the quarters ended March 31, 2018 and June 30, 2018 as a result of warrant and option exercises.

Off-Balance Sheet Transactions

The Company did not engage in any off-balance sheet transactions during the year ended December 31, 2018, other than commitments as disclosed.

Related Party Transactions

The Company did not engage in any related party transactions during the year ended December 31, 2018, other than key management compensation as disclosed.