2022 ANNUAL REPORT

QUESTERRE ENERGY CORPORATION

QUESTERRE

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QUESTERRE ENERGY CORPORATION is an energy technology and innovation company. It is leveraging its expertise gained through early exposure to low permeability reservoirs to acquire significant high-quality resources. We believe we can successfully transition our energy portfolio. With new clean technologies and innovation to responsibly produce and use energy, we can sustain both human progress and our natural environment.

Questerre is a believer that the future success of the oil and gas industry depends on a balance of economics, environment and society. We are committed to being transparent and are respectful that the public must be part of making the important choices for our energy future. Questerre's common shares are traded on the Toronto Stock Exchange and Oslo Stock Exchange under the symbol QEC.

President’s Message

We have been building a foundation for our business that does not rely just on our Utica discovery. Our successes this year in cementing that foundation, reflect our efforts over the past few years.

We took advantage of higher prices to eliminate debt because we prioritized preserving financial liquidity during the pandemic. We now have a working capital surplus of close to $25 million, representing mainly cash. We also have an undrawn credit facility of $16 million. This will fund the upcoming 50/50 drilling program at Kakwa North. We proved up the value of these lands with a successful farmout for an $80 million investment four years ago. We recently converted our royalty interest to a working interest in the original farm-in wells, adding just over 700 boe/d in the fourth quarter.

By focusing on capital preservation, the restructuring of our investee company, Red Leaf, was also successful. They are now well-positioned to advance their new version of the technology that integrates carbon capture to facilitate a CCUS project. This is a game changer for the future of what was otherwise an energy intensive process. Plus, taking over the operatorship and 100% equity position of the niche market wax processing project in Utah has opened up an exciting opportunity.

Despite our efforts to eliminate emissions and build social acceptability, including an agreement with the Abenaki First Nation, we did not convince the Government of Quebec who was facing an imminent election. The Government enacted Bill 21, revoking our exploration licenses and effectively nationalizing our discovery without just compensation. The value of this discovered giant natural gas field to the province of Quebec is enormous. It is large enough to satisfy domestic demand and supply LNG to Europe through a nearby permitted facility. It is an unjust enrichment to nationalize it indirectly by breaching the contracts we made with the province. We are preserving our legal claim and challenging the validity of the law. However, as we have said consistently, we prefer a political and business solution. We have discovered an enormous source of secure and reliable energy for the people of Quebec. We look forward to upcoming consultations in Quebec on solving the impending electricity energy crisis with our Clean Gas and hydrogen solutions.

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

Quebec

We filed our claim against the Government of Quebec just over one year ago. We assert that the Government has inter alia, fundamentally breached its duty to act in good faith, and in accordance with the due process of the law, to honor its contractual commitments and its duty to consult with our First Nation partners and respect their rights. Furthermore, their decision to ban our Clean Gas and hydrogen project that would eliminate emissions conflicts with a recent Supreme Court of Canada ruling that emissions asserting that climate change is a worldwide issue requiring global solutions. We anticipate a hearing date for our claim could be set later this year.

Many of our shareholders have enquired about quantifying the value of our licenses for our claim. We have commissioned a report to quantify the value of our multi-Tcf gas discovery on the basis that the Government abided by the law they passed in 2016 and allowed us to proceed with development. This report is privileged under Canadian law and must be introduced in accordance with the rules of evidence. It will be disclosed in due course as we validate with our expert witness the possible scenarios as well as the key assumptions including the pace and likelihood of development and the appropriate discount rate for the expected cash flows. However, it cannot be disclosed prior to its finalization it in accordance with the Court requirements.

The looming electricity shortage in Quebec is an opportunity for us to still move forward with the Government. For a province that generates over 90% of its electricity from hydro, this shortage seemed inconceivable only a few years ago. Yet the Government has recently publicly acknowledged the province will in fact experience a shortfall. Part of the longer-term solution is the possible construction of additional hydroelectric dams and alternative energy projects. However, current demand anticipating electrification of the economy, requires additional energy sources. The alternative is a severe curtailment of industrial and other demand during peak periods.

Volkswagen recently announced it will locate its battery plant in Ontario. Minister Fitzgibbon recently stated this was in part because Quebec did not have sufficient electricity supply. We see our Clean Gas and hydrogen project as a more viable option to maintain Quebec's economic competitiveness. It would meet their short-term needs to free up hydroelectricity for heating demand. It would also offer a cheap and environmentally friendly way to produce hydrogen in the longer term. We continue to engage with stakeholders and the Government on how our project could meet their needs.

Red Leaf and Jordan

We are seeing some early successes with the engagement of stakeholders for Red Leaf's wax processing project in Utah that will upgrade the value of the local waxy oil. They signed a collaboration agreement with the Ute Tribe, the largest indigenous landholder in the state to supply crude feedstock, market finished products and provide utilities. Several of the largest producers in the Uintah Basin have expressed an interest in our project as an opportunity to maximize the value of the light sweet and waxy oil. Although the learning curve is steep, we are encouraged by the robust business case and the regulatory path forward. The project falls under state jurisdiction and holds a grandfathered air permit, with the remaining anticipated permits requiring six to nine months of lead time. There are many more milestones, including securing financing, but we remain optimistic about this opportunity.

We are also optimistic about the prospects for their technology to produce oil from shale that incorporates carbon capture. This would leverage the cash tax incentives for carbon capture under the US *Inflation Reduction Act*. Together with Red Leaf, we formed a consortium with two Jordanian companies to assess a 600 to 1,000 bbl/d facility. Early this year, we met with the Government of Jordan to discuss our approach as well as the amendments necessary for the proposed concession agreement.

Operating & Financial

With three (0.75 net) wells brought on production at Kakwa Central this year, our volumes increased over the last year. The higher volumes also reflect the conversion of the Kakwa North royalty interest into a working interest in the fourth quarter. Higher prices generated adjusted funds flow from operations of $26.3 million. Net of capital investment of $11.6 million in 2022, this resulted in a working capital surplus of $24.5 million. This surplus also includes the refund of $7.7 million in restricted cash from the Quebec Government. Pending a ruling on our claim to have Bill 21 declared invalid, we are segregating these funds internally as we are responsible for reclamation costs under the pre-existing regulations in Quebec.

We only participated in one (0.25 net) of the two (0.50 net) wells drilled by the operator at Kakwa Central this winter. The expected return on our capital for the second well was challenged by lower commodity prices, inflation in well costs and their proposed completion design that might not maximize recoveries. As a result, we expect our production will experience natural declines this year prior to the commencement of the Kakwa North drilling program of up to three (1.5 net) wells late this fall.

Outlook

With our current liquidity, we are well positioned to participate in the proposed drilling at Kakwa North. If the operator drills three (1.5 net) wells, we could see our production materially increase in the second half of next year by over 1,500 boe/d.

We have redoubled our efforts in Quebec. As we follow the legal process, we have met with several European countries on how our project can provide near-zero emissions natural gas delivered through a permitted LNG export facility in Quebec to improve their energy security. We have encouraged them to engage with the Quebec Government on a path forward. We have discussed with Government of Quebec and local business and other groups how our project could be a solution to their energy crisis. Though the timeline and outcome of these initiatives is far from certain, we remain committed to crystallizing value for our discovery. We have also made significant progress with our high impact projects in the Kingdom of Jordan and Utah. Our future is now less dependent on the Quebec Utica.

