Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") was prepared as of March 21, 2024 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, 2023 and 2022. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2023 dated March 21, 2024 ("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 judicial plans to achieve a hearing of the Company's claim made in connection with Quebec's Bill 21;
- working collaboratively to find a political and business solution with the Government of Quebec;

- future production of oil, natural gas and natural gas liquids;
- future commodity prices in light of decisions by OPEC and its allies, including Saudi Arabia and Russia on production levels, the war in Ukraine, and the conflict in the Middle East;
- legislative and regulatory developments in the Province of Quebec;
- the enhancement of existing production through workovers and expanding the pilot secondary recovery scheme at Antler;
- the implementation of the Company's Clean Tech Energy project in Quebec;
- the transfer of wells drilled in 2024 from the proved undeveloped to the proved producing category;
- the outlook for heavier crude and demand for condensate as diluent as the TMX pipeline commences service;
- 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 its allies, including Saudi Arabia and Russia, on production levels, the war in Ukraine, and the conflict in the Middle East;
- 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)	**2023**	2022
Net cash from operating activities	**$ 16,317**	$ 28,810
Change in non-cash working capital	**(462)**	(2,072)
Adjusted funds flow from operations	**$ 15,855**	$ 26,738

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". Working capital surplus, 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, 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,	2023	2022	2021
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Revenue	**41,701**	51,751	30,404
Adjusted Funds Flow from Operations	**15,855**	26,738	14,477
Basic and Diluted ($/share)	**0.04**	0.03	0.03
Net Income (Loss)	**(23,708)**	14,067	(4,301)
Basic and Diluted ($/share)	**(0.06)**	0.03	(0.01)
Capital Expenditures	**10,148**	11,591	4,665
Working Capital Surplus [1]	**29,866**	24,007	1,834
Total Non-Current Financial Liabilities	**134**	191	1,975
Total Assets	**172,346**	196,486	184,264
Shareholders' Equity	**143,667**	166,128	148,961
Common Shares Outstanding (thousands)	**428,516**	428,516	428,516
Weighted average - basic (thousands)	**428,516**	428,516	428,034
Weighted average - diluted (thousands)	**428,516**	430,524	428,034
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	**1,056**	1,020	890
Natural Gas (Mcf/d)	**4,749**	4,167	3,538
Total (boe/d)	**1,848**	1,715	1,480
Average Sales Price [2]			
Crude Oil and Natural Gas Liquids ($/bbl)	**94.01**	121.58	84.81
Natural Gas ($/Mcf)	**3.02**	6.10	3.84
Total ($/boe)	**61.83**	82.67	56.34
Netback ($/boe)			
Petroleum and Natural Gas Revenue [3]	**61.83**	82.67	56.34
Royalties Expense [3]	**(8.89)**	(7.72)	(3.46)
Percentage	**14%**	9%	6%
Operating Expense [3]	**(23.84)**	(24.47)	(21.81)
Operating Netback	**29.10**	50.51	31.06
General and Administrative Expense [3]	**(7.54)**	(7.07)	(4.46)
Cash Netback	**21.56**	43.43	26.59
Wells Drilled			
Gross	**2.00**	1.00	3.00
Net	**1.35**	0.25	0.75

[1] Refer to the Current Assets and Current Liabilities in the Balance Sheet for the years ended December 31, 2023 and 2022.
[2] Refer to Note 15 in the Consolidated Financial Statements for the years ended December 31, 2023 and 2022.
[3] Refer to Consolidated Statement of Comprehensive Loss and Comprehensive Loss for the years ended December 31, 2023 and 2022.

Highlights

- Quebec Superior Court grants stay on key provisions of Bill 21
- Questerre presents carbon storage pilot to Quebec Government
- Average daily production of 1,848 boe per day with adjusted funds flow from operations of $15.9 million
- Total proved and probable reserves assessed at 26.4 MMboe with a before tax NPV-10% value of $195 million declining 25% due to lower forecast natural gas prices and an 11% decrease in reserves

2023 Activities

Western Canada

Kakwa, Alberta

With ongoing drilling at Kakwa Central, production volumes increased over the prior year. Volumes 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 of 2022.

