



QUESTERRE ENERGY CORPORATION
ANNUAL INFORMATION FORM
For the Year Ended December 31, 2025

March 31, 2026

TABLE OF CONTENTS

INTRODUCTION	5
THE COMPANY	5
Inter-corporate Relationships	5
GENERAL DEVELOPMENT OF THE BUSINESS	6
History of the Company	6
Significant Acquisitions	8
DESCRIPTION OF THE BUSINESS	10
Business of the Company	10
Corporate Strategy	10
Employees	10
Environmental Matters	10
Competitive Conditions	10
Marketing	11
Cyclical and Seasonal Nature of Industry	11
Specialized Skill and Knowledge	11
Social and Environmental Policies	11
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	11
Petroleum and Natural Gas Reserves	11
Forecast Prices and Costs Employed by McDaniel and GLJ - January 1, 2026	17
RECONCILIATION OF CHANGES IN RESERVES	18
Gross Reserves Reconciliation	18
ADDITIONAL INFORMATION RELATING TO RESERVES DATA	20
Undeveloped Reserves	20
Significant Factors or Uncertainties Affecting Reserves Data	22
Future Development Costs	23
OTHER OIL AND GAS INFORMATION	23
Oil and Gas Properties	23
Wells	27
Properties with No Attributed Reserves	27
Significant Factors of Uncertainties Relevant to Properties with No Attributed Reserves	28
Forward Contracts	29
Income Tax Horizon	29
Costs Incurred	30
Exploration and Development Activities	30
Production Estimates	31
Netback and Production History	32
Production Volume by Field	33
RISK FACTORS	33
Quebec Assets	33
Liquidity and the Company's Substantial Capital Requirements	33
Additional Funding Requirements	34
Volatility in the Oil and Gas Industry	34
U.S. Tariffs	35
Anti-greenwashing Rules	35
Carbon Pricing Risk	36

Credit Facilities	36
Secured Debt	37
Prices, Markets and Marketing of Crude Oil and Natural Gas	37
Exploration, Development and Production Risks	38
Political Uncertainty	39
Non-Government Organizations	41
Changing Investor Sentiment	41
Global Financial Markets	42
Adverse Economic Conditions	42
Gathering and Processing Facilities and Pipeline Systems	43
Alternatives to and Changing Demand for Petroleum Products	44
Environmental Risks	44
Climate Change	45
Fiscal and Royalty Regime	47
Impact of Future Financings on Market Price	47
Regulatory	47
Insurance	48
Project Risks	48
Competition	49
Title	50
Reserve Estimates	50
Reserve Replacement	50
Capital Markets	51
Operational Dependence	51
Key Employees	52
Management of Growth	52
Expiration of Licenses and Leases	52
Permits and Licenses	52
Variations in Foreign Exchange Rates	53
Credit Facility	36
Issuance of Debt	54
Hedging	54
Liability Management	54
Access Restrictions	55
Availability of Drilling Equipment Access Restrictions	55
Indigenous Claims	55
Geopolitical Risks	56
Conflicts of Interest	56
Dilution	57
Seasonality	57
Hydraulic Fracturing	57
Third Party Credit Risk	58
Dividends are Discretionary	58
Future Sales of Common Shares	58
Emission Regulation	59
Technology	59
Investment in Red Leaf	59
Possible Failure to Realize Anticipated Benefits of Acquisitions and Dispositions	59
Cost of New Technologies	59
Risks Associated with Interests in Jordan	60
Tax Matters	61
Internal Controls	62

Litigation	62
Breach of Confidentiality	62
Volatility of Market Price of Common Shares	63
Information Technology Systems and Cyber-Security	63
Firm Commitment Transportation and Processing Arrangements	64
Inflation and Cost Management	64
Reputation Risk	65
Forward-Looking Statements and Information May Prove Inaccurate	65
INDUSTRY CONDITIONS	65
Canadian Government Regulation	69
Pricing and Marketing – Oil	69
Pricing and Marketing – Natural Gas	69
Pricing and Marketing – Natural Gas Liquids	70
Exports from Canada	70
Pipelines	70
Crude Oil and Bitumen by Rail	72
Curtailment	72
Trade Agreements	72
Extractive Sector Transparency Measures Act	73
Provincial Royalties and Incentives	73
Land Tenure	76
Production and Operation Regulations	77
Environmental Regulation	77
Liability Management Rating Programs	<u>7980</u>
Climate Change Regulation	82
DIVIDENDS OR DISTRIBUTIONS	91
DESCRIPTION OF SHARE CAPITAL	91
Common Shares and Class B Shares	<u>9192</u>
Preferred Shares	92
MARKET FOR SECURITIES	<u>9596</u>
Price Range and Volume of Trading of Common Shares	<u>9596</u>
PRIOR SALES	<u>9697</u>
ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER	<u>9697</u>
DIRECTORS AND OFFICERS	<u>9798</u>
CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS	<u>9899</u>
AUDIT COMMITTEE	<u>99100</u>
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS	<u>99100</u>
TRANSFER AGENT AND REGISTRAR	<u>99100</u>
MATERIAL CONTRACTS	<u>99100</u>
INTERESTS OF EXPERTS	<u>99100</u>
CONFLICTS	<u>100101</u>
LEGAL PROCEEDINGS	<u>100101</u>
REGULATORY ACTIONS	<u>100101</u>
ADDITIONAL INFORMATION	<u>100101</u>
SELECTED ABBREVIATIONS	<u>101102</u>

FORWARD-LOOKING STATEMENTS

[101+02](#)

NON-GAAP MEASURES

[104+05](#)

PRESENTATION OF OIL AND GAS INFORMATION

[104+05](#)

APPENDIX A – FORM 51-101F2 – REPORT ON RESERVES DATA BY A QUALIFIED RESERVES EVALUATOR

APPENDIX B – FORM 51-101F2 – REPORT ON RESERVES DATA BY A QUALIFIED RESERVES EVALUATOR

APPENDIX C – FORM 51-101F3 – REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

APPENDIX D – DEFINITIONS USED FOR RESERVE CATEGORIES

APPENDIX E – AUDIT COMMITTEE INFORMATION REQUIRED IN AIF

APPENDIX F – AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

INTRODUCTION

In this Annual Information Form (“AIF”), the terms “**Questerre** or the “**Company**” means Questerre Energy Corporation and its subsidiaries and partnership interests on a consolidated basis including information with respect to predecessor corporations.

