Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") was prepared as of March 23, 2023 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, 2022 and 2021. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2022 dated March 23, 2023 ("AIF"), is available on SEDAR under Questerre's profile at www.sedar.com.

Questerre is an energy technology and innovative company 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 using 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;
- the timing of case management conferences and a hearing of the Company's claim made in connection with Quebec's Bill 21;
- future production of oil, natural gas and natural gas liquids;

- future commodity prices in light of decisions by OPEC and non-OPEC member countries, including Saudi Arabia and Russia on production levels, the war in Ukraine, as well as the lingering impacts of COVID-19;
- legislative and regulatory developments in the Province of Quebec;
- the enhancement of existing production through workovers and monitoring of the pilot secondary recovery scheme at Antler;
- the transfer of wells drilled in 2022 from the proved undeveloped to the proved producing category;
- hedging policy;
- liquidity and capital resources;
- the Company's assessment of a small scale commercial project in Jordan;
- the Company's negotiations and finalization of 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;
- ability of the Company to meet its foreseeable obligations;
- capital expenditures and the funding thereof;
- Questerre's reserves;
- impacts of capital expenditures on the Company's reserves;
- 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;
- the timing of receivables from joint venture partners;
- flow-through shares and use of proceeds and renunciation and indemnity obligations associated therewith;
- insurance;
- use of financial instruments; and
- critical accounting estimates.

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:

- Quebec's Bill 21, the revocation of licenses in Quebec and potential compensation;
- volatility in market prices for oil, natural gas liquids and natural gas due to, among other things, the production agreements between OPEC and non-OPEC member countries, including Saudi Arabia and Russia, on production levels, the war in Ukraine, as well as the lingering impact of COVID-19;
- access to capital;
- general economic conditions;
- the terms and availability of credit facilities;

- counterparty credit risk;
- 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;
- insufficient advancement by Red Leaf in the engineering of its proprietary process;
- 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;
- 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 are by their nature deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

The discounted and undiscounted net present values of future net revenue attributable to reserves 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.

Adjusted Funds Flow from Operations Reconciliation

($ thousands)	2022	2021
Net cash from operating activities	$ 28,810	$ 14,075
Interest received	(568)	(207)
Interest paid	156	433
Change in non-cash working capital	(2,072)	176
Adjusted funds flow from operations	$ 26,326	$ 14,477

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

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.

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 any outstanding risk management contracts.

Select Annual Information

As at/for the years ended December 31,	2022	2021	2020
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Revenue	**51,751**	30,404	21,924
Adjusted Funds Flow from Operations	**26,325**	14,477	6,146
Basic and Diluted ($/share)	**0.06**	0.03	0.01
Net Income (Loss)	**14,111**	(4,301)	(117,623)
Basic and Diluted ($/share)	**0.03**	(0.01)	(0.28)
Capital Expenditures	**11,591**	4,665	5,622
Working Capital Surplus (Deficit) [(1)]	**24,491**	1,834	(7,705)
Total Non-Current Financial Liabilities	**191**	1,975	2,025
Total Assets	**196,486**	184,264	196,177
Shareholders' Equity	**166,128**	148,961	152,120
Common Shares Outstanding (thousands)	**428,516**	428,516	427,516
Weighted average - basic (thousands)	**428,516**	428,034	427,613
Weighted average - diluted (thousands)	**430,524**	428,034	427,613
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	**1,020**	890	1,278
Natural Gas (Mcf/d)	**4,167**	3,538	4,126
Total (boe/d)	**1,714**	1,480	1,966
Average Sales Price [(2)]			
Crude Oil and Natural Gas Liquids ($/bbl)	**121.58**	84.81	41.80
Natural Gas ($/Mcf)	**6.10**	3.84	2.51
Total ($/boe)	**82.72**	56.34	30.47
Netback ($/boe)			
Petroleum and Natural Gas Revenue [(3)]	**82.72**	56.34	30.47
Royalties Expense [(3)]	**(7.72)**	(3.46)	(1.83)
Percentage	**9%**	6%	6%
Operating Expense [(3)]	**(24.47)**	(21.81)	(16.60)
Operating Netback	**50.54**	31.06	12.04
General and Administrative Expense [(3)]	**(7.08)**	(4.46)	(3.52)
Cash Netback	**43.46**	26.59	8.52
Wells Drilled			
Gross	**1.00**	3.00	1.00
Net	**0.25**	0.75	0.25

(1) Refer to the Current Assets and Current Liabilities in the Balance Sheet for the years ended December 31, 2022 and 2021.
(2) Refer to Note 15 in the Consolidated Financial Statements for the years ended December 31, 2022 and 2021.
(3) Refer to Consolidated Statement of Comprehensive Loss and Comprehensive Loss for the years ended December 31, 2022 and 2021.