Michael Binnion, President and Chief Executive Officer

Environmental, Social and Governance

Questerre believes the oil and gas industry can go from laggards to leaders on the global environment.

From today to 2050, the world's population is estimated to grow from 7.5 billion to almost 9.5 billion people who will expect a better standard of living. We believe providing the increased energy needed tomorrow, with lower environmental impacts than today, is the challenge of our times. We refer to this as the '7 to 9 challenge.' Transitioning our energy diet to lower emissions is essential to meet this challenge and we believe the oil and gas industry has the biggest improvements to make.

Our Clean Tech Energy project to deliver the world's first zero emissions natural gas production is an example of meeting this challenge. It will have a dramatic impact on the emissions from production in addition to other environmental criteria. It will also contribute to reducing the emissions from consumption by providing a cleaner burning alternative domestically and internationally through LNG exports. We are also looking at hydrogen production combined with carbon capture to further reduce the emissions from consumption.

It requires a new way of thinking to become leaders on environmental issues. Our industry runs most of today's energy systems. We have the experience, expertise, capital and technology to meet the world's energy and environmental challenges. Delivering on projects like our zero emissions natural gas project is just one example of how our industry can be leaders on transitioning our global energy systems.

Questerre has also taken leadership in working with communities and First Nations for local benefits. We have committed to share 3% of our profits with them. We have also engaged with local First Nations to include them in our contracting and benefits program.

We unilaterally made the decision not to work in communities where the plurality of the community does not want development. Our approach of consulting first and applying for permits second is consistent with this approach.

People know they need energy to maintain progress for their families and communities. They want to know the providers of that energy are being responsible and sustainable in the way it is produced. Questerre is an entrepreneurial leader in making the seemingly impossible task of producing more with less impact, possible. Our zero emissions Clean Tech Energy project is our contribution to meeting this '7 to 9 challenge.'

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.

Management's Report

The consolidated financial statements of Questerre Energy Corporation were prepared by management in accordance with International Financial Reporting Standards. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements reliably report the Company's operations and that the Company's assets are safeguarded. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

Ernst and Young LLP an independent firm of Chartered Professional Accountants, has been engaged to audit the consolidated financial statements of the Company and provide an independent opinion. They have conducted an independent examination of the Company's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors, has met with Ernst and Young LLP and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors, who have approved the consolidated financial statements.

Michael Binnion
President and Chief Executive Officer

Jason D'Silva
Chief Financial Officer

Calgary, Alberta, Canada
March 23, 2023

Independent Auditor's Report

To the Shareholders of Questerre Energy Corporation

Opinion

We have audited the consolidated financial statements of Questerre Energy Corporation (the Company) which comprise the consolidated balance sheet as at December 31, 2022, and the consolidated statement of net income (loss) and comprehensive income (loss), consolidated statement of changes in equity and consolidated statement of cash flows for the year then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2022, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRSs).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matter

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. This matter was addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on this matter. For the matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated* financial *statements* section of our report, including in relation to this matter. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matter below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

Key audit matter	How our audit addressed the key audit matter
Impairment of property, plant and equipment As at December 31, 2022, the carrying amount of property, plant and equipment in the Western Canada operating segment was $141.1 million. Property, plant and equipment is tested for impairment only when circumstances indicate that the carrying amount of a Cash Generating Unit ("CGU") may exceed its recoverable amount. As impairment indicators existed for all CGUs in the Western Canada operating segment, property, plant and equipment for all CGUs in the segment were tested for impairment. For the year ended December 31, 2022, an impairment of $0.9 million was recorded with respect to property, plant and equipment in the Antler, Saskatchewan CGU. Refer to Note 2(e) for a description of the Company's estimates and judgements relating to impairment and to Note 3(f) for a description of the Company's impairment of non-financial assets accounting policy. Refer to Note 8 for the Company's property, plant and equipment impairment disclosures. Auditing the Company's estimated recoverable amounts for all CGUs was complex due to the subjective nature of the underlying inputs and assumptions and the significant effect changes in these could have on the recoverable amount. Additionally, the evaluation of this estimate required specialized skills and knowledge. The primary inputs noted in the fair value less cost of disposal model were forecasted production, escalated pricing, royalties, operating costs, future development costs and an after-tax discount rate. Determining the amount of impairment requires an estimate of a CGU's respective recoverable amount. The recoverable amounts of the CGUs were determined using a fair value less costs of disposal model based on expected after-tax future net cash flows from the production of proved plus probable reserve volumes using forecast commodity prices and costs, discounted using market-based rates. Proved plus probable reserves were determined by the Company's independent petroleum engineers (management's experts).	To test the Company's estimated recoverable amounts of the significant CGUs within the Western Canada operating segment, we performed the following procedures, among others: • Evaluated management's experts' competence, capability and objectivity as well as obtained an understanding of the work they performed. The appropriateness of their work as audit evidence was evaluated by considering the relevance and reasonableness of the methods and assumptions utilized; • Involved our internal valuation specialists to assess the methodology applied, and the various inputs utilized in determining the after-tax discount rate by referencing current industry, economic, and comparable company information, as well as company and cash-flow specific risk premiums; • With the assistance of our internal valuation specialists, we compared the market capitalization to net assets and observed quantitative and qualitative reconciliations using market data and transactions; • Compared forecasted benchmark commodity pricing against historical realized prices and to other third-party price forecasts; • Assessed forecasted production, royalties, operating costs, and future development costs by comparing them to historical results; and • Evaluated the adequacy of the impairment note disclosure included in Note 8 of the accompanying consolidated financial statements in relation to this matter.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- Annual report, other than the financial statements and our auditor's report thereon

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis and the Annual Report prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRSs, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Robert Mitchell.

Ernst + Young LLP

Ernst and Young LLP

Chartered Professional Accountants

Calgary, Alberta Canada

March 23, 2023

Consolidated Balance Sheets

($ thousands)	Note	December 31, 2022	December 31, 2021
Assets			
Current Assets			
Cash and cash equivalents	5	$ 29,590	$ 8,531
Accounts receivable	6	4,600	4,016
Deposits and prepaid expenses		968	1,068
		35,158	13,615
Right-of-use assets	19	238	196
Investments	7	5,796	7,965
Property, plant and equipment	8	141,067	140,120
Exploration and evaluation assets	9	14,227	14,710
Restricted cash	13	–	7,658
		$ 196,486	$ 184,264
Liabilities			
Current Liabilities			
Lease liabilities	19	$ 59	$ 52
Accounts payable and accrued liabilities		10,634	8,361
Current portion of asset retirement obligation	12	484	–
Credit Facilities	13	33	3,420
		11,210	11,833
Lease liabilities	19	191	155
Contingent liabilities		–	1,820
Asset retirement obligation	12	18,957	21,495
		30,358	35,303
Shareholders' Equity			
Share capital	14	429,878	429,878
Contributed surplus		26,301	24,068
Accumulated other comprehensive income (loss)		296	(527)
Deficit		(290,347)	(304,458)
		166,128	148,961
		$ 196,486	$ 184,264

Commitments (note 20)

The notes are an integral part of these consolidated financial statements.