Certain other terms used but not defined herein are defined in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“**NI 51-101**”) and in the Canadian Oil and Gas Evaluation Handbook Volume I (the “**COGE Handbook**”). Unless otherwise specified, information in this AIF is as at the end of the Company’s most recently completed financial year, being December 31, 2025. All financial information included in this AIF is determined using International Financial Reporting Standards, unless otherwise indicated. In this AIF, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

See “**Selected Abbreviations**”, “**Forward-Looking Statements**” and “**Presentation of Oil and Gas Information**”.

THE COMPANY

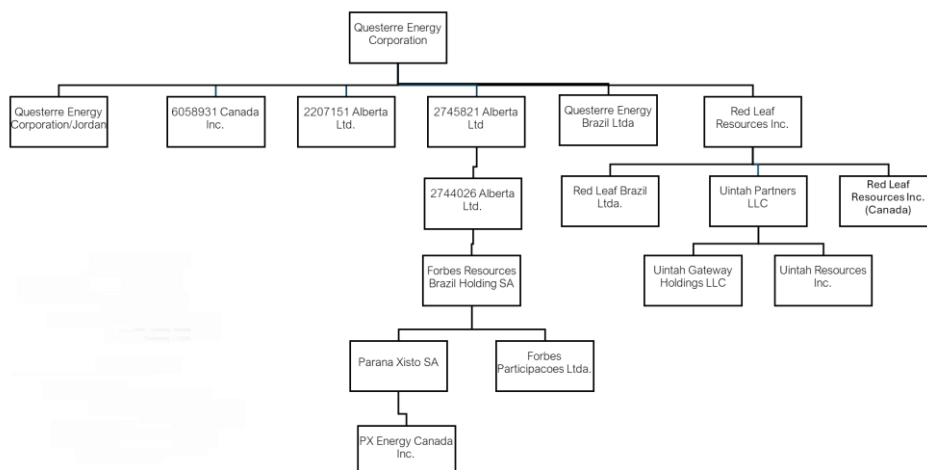
Questerre was incorporated under the Companies Act (Alberta) on October 25, 1971, under the name “Westpro Equipment Ltd.” and continued under the Business Corporations Act (Alberta) (the “ABCA”) on December 13, 1982. On July 13, 1990, the Company was continued under the Companies Act (British Columbia). On December 5, 2000, the Company was continued from British Columbia to Alberta under the ABCA and its name was changed to “Questerre Energy Corporation”. On June 26, 2003, the issued Class “A” Common voting shares were subdivided into three new Class “A” Common voting shares (“Common Shares”) for each old Class “A” Common voting share of the Company. On January 27, 2026, the Company completed a reorganization pursuant to which each of the Company’s existing Class “A” Common voting shares were exchanged for one (1) new class of Class “A” Common voting share (each, a “Common Share”) and one (1) Series 2 Preferred Share.

The principal, head and registered office of the Company is located at Suite 1650, 801 - Sixth Avenue S.W., Calgary, Alberta T2P 3W2.

Questerre is an energy technology and innovation company. Questerre is actively engaged in the acquisition, exploration, and development of oil and gas projects, in specific non-conventional projects such as tight oil, oil shale, shale oil and shale gas. Questerre holds assets in Canada, USA, Brazil, and the Hashemite Kingdom of Jordan (“Jordan”). Its assets in Brazil are held through Paraná Xisto S.A. (“PX Energy”) and include integrated mining, processing and refining operations for oil shale. Questerre’s assets in the USA are held through Red Leaf Resources Inc. (“Red Leaf”), a technology company focused on developing its proprietary technology with an initial focus on oil shale.

Inter-corporate Relationships

The Company has six direct wholly-owned subsidiaries, 6058931 Canada Inc., a corporation existing under the *Canada Business Corporations Act*, Questerre Energy Corporation/Jordan existing under the laws of Jordan, 2207151 Alberta Ltd. and 2745821 Alberta Ltd., corporations existing under the ABCA, Questerre Energy Brazil Ltda., a corporation existing under the laws of Brazil, and Red Leaf Resources Inc., a corporation existing under the laws of Delaware. Forbes Resources Brazil Holding S.A. (“FRBH”), a corporation existing under the laws of Brazil, is a direct wholly-owned subsidiary of 2744026 Alberta Ltd., which is wholly owned by 2745821 Alberta Ltd. PX Energy, a corporation existing under the laws of Brazil, is a direct wholly-owned subsidiary of FRBH. PX Energy Canada Inc., a corporation existing under the ABCA, is an indirect wholly-owned subsidiary of the Company where the majority of the shares are held by PX Energy.



GENERAL DEVELOPMENT OF THE BUSINESS

History of the Company

Questerre initially operated as an oil and gas exploration and production company with minority interests in several producing properties in Western Canada. In November 2000, a new management team was assembled and Questerre changed its focus to pursuing what management believes will be scalable high-impact projects in Canada.

The Company acquired an interest in two projects in 2001 – the Beaver River Field (the “**Field**”) located in northeast British Columbia and the St. Lawrence Lowlands (the “**Quebec Lowlands**”) situated in Quebec. Since late 2004, the Company has also been developing a portfolio of conventional oil and gas assets, primarily in Alberta and Saskatchewan. The Company subsequently disposed of its interest in the Field in 2011.