Highlights

- Strong financial position with a working capital surplus of close to $25 million and an unutilized credit facility of $16 million
- Conversion of royalty interest in Kakwa North farm-in wells add 700 boe/d in the fourth quarter
- Government of Quebec enacts Bill 21 to revoke oil and gas exploration licenses
- Before tax NPV-10% of total proved and probable reserves unchanged at $270 million even with a 10% decrease in volumes to 30 MMBoe
- Average daily production of 1,714 boe/d and adjusted funds flow from operations of $26.3 million

2022 Activities

Western Canada

Kakwa, Alberta

Following the resumption of drilling at Kakwa Central in late 2021, production volumes increased over the prior year. These also reflect the conversion of the Company's royalty interest in the farm-in wells at Kakwa North to a working interest in the fourth quarter.

Capital investment in Kakwa totalled $11 million for the year (2021: $3.2 million) with daily production averaging 1,404 boe/d (2021: 1,174 boe/d) comprising of 4.2 MMcf/d of natural gas (2021: 3.5 MMcf/d) and 720 bbl/d of condensate and natural gas liquids (2021: 589 bbl/d). Total proved and probable reserves as of December 31, 2022, were estimated at 28.4 MMBoe (2021: 31.5 MMBoe) with a before tax NPV-10% of $247.2 million (2021: $234.2 million). The Company currently holds 40,960 (18,020 net) acres in the Kakwa area.

At Kakwa Central, the operator completed and tied-in three (0.75 net) wells during 2022. Questerre holds a 25% interest in these wells. The operator subsequently spud two wells including one in the first quarter of this year. Questerre elected to participate in only one of these two wells. The operator has tentatively proposed to drill up to three (0.75 net) wells in the fourth quarter of this year.

Effective the end of the third quarter last year, the operator of Kakwa North advised that it had recovered 100% of the capital and operating costs associated with the initial four farm-in wells. The Company subsequently elected to convert its 5% royalty interest in these wells to a 50% working interest. The operator is proposing up to three (1.5 net) wells commencing in the fourth quarter of this year.

The Company plans to participate in the drilling programs at Kakwa North and Kakwa Central subject to, among other things, commodity prices, the costs and design of the proposed drilling and completion programs.

Antler, Saskatchewan

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

With the exception of routine operating expenditures, including workovers, nominal capital of $0.5 million was invested during the year (2021: $0.1 million). Daily production averaged 268 bbl/d (2021: 278 bbl/d). Total proved and probable reserves as at December 31, 2022 were estimated at 1.2 MMBbls (2021: 1.4 MMBbls) with a before tax NPV-10% of $25.2 million (2021: $36.1 million). The Company currently holds 11,035 net acres in the area.

In 2023, the Company expects to continue its work to enhance existing production through workovers and expanding the pilot secondary recovery scheme.

St. Lawrence Lowlands, Quebec

The Company's primary goal is to protect its legal rights following the enactment of Bill 21, *An Act mainly to end petroleum exploration and production and the public financing of those activities* ("Bill 21") by the Government of Quebec. Concurrently, it continues to seek opportunities to work with the Government of Quebec to advance its Clean Tech Energy project.

Bill 21 was enacted on August 23, 2022. It revokes petroleum exploration and production licences, including the 16 exploration licenses held by the Company. It provides that the Government must establish a compensation program pertaining to the revocation of licences. The Act requires, in particular, the holders of a revoked licence to permanently close wells and restore sites according to the terms and conditions determined by the Government. Bill 21 validates the regulations made under the authority of the *Petroleum Resources Act*, certain decisions which effectively limit or prohibit, directly or indirectly, exploration for petroleum and underground reservoirs and production of petroleum and brine as well as the collection by the Minister of the annual fees for oil and gas activities.