Signed on behalf of the Board of Directors

Bjorn Inge Tonnessen, Director

Dennis Sykora, Director

Consolidated Statements of Net Income (Loss) and Comprehensive Income (Loss)

($ thousands, except per share amounts)	Note	For the year ended December 31, 2022	2021
Revenue			
Petroleum and natural gas revenue	15	$ 51,751	$ 30,404
Royalties		(4,832)	(1,869)
Petroleum and natural gas revenue, net of royalties		46,919	28,535
Expenses			
Direct operating		15,306	11,780
General and administrative		4,427	2,409
Depletion, depreciation and accretion	8,12,19	9,900	6,094
Impairment	8,9	857	12,111
Lease expiries	9	129	220
Loss on equity investment	7	2,540	–
Share based compensation	11	1,891	476
Interest expense		156	433
Interest and other income		(2,354)	(680)
Income (loss) before taxes		14,067	(4,308)
Deferred tax expense (recovery)	10	(44)	(7)
Net income (loss)		14,111	(4,301)
Other Comprehensive Income (Loss), Net of Tax			
Items that may be reclassified subsequently to profit or loss:			
Foreign currency translation adjustment		496	(17)
Income (loss) on foreign exchange on investments	7	327	(37)
		823	(54)
Total Comprehensive Income (Loss)		$ 14,934	$ (4,355)
Net Income (Loss) per Share			
Basic and diluted	14	$ 0.03	$ (0.01)

The notes are an integral part of these consolidated financial statements.

Consolidated Statements of Changes in Equity

($ thousands)	For the year ended December 31, 2022	2021
Share Capital		
Balance, beginning of year	$ 429,878	$ 429,703
Options exercised	-	175
Balance, end of year	429,878	429,878
Contributed Surplus		
Balance, beginning of year	24,068	23,047
Share based compensation	2,233	1,021
Balance, end of year	26,301	24,068
Accumulated Other Comprehensive Income (Loss)		
Balance, beginning of year	(527)	(473)
Other comprehensive income (loss)	823	(54)
Balance, end of year	296	(527)
Deficit		
Balance, beginning of year	(304,458)	(300,157)
Net income (loss)	14,111	(4,301)
Balance, end of year	(290,347)	(304,458)
Total Shareholders' Equity	$ 166,128	$ 148,961

The notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

($ thousands)	Note	For the years ended December 31, 2022	2021
Operating Activities			
Net income (loss)		$ 14,111	$ (4,301)
Adjustments for:			
Depletion, depreciation and accretion	8,12,19	9,900	6,094
Impairment	8,9	857	12,111
Lease expiries	8,9	129	220
Loss on equity investment	7	2,540	–
Share based compensation	11	1,891	476
Deferred tax expense (recovery)	10	(44)	(7)
Interest expense		156	433
Interest and other income		(2,336)	(359)
Abandonment expenditures	12	(878)	(190)
		26,326	14,477
Interest expense		(156)	(433)
Interest income		568	207
Change in non-cash working capital	18	2,072	(176)
Net cash from operating activities		28,810	14,075
Investing Activities			
Property, plant and equipment expenditures	8	(2,779)	(502)
Exploration and evaluation expenditures	9	(8,812)	(4,163)
Change in non-cash working capital	18	(378)	904
Net cash used in investing activities		(11,969)	(3,761)
Financing Activities			
Proceeds from issue of share capital		–	175
Principal portion of lease payments	19	(53)	(53)
Increase in credit facilities	13	5,413	17,993
Repayment of credit facilities	13	(8,800)	(30,000)
Net cash used in financing activities		(3,440)	(11,885)
Change in cash, cash equivalents and restricted cash		13,401	(1,571)
Cash, cash equivalents and restricted cash, beginning of year		16,189	17,760
Cash, cash equivalents and restricted cash, end of year		$ 29,590	$ 16,189

The notes are an integral part of these consolidated financial statements.

1. Reporting Entity

Questerre Energy Corporation ("Questerre" or the "Company") is an energy technology and innovation company actively engaged in the acquisition, exploration and development of oil and gas projects, specifically, non-conventional projects such as tight oil, oil shale, shale oil and shale gas. The consolidated financial statements of the Company as at and for the years ended December 31, 2022, and 2021 comprise the Company and its wholly-owned subsidiaries in those periods owned. The Company wholly owns Questerre Energy Corporation/Jordan, which holds interests in the oil shale assets in Jordan.

Questerre is incorporated under the laws of the Province of Alberta and is domiciled in Canada. The address of its registered office is 1650, 801 Sixth Avenue SW, Calgary, Alberta.

a) Segmented Disclosure

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources, and assessing operational performance by Questerre's chief operating decision makers comprising of the Chief Executive Officer and other members of executive management. The operating segments have been aggregated based on several factors including geographic location and stage of development as well as the assignment of reserves and resources.

The accounting policies applied by the segments are the same as those applied by the Company.

The Company's operating segments at year end are as follows:

- Western Canada – Exploration and development activities in Western Canada including Alberta, Saskatchewan and Manitoba with existing production of natural gas, crude oil and natural gas liquids.
- Quebec – Claim against Government for a significant natural gas discovery in the province and plans to develop a clean technology energy project.
- Corporate & other – General and administrative resources to manage the respective operating segments. Includes exploration activities in the Kingdom of Jordan and an investment in Red Leaf Resources Inc. ("Red Leaf").

Segmented assets are those assets associated with each operating segment as recorded on the consolidated balance sheets.

The table below details the breakdown of assets by operating segment to the consolidated balance sheets and the reconciliation of income (loss) by operating segment to the consolidated statements of net income (loss) and comprehensive income (loss).

($ thousands)	Western Canada	Quebec	Corporate & other	Consolidated
Assets by operating segment				
Exploration and Evaluation	$ 7,415	$ –	$ 6,812	$ 14,227
Property, Plant & Equipment	141,067	–	–	141,067
Other	5,568	7,658	27,966	41,192
Total Assets, December 31, 2022	**$ 154,050**	**$ 7,658**	**$ 34,778**	**$ 196,486**
Exploration and Evaluation	$ 8,855	$ –	$ 5,855	$ 14,710
Property, Plant & Equipment	140,120	–	–	140,120
Other	5,084	7,658	16,692	29,434
Total Assets, December 31, 2021	$ 154,059	$ 7,658	$ 22,547	$ 184,264

Results by operating segment				
Revenues	$ 46,919	$ –	$ –	$ 46,919
Expenses	(25,707)	(485)	(4,120)	(30,312)
Other income	–	–	(2,540)	(2,540)
Segmented Income, December 31, 2022	$ 21,212	$ (485)	$ (6,660)	**$ 14,067**
Deferred tax expense				44
Total Income, December 31, 2022				**$ 14,111**
Revenues	$ 28,535	$ –	$ –	$ 28,535
Expenses	(29,699)	(506)	(2,638)	(32,843)
Segmented Loss, December 31, 2021	**$ (1,164)**	**$ (506)**	**$ (2,638)**	**$ (4,308)**
Deferred tax recovery				7
Total Loss, December 31, 2021				$ (4,301)

2. Basis of Preparation

a) Statement of compliance

The Company prepares its consolidated financial statements in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Boards ("IASB"). The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as at March 23, 2023, the date the Board of Directors approved the statements.

b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for financial assets classified as fair value through profit and loss which are measured at fair value with changes in fair value recorded in profit or loss and changes due to foreign exchange recorded through other comprehensive income or loss as disclosed in Note 3.

c) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. The Company has a wholly-owned subsidiary with a functional currency of the Jordanian Dinar.

d) Jointly controlled assets

The Company conducts many of its oil and gas production activities through jointly controlled operations. Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

e) Use of estimates and judgments

The preparation of 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 reserve engineers in accordance with the COGE Handbook and Canadian Securities Administrators' *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities*. The estimation of reserves is a subjective process. Forecasts are based on engineering data, anticipated future commodity prices, expected production volumes, future operating and development costs, 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 areas, in particular, the valuation of property, plant, and equipment (“PP&E”), and the calculation of depletion.