Between 2005 and 2010, the Company focused on the exploration and commercial appraisal of the natural gas potential of the Quebec Lowlands including the Utica shale with its partner, Repsol Oil & Gas Canada Inc. (“**Repsol**”) (formerly Talisman Energy Inc.). In 2019, the Company settled outstanding litigation with the operator and acquired its assets in the Quebec Lowlands. In the fall of 2010, the appraisal work was suspended pending the results of a strategic environmental assessment (“**SEA**”) on shale gas development in Quebec. Upon the completion of the SEA in 2014, the Government of Quebec commissioned a strategic environmental assessment of oil and gas development in the province and committed to introducing new hydrocarbon legislation in 2016. The legislation entitled the *Petroleum Resources Act* (“**PRA**”) as part of Bill 106, *An Act to implement the 2030 Energy Policy and to amend various legislative provisions* (“**Bill 106**”) was passed as law in December 2016. Following the introduction of the hydrocarbon regulations in September 2018 by the Ministry of Energy and Natural Resources (“**MERN**”), including a restriction on oil and gas activities, specifically the prohibition of hydraulic fracturing and increasing minimum setbacks for activity from urbanized areas and bodies of water, the legislation was enacted. In 2022, the Government of Quebec subsequently introduced and enacted Bill 21, *An Act mainly to end petroleum exploration and production and the public financing of those activities* (“**Bill 21**”). Activity in Quebec remains suspended pending the resolution of the situation in the province.

Bill 21 revokes petroleum exploration and production licences, including the 16 exploration licenses held by the Company. In 2022, the Company filed a claim against the Government of Quebec asserting among other things that the Government's actions represent an expropriation without compensation, a breach of 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 Indigenous partners and respect their rights. The claim also sought to have Bill 21 declared invalid.

The announcement of the SEA in Quebec led Questerre to pursue unconventional projects elsewhere. In the fall of 2011, the Company assembled a portfolio of oil shale mining opportunities including licensing rights to a proprietary technology to produce oil from shale.

In March 2012, Questerre acquired an equity interest in Red Leaf. Red Leaf's principal assets are its proprietary technology to recover oil from shale and its oil shale leases in the state of Utah. In 2017, the Company further increased its equity interest in Red Leaf. In 2022, Red Leaf consolidated its debt and equity ownership of a subsidiary and acquired a 100% interest in over 7,000 acres of surface leasehold rights in the Uintah Basin, Utah including the rights to carbon sequestration and a permit for a 40,000 barrels per day wax processing facility. In December 2025, the Company consolidated its equity ownership of Red Leaf.

During 2012, the Company acquired and developed a new core area in the Kakwa area of west central Alberta targeting liquids-rich natural gas.

To further expand its oil shale portfolio, in the second quarter of 2015, the Company concluded a Memorandum of Understanding ("**MOU**") for the appraisal and development of oil shale acreage in the Jordan with the Ministry of Energy and Mineral Resources ("**MEMR**"). The MOU covered an area of 265 square kilometers in the Isfir-Jafr area, approximately 200 km south of the capital, Amman. In the fall of 2019, the Company was advised by the MEMR that it intends to move forward from the MOU to a concession agreement for the Company's acreage in Jordan. In May 2025, Questerre was advised that its exclusive rights to the project expired and any extension would be subject to the negotiation of a new agreement.

Year Ended December 31, 2023

In October 2023, a hearing was held at the Quebec Superior Court (Civil Division) on the application by the Company and other license holders to suspend certain provisions of Bill 21 pending a hearing on the merits of its case, including the constitutionality of Bill 21.

Year Ended December 31, 2024

In January 2024, the Quebec Superior Court (Civil Division) ruled on the application by the Company. The Justice ruled that the Company's application met the key criteria for a stay and stayed certain provisions of Bill 21. In June 2024, the Attorney General of Quebec was granted leave to appeal this ruling. In October 2024, the Quebec Court of Appeal heard the appeal and rendered its ruling in May 2025.

In October 2024, in connection with its claim against the Government of Quebec, the Company filed an independent report on potential economic losses. Based on the scope and subject to the restrictions, qualifications and major assumptions, under various scenarios, all of which are set out in the report, the report estimates the economic losses if the licenses are successfully revoked under three different scenarios with estimates ranging from \$700 million to \$4.8 billion. A copy of the report is available on the disclosure system in Norway and on SEDAR+ in Canada, which report does not form part of nor is deemed to be incorporated herein by reference.

Year Ended December 31, 2025

On May 26, 2025, the Quebec Court of Appeal annulled a decision by the Quebec Superior Court (Civil Division) justice in January 2024 suspending key provisions of Bill 21. Subsequently, the Supreme Court of Canada declined to hear the Company's application to appeal this decision.

On September 26, 2025, the Company closed the acquisition of 100% of the common shares PX Energy (the "**PX Energy Acquisition**"). The PX Energy Acquisition was completed by the purchase of all issued and outstanding shares of its parent company, FRBH from the vendors through a wholly owned subsidiary of the Company.

At the end of December 2025, the Company acquired the remaining 62% common equity interest and the remaining 84% preferred equity interest in Red Leaf.

Recent Developments

On January 27, 2026, the Company completed a reorganization pursuant to which each of the Company's existing Common Shares were exchanged for one (1) new class of Common Share and one (1) Series 2 Preferred Share. The Series 2 Preferred Shares were issued to ensure that the then current shareholders would receive the benefit of the Company's operations related to its Quebec assets (the "**Quebec Business**"). These Series 2 Preferred Shares are generally designed to track the economic performance and value of the Quebec Business. The issuance of the Series 2 Preferred Shares is generally intended to ring-fence the value of the Quebec Business for the benefit of current Shareholders, while continuing to provide an investment opportunity in the business of the Corporation, other than the Quebec Business. For a description of the Series 2 Preferred Shares, see "Description of Share Capital – Preferred Shares – Series 2 Preferred Shares".