As a result of the enactment of Bill 21, the Government of Quebec returned to the Company cash security deposits in the amount of $7.7 million representing the estimated abandonment and reclamation costs associated with its wells in the province. Consistent with the Company's legal claim to have Bill 21 declared invalid and in compliance with its obligations to fund these costs under the pre-existing *Petroleum Resources Act*, the Company continues to segregate these funds internally. The Company also continues to carry an asset retirement obligation for these wells.

The Company subsequently amended its original claim filed earlier in the year to have the Superior Court declared Bill 21 invalid. In addition to its claim that the Government's introduction of the regulations in 2018 represent an expropriation without compensation and with no demonstrated public utility, the claim also notes the violation of the Company's rights under the *Quebec Civil Code,* the *Quebec Charter of Rights and the constitution*. The amended application further details the unclear and ambiguous nature of Bill 21, the Government's breach of its duty to act in good faith, its duty to honor its contractual commitments and its duty to consult.

In the fall of 2022, following the request by the Attorney General, the Superior Court of Quebec appointed a single judge to separately manage all the litigation by licensee holders, including Questerre. The litigation includes the judicial review application for the regulations of the *Petroleum Resources Act* and the claim for expropriation referenced above filed in 2018 and 2022, respectively.

In 2023, the parties anticipate holding a series of case management conferences to determine the next steps in the proceedings as well as the specific items of the respective claims that can be dealt with collectively and which must be dealt with individually. Subject to the timing and outcome of these conferences, the Company anticipates a hearing date for its claim could be set later this year.

The Company is pursuing available remedies to protect its legal rights and challenge the validity of Bill 21. It is seeking just compensation for the value of its licenses including the significant natural gas discovery. The Company plans to assist other stakeholders and partners, including the First Nations and local royalty holders, to ensure their rights are also protected against the Government's unconstitutional actions.

Oil Shale Mining

The Company continued to assist its investee, Red Leaf Resources Inc. ("Red Leaf"), to advance their recently acquired refinery project and their proprietary technology to produce oil from shale.

Red Leaf is a private Utah based company whose principal assets include its proprietary technology to produce oil from shale, oil shale leases in the state of Utah and approximately US$15 million in unrestricted cash as of December 31, 2022. It also holds freehold surface rights and a permit for a small-scale refinery project. The Company currently owns approximately 41% of the common share capital of Red Leaf.

Early in 2022, through the exercise of a security interest, Red Leaf acquired 7,300 acres of surface rights in the oil-producing Uintah Basin in Utah. The lands include a grandfathered state permit for a 40,000 barrel per day wax processing refinery. It is situated at the terminus of the proposed Uintah Basin Railway to provide the basin access to markets on the US Gulf Coast.

Red Leaf's primary focus has been to validate the business case for the project as well as the preliminary engineering design and cost estimates. The Company recently entered into a collaboration agreement with the Ute Tribe, a Federally recognized Indian Tribe to jointly develop this project. The agreement includes the potential supply of utilities to the project, raw crude and marketing of finished products.

Red Leaf has also been advancing its patented technology that was redesigned to incorporate carbon capture into the process. The company anticipates it will benefit from the tax incentives under the recently introduced US *Inflation Reduction Act* for carbon capture. During the year, Hatch, a global engineering firm, validated the new design and identified a path to commercial development. The company is currently designing a small-scale commercial project as the first phase.

The Company plans to utilize the Red Leaf technology for its project in the Kingdom of Jordan. Given the ongoing redesign of the technology, limited third party engineering was conducted on its acreage in the Kingdom in 2022. In conjunction with Red Leaf, the Company is assessing the potential for a small scale commercial project in Jordan with local partners that could provide both engineering and fabrication services as well as offtake for the produced crude oil.

Consistent with the prior year, negotiations with the Government of Jordan for the fiscal and other terms of the concession agreement for the project remain ongoing. Questerre continues to hold the exclusive exploration rights to the project during the term of these negotiations.

Drilling Activities

During 2022, one (0.25 net) well was spud at Kakwa Central compared to three (0.75 net) wells last year.

Production

	2022			2021		
	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	720	4,167	1,414	589	3,538	1,179
Saskatchewan and Manitoba	300	–	300	301	–	301
	1,020	4,167	1,714	890	3,538	1,480

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

Volumes on average increased by just over 15% over the prior year reflecting the higher production at Kakwa.

This includes the addition of the three (0.75 net) new wells at Kakwa Central that were tied-in during the second quarter and accounted for over 80% of volumes from the area. Kakwa North accounted for the remainder of the volumes and increased materially in the fourth quarter following the conversion of the royalty interest to a working interest. Consistent with prior years, Kakwa represented over 80% of corporate volumes.