Refer to Note 8 & 9 for carrying amounts of property, plant and equipment, exploration and evaluation assets.

Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation assets (“E&E”) requires judgement in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. In addition, Management uses judgement to determine when E&E assets are reclassified to PP&E assets.

Exploration and evaluation assets are subject to ongoing management review to confirm the continued intent to establish the technical feasibility and commercial viability of the assets. In making this determination, various factors are considered such as drilling results, future capital and operating expenditures, including judgement over the amount of economically recoverable resources, and whether the appropriate government, regulatory, or internal approvals are likely to be received.

Cash generating units (“CGU”)

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.

Refer to Note 8 for carrying amounts of property, plant and equipment.

Impairment of property, plant and equipment, exploration and evaluation assets

The Company assesses its oil and 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 fair value less costs of disposal (“FVLCD”). The net book value of PP&E recognized is based on historical cost until tested for impairment using market values. The market value of PP&E is the estimated amount for which PP&E could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in PP&E) are generally estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on internally and externally prepared reserve reports. The significant assumptions are based on Level 3 unobservable information with the primary inputs being forecasted production, escalated pricing, royalties, operating costs, future development costs. The after-tax discount rate is specific to the asset with reference to general market conditions. The market value of E&E assets is estimated with reference to the market values of current arm's length transactions in comparable locations. Refer to Notes 8 and 9.

Asset retirement obligation

Determination of the Company's asset retirement obligation is based on Government regulations, operator estimates and 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.

Refer to Note 12 for the carrying amounts related to the asset retirement obligation.

Share based compensation

The Company has a stock option plan enabling employees, officers and directors to receive Class "A" Common voting shares ("Common Shares") or cash at exercise prices equal to the market price or above on the date the option is granted. Notwithstanding, the Company has the right to only equity settle options. While the Company primarily has equity settled options, it may change this in the future at its discretion. 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.

For further detail refer to Note 11.

Income tax accounting

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

The 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.

Refer to Note 10.

Investment in Red Leaf

Questerre holds investments in certain private companies including its investment in Red Leaf.

The Company uses the equity method of accounting to reflect its ownership in Red Leaf. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of Red Leaf's income or loss, less distributions received. The Company is deemed to have significant influence in Red Leaf on the basis that it holds more than 20% of the voting power and the ability to participate in the decision making process of Red Leaf through its current Board representation.

Refer to Note 7 for the carrying amounts related to the Company's investment in Red Leaf.

3. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements.

a) Basis of consolidation

Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are considered.

Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

b) Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership. Financial liabilities are derecognized when the obligation specified in the contract is discharged, cancelled or expires.

Financial assets and liabilities are offset and the net amount is reported in the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

The Company classifies its financial instruments in the following categories, at initial recognition, depending on the purpose for which the instruments were acquired.

Financial assets and liabilities at fair value through profit or loss

A financial asset or liability is classified in this category if it is held for trading. Derivatives are also included in this category unless they are designated as hedges. The Company has designated its risk management contracts in this category.

Financial assets at amortized cost

Financial assets at amortized cost are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They include accounts receivable and deposits. These assets are included in current assets due to their short-term nature. They are recognized initially at the amount expected to be received, less, when material, a discount to reduce to fair value. Subsequently, they are measured at amortized cost using the effective interest method less a provision for impairment.

Cash and cash equivalents include deposits held with banks, less outstanding cheques, and short-term deposits with original maturities of one year or less.

Financial liabilities at amortized cost

Financial liabilities at amortized cost comprise credit facilities and accounts payable and accrued liabilities. Financial liabilities are initially recognized at the amount required to be paid, less, when material, a discount to reduce the payables to fair value. Subsequently, financial liabilities are measured at amortized cost using the effective interest method.

Financial liabilities are classified as current liabilities if payment is due within twelve months.

c) Investments

For the purposes of testing for impairment, the Company measures the fair market value of Red Leaf by valuation techniques such as a net liquidation approach. Judgment is required in measuring the fair value of the Company's investment in Red Leaf, which may result in material adjustments to its related carrying value.

d) Share capital

Common Shares are classified as equity. Incremental costs directly attributable to the issue of Common Shares are recognized as a deduction from equity, net of any tax effects.

e) Property, plant and equipment and exploration and evaluation assets

Recognition and measurement

Exploration and evaluation expenditures

Costs incurred prior to acquiring the legal rights to explore an area are recognized as exploration and evaluation expense in profit or loss.

Exploration and evaluation costs, including the costs of acquiring licenses, exploratory well expenditures, costs to evaluate the commercial potential of underlying resources and directly attributable general and administrative costs, are capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by exploration area pending determination of technical feasibility and commercial viability. Gains and losses on exploration and evaluation assets are recognized on disposal through the income statement.

At each reporting period, exploration and evaluation assets are assessed for impairment to determine if (i) sufficient data exists to determine technical feasibility and commercial viability, or (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable based on several factors including the assignment of reserves. A review of each exploration license or field is carried out, at each reporting date, to ascertain whether technical feasibility and commercial viability has been achieved. Upon determination of technical feasibility and commercial viability, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment.

Every reporting period, the Company evaluates individually significant exploration and evaluation wells for impairment, if there are specific impairment indicators evident at the well level. If technical feasibility and commercial viability of the well is not established, the well costs are written off. For insignificant wells, overall exploration and evaluation well indicators are evaluated. If there are indicators of impairment, the wells are tested for impairment at the CGU level.

Development and production costs

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Cost includes all costs required to acquire developed or producing oil and gas properties and to develop oil and gas properties. Development and production assets are grouped into CGUs for impairment testing.

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of the property, plant and equipment and are recognized net within gain (loss) on divestures in profit or loss.

Exchanges of properties are measured at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured. When the exchange is at fair value, a gain or loss is recognized in profit or loss.

Other property, plant and equipment

Expenditures related to workovers or betterments that improve the productive capacity or extend the life of an asset are capitalized. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

Depletion and depreciation

The net carrying value of development and production assets is depleted using the unit of production method based on estimated proved and probable reserves, considering estimated future development costs necessary to bring those reserves into production. These estimates are evaluated by independent reserve engineers at least annually.

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the respective useful lives.

Depreciation methods and useful lives are reviewed at each reporting date.

f) Impairment

Non-financial assets

The carrying amounts of the Company's non-financial assets, other than deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated and compared to the carrying amount. For goodwill an impairment test is completed each year, or when any indication of impairment exists.

For the purpose of impairment testing, assets are grouped together into CGUs. Exploration and evaluation assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their reclassification to producing assets.

The recoverable amount of an asset or a CGU is the greater of its VIU and FVLCD. FVLCD is determined using discounted future cash flows of proved and probable reserves using an after tax discount rate for FVLCD. In determining FVLCD, recent market transactions are considered, if available. In the absence of such transactions, the discounted cash flow model is used. In assessing VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized. Impairment reversals are recognized in profit or loss.