Capital investment in Kakwa totalled $3.6 million for the year (2022: $11 million) with daily production averaging 1,536 boe/d (2022: 1,404 boe/d) comprising of 4.7 MMcf/d of natural gas (2022: 4.2 MMcf/d) and 753 bbl/d of condensate and natural gas liquids (2022: 720 bbl/d). Total proved and probable reserves as of December 31, 2023, were estimated at 25.0 MMBoe (2022: 28.4 MMBoe) with a before tax NPV-10% of $178.6 million (2022: $247.2 million). The Company currently holds 40,320 (17,700 net) acres in the Kakwa area.

At Kakwa Central, the operator completed and tied-in two wells during 2023. Questerre holds a 25% interest in one well and elected to forego participation in the second well. The operator has proposed to drill up to three (0.75 net) wells in 2024. Questerre has participated in the first (0.25 net) well of this program and intends to participate in the remaining two (0.5 net) wells.

No drilling activities were conducted on the Kakwa North acreage during the year. In the fourth quarter of 2022, Questerre converted its royalty interest in the four farm-in wells into a 50% working interest. The operator is assessing three (1.5 net) wells that could spud 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, and 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.

$5.5 million was invested at Antler during the year to drill and complete one 100% well and expand the secondary recovery scheme (2022: $0.5 million). Daily production averaged 239 bbl/d (2022: 268 bbl/d). Total proved and probable reserves as at December 31, 2023 were estimated at 1.3 MMBbls

(2022: 1.2 MMBbls) with a before tax NPV-10% of $23.3 million (2022: $25.2 million). The Company currently holds 11,316 net acres in the area.

In 2024, 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 objective remains the implementation of its Clean Tech Energy project in Quebec through a business and political solution. Concurrently, it is protecting its legal rights following the enactment in August 2022 of Bill 21, *An Act mainly to end petroleum exploration and production and the public financing of those activities in Quebec* ("Bill 21").

During the year, the Company presented to the Quebec Ministry of Economy, Innovation and Energy ("MEIE") its plans for a carbon storage test on its lands. The prospective storage formation underlying its licenses was identified by the Company after an assessment of its proprietary seismic and well data. This meeting follows the request from the MEIE for proposals for pilot projects that would foster the energy transition and attain targets in the fight against climate change pursuant to Bill 21.

In early 2024, the Company submitted a formal application for a pilot project. The project includes a comprehensive program to assess the carbon storage potential including injection and monitoring wells, compression facilities and a pipeline to an adjacent industrial park. This included infrastructure will facilitate the transition to a commercial project. The project also includes the test of new technology for zero-emissions hydrogen and power production that will provide a source of carbon dioxide for the project.

A hearing was held in October 2023 on the application by the Company and other license holders to stay certain provisions of Bill 21 for the duration of the judicial proceedings. Early in the new year, the Justice ruled that the Company's application met the key criteria for a stay and stayed some of these provisions. The Justice also ruled that the judgement be enforced even if the Attorney General files an appeal, also known as 'provisional execution'. He noted that Questerre and the other plaintiffs run the risk of serious and irreparable harm in the absence of this order for provisional execution. Subsequently, the Attorney General of Quebec has recently filed an application to appeal this ruling.

The Company is proceeding with the main hearing on the merits of the case in accordance with procedural rules in Quebec, including its debate on the constitutional validity of Bill 21. The judicial process is at the discoveries stage. The next step is pre-trial examinations. Following the completion of pre-trial examinations, a date will be set for the main hearing.

Oil Shale Mining

The Company continued to assist its investee, Red Leaf Resources Inc. ("Red Leaf"), advance their assets in the Unitah Basin and their proprietary technology to produce oil from shale that incorporates carbon capture.

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$12 million in unrestricted cash as of December 31, 2023. It also holds freehold surface rights as well as carbon sequestration rights and a permit for a wax processing facility in the oil-producing Uintah Basin in the state of Utah. The Company currently owns approximately 41% of the common share capital of Red Leaf.