The product mix from Kakwa is split equally between condensate and other natural gas liquids and natural gas. In conjunction with the light oil production from Antler and Manitoba, this contributed to a crude oil and liquids weighting of 60%, unchanged from prior years. Production volumes from these areas were largely flat over the prior year with the resumption of workovers in a higher price environment that offset natural declines.

With only one (0.25 net) new well at Kakwa Central, the Company anticipates its production will decline over the prior year. Subject to the timing and participation in the drilling programs here and at Kakwa North, the Company could see an increase in its volumes in early 2024.

2022 Financial Results

Petroleum and Natural Gas Revenue

	2022			2021		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Alberta	$ 29,093	$ 9,797	$ 38,890	$ 16,498	$ 5,056	$ 21,554
Saskatchewan and Manitoba	12,861	–	12,861	8,850	–	8,850
	$ 41,954	$ 9,797	$ 51,751	$ 25,348	$ 5,056	$ 30,404

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

Materially higher prices for all commodities were mainly responsible for the substantial increase in petroleum and natural gas revenue over the prior year. Of the 70% increase in revenue, over three quarters was due to higher prices with the remainder due to higher production volumes.

Pricing

	2022	2021
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	5.15	3.37
Crude Oil - Canadian Light Sweet Blend ($/bbl)	121.49	82.34
Realized prices:		
Natural Gas ($/Mcf)	6.10	3.84
Crude Oil and Natural Gas Liquids ($/bbl)	121.58	84.81

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

Crude oil prices rose by nearly 50% over the prior year with the benchmark West Texas Intermediate (“WTI”) averaging over US$95/bbl compared to US$67/bbl last year.

In the first half of the year, prices increased to their highest levels in more than a decade. This was largely due to the Russian invasion of Ukraine and its impact on global supplies. Prices declined in the second half of the year. This was attributable to concerns of a global economic slowdown, the risk of Chinese demand recovery and the Strategic Petroleum Reserve releases in the United States in response to rising gasoline prices. Prices were supported by North American producers exercising capital discipline relative to growth and OPEC’s compliance with its production quotas. In Canada, increasing export demand contributed to tightening differentials. In 2022, the discount between WTI and the Canadian benchmark Edmonton Mixed Sweet Blend (“MSW”) was US$1.82/bbl compared to US$3.88/bbl in 2021.

Realized prices for Questerre’s light oil and natural gas liquids track the MSW benchmark with condensate receiving a premium and other liquids receiving a discount.

Natural gas prices experienced a similar increase over the prior year. The benchmark Henry Hub averaged US$6.44/MMBtu compared to US$3.91/MMBtu last year.

Prices reflected the tightening supply demand balance. Although US dry gas production grew over the prior year by over 3% or 3 Bcf/d, it was outpaced by demand for domestic consumption and exports. Demand grew by over 5% or 4.4 Bcf/d in all categories including power generation and residential and commercial. US LNG exports also grew as Europe competed with Asia for supplies to reduce their dependence on Russian gas. Canadian natural gas prices saw a similar increase but lagged US prices due to volatile differentials. This was attributable to delayed pipeline expansions and ongoing maintenance issues on the primary pipeline system in Western Canada, particularly in the third quarter.

Realized natural gas prices, reflecting the higher heat content from Kakwa production, averaged $6.10/Mcf (2021: $3.84/Mcf) compared to the AECO benchmark price of $5.15/Mcf (2021: $3.37/Mcf).

Royalties

($ thousands)	2022	2021
Alberta	$ 3,882	$ 1,232
Saskatchewan and Manitoba	950	637
	$ 4,832	$ 1,869
% of Revenue:		
Alberta	10%	6%
Saskatchewan and Manitoba	7%	7%
Total Company	9%	6%

Gross royalties increased over the prior year due to both higher commodity prices and effective royalty rates on production in Alberta. As a percentage of revenue this increased to 9% this year from 6% last year.

In Alberta, royalties increased over twofold due to the expiration of prior Crown incentive programs. This resulted in Crown royalties of 40% on condensate production from older vintage wells. By comparison newer wells benefit from incentives and record royalty rates of 5% on condensate production.

As the effective rate remained unchanged from last year, royalties on production in Saskatchewan and Manitoba increased commensurate with the change in revenue.