Impairment of financial assets

Questerre applies the simplified approach to providing for expected credit losses prescribed by IFRS 9 *Financial Instruments* ("IFRS 9") which permits the use of the lifetime expected loss provision for all trade receivables carried at amortized costs.

At each reporting date, the Company measures the lifetime expected loss provision taking into consideration Questerre's historical credit loss experience as well as forward-looking information in order to establish loss rates. The impairment loss (or reversal) is the amount of expected credit losses that is required to adjust the loss allowance at the reporting date to the amount that is required to be recognized. Also refer to Note 6.

Share based compensation

The Company has issued options to directors, officers and employees.

The Company accounts for its stock-based compensation awards on the basis that they will be equity settled. Under the equity settled method, compensation costs attributable to stock options granted to employees, officers or directors are measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. The exercise of stock options is recorded as an increase in Common Shares with a corresponding reduction in contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

g) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

Asset retirement obligation

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Asset retirement obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the balance sheet date. The best estimate of the provision is recorded on a discounted basis using a risk-free interest rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as accretion of the asset retirement obligation whereas increases or decreases due to changes in the estimated future cash flows and risk-free rates are adjusted through property, plant and equipment or exploration and evaluation assets. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision.

h) Revenue from commodity sales and royalties

Questerre principally generates revenue from the sale of commodities, which include crude oil, natural gas, condensate and natural gas liquids ("NGLs"). Questerre also generates revenue from royalties on production from leases where it owns a working interest. Revenue associated with the sale of commodities is recognized when control is transferred from Questerre to its customers. Questerre's commodity sale contracts represent a series of distinct transactions. Questerre considers its performance obligations to be satisfied and control to be transferred when all of the following conditions are satisfied:

- Questerre has transferred title and physical possession of the commodity to the buyer;
- Questerre has transferred the significant risks and rewards of ownership of the commodity to the buyer; and
- Questerre has the present right to payment.

Revenue represents the Company's share of commodity sales net of royalty obligations to governments and other mineral interest owners. Questerre sells its production pursuant to variable priced contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under these contracts, the Company is required to deliver a variable volume of crude oil, natural gas, condensate or NGLs to the contract counterparty.

Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed upon transaction price, whereby any variability in revenue is related specifically to the Company's efforts to deliver production. Therefore, the resulting revenue is allocated to the production delivered in the period during which the variability occurs. Payment terms for Questerre's commodity sales contracts are on the 25^{th} of the month following delivery. Questerre does not have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year and therefore Questerre does not adjust its revenue transactions for the time value of money. The Company enters into contracts with customers that can have performance obligations that are unsatisfied, or partially unsatisfied, at the reporting date.

Royalty revenue is recognized as it accrues in accordance with the terms of the governing agreement, which is generally in the month when the product is produced with production volumes primarily marketed with the payor's production. Royalty revenue is measured at fair value of the consideration received when Management can reliably estimate the amount pursuant to the terms of the royalty agreement. An accrual is included in revenue and accounts receivable for amounts not received at the reporting date based on historical trends, new wells on stream and current market prices.

Differences between the estimates and actual amounts received are adjusted and recorded in the period when the actual amounts are received.

i) Income tax

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes.

Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax asset will be realized.

The effect of a change in enacted or substantively enacted income tax rates on future income tax assets and liabilities is recognized in profit or loss in the period that the change occurs unless the original entry was recorded to equity.

j) Net profit or loss per share

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated using the weighted average number of shares outstanding, adjusted for the potential number of shares which may have a dilutive impact on net profit. Potentially dilutive shares include stock options. The weighted average number of diluted shares is calculated in accordance with the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase Common Shares at the average market price.

Since the options may be settled in cash or shares at the Company's discretion and therefore there is no obligation to settle in cash, the share units are accounted for as equity-settled share based payment transactions and included in diluted profit per share if the effect is dilutive.

k) Leases

Under IFRS 16, the Company recognizes right-of-use assets and lease liabilities for most leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements and may continue to be treated as operating leases. The right-of-use assets recognized are subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use assets or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property and equipment. In addition, the right-of-use assets are periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liabilities.

The lease liabilities are initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. The Company uses its incremental borrowing rate as the discount rate.

The lease liabilities are subsequently measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option.

When the lease liabilities are re-measured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use assets or is recorded in profit or loss if the carrying amount of the right-of-use assets has been reduced to nil. The Company presents right-of-use assets and lease liabilities separately in the balance sheet.

The application of IFRS 16 requires significant judgments and estimations to be made. Areas that require judgment include identifying whether a contract (or part of a contract) includes a lease, determining whether it is reasonably certain that an extension or termination option will be exercised, determining whether variable payments are in substance fixed, establishing whether there are multiple leases in an arrangement and determining the stand-alone amounts for lease and non-lease components. Other sources of estimation uncertainty in the application of IFRS 16 include estimating the lease term, determining the appropriate discount rate to apply to lease payments and assessing whether a right-of-use assets are impaired.

4. Changes in Accounting Policies and Disclosures

Future Accounting Pronouncements

In January 2021, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to clarify its requirements for the presentation of liabilities as current or non-current in the consolidated balance sheet. The amendment is effective for periods beginning on or after January 1, 2024.

In February 2021, the IASB issued amendments to IAS 8, in which it introduces a definition of ‘accounting estimates’. This will clarify the distinction between changes in accounting estimates and policies and the correction of errors. The amendments are effective for periods beginning on or after January 1, 2023.

In May 2020, the IASB issued Onerous Contracts – Cost of Fulfilling a Contract, which made amendments to IAS 37 *Provisions Contingent Liabilities and Contingent Assets*. Effective January 1, 2022, the amendments specify which costs an entity includes in determining the cost of fulfilling a contract for the purpose of assessing whether the contract is onerous.

5. Cash and Cash Equivalents

($ thousands)		December 31, 2022		December 31, 2021
Bank balances	$	6,053	$	37
Short-term bank deposits		23,537		8,494
	$	29,590	$	8,531

6. Financial Risk Management and Determination of Fair Values

a) Overview

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as credit risk, liquidity risk and market risk. The Company manages its exposure to these risks by operating in a manner that minimizes this exposure.

b) Fair value of financial instruments

The Company's financial instruments as at December 31, 2022 included cash and cash equivalents, accounts receivable, deposits, investments, credit facilities and accounts payable and accrued liabilities. As at December 31, 2022, excluding the investment in Red Leaf, the fair values of the Company's financial assets and liabilities equaled their carrying values due to the short-term maturity.

Disclosures about the inputs to fair value measurements are required, including their classification within a hierarchy that prioritizes the inputs to fair value measurement.

Level 1 Fair Value Measurements

Level 1 fair value measurements are based on unadjusted quoted market prices.

Level 2 Fair Value Measurements

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted indices.

Level 3 Fair Value Measurements

Level 3 fair value measurements are based on unobservable information.

The Company's has no financial instruments within the Level 3 hierarchy.

c) Credit risk

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 principally from the Company's receivables from joint venture partners and oil and gas marketers. The carrying amounts of accounts receivable and cash and cash equivalents represent the maximum credit exposure.

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 companies and the Company has not experienced any credit loss relating to these sales.