Significant Acquisitions

Questerre completed the PX Energy Acquisition, which was a significant acquisition during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 Continuous Disclosure Obligations ("**NI 51-102**").

The Company filed a Business Acquisition Report in respect of the PX Energy Acquisition, a copy of which is available on the disclosure system in Norway and on SEDAR+ in Canada.

The consideration for the Acquisition includes the issuance of 15 million Common Shares subject to a lock-up and voting agreement (the "**First Tranche Common Shares**") with a deemed value of \$5.0 million and contingent equity consideration of two additional tranches of 25 million Common Shares with an estimated fair value of \$13.9 million as detailed below:

- 25 million Common Shares subject to the achievement of US\$30 million in free cash flow within any twelve month period between the closing of the Acquisition and September 30, 2027, or the completion of an equity issue by the Company of \$25 million at a price of \$0.50 per Common Share no later than September 30, 2027;
- 25 million Common Shares subject to the achievement of US\$40 million in free cash flow within any twelve month period between the closing of the Acquisition and September 30, 2028, or the completion of an equity issue by the Company of \$25 million at a price of \$1.00 per Common Share no later than September 30, 2028.

The consideration for the Acquisition also included the assumption by the Company's subsidiary of the vendor's obligations under a business combination agreement ("**BCA**") as amended, with a special purpose acquisition company ("**SPAC**"). Pursuant to the BCA, the Company's wholly owned subsidiary has assumed

the obligation to combine with the SPAC in a go public transaction. The BCA is subject to conditions precedent including receipt of regulatory approvals, the filing of a Proxy/Registration Statement with the Securities and Exchange Commission and the completion of this transaction prior to December 31, 2026. Under the BCA, the Company's subsidiary assumed obligations related to the SPAC, along with other liabilities, with an estimated fair value of \$7.6 million.

Related to the SPAC and subject to the issuance of the First Tranche Common Shares and associated transactions, the Company's subsidiary will assume convertible promissory notes originally issued by the vendor in the principal amount of \$15.2 million. The notes bear interest at 12% per annum and are due on December 31, 2026. PX Energy has issued a US\$5 million guarantee for these notes. Subject to conditions precedent in the BCA and the closing of the SPAC transaction, the notes are convertible into common shares of the SPAC. If the SPAC transaction does not proceed, the notes are due and payable or convertible into equity of the Company's subsidiary. Liabilities acquired under the acquisition included US\$80 million in senior secured callable bonds issued by FRBH with a maturity date of April 24, 2028. The bonds have a face value of US\$80 million and an acquisition date fair value of US\$64 million. The carrying amount will accrete from US\$64 million to US\$80 million with the accretion recognized on the income statement as finance costs at the effective interest rate. Interest will also be recognized as incurred. The bonds are secured by a fiduciary assignment of the equity of PX Energy and security over the assets of PX Energy.

In conjunction with the closing of the Acquisition, the holders of bonds representing a requisite majority agreed to amend the terms of the bonds as detailed below. These amendments may need to be formalized in an amending agreement to the bond terms.

Interest reduced from 16% per annum to 10% per annum effective August 1, 2025. All accrued and unpaid interest up to December 31, 2025, converts into shares in the SPAC transaction. If the SPAC transaction does not proceed, no interest is payable in 2025. Thereafter, interest is payable quarterly based on Brent pricing ranging from 4% based on Brent pricing under US\$55 per barrel to 20% based on Brent pricing greater than US\$95 per barrel with interest not to exceed 16% over the term of the bonds. Interest in 2026 may be payable in cash or in kind at the issuer's election with interest in 2027 onwards payable in kind if Brent prices are below US\$65 per barrel.

Concurrent with the Acquisition, the Company entered a binding term sheet with a prospective joint venture partner for a 50/50 joint venture for the ownership and management of PX Energy (the "**Joint Venture**"). In January 2026, the Company was advised by the prospective partner that the term sheet for a 50/50 joint venture expired in accordance with its terms.

DESCRIPTION OF THE BUSINESS

Business of the Company

Questerre is an energy technology and innovation company. Questerre directly and through its wholly owned subsidiaries is actively engaged in the acquisition, exploration, and development of oil and gas projects, in specific non-conventional projects such as tight oil, oil shale, shale oil and shale gas. Questerre holds assets in Canada, USA, Brazil, and Jordan.

Corporate Strategy

Management of Questerre intends to leverage its specialized knowledge of non-conventional oil and gas resources to acquire and develop these projects.

To mitigate the financial and operational risks associated with its high impact non-conventional projects, the Company normally seeks industry partners to jointly participate in their development. The Company plans to further diversify risk through the acquisition and development of a portfolio of lower risk projects to provide near-term cash flow and growth opportunities.

Employees

At December 31, 2025, Questerre's Canadian work force consisted of 11 full time employees and 7 part time employees. Its Brazil work force consisted of 200 full time employees and 6 part time employees.

Environmental Matters

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations and requires that well and facility sites be abandoned and reclaimed to the satisfaction of governmental authorities. As at December 31, 2025, Questerre recorded an obligation on its balance sheet of \$20 million for Canadian asset retirement and \$17 million for the Brazilian asset retirement. The Company maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. The Company also has operational and emergency response procedures and safety and environmental programs in place to reduce potential loss exposure. See "Risk Factors" and "Industry Conditions".