Operating Costs

($ thousands)	2022	2021
Alberta	$ 11,310	$ 8,479
Saskatchewan and Manitoba	3,511	2,795
Quebec	485	506
	$ 15,306	$ 11,780
$/boe:		
Alberta	21.90	19.71
Saskatchewan and Manitoba	32.15	25.44
Total Company	$ 24.47	$ 21.81

Inflationary pressures on general industry costs and higher production volumes at Kakwa contributed to an overall 30% increase over the prior year.

Operating costs at Kakwa reflect both higher costs at the Kakwa Central joint venture, particularly related to fuel and power and well workovers, as well as operating costs for Kakwa North and an associated area following the conversion of the royalty interest into a working interest. On a unit of production basis, this increase was offset by higher production volumes and resulted in a 10% increase to just under $22 per boe from $20 per boe last year.

At Antler, in addition to higher fuel and power expense, higher costs were incurred for workovers as well as chemicals with a new program designed to mitigate the frequency of workovers. Operating costs in Quebec remained flat and represent the maintenance costs associated with the assets in the province.

General and Administrative Expenses

($ thousands)	2022	2021
General and administrative expenses, gross	$ 4,655	$ 3,454
Capitalized expenses and overhead recoveries	(228)	(1,045)
General and administrative expenses, net	$ 4,427	$ 2,409

Gross General & Administrative expenses ("G&A") increased by 30% to $4.7 million from $3.5 million last year. Higher expenses were incurred in several categories, including salaries and benefits, as well as government and public relations related to the Company's project in Quebec. Capitalized expenses are overhead costs associated with the Company's projects in Montney, Alberta and Jordan. These decreased substantially in the current year following the impairment of the Quebec assets in 2021.

Depletion, Depreciation, Impairment, Accretion and Lease Expiries

For the year ended December 31, 2022, the Company recorded depletion, depreciation, and accretion expense of $9.9 million (2021: $6.1 million) with depletion accounting for over 90% of this amount. The higher amount reflects both the higher production volumes in the current year as well as increases in the carrying value of its assets and future development costs. The carrying value of its assets in the current year reflect the reversal of previously incurred impairment expense of $91.7 million last year as detailed below. On a unit of production basis this increased to $15.25/boe from $10.71/boe last year.

The Company assessed the carrying value of its plant, property and equipment assets ("PP&E") as at December 31, 2022 for indicators of impairment or indicators to reverse previously recorded impairment. Based on this review the Company's Western Canada cash generating units ("CGUs") were tested 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 future operating costs reducing the value of the reserves at Antler, Saskatchewan the Company recorded an impairment expense of $0.9 million. No impairment expense was recorded with respect to its other CGUs.

In 2021, due to the higher future commodity prices, the Company recorded a reversal of $91.7 million of previously impaired expenses. Of this amount, $76 million was attributed to the Kakwa, Alberta CGU and $15.7 million was attributed to the Antler, Saskatchewan CGU. No impairment reversals were recorded for the Company's other CGUs.

The Company assessed the carrying value of its exploration and evaluation ("E&E") assets and noted no indicators of impairment. In 2021, as a result of the introduction of Bill 21 in Quebec, the Company impaired the full carrying value of its E&E assets of $104 million.

Share Based Compensation

Pursuant to the Company's share 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 share-based compensation expense of $1.9 million (2021: $0.5 million) net of $0.3 million (2021: $0.7 million) in expense that was capitalized during the year.

Equity Investment

Questerre holds approximately 41% of the equity capital of Red Leaf. The Company uses the equity method of accounting for its ownership of Red Leaf. Under this method, the Company records its proportionate share of Red Leaf's net loss and any impairment or reversals of previously recorded impairments are recognized through the income statement.

During the year as a result of the reduction in the net asset value, the Company recorded an expense of $2.5 million (2021: Nil). For more information, please see Note 7 to the Financial Statements.

Other Income and Expenses

The Company incurred interest expense of $0.2 million (2021: $0.4 million) related to its credit facilities with a Canadian chartered bank. The amount drawn on the facilities at year-end was essentially nil

(2021: $3.4 million) and the effective interest rate was 5.33% (2021: 3.45%). The Company also earned interest income of $0.04 million on its cash and term deposits (2021: $0.2 million).

Included in other income is $1.8 million reflecting the discharge of a contingent liability related to the acquisition of assets in Quebec completed in 2019.