During the year, the company completed a pre-FEED engineering study on the facility to validate the design and capital costs. In advance of seeking funding for the project, the company is focused on securing off-take agreements for the facility's production, supply contracts with producers and engaging a qualified engineering firm to manage the construction. Concurrently, the company is assessing the development of an industrial park on its lands that would provide prospective tenants with both zero-emissions power and takeaway capacity for any produced emissions utilizing its carbon storage rights.

Red Leaf has also been engineering the design of a small-scale commercial project for a group of local companies in the Kingdom of Jordan. It is anticipated that these companies could provide both engineering and fabrication services in-country as well as a potential off-take for the produced crude oil. Red Leaf has recently been evaluating broader applications of their technology beyond the production of oil from shale.

The Company plans to utilize the Red Leaf technology for its project in the Kingdom of Jordan. Discussions with the Government of Jordan for this small-scale commercial project and the related negotiations for 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 2023, one net operated well was spud at Antler and one (0.35 net) well at Pierson compared to one (0.25 net) well last year at Kakwa.

Production

	2023			2022		
	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	**753**	**4,749**	**1,545**	720	4,167	1,415
Saskatchewan and Manitoba	**303**	**–**	**303**	300	–	300
	1,056	**4,749**	**1,848**	1,020	4,167	1,715

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

With higher production volumes at Kakwa, daily production increased by under 10% for the year ended December 31, 2023.

Production at Kakwa is split 60/40 between Kakwa Central and Kakwa North. At Kakwa Central one (0.25 net) well was tied in during the year. At Kakwa North, production is from the Company's interest in four wells. The Company converted a royalty interest to a working interest in these wells in the fourth quarter of 2022. Consistent with prior years, Kakwa represents over 80% of corporate volumes.

The product mix at Kakwa is equally split between natural gas and liquids that include condensate. Aggregated with the light oil production from Saskatchewan and Manitoba, the Company's liquids weighting is close to 60%, unchanged from prior years. Production volumes from these areas were flat over the prior year with new wells in both areas offsetting natural declines.

New wells at Kakwa Central are expected to be on-stream in the fourth quarter of 2024. As a result, the Company anticipates its volumes will decline over this year. Subject to the timing of a possible drilling program at Kakwa North, the Company could see incremental volumes in the second quarter of 2025.

2023 Financial Results

Petroleum and Natural Gas Revenue

	2023			2022		
($ thousands)	**Oil and Liquids**	**Natural Gas**	**Total**	Oil and Liquids	Natural Gas	Total
Alberta	**$ 25,418**	**$ 5,486**	**$ 30,904**	$ 29,093	$ 9,797	$ 38,890
Saskatchewan and Manitoba	**10,797**	**–**	**10,797**	12,861	–	12,861
	$ 36,215	**$ 5,486**	**$ 41,701**	$ 41,954	$ 9,797	$ 51,751

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

The effect of increased production volumes on revenue was completely offset by the decline in realized commodity prices. Petroleum and natural gas revenue dropped by 20% with a nearly 30% drop in prices reduced by a just under 10% increase in production volumes.

Pricing

	2023	2022
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	**2.64**	5.15
Crude Oil - Canadian Light Sweet Blend ($/bbl)	**100.39**	121.49
Realized prices:		
Natural Gas ($/Mcf)	**3.02**	6.10
Crude Oil and Natural Gas Liquids ($/bbl)	**94.01**	121.58

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

Although crude oil prices remained relatively stable during the year, they declined by almost 20% over last year. The benchmark West Texas Intermediate averaged US$77.62 per barrel this year compared to US$94.76 per barrel in 2022.

In the first half of the year, prices reflected tightening fundamentals with optimism about demand growth from developing countries, particularly India and China, and supply cuts by OPEC members.

These impacts were moderated by the rising interest rates, inflation, and the risks of a recession. Later in the year, prices were supported by US inventories reaching near five-year lows and the concerns of the Israel-Hamas conflict expanding to the broader region, including reduced crude flows through the Suez Canal. In Canada the outlook for heavier crude and the associated demand for condensate as a diluent is expected to improve as the TMX pipeline commences service in 2024.

Mirroring the decline in the WTI price, Questerre's realized prices fell to $94.01 per barrel from $121.58 per barrel last year. This compared to the benchmark Edmonton Mixed Sweet blend that averaged $100.39 in 2023 compared to $121.49 last year.