Foreign Operations

In connection with the PX Energy Acquisition and the Company's acquisition of the remaining equity ownership interest in Red Leaf, the Company's operating activities include foreign operations in Brazil and the USA. Despite Brazil's large economy, it is still considered a developing country. To date, PX Energy has benefitted from several initiatives provided by various levels of government in support of oil and gas development in Brazil. However, all oil and gas exploration, development and production activities are subject to significant political, economic and other uncertainties and these risks are generally considered higher when operating in an emerging market. See "Risk Factors" in this AIF for further details.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Questerre competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Questerre's competitors include resource companies which have greater financial

resources, staff and facilities than those of Questerre. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Questerre believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development. See "Risk Factors".

Marketing

In Canada, Questerre's crude oil, natural gas and NGL production is sold primarily through marketing companies at current market prices. Crude oil contracts are generally month to month and cancellable on 30 days' notice, NGL contracts are generally for a period of up to one year and are cancellable on 90 days' notice and natural gas contracts are generally for one year.

In Brazil, refined petroleum products are sold to wholesale customers and distributors. Crude oil sales are generally conducted under term contracts, with pricing linked to applicable benchmark indices and adjusted for quality, location and transportation.

Cyclical and Seasonal Nature of Industry

Questerre's operational results and financial condition are dependent on the international prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the financial condition of Questerre. Further, in Canada production of oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Although the Company's business in Brazil is not seasonal, seasonality may impact demand and price for oil and natural gas and may also impact the timing of operations. See "Risk Factors".

Specialized Skill and Knowledge

Questerre believes its success is dependent on the performance of its management and key employees, many of whom have specialized knowledge and skills relating to oil and gas operations. Questerre believes that it has adequate personnel with the specialized skills required to successfully carry out its operations. See "Risk Factors" in this AIF.

Social and Environmental Policies

Questerre is committed to meeting industry standards in each jurisdiction in which it operates with respect to human rights, environment, health and safety policies. Management, employees and contractors are governed by and required to comply with Questerre's environment, health and safety policy as well as all applicable federal, provincial, and municipal legislation and regulations. Questerre has established roles and responsibilities to facilitate effective management of its environment, health and safety policy throughout the organization. It is the primary responsibility of the managers, supervisors and other senior field staff of Questerre to oversee safe work practices and ensure that rules, regulations, policies and procedures are being followed.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Petroleum and Natural Gas Reserves

McDaniel & Associates Consultants Ltd. ("McDaniel"), independent petroleum engineers of Calgary, Alberta prepared an Evaluation of Oil & Gas Reserves dated March 9, 2026 (the "McDaniel Report") which evaluation

is effective December 31, 2025. **The McDaniel Report is in respect of Questerre’s conventional oil and gas properties in Canada and excludes its assets in the Quebec Lowlands and its oil shale assets in Brazil and the US.** In preparing its report, McDaniel obtained basic information from Questerre, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the McDaniel Report is based, was obtained from public records, other operators and from McDaniel’s non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by McDaniel as represented.

GLJ Ltd. (“**GLJ**”), independent petroleum engineers of Calgary, Alberta prepared the Reserve Assessment and Evaluation of Oil and Gas Properties dated March 2026 (the “GLJ Report”) which report is effective December 31, 2025. The GLJ Report is in respect of the Mina de Xisto Field in Brazil held by PX Energy. Information used in the preparation of the GLJ Report was obtained from PX Energy. The GLJ Report is based on certain factual data supplied by the Company and GLJ’s opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to GLJ. GLJ accepted this data as presented and neither title searches nor field inspections were conducted

No reserves are currently assigned to the Company’s assets in Jordan or held by Red Leaf in the USA.

The following tables set forth contain certain information relating to the oil and natural gas reserves of the Company’s properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2025, numbers may vary slightly from those presented in the McDaniel Report and the GLJ Report due to rounding. Due to rounding, certain columns may not add exactly. The information set forth below is derived from the McDaniel Report and/or the GLJ Report, as applicable, which reports have been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101.

All evaluations and reviews of future net revenue are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The estimated future net revenue from the production of disclosed oil and natural gas reserves does not represent the fair market value of the Company’s reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein. All of the Company’s crude oil, NGLs and natural gas reserves are in Canada and Brazil.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

- Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator for Canada in Form 51-101F2
- Appendix B: Report on Reserves Data by Independent Qualified Reserves Evaluator for Brazil in Form 51-101F2
- Appendix C : Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3

Definitions used for reserve categories in the McDaniel and GLJ Reports are attached as Appendix C hereto.

**SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2025
FORECAST PRICES AND COSTS**

Reserves Category	Light & Medium Oil		Heavy Oil		Tight Oil	
	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)
Proved - Canada						
Developed Producing	532.3	504.4	—	—	—	—
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved - Canada	532.3	504.4	—	—	—	—
Proved - Brazil						
Developed Producing	546	519	2,496	2,371	7,159.9	6,801.9
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved - Brazil	546.4	519.1	2,495.7	2,371.0	7,159.9	6,801.9
Total Proved - Combined	1,078.7	1,023.5	2,495.7	2,371.0	7,159.9	6,801.9
Total Probable - Canada	728.6	707.6	—	—	—	—
Total Probable - Brazil	311.3	268.1	299	285	859.2	816.2
Total Probable - Combined	1,039.9	975.7	299.5	284.5	859.2	816.2
Total Proved + Probable Combined	2,118.5	1,999.2	2,795.2	2,655.5	8,019.1	7,618.1

FOR CANADA:

- (1) Gross reserves are working interest reserves before royalty deductions.
- (2) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.
- (3) Natural Gas Liquids include Condensate volumes.

FOR BRAZIL:

- (1) Conventional Gas volumes are volume associated with Processing the Shale Ore.
- (1) Gross reserves are working interest reserves before royalty deductions.
- (2) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.
- (2) All reserves volumes are sales volume after internal consumption.
- (3) Reserves Volumes do not include Sludge Oil Processing Volumes.