Other Comprehensive Income (Loss)

In 2022, the Company recorded other comprehensive income of $0.8 million (2021: $0.1 million loss) related to the change in foreign exchange rates. A gain of $0.3 million in the current year (2021: $0.04 million loss) was attributable to the change in the US dollar denominated investment in Red Leaf. The Company also incurred a gain of $0.5 million (2021: $0.02 million loss) due to the appreciation in the Jordanian dinar impacting its dinar-denominated assets in Jordan.

Total Comprehensive Income (Loss)

For the year ended December 31, 2022, the Company recorded net income of $14.1 million compared to a loss of $4.3 million last year. As expenses in aggregate remained unchanged over the prior year, the increase in the current year is due to the materially higher petroleum and natural gas revenue.

Including other comprehensive income, total comprehensive income increased to $14.9 million from a loss of $4.4 million last year.

Cash Flow from Operating Activities

The Company recorded cash flow from operating activities of $28.8 million (2021: $14.1 million). The variance over last year is due to the higher adjusted flow from operations from higher net income offset partly by the increase in non-cash working capital compared to a decrease in the prior year.

Cash Flow used in Investing Activities

Cash flow used in investing activities increased to $12 million from $3.8 million last year. This is attributable to the higher capital investment at Kakwa and, to a less extent, the reduction in non-cash working capital compared to an increase last year.

Cash Flow provided by Financing Activities

In 2022, the Company reported net cash used in financing activities of $3.4 million, representing the net reduction in borrowing under its credit facility. In the prior year, the Company reduced its borrowings by $11.9 million. Amounts in 2021 also include $0.2 million related to the exercise of stock options.

Capital Expenditures

($ thousands)	**2022**	2021
Alberta	**$ 10,955**	$ 3,220
Saskatchewan, Manitoba and Jordan	**522**	120
Quebec	**114**	1,325
Total	**$ 11,591**	$ 4,665

Notes:
1. Capital expenditures exclude certain non-cash items such as, share based compensation and asset retirement obligations.

For the year ended December 31, 2022, the Company incurred capital expenditures of $11.6 million as follows:

- In Alberta, $11.0 million to finish drilling, complete and tie-in three (0.75 net) wells on the Kakwa Central joint venture;
- In Saskatchewan, $0.5 million was spent on the pressure maintenance scheme; and
- In Jordan, $0.1 million was spent on advancing the engineering for its oil shale project.

For the year ended December 31, 2021, the Company incurred capital expenditures of $4.7 million as follows:

- In Alberta, $3.3 million for drilling three (0.75 net) wells on the Kakwa Central joint venture;
- In Quebec, $1.3 million for well monitoring and capitalized overhead related to advancing social acceptability and engineering for its Clean Tech Energy project; and
- In Jordan, $0.1 million was spent on advancing the engineering for its oil shale project.

Fourth Quarter 2022 Results

In the last quarter of 2022, petroleum and natural gas revenue increased by over 50% to $13.6 million from $8.9 million in the same period last year. Over 90% of this increase was attributed to the increase in production volumes with the remainder due to the increase in commodity prices.

The conversion of the royalty interest to a working interest in the four original farm-in wells at Kakwa North were responsible for the increase in production volumes in the fourth quarter to 2,023 boe/d from 1,398 boe/d last year. Consistent with the fiscal year, benchmark pricing for both oil and gas increased over the prior year but decreased over the preceding quarter. The differential between WTI and Canadian condensate prices remained a premium but decreased over the prior year.

Operating costs for the quarter increased by almost 50% to $5.3 million from $3.7 million last year. While expenses remained stable in Saskatchewan, Manitoba and Quebec, the increase was attributable to higher costs at Kakwa. These largely reflect the operating costs associated with the new production volumes at Kakwa North. This increase in gross costs was offset by the higher volumes resulting in no changes on a boe basis from the prior year.

Including impairment relating to its Antler, Saskatchewan CGU and other income of $2.1 million, the Company reported a net loss of $0.1 million and total comprehensive loss of $0.5 million for the quarter. By comparison in 2021, the Company reported a net loss of $10.1 million and total comprehensive loss of $10.2 million. The quarterly loss in the current year is attributed to the change in foreign exchange related to the carrying value of its investment in Red Leaf and Jordan. The loss in the prior year was attributable to the impairment of the full carrying value of its E&E assets in Quebec of $104 million offset by the reversal of previously incurred impairment of its PP&E assets of $92 million in the quarter due to higher future commodity prices.