Natural gas prices experienced a more substantial decline and fell over 60% in the year. The benchmark Henry Hub averaged US$2.54 per MMBtu compared to US$6.44 per MMBtu last year.

The decline was driven by record natural gas production in the United States. This increased to 104 Bcf per day led by growth in the major producing basins including the Permian and Appalachian. This growth outpaced the increases in natural gas exports by pipeline and LNG as well as the increased demand for power generation. Lower residential and commercial demand during a warmer than expected winter also contributed to the lower prices. In Canada, production levels remained largely flat and prices reflected the increased storage levels and lack of access to international markets.

With a higher heat content for the natural gas production from Kakwa, realized prices reflect a premium over the benchmark prices. In 2023, Questerre's realized price was $3.02 per Mcf (2022: $6.10 per Mcf) compared to the AECO benchmark of $2.64 per Mcf (2022: $5.15 per Mcf).

Royalties

($ thousands)	**2023**	2022
Alberta	**$ 5,081**	$ 3,882
Saskatchewan and Manitoba	**914**	950
	$ 5,995	$ 4,832
% of Revenue:		
Alberta	**16%**	10%
Saskatchewan and Manitoba	**8%**	7%
Total Company	**14%**	9%

Royalties increased over the prior year due mainly to the higher effective rates on production from Alberta. As a percentage of revenue, this increased from 9% last year to 14% this year.

The higher royalty rates in Alberta reflect the expiry of Crown incentive programs for wells drilled at Kakwa. Incrementally, the addition of working interest volumes at Kakwa North where these programs previously expired also contributed to the higher rates. This equates to royalty rates of 40% on condensate production from older vintage wells compared to effective rates of 5% from wells that meet the applicable incentive program criteria.

Royalty rates on production in Manitoba and Saskatchewan increased marginally due to the addition of a new well that attracted higher rates.

Operating Costs

($ thousands)	**2023**	2022
Alberta	**$ 11,499**	$ 11,310
Saskatchewan and Manitoba	**4,050**	3,511
Quebec	**533**	485
	$ 16,082	$ 15,306
$/boe:		
Alberta	**20.39**	21.90
Saskatchewan and Manitoba	**36.61**	32.15
Total Company	**$ 23.84**	$ 24.47

Gross operating costs increased by just over 5% because of higher production volumes in the year. On a unit of production basis, this remained relatively stable at approximately $24 per boe.

In Alberta, operating costs in the current year include a full year of production from Kakwa North compared to only a single quarter in the prior year. In Saskatchewan, the increase in operating costs is attributable to unexpected issues with a workover in the third quarter. Operating costs in Quebec reflect the costs associated with maintaining the Company's assets in the province.

General and Administrative Expenses

($ thousands)	**2023**	2022
General and administrative expenses, gross	**$ 5,356**	$ 4,655
Capitalized expenses and overhead recoveries	**(270)**	(228)
General and administrative expenses, net	**$ 5,086**	$ 4,427

Gross General & Administrative expenses ("G&A") increased by 20% to $5.4 million from $4.7 million last year. Nominally higher expenses reflecting, in part, general cost inflation, were incurred in several categories, including salaries and benefits, consulting as well as legal and government and public relations related to the Company's project in Quebec. Capitalized expenses are overhead costs associated with the Company's projects in Alberta and Jordan.

Depletion, Depreciation, Impairment, Accretion and Lease Expiries

For the year ended December 31, 2023, the Company recorded depletion, depreciation, and accretion expense of $12.6 million (2022: $9.9 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. On a unit of production basis this increased to $17.60/boe from $15.25/boe last year.

The Company assessed the carrying value of its plant, property and equipment assets ("PP&E") as at December 31, 2023, for indicators of 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 higher of the fair value less costs of disposal ("FVLCD") and value in use ("VIU") using a discounted cash flow model. Due to a decrease in future gas prices, an increase in the future operating costs reducing the value of the reserves and a 11% reduction in reserves, the Company recorded an impairment expense of $23.7 million (2022: $0.9 million). Of this amount the Antler CGU, recorded an impairment expense of $5.3 million (2022: $0.9 million) based on a FVLCD assessment and the Kakwa CGU recorded an impairment expense of $18.4 million (2022: nil) based on a VIU assessment. No impairments were recorded for the Company's other CGUs.