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

The Company's accounts receivables are aged as follows:

($ thousands)	December 31, 2022	December 31, 2021
Current	$ 4,539	$ 3,154
31 - 60 days	4	1
61 - 90 days	10	11
>90 days	209	1,012
Expected credit loss provision	(162)	(162)
	$ 4,600	$ 4,016

The Company does not anticipate any material default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. There are no material financial assets that the Company considers past due that are considered impaired.

Cash and cash equivalents include cash bank balances and short-term deposits. The Company manages the credit risk exposure by investing in Canadian banks. Management does not expect any counterparty to fail to meet its obligations.

d) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual capital expenditure budgets which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

Since the Company operates in the upstream oil and natural gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production, develop reserves and to potentially acquire strategic assets. The Company's capital programs are funded principally by cash obtained through its credit facilities, equity issuances and from operating activities. During times of low oil and natural gas prices or when cash resources may be limited, a portion of capital programs can generally be deferred, however, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources. Occasionally, to the extent possible, the Company will use derivative instruments to manage cash flow in the event of commodity price declines.

The Company's financial obligations relates to amounts due under the credit facilities, including trade and other payables, which consist of invoices payable to trade suppliers relating to the office and field operating activities and its capital spending program. The Company processes invoices within a normal payment period and all amounts are due within the next 12 months.

The timing of cash outflows relating to financial liabilities as at December 31, 2022 and 2021 are as follows:

($ thousands)	Less than one year	One to three years	Subsequent years	Total
Credit Facilities	$ 33	$ –	$ –	$ 33
Trade and other liabilities	10,634	–	–	10,634
Lease Liabilities	59	191	–	250
Current portion of asset retirement obligation	484	–	–	484
December 31, 2022	**$ 11,210**	**$ 191**	**$ –**	**$ 11,401**

($ thousands)	Less than one year	One to Three Years	Subsequent years	Total
Credit Facilities	$ 3,420	$ –	$ –	$ 3,420
Trade and other liabilities	8,361	–	–	8,361
Lease Liabilities	52	150	5	207
Contingent Liabilities	–	1,820	–	1,820
December 31, 2021	$ 11,833	$ 1,970	$ 5	$ 13,808

e) Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's profit or loss or the value of the financial instruments. The objective of the Company is to mitigate exposure to these risks while maximizing returns to the Company.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted not only by the relationship between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand. The Company may enter into oil and natural gas contracts to protect, to the extent possible, its cash flow on future sales. The contracts reduce the volatility in sales revenue by locking in prices with respect to future deliveries of oil and natural gas.

As at December 31, 2022, the Company had no outstanding commodity risk management contracts.

Currency risk

All of Questerre's petroleum and natural gas sales are denominated in Canadian dollars; however, the underlying market prices for these commodities are impacted by the exchange rate between Canada and the United States. The Company also incurs expenditures in its Jordanian subsidiary that are denominated in Jordanian Dinar and United States dollars. As at December 31, 2022, the Company had no forward foreign exchange contracts in place.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. At December 31, 2022, the Company had credit facilities outstanding of essentially nil (December 31, 2021: $3.4 million).

f) Capital management

The Company believes with its expected positive cash flow from operations and existing credit facilities in the near future it will be able to meet its foreseeable obligations in the normal course of operations. On an ongoing basis, the Company reviews its capital expenditures to ensure that funds flow from operations or access to credit facilities are available to fund these capital expenditures. To execute its current business plan including incurring capital expenditures related to the full participation in the current and future drilling programs it anticipates it will be require access to additional financial liquidity.

The volatility of commodity prices has a material impact on Questerre's cash flow from operations. Questerre attempts to mitigate the effect of lower prices by entering into risk management contracts, shutting in production in unusually low pricing environments, reallocating capital to more profitable areas and reducing capital spending based on results and other market considerations.

The Company considers its capital structure to include shareholders' equity and any outstanding amounts under its credit facilities. The Company will adjust its capital structure to minimize risk and its cost of capital through the issuance of shares, securing additional credit facilities and adjusting its capital spending as required. Questerre monitors its capital structure based on the current and projected funds flow from operations.

($ thousands)	December 31, 2022	December 31, 2021
Credit facilities	$ 33	$ 3,420
Shareholders' equity	166,128	148,961

7. Investment in Red Leaf

Red Leaf is a private Utah based oil shale and technology company whose principal assets are its proprietary technology to recover oil from shale and its oil shale leases in the state of Utah. The Company also holds acreage permitted for a wax processing project in the state.

As at December 31, 2022, Questerre holds 132,292 common shares, representing approximately 41% of the common share capital of Red Leaf and 288 Series A Preferred Shares of Red Leaf representing approximately 16% of the issued and outstanding preferred shares capital of Red Leaf on a non-diluted basis.

Questerre has determined its investment in Red Leaf will be accounted for using the equity method. This is based on several criteria including its current equity interest in Red Leaf and ability to participate in the decision making process of Red Leaf through its current Board representation. The Company measures the fair market value of its investment using a net liquidation approach. The net liquidation value is calculated as the net current assets of Red Leaf less abandonment and other liabilities, the accrued and unpaid dividends associated with the preferred shares and an estimate of research and development and general and administrative expenses for the upcoming fiscal year.

($ thousands)	December 31, 2022	December 31, 2021
Balance, beginning of year	$ 7,965	$ 7,979
Loss on equity investment	(2,540)	–
Gain (loss) on foreign exchange	371	(14)
Balance, end of the year	$ 5,796	$ 7,965

The assets, liabilities, and net loss of Red Leaf for the respective years were comprised as follows:

($ thousands)[(1)]	December 31, 2022	December 31, 2021
Cash and Cash Equivalents	$ 24,285	$ 26,770
Other Current Assets	–	268
Current Liabilities	268	617
Non-current liabilities	4,067	2,150
Net Loss[(2)]	$ (2,546)	$ (3,977)

(1) Converted at an exchange rate of US$1=C$1.3544

(2) Converted at an average exchange rate of US$1=C$1.3011

The issued and outstanding share capital of Red Leaf as of December 31, 2022 is comprised of the following:

	Issued and Outstanding	Questerre Ownership
Common Shares	319,728	132,292
Preferred Shares	1,795	288

The Series A Preferred Shares carry voting rights and dividends accrue on a cumulative basis, whether or not declared, at a rate of 8% per annum compounding annually. On the occurrence of a defined liquidation event, including certain reorganizations, takeovers, the sale of all or substantially all the assets of the company, and shareholder distributions, the Series A Preferred shareholders are entitled to an amount representing the original issue price plus any accrued dividends. As of December 31, 2022, this priority amount is approximately US$1.2 million.

8. Property, Plant and Equipment

A reconciliation of the PP&E assets is detailed below.

($ thousands)	Total
Cost or deemed cost:	
Balance, December 31, 2020	$ 290,923
Change to asset retirement net of additions	1,694
Balance, December 31, 2021	292,617
Change to asset retirement net of additions	1,361
Transfer from exploration and evaluation assets	9,848
Balance, December 31, 2022	$ 303,826
Accumulated depletion, depreciation and impairment losses:	
Balance, December 31, 2020	$ 238,439
Depletion and depreciation	5,794
Reversal of impairment	(91,736)
Balance, December 31, 2021	152,497
Depletion and depreciation	9,405
Impairment	857
Balance, December 31, 2022	$ 162,759

($ thousands)	Total
Net book value:	
At December 31, 2021	$ 140,120
At December 31, 2022	$ 141,067

During the years ended December 31, 2022 and 2021, the Company did not capitalize any administrative overhead or share based compensation expense directly related to development activities. Included in the December 31, 2022, depletion calculation are future development costs of $317.9 million (December 31, 2021: $271.3 million).