In the fourth quarter, net cash from operating activities increased to $5.3 million from $3.8 million last year. This reflects the higher adjusted funds flow from operations over the prior year and a material increase in non-cash working capital. Net cash used in investing activities increased over the prior year quarter with higher capital spending. No cash was used in financing activities compared to the prior year when the Company reduced borrowings under its credit facility by $4 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.

The Company continues to manage its financial liquidity through ensuring capital expenditures can be financed through a combination of cash flow from operations and available debt facilities.

At December 31, 2022, there were effectively no borrowings under its credit facility (December 31, 2021: $3.4 million) and the Company is compliant with all its covenants under the credit facilities. Under the terms of the credit facilities, 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 current liabilities (excluding bank debt outstanding and unrealized hedging losses). The Adjusted Working Capital Ratio at December 31, 2022 was 6.13 and the covenant was met. See Note 13 of the Financial Statements.

While the credit facilities were maintained at $16 million, the facilities could be reduced at their next review scheduled during the second quarter of 2023. 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. In the current market, the Company may be unable to secure additional financing on acceptable terms, if at all. The Company believes that it has access to sufficient financial liquidity to meet its foreseeable obligations in the normal course of operations over the next 12 months.

The Company is committed to the 2023 future development costs associated with proved reserves in its independent reserves assessment as of December 31, 2022. It anticipates that, as a result, reserves associated with wells drilled in 2023 will be transferred from the proved undeveloped to the proved producing 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, 2022, 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 fiscal year end.

(thousands)	March 23, 2023	December 31, 2022	December 31, 2021
Common Shares	428,516	428,516	428,516
Stock Options	46,738	35,298	30,308
Weighted average Common Shares			
Basic		428,516	428,034
Diluted		430,524	428,034

A summary of the Company's stock option activity during the years ended December 31, 2022 and 2021 follows:

	December 31, 2022		December 31, 2021	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	30,308	$ 0.35	25,351	$ 0.38
Granted	11,490	0.34	8,350	0.18
Forfeited	–	–	(2,343)	0.18
Expired	(6,500)	0.69	(50)	0.18
Exercised	–	–	(1,000)	0.18
Outstanding, end of period	35,298	$ 0.28	30,308	$ 0.35
Exercisable, end of period	22,643	$ 0.28	20,866	$ 0.42

Commitments

A summary of the Company's net commitments at December 31, 2022 follows:

($ thousands)	2023	2024	2025	2026	Total
Transportation and Processing	$ 3,162	$ 2,884	$ 2,015	$ 1,240	$ 9,301

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 commodity prices, exploration and development drilling as well as production operations, foreign exchange and interest rate fluctuations. Unforeseen significant changes in such areas as markets, prices, royalties, interest rates, government regulations and global economic conditions 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, 2022.

Volatility in the oil and gas industry is a major risk facing the Company. Market events and conditions, including global oil and natural gas supply and demand, actions taken by OPEC and non-OPEC member countries' decisions on production growth and spare capacity, including recent decisions by Saudi Arabia and Russia, on production growth and spare capacity, market volatility and disruptions, weakening global relationships, the war in Ukraine, conflict between the U.S. and Iran, isolationist and punitive trade policies, hostilities in the Middle East, Ukraine and Taiwan, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. Russia's invasion of Ukraine has led to sanctions being levied against Russia by the international community and may result in additional sanctions or other international action, any of which may have a destabilizing effect on commodity prices and global economies more broadly. These events and conditions have been a factor in the decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax and royalty changes and other environmental regulations .

In addition, the difficulties in obtaining the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Company's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have previously reduced the Company's cash flow leading to a reduction in funds available for capital expenditures. As a result, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis. Any decrease in value of the Company's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Company's indebtedness, could result in the Company having to repay all or a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Company may have difficulty raising additional funds in the future to raise funds on unfavourable and highly dilutive terms.

Another 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. 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.

Questerre faces several 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 $0.05 million at December 31, 2022 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 has historically used its best efforts to ensure that qualifying expenditures of Canadian Exploration Expense ("CEE") are incurred in order to meet its flow-through obligations. In 2017, the Federal Government amended the law regarding what expenses constitute CEE. Generally, oil and gas drilling expenses are now Canadian Development Expense rather than CEE. In the event that the Company has CEE expenditures reclassified under audit by the Canada Revenue Agency or fails to incur expenditures required under a flow-through share agreement, the Company may be required to liquidate certain of its assets in order to meet the indemnity obligations under 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, 2022, 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.