The estimates of FVLCD and VIU were determined using discount rates ranging from 12.5% to 15.6% and forecasted after tax cash flows based on proved plus probable reserves, with escalating prices, future development costs and an estimate of G&A where applicable.

The Company assessed the carrying value of its exploration and evaluation ("E&E") assets and impaired its assets in Saskatchewan by $0.8 million. No other impairment was recorded in the current year.

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 $1.4 million (2022: $1.9 million) net of $0.2 million (2022: $0.3 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.

As a result of the reduction in the net asset value, the Company recorded an expense of $1.2 million (2022: $2.5 million). For more information, please see Note 7 to the Financial Statements.

Interest and Other Income

The Company earned interest and other income of $1.5 million for the year ended December 31, 2023. The interest was earned on its cash and term deposits that totaled $35 million at year-end. In the prior year, other income included $1.8 million for the discharge of a contingent liability related to the 2019 acquisition of assets in Quebec.

Other Comprehensive Income (Loss)

In 2023, the Company recorded other comprehensive loss of $0.4 million (2022: $0.9 million income) related to the change in foreign exchange rates. A loss of $0.1 million in the current year (2022: $0.4 million gain) was attributable to the change in the US dollar denominated investment in Red Leaf. The Company also incurred a loss of $0.3 million (2022: $0.5 million gain) due to the depreciation in the Jordanian dinar impacting its dinar-denominated assets in Jordan.

Net Income (Loss) and Total Comprehensive Income (Loss)

For the year ended December 31, 2023, the Company recorded a net loss of $23.7 million compared to net income of $14.1 million in the prior year. The loss in the current year is due to lower petroleum and natural gas revenue and higher expenses in all categories, specifically, impairment.

Including other comprehensive loss, the Company reported a total comprehensive loss of $24.1 million compared to income of $14.9 million last year.

Cash Flow from Operating Activities

The Company reported cash flow from operating activities of $16.3 million (2022: $28.8 million). The variance over the prior year is attributed to the lower adjusted funds flow from operations and a smaller change in the non-cash working capital.

Cash Flow used in Investing Activities

Commensurate with nominally lower capital spending, the cash used in investing activities declined to $10.8 million from $12 million last year. Expenditures on PP&E and E&E decreased by $1.5 million to $10.1 million and the Company recorded a higher decrease in non-cash working capital in the current year.

Cash Flow provided by Financing Activities

In the current year, effectively no cash was used for financing activities. The prior year amount of $3.4 million reflects the net repayment of drawings under the credit facilities.

Capital Expenditures

($ thousands)	**2023**	2022
Alberta	**$ 3,616**	$ 10,955
Saskatchewan, Manitoba and Jordan	**6,532**	636
Total	**$ 10,148**	$ 11,591

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

For the year ended December 31, 2023, the Company incurred capital expenditures of $10.1 million as follows:

- In Alberta, $3.6 million to finish drilling, complete and tie-in one (0.25 net) well on the

Kakwa Central joint venture;

- In Saskatchewan, $5.5 million was spent to drill, complete and tie-in one well and recompletions for the pressure maintenance scheme; and
- $1 million was spent to drill, complete and tie-in of one (0.35 net) well in Manitoba and on other assets.

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.

Fourth Quarter 2023 Results

In the fourth quarter of the year, petroleum and natural gas revenue declined by nearly 30% to $9.7 million from $13.6 million last year. Approximately one third of this decline is due to lower production volumes with the remainder due to the drop in realized commodity prices.

Production volumes declined over the prior year as only one (0.25 net) well was brought on production at Kakwa Central in the current year compared to three (0.75 net) wells last year. This was offset by incremental volumes at Antler as one new well was brought on production. Both crude oil and natural gas prices declined over the prior year and preceding quarter. The differential between WTI and Canadian condensate prices declined to a discount compared to a premium last year.