Reserves Category	Conventional Natural Gas		Shale Gas		Natural Gas Liquids ⁽³⁾	
	Gross ⁽¹⁾ (MMcf)	Net ⁽²⁾ (MMcf)	Gross ⁽¹⁾ (MMcf)	Net ⁽²⁾ (MMcf)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)
Proved - Canada						
Developed Producing	16.8	68.1	10,692.4	9,819.9	1,402.2	1,115.8
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	—	—	27,277.5	25,175.2	3,638.2	3,084.3
Total Proved - Canada	16.8	68.1	37,970	34,995	5,040	4,200
Proved - Brazil						
Developed Producing	5,075.4	4,821.6	—	—	2,495.7	2,371.0
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved - Brazil	5,075.4	4,821.6	—	—	2,496	2,371
Total Proved - Combined	5,092.2	4,889.7	37,969.8	34,995.1	7,536.2	6,571.1
Total Probable - Canada	3.2	13.6	33,981.3	30,213.5	4,058.1	3,089.0
Total Probable - Brazil	609.0	578.6	—	—	299.5	284.5
Total Probable - Combined	612.2	592.1	33,981.3	30,213.5	4,357.6	3,373.5
Total Proved + Probable Combined	5,704.4	5,481.9	71,951.1	65,208.6	11,893.8	9,944.6

SUMMARY NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2025
FORECAST PRICES AND COSTS

Reserves Category	Before Income Taxes Discounted at (%/year)				
	@0.0% (M\$)	@5.0% (M\$)	@10.0% (M\$)	@15.0% (M\$)	@20.0% (M\$)
Proved					
Developed Producing	58,278.3	52,693.9	47,403.3	42,964.4	39,325.0
Developed Non-Producing	—	—	—	—	—
Undeveloped	78,719.3	45,493.7	25,183.4	12,405.8	4,159.0
Total Proved - Canada	136,997.6	98,187.6	72,586.7	55,370.2	43,484.0
Proved					
Developed Producing	247,896.5	163,684.6	113,260.1	81,740.5	61,237.4
Developed Non-Producing	—	—	—	—	—
Undeveloped	—	—	—	—	—
Total Proved - Brazil	247,896.5	163,684.6	113,260.1	81,740.5	61,237.4
Total Proved - Combined	384,894.1	261,872.1	185,846.8	137,110.7	104,721.4
Total Probable - Canada	174,097.6	99,127.7	60,759.2	39,779.4	27,598.7
Total Probable - Brazil	600,027.0	383,108.2	258,691	183,468	135,760
Total Probable - Combined	774,124.6	482,235.9	319,450.0	223,247.5	163,358.4
Total Proved + Probable Combined	1,159,018.7	744,108.0	505,296.7	360,358.2	268,079.8

Reserves Category	After Income Taxes Discounted at (%/year)				
	@0.0% (M\$)	@5.0% (M\$)	@10.0% (M\$)	@15.0% (M\$)	@20.0% (M\$)
Proved					
Developed Producing	58,278.3	52,693.9	47,403.3	42,964.4	39,325.0
Developed Non-Producing	—	—	—	—	—
Undeveloped	78,719.2	45,493.7	25,183.4	12,405.8	4,159.0
Total Proved - Canada	136,997.5	98,187.6	72,586.7	55,370.2	43,484.0
Proved					
Developed Producing	159,479.3	105,593.4	73,116.3	52,720.5	39,411.5
Developed Non-Producing	—	—	—	—	—
Undeveloped	—	—	—	—	—
Total Proved - Brazil	159,479.3	105,593.4	73,116.3	52,720.5	39,411.5
Total Proved - Combined	296,476.8	203,780.9	145,703.0	108,090.7	82,895.5
Total Probable - Canada	172,888.7	98,723.0	60,616.4	39,726.5	27,578.2
Total Probable - Brazil	400,150.3	255,289.9	172,371	122,317	90,607
Total Probable - Combined	573,038.9	354,012.8	232,987.6	162,043.7	118,184.8
Total Proved + Probable Combined	869,515.7	557,793.8	378,690.7	270,134.4	201,080.4

(1) The unit values are based on net reserve volumes.

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2025
FORECAST PRICES AND COSTS**

CANADA		Revenue ⁽¹⁾	Royalties ⁽²⁾	Operating Costs	Development Costs	Abandonment & Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Reserves Category		M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$
Total Proved									
Reserves		661,527	79,569	271,952	155,527	17,483	136,997	—	136,997
Total Proved + Probable Reserves		1,305,928	186,037	508,896	279,180	20,720	311,095	1,209	309,886
BRAZIL									
Reserves Category		Revenue ⁽¹⁾	Royalties ⁽²⁾	Operating Costs	Development Costs	Abandonment & Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
		M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$
Total Proved									
Reserves		2,210,523	62,047	1,739,347	143,886	17,345	247,897	88,417	159,479
Total Proved + Probable Reserves		3,226,187	70,723	2,121,889	165,854	19,798	847,924	288,294	559,630

(1) Includes all product revenues and other revenues as forecast.

(2) Royalties include any net profits, interests paid, as well as the Saskatchewan Corporation Capital Tax Surcharge.

FUTURE NET REVENUE BY PRODUCT TYPE
AS OF DECEMBER 31, 2025
FORECAST PRICES AND COSTS

		Future Net Revenue Before Income Taxes (discounted @ 10%) M\$	Unit Value ⁽¹⁾ \$/Mcf \$/bbl
CANADA			
Reserves Category	Product Type		
Total Proved Reserves	Light and Medium Oil (Including Solution Gas and By-products)	14,960	29.66
	Conventional Natural Gas (Including By-products)	208	3.06
	Shale Gas (Including By-products)	57,418	1.64
	Total	72,587	
Total Proved + Probable Reserves	Light and Medium Oil (Including Solution Gas and By-products)	19,532	16.11
	Conventional Natural Gas (Including By-products)	245	3.00
	Shale Gas (Including By-products)	113,569	1.74
	Total	133,346	
BRAZIL			
Reserves Category	Product Type		
Total Proved Reserves	Tight Oil	113,260	1.80
Total Proved + Probable Reserves	Tight Oil	371,951	5.18

(1) Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group.