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. The federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with the Company's counterparts who operate in jurisdictions where there are less costly carbon regulations.

Interest Rate Risk

Interest rate risk is the risk that changes in the applicable interest rates for its credit facilities will impact the Company's interest expense. At December 31, 2022, the Company had credit facilities outstanding effectively of nil (December 31, 2021: $3.4 million) with an effective rate of 5.33% (2021: 3.45%).

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

All of Questerre's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* 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 is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices. These estimates are evaluated by independent reserve engineers at least annually.

Proved 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 estimates impact a number of the areas, in particular, the valuation of property, plant and equipment 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 way 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 Government regulations, operator estimates, 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.

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. The primary risk related to the investment in Red Leaf is the decline in the net current assets of the company without a sufficient advancement in the engineering for their proprietary technology or their refinery project.

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, 2022.
- 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, 2022 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, 2022 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.

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Quarterly Financial Information

($ thousands, except as noted)	**December 31, 2022**	September 30, 2022	June 30, 2022	March 31, 2022
Production (boe/d)	**2,023**	1,629	1,909	1,288
Average Realized Price ($/boe)	**72.87**	77.40	97.95	82.56
Petroleum and Natural Gas Revenue	**13,562**	11,602	17,013	9,574
Adjusted Funds Flow from Operations	**4,670**	5,183	12,183	4,290
Net Profit (Loss)	**(122)**	2,759	9,051	2,423
Basic and Diluted ($/share)	**–**	0.01	0.02	0.01
Capital Expenditures, net of acquisitions and dispositions	**2,169**	1,653	2,843	4,926
Working Capital Surplus (Deficit)	**24,491**	14,433	10,564	1,192
Total Assets	**196,486**	196,258	194,419	186,201
Shareholders' Equity	**166,128**	166,235	161,969	151,862
Weighted Average Common Shares Outstanding				
Basic (thousands)	**428,516**	428,516	428,516	428,516
Diluted (thousands)	**428,516**	430,727	428,747	432,112

($ thousands, except as noted)	December 31, 2021	September 30, 2021	June 30, 2021	March 31, 2021
Production (boe/d)	1,398	1,363	1,479	1,679
Average Realized Price ($/boe)	69.11	58.83	52.72	46.62
Petroleum and Natural Gas Revenue	8,887	7,376	7,095	7,046
Adjusted Funds Flow from Operations	3,790	3,578	4,224	2,885
Net Profit (Loss)	(10,107)	2,006	2,892	908
Basic and Diluted ($/share)	(0.02)	–	0.01	–
Capital Expenditures, net of acquisitions and dispositions	3,177	541	450	497
Working Capital Surplus (Deficit)	1,834	1,698	(1,243)	(5,449)
Total Assets	184,264	192,709	194,053	194,417
Shareholders' Equity	148,961	158,922	156,316	153,108
Weighted Average Common Shares Outstanding				
Basic (thousands)	428,516	428,516	427,571	427,516
Diluted (thousands)	428,516	428,516	427,743	427,879

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. Revenue has begun increasing in the last five quarters due to the recovery in commodity prices.
- Production volumes reflect the capital investment in drilling and completing wells at Kakwa in preceding quarters. In the fall of 2021, with the increase in prices, capital investment increased in

the fourth quarter. Prior thereto, with non-essential capital investment largely suspended during the pandemic, production volumes declined.

- The level of capital expenditures over the quarters has varied largely due to the timing and number of wells drilled and completed as well as, the timing of the infrastructure investment at Kakwa Alberta.
- The working capital position has generally increased when capital expenditures and other investments have been lower than adjusted funds flow from operations and cash from financing activities.
- Shareholders' equity increased as a result of net income, primarily from higher commodity prices. It decreased in the fourth quarter of 2021 as a result of the impairment related to its investment in Quebec.

Off-Balance Sheet Transactions

The Company did not engage in any off-balance sheet transactions during the year ended December 31, 2022.

Related Party Transactions

The Company paid fees of $0.1 million in 2022 (2021: $0.2 million) to a law firm where a Director of the Company is currently a partner.