Operating costs decreased materially over the prior year and preceding quarter, both on a gross and unit of production basis. In the fourth quarter, operating costs totaled $3.5 million compared to $5.3 million last year. The change is mainly due to lower operating costs at Kakwa in fuel and power along with workovers.

Including impairment expense relating to its Kakwa, Alberta and Antler, Saskatchewan CGUs, the Company reported a net loss of $26 million for the quarter (2022: $0.1 million loss) and total comprehensive loss of $26 million (2023: $0.5 million). The loss is largely due to the impairment expense in the current year offset by lower operating expenses. In the prior year, the smaller loss is due to the higher petroleum and natural gas revenue and smaller impairment expense.

In the fourth quarter, net cash from operating activities was $5.2 million (2022: $5.3 million). This reflects the lower adjusted funds flow from operations of $3.2 million and a larger increase in non-cash working capital of $2 million in the current year compared to $4.9 million and $0.4 million respectively last year. Net cash used in investing activities increased over the prior year due to higher capital spending. There was no change in the net cash used in financing activities.

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, 2023 and 2022, there were effectively no borrowings under its credit facility 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, 2023 was 5.76 (2022: 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 2024. 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 2024 future development costs associated with proved reserves in its independent reserves assessment as of December 31, 2023. It anticipates that, as a result, reserves associated with wells drilled in 2024 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, 2023, 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 21, 2024	December 31, 2023	December 31, 2022
Common Shares	428,516	428,516	428,516
Stock Options	38,420	38,140	35,298
Weighted average Common Shares			
Basic		428,516	428,516
Diluted		428,516	430,524

A summary of the Company's stock option activity during the years ended December 31, 2023 and 2022 follows:

	December 31, 2023		December 31, 2022	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	35,298	$ 0.28	30,308	$ 0.35
Granted	6,000	0.24	11,490	0.34
Expired	(3,158)	0.48	(6,500)	0.69
Outstanding, end of period	38,140	$ 0.26	35,298	$ 0.28
Exercisable, end of period	28,153	$ 0.25	22,643	$ 0.28

Commitments

A summary of the Company's net commitments at December 31, 2023 follows:

($ thousands)	2024	2025	2026	2027	Total
Transportation and Processing	$ 3,429	$ 2,515	$ 1,566	$ 545	$ 8,055

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, 2023.

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 $0.04 million at December 31, 2023 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, 2023, 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, 2023, and 2022 the Company had credit facilities outstanding effectively of nil with an effective rate of 7.95% (2022: 5.33%).

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 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, 2023.
- 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, 2023 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, 2023 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.

Quarterly Financial Information

($ thousands, except as noted)	**December 31, 2023**	September 30, 2023	June 30, 2023	March 31, 2023
Production (boe/d)	**1,794**	1,830	1,978	1,790
Average Realized Price ($/boe)	**59.04**	63.71	59.46	65.38
Petroleum and Natural Gas Revenue	**9,743**	10,725	10,702	10,531
Adjusted Funds Flow from Operations	**3,209**	3,034	5,335	4,277
Net Profit (Loss)	**(26,003)**	(337)	1,692	940
Basic and Diluted ($/share)	**(0.06)**	–	–	–
Capital Expenditures, net of acquisitions and dispositions	**3,588**	845	2,469	3,246
Working Capital Surplus (Deficit)	**29,866**	30,191	28,013	25,523
Total Assets	**172,346**	197,716	201,213	199,264
Shareholders' Equity	**143,667**	169,636	169,444	167,371
Weighted Average Common Shares Outstanding				
Basic (thousands)	**428,516**	428,516	428,516	428,516
Diluted (thousands)	**428,516**	428,516	431,100	431,064

($ 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

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 increased due to the recovery in commodity prices in 2022 and largely stabilized in 2023.
- Production volumes reflect the capital investment in drilling and completing wells at Kakwa in preceding quarters. Additionally, effective the fourth quarter of 2022, the Company converted its royalty interest to a working interest at Kakwa North.

- 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. In the fourth quarter of 2023, $3 million was invested at Antler.
- 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, except in the last quarter when a net loss reduced shareholders equity.

Off-Balance Sheet Transactions

The Company did not engage in any off-balance sheet transactions during the year ended December 31, 2023.