Forecast Prices and Costs Employed by McDaniel and GLJ - January 1, 2026

McDaniel and GLJ employed the following pricing, exchange rate and inflation rate assumptions in estimating Questerre's reserves data as of January 1, 2026. These are based on the average of commodity price forecasts effective January 1, 2026, from three qualified reserves evaluators who are independent of the Company, being GLJ Ltd., Sproule Associates Ltd., and McDaniel's (each of which is available on their respective websites at www.gljpc.com, www.sproule.com and www.mcdan.com).

Summary of Crude Oil and Natural Gas Liquids Price Forecasts January 1, 2026

Year	WTI Crude Oil \$/US/bbl (1)	Brent Crude Oil \$/US/bbl (2)	Edmonton Light Crude Oil \$/C/bbl (3)	Western Canadian Select Crude Oil \$/C/bbl (5)	Alberta Heavy Crude Oil \$/C/bbl (6)	Edmonton Ethane \$/bbl	Edmonton Propane \$/bbl	Edmonton Butanes \$/bbl	Edmonton Natural Gasolines \$/bbl	Inflation %	US/CAN Exchange Rate \$/US/\$CAN
History											
2025	65.50	69.10	85.65	75.05	70.45		32.35	37.75	88.60	2.05	0.720
Forecast											
2026	59.92	63.92	77.54	65.13	60.09	9.59	25.10	36.95	80.01	—	0.730
2027	65.10	69.13	83.60	70.43	64.94	10.64	27.28	39.79	86.19	2.00	0.740
2028	70.28	74.36	90.17	76.90	71.16	11.34	29.67	42.87	92.83	2.00	0.740
2029	71.93	76.10	92.32	78.71	72.84	11.66	30.37	43.89	95.04	2.00	0.740
2030	73.37	77.62	94.17	80.29	74.30	11.89	30.98	44.77	96.94	2.00	0.740
2031	74.84	79.17	96.06	81.90	75.80	12.14	31.60	45.66	98.89	2.00	0.740
2032	76.34	80.76	97.98	83.53	77.32	12.39	32.23	46.58	100.86	2.00	0.740
2033	77.87	82.37	99.93	85.20	78.87	12.64	32.87	47.51	102.88	2.00	0.740
2034	79.42	84.02	101.93	86.91	80.46	12.90	33.53	48.46	104.94	2.00	0.740
2035	81.01	85.70	103.97	88.65	82.08	13.16	34.20	49.43	107.04	2.00	0.740
2036	82.63	87.41	106.05	90.42	83.72	13.43	34.89	50.42	109.18	2.00	0.740
2037	84.29	89.16	108.17	92.23	85.39	13.70	35.58	51.42	111.36	2.00	0.740
2038	85.97	90.94	110.34	94.07	87.10	13.97	36.30	52.45	113.59	2.00	0.740
2039	87.69	92.76	112.54	95.96	88.84	14.25	37.02	53.50	115.86	2.00	0.740
2040	89.44	94.62	114.80	97.87	90.62	14.53	37.76	54.57	118.18	2.00	0.740
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.00	0.740

- (1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.5% sulphur
- (2) North Sea Brent Blend 37 degrees API, 1.0% sulphur
- (3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
- (4) Western Canadian Select at Hardisty, Alberta
- (5) Heavy crude oil 12 degrees API at Hardisty, Alberta (after deduction of blending costs to reach pipeline quality)
- (6) Historical prices based on AECO 7A (near month prices). 5A (daily price) expected to be equal to 7A over long term. 2025 historical prices: 7A \$1.86/MMBTU, 5A \$1.62/MMBTU
- (7) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the Crown royalty calculations.

**Summary of Natural Gas Price Forecasts
January 1, 2026**

Year	U.S. Henry Hub Gas Price \$US/MMBtu	Alberta AECO Spot Price \$/MMBtu (1)	Alberta Average Plantgate \$/MMBtu (2)	Alberta Aggregator Plantgate \$/MMBtu	Empress \$/MMBtu	Sask. Prov. Gas Plantgate \$/MMBtu	British Columbia Average Plantgate \$/MMBtu	British Columbia Station 2 \$/MMBtu
History								
2025	3.55	1.85	1.65	1.65	2.15	2.10	1.00	1.15
Forecast								
2026	3.74	3.00	2.80	2.80	3.18	3.03	2.23	2.66
2027	3.78	3.30	3.10	3.10	3.42	3.33	2.63	3.07
2028	3.85	3.49	3.28	3.28	3.61	3.52	2.80	3.25
2029	3.93	3.58	3.37	3.37	3.70	3.62	2.89	3.34
2030	4.01	3.65	3.44	3.44	3.78	3.69	2.95	3.41
2031	4.09	3.72	3.50	3.50	3.85	3.77	3.01	3.47
2032	4.17	3.80	3.58	3.58	3.93	3.85	3.08	3.55
2033	4.26	3.88	3.65	3.65	4.01	3.93	3.14	3.62
2034	4.34	3.95	3.72	3.72	4.09	4.01	3.21	3.69
2035	4.43	4.03	3.79	3.79	4.17	4.09	3.28	3.77
2036	4.52	4.11	3.87	3.87	4.25	4.17	3.34	3.84
2037	4.61	4.20	3.95	3.95	4.33	4.25	3.41	3.92
2038	4.70	4.28	4.03	4.03	4.42	4.34	3.48	4.00
2039	4.79	4.37	4.11	4.11	4.51	4.42	3.55	4.08
2040	4.89	4.45	4.19	4.19	4.60	4.51	3.62	4.16
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

- (1) Historical prices based on AECO 7A (near month prices). 5A (daily price) expected to be equal to 7A over long term. 2025 historical prices: 7A \$1.86/MMBTU, 5A \$1.62/MMBTU
- (2) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the Crown royalty calculations.