The Company assessed the carrying value of its PP&E as at December 31, 2022, for indicators of impairment. Based on this review, the Company's Western Canada CGUs were tested in accordance with the Company's accounting policy. The recoverable amount of the CGUs were estimated based on the FVLCD using a discounted cash flow model. Due to an increase in the future operating costs reducing the value of the reserves in the Antler, Saskatchewan CGU, the Company recognized an impairment expense of $0.9 million. No impairments were recorded for the Company's other CGUs.

The estimates of FVLCD were determined using discount rates ranging from 12.5% to 15% and forecasted after tax cash flows based on proved plus probable reserves, with escalating prices and future development costs.

As at December 31, 2022, the future prices used to determine cash flows from crude oil and natural gas reserves were as follows:

	2023	2024	2025	2026	2027	Average Annual % Change Thereafter
WTI (US$/barrel)	80.33	78.50	76.95	77.61	79.16	2.00
AECO ($/MMbtu)	4.23	4.40	4.21	4.27	4.34	2.00

In the prior year, due to the higher future commodity prices, the Company recorded a reversal of $91.7 million in impairment expense incurred in 2020. Of this amount, $76 million was attributable to the Kakwa, Alberta CGU and $15.7 million to the Antler, Saskatchewan CGU. No impairment reversals were recorded for the Company's other CGUs.

The estimates of FVLCD were determined using discount rates ranging from 11% to 13% and forecasted after tax cash flows based on proved plus probable reserves, with escalating prices and future development costs. As at December 31, 2021, the future prices used to determine cash flows from crude oil and natural gas reserves were as follows:

	2022	2023	2024	2025	2026	Average Annual % Change Thereafter
WTI (US$/barrel)	72.83	68.78	66.76	68.09	69.45	2.00
AECO ($/MMbtu)	3.56	3.21	3.05	3.11	3.17	2.00

9. Exploration and Evaluation Assets

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of technical feasibility and commercial viability. Additions represent the Company's share of costs incurred on exploration and evaluation assets during the period.

A reconciliation of the movements in exploration and evaluation assets is detailed below.

($ thousands)		December 31, 2022		December 31, 2021
Balance, beginning of year	$	14,710	$	114,203
Additions		8,955		4,719
Transfers to property, plant and equipment		(9,849)		–
Undeveloped lease impairments		–		(103,847)
Undeveloped lease expiries and farmouts		(129)		(220)
Foreign currency translation adjustment - Jordan		540		(145)
Balance, end of period	$	14,227	$	14,710

During the year ended December 31, 2022, the Company capitalized administrative overhead charges of $0.3 million (2021: $1.1 million) and $0.3 million (2021: $0.7 million) for capitalized share based compensation expense directly related to exploration and evaluation activities.

As a result of the introduction of Bill 21 - *An Act mainly to end petroleum exploration and production and the public financing of those activities*, the Company impaired the full carrying value of its Quebec exploration and evaluation assets of $104 million in 2021.

The Company is seeking just compensation for the value of its licenses and objects to the revocation of its licenses and validity of Bill 21 until just compensation is received.

10. Deferred Income Taxes

The tax on the Company's net loss before taxes differs from the amount that would arise using the weighted average tax rate applicable to profits or losses of the consolidated entities as follows:

($ thousands)		December 31, 2022		December 31, 2021
Net loss before taxes	$	14,067	$	(4,308)
Combined federal and provincial tax rate		23.60%		23.58%
Computed "expected" deferred tax expense (recovery)		3,320		(1,016)
Increase in deferred taxes resulting from:				
Non-deductible differences and permanent items		264		241
Change in deferred tax asset not recognized		(3,584)		775
Deferred tax expense	$	-	$	–

The Company evaluated the recoverability of its deferred tax assets using forecasted before-tax cash flows based on proved reserves, with escalating prices and future development costs obtained from an independent reserve evaluation report and a deduction for estimated general and administrative costs associated with these proved reserves. As a result, no deferred tax asset was recorded. The combined statutory tax rate was 23.60% in 2022 and 23.58% in 2021.

The movement in deferred tax assets and liabilities during the year, without taking into consideration the valuation allowances, are as follows:

($ thousands)	Petroleum and natural gas properties	Investments	Asset retirement obligation	Share issue costs	Non-capital losses	Capital losses
December 31, 2021	$ 25,248	$ 3,649	$ 5,071	$ 69	$ 12,282	$ 4,302
Change	2,795	228	(483)	(34)	(6,241)	3
December 31, 2022	**$ 28,043**	**$ 3,877**	**$ 4,588**	**$ 35**	**$ 6,041**	**$ 4,305**

The amount and timing of reversals of temporary differences will be dependent upon, among other things, the Company's future operating results, and acquisitions and dispositions of assets and liabilities.

Non-capital loss carry-forwards at December 31, 2022 expire from 2036 to 2042.

The following temporary differences have not been recognized:

($ thousands)	December 31, 2022	December 31, 2021
Petroleum and natural gas properties	$ 118,822	$ 107,061
Investments	32,862	30,944
Asset retirement obligation and leases	19,453	21,504
Share issue costs	146	294
Non-capital losses	25,598	52,084
Capital losses	36,488	36,488
Total	$ 233,369	$ 248,375

11. Share Based Compensation

The Company has a stock option program that provides for the issuance of options to purchase Common Shares to its directors, officers and employees at or above grant date market prices. The options granted under the plan generally vest evenly over a three-year period starting at the grant date or one year from the grant date. The grants generally expire five years from the grant date or five years from the commencement of vesting.

Under the Company's option plan, a put right is included that allows the optionee to settle options with cash or equity. Under the put right, the optionee will receive the net cash proceeds that is the excess of the closing price of the Common Shares at the day of the put notice over the exercise price of the option. The Company has the option to decline a put right exercise at any time. The Company does not intend to cash settle options in future periods. The number and weighted average exercise prices of stock options are as follows:

	Options Outstanding			Options Exercisable		
	Number of Options *(thousands)*	Weighted Average Years to Expiry	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Years to Expiry	Weighted Average Exercise Price
\$0.15 - \$0.30	20,700	2.21	\$ 0.22	16,625	2.03	\$ 0.23
\$0.31 - \$0.50	14,598	3.31	0.37	6,018	2.24	0.41
	35,298	**2.67**	**\$ 0.28**	**22,643**	**2.09**	**\$ 0.28**

The following table summarizes information about stock options outstanding and exercisable at December 31, 2022:

	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

The fair value of the options granted were calculated using the Black-Scholes valuation model. The following weighted average assumptions were used in the model for options granted in 2022 and 2021:

	December 31, 2022	December 31, 2021
Weighted average fair value per award (\$)	**0.26**	0.14
Volatility (%)	**101.83**	104.47
Forfeiture rate (%)	**10.24**	11.02
Expected life (years)	**5.00**	5.00
Risk free interest rate (%)	**1.63**	0.42

This forfeiture rate estimate is adjusted to the actual forfeiture rate. Expected volatility and expected life is based on historical information.

12. Asset Retirement Obligation

The Company's asset retirement and abandonment obligations result from its ownership interest in oil and natural gas assets. The total asset retirement obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of the asset retirement obligation to be $19.4 million as at December 31, 2022 (December 31, 2021: $21.5 million) based on an undiscounted total future liability of $23.3 million (December 31, 2021: $24.9 million). These payments are expected to be made over the next 31 years. The average discount factor, being the risk-free rate related to the liabilities, is 3.63% (December 31, 2021: 1.31%). An inflation rate of 2% (December 31, 2021: 2%) over the varying lives of the assets is used to calculate the present value of the asset retirement obligation.

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

($ thousands)		December 31, 2022		December 31, 2021
Balance, beginning of year	$	21,495	$	20,369
Liabilities settled		(878)		(190)
Revisions due to change in discount rates & estimates		(2,330)		965
Liabilities incurred		335		104
Accretion		819		247
Balance, end of year	$	19,441	$	21,495

13. Credit Facilities

The Company's facilities with a Canadian chartered bank were maintained at $16 million for the year. The credit facilities include a revolving operating demand facility of $16 million ("Facility A"). Facility A can be used for general corporate purposes, ongoing operations, and capital expenditures within Canada. Any borrowing under the credit facilities, with the exception of letters of credit, bears interest at the bank's prime interest rate and an applicable basis point margin based on the ratio of debt to cash flow measured quarterly. The facilities are secured by a debenture with a first floating charge over all assets of the Company and a general assignment of books debts.

Under the terms of the credit facility, the Company has provided a covenant that it will maintain an Adjusted Working Capital Ratio greater than 1.0. The ratio is defined as current assets (excluding unrealized hedging gains and including undrawn Credit Facility A availability) to current liabilities (excluding bank debt outstanding and unrealized hedging losses). The Adjusted Working Capital Ratio at December 31, 2022 was 6.13 (2021: 3.05) and the covenant was met. At December 31, 2022, effectively nil (December 31, 2021: $3.4 million) was drawn on Facility A with an effective average interest rate of 5.33% for 2022 (2021: 3.45%).

As at December 31, 2022, the Company was returned the outstanding letters of credit for $7.7 million by the Quebec Government for abandonment and reclamation liabilities. 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 following table reconciles the movement in the credit facilities during the year.

($ thousands)	December 31, 2022	December 31, 2021
Credit Facilities, beginning of year	$ 3,420	$ 15,427
Drawdown from Credit Facilities	5,413	17,993
Repayment of Credit Facilities	(8,800)	(30,000)
Credit Facilities, end of year	$ 33	$ 3,420

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, in fact, be reduced or eliminated, the Company would need to seek alternative credit facilities or consider the issuance of equity to enhance its liquidity. The next scheduled review will be in the second quarter of 2023.

14. 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.

a) Issued and outstanding – Common Shares

	Number (thousands)	Amount ($ thousands)
Balance, December 31, 2020	427,516	$ 429,703
Options exercised	1,000	175
Balance, December 31, 2021 and December 31, 2022	**428,516**	**$ 429,878**

b) Per share amounts

Basic net income (loss) per share is calculated as follows:

(thousands, except as noted)	December 31, 2022	December 31, 2021
Net income (loss)	$ 14,111	$ (4,301)
Issued Common Shares at beginning of year	428,516	427,516
Issued on exercised of options	–	518
Weighted average number of Common Shares outstanding (basic)	428,516	428,034
Basic net income (loss) per share	$ 0.03	$ (0.01)

Diluted net income (loss) per share is calculated as follows:

(thousands, except as noted)	December 31, 2022	December 31, 2021
Net income (loss)	$ 14,111	$ (4,301)
Weighted average number of Common Shares outstanding (basic)	428,516	428,034
Effect of outstanding options (diluted)	2,008	–
Weighted average number of Common Shares outstanding (diluted)	430,524	428,034
Diluted net income (loss) per share	$ 0.03	$ (0.01)

Under the current stock option plan, options can be exchanged for Common Shares of the Company, or for cash at the Company's discretion. They are considered potentially dilutive and are included in the calculation of diluted net loss per share for the period. The average market value of the Common Shares for purposes of calculating the dilutive effect of options was based on quoted market prices for the period that the options were outstanding. At December 31, 2022, 20.5 million options (December 31, 2021: 30.3 million) were excluded from the diluted weighted average number of Common Shares outstanding calculation as their effect would have been anti-dilutive.

15. Petroleum and Natural Gas Revenue

($ thousands)	December 31, 2022	December 31, 2021
Oil and liquids	$ 40,910	$ 24,058
Natural gas	9,230	4,413
Royalty revenue	1,611	1,933
	$ 51,751	$ 30,404

16. Employee Salaries and Benefits

($ thousands)	December 31, 2022	December 31, 2021
Salaries, bonuses and other short-term benefits	$ 2,123	$ 1,572
Share based compensation	1,931	1,004
	$ 4,054	$ 2,576

17. Key Management Compensation

Key management includes directors and officers. The compensation paid or payable to key management is as follows:

($ thousands)	December 31, 2022	December 31, 2021
Salaries, bonuses, director fees and other short-term benefits	$ 1,715	$ 1,418
Share based compensation	2,071	1,098
	$ 3,786	$ 2,516

The Company has entered into written executive employment agreements with each of the officers of the Company. Each of these written agreements provides that in the event of a change of control of the Company, each of the officers is entitled to: (i) 18 months of then applicable base salary with 24 months for the CEO; and (ii) the vesting of all options to purchase Common Shares. In the event of a change in control, all options will vest and the severance payable to key management would have been $2.1 million at December 31, 2022. This amount does not include accelerated share based compensation expense.

18. Supplemental Cash Flow Information

Changes in non-cash working capital are detailed below:

($ thousands)	December 31, 2022	December 31, 2021
Accounts receivable	$ (584)	$ (1,333)
Deposits and prepaid expenses	99	(114)
Accounts payable and accrued liabilities	2,179	2,175
Change in non-cash working capital	$ 1,694	$ 728
Related to:		
Operating activities	$ 2,072	$ (176)
Investing activities	(378)	904
	$ 1,694	$ 728

19. Right-of-use Assets and Lease Liabilities

a) *Right-of-use assets*

($ thousands)	Real Estate	Other	Total
Cost			
Balance, January 1, 2021, and December 31, 2021	$ 416	$ 25	$ 441
Additions	95	–	95
Balance, December 31, 2022	$ 511	$ 25	$ 536
Accumulated Depreciation			
Balance, December 31, 2021	$ 231	$ 14	$ 245
Depreciation	47	5	53
Balance, December 31, 2022	$ 279	$ 20	$ 298
Carrying value			
Balance, January 1, 2021, and December 31, 2021	$ 184	$ 11	$ 196
Additions, net of depreciation	48	(5)	42
Balance, December 31, 2022	$ 232	$ 6	$ 238

b) *Lease liabilities*

($ thousands)		
Balance, January 1, 2021	$	255
Interest expense		9
Lease payments		(57)
Balance, December 31, 2021	$	207
Additional leases acquired during period		95
Interest expense		5
Lease payments		(57)
Balance, December 31, 2022	$	250
Current portion		59
Long term portion		191
Balance, December 31, 2022	$	250

Amounts related to lease liabilities recognized in profit or loss are as follows:		
Interest expense on lease liabilities	$	5

20. 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

21.Related Party Transactions

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

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