Questerre's weighted average realized sales prices for the year ended December 31, 2025, were \$79.80 per bbl for Canadian oil and NGL production, \$86.47 per bbl for Brazilian oil and NGLs and \$2.35 per Mcf for natural gas.

RECONCILIATION OF CHANGES IN RESERVES

Gross Reserves Reconciliation

Canada

The following table sets forth a reconciliation of Questerre's total gross proved, probable and proved plus probable reserves in Canada at December 31, 2025, against such reserves as at December 31, 2024, based on forecast price and cost assumptions.

The change in technical revisions for shale gas and natural gas liquids in the proved category is due to updated forecasts for existing production and undrilled locations, based in part on offset production, in both Kakwa Central and Kakwa North. The change in this same category for light crude oil is due to the updated forecasts for production at Antler and Pierson, Manitoba. The change in the probable category is due to the updated forecasts for undrilled locations based on offset production on the Kakwa North acreage as well as updated

forecasts for existing production at Antler. Dispositions relate to the Company's decision to forego participation in a three (0.75 net) well program at Kakwa Central that commenced in the fall of 2025.

The change in reserves due to economic factors in the light crude oil category relates primarily to the reduced operating costs on the existing production at Antler and in the other categories relates to higher estimates of operating costs for future drilling locations at Kakwa Central and Kakwa North.

	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL			TIGHT OIL			CONVENTIONAL NATURAL GAS		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
CANADA	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	MMcf
December 31, 2024	641.5	659.1	1,300.6	—	—	—	24.7	7.4	32.1
Extensions & Improved Recovery	78.6	20.7	99.3	—	—	—	—	—	—
Technical Revisions	9.6	(15.0)	(5.4)	—	—	—	0.2	(4.0)	(3.8)
Discoveries	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(98.7)	63.8	(34.9)	—	—	—	(2.7)	(0.2)	(2.9)
Production	(98.7)	—	(98.7)	—	—	—	(5.4)	—	(5.4)
December 31, 2025	532.3	728.6	1,260.9	—	—	—	16.8	3.2	20.0

	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL			TIGHT OIL			CONVENTIONAL NATURAL GAS		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
BRAZIL	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	MMcf
December 31, 2024	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—
Acquisitions	583	282	865	7,290	859	8,149	5,075	609	5,685
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—
Production	(46.8)	—	(46.8)	(130)	—	(130)	(0.1)	—	(0.1)
December 31, 2025	536.0	282.2	818.2	7,159.9	859.2	8,019.1	5,075.4	609.0	5,684.4

	SHALE GAS			NATURAL GAS LIQUIDS			TOTAL		
	Gross Proved MMcf	Gross Probable MMcf	Gross Proved Plus Probable MMcf	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved Mboe	Gross Probable Mboe	Gross Proved Plus Probable Mboe
FACTORS - CANADA									
December 31, 2024	39,866.3	34,568.8	74,435.1	5,611.7	4,512.8	10,124.5	12,901.7	10,934.6	23,836.3
Extensions & Improved Recovery	—	—	—	—	—	—	79	21	99
Technical Revisions	2,038.9	(147.3)	1,891.6	77.5	(380.3)	(302.8)	427.0	(420.5)	6.4
Discoveries	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	(938.6)	(229.8)	(1,168.4)	(185.9)	(46.0)	(231.9)	(342.3)	(84.3)	(426.6)
Economic Factors	(395.4)	(210.4)	(605.8)	(61.9)	(28.5)	(90.4)	(227.0)	0.2	(226.8)
Production	(2,601.4)	—	(2,601.4)	(400.9)	—	(400.9)	(934.1)	—	(934.1)
December 31, 2025	37,969.8	33,981.3	71,951.1	5,040.5	4,058.0	9,098.5	11,903.9	10,450.7	22,354.6

	SHALE GAS			NATURAL GAS LIQUIDS			TOTAL		
	Gross Proved MMcf	Gross Probable MMcf	Gross Proved Plus Probable MMcf	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved Mboe	Gross Probable Mboe	Gross Proved Plus Probable Mboe
FACTORS - BRAZIL									
December 31, 2024	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	2,506	299	2,806	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—
Production	—	—	—	(10.4)	—	(10.4)	—	—	—
December 31, 2025	—	—	—	2,495.7	299.5	2,795.2	—	—	—

Brazil

The Company completed the PX Energy Acquisition during the year ended December 31, 2025 and as such, there were no reserves associated with this area at the beginning of the year.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

The following discussion generally describes the basis on which Questerre attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Undeveloped Reserves

The following tables set forth the volumes of proved and probable undeveloped reserves that were first attributed in each of Questerre's three most recent financial years and, before that time, in the aggregate. These undeveloped reserves are attributable to the Company's assets in Canada. There are no undeveloped reserves attributable to the Company's assets in Brazil.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbbls)		Tight Oil (Mbbbls)		Conventional Gas (MMcf)		Shale Gas (MMcf)		Natural Gas Liquids (Mbbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2023	—	66.4	—	—	—	—	—	36,349.2	—	4,848.7
2024	—	66.4	—	—	—	—	—	32,008.7	—	4,421.5
2025	—	—	—	—	—	—	—	27,277.5	—	3,638.2

Proved undeveloped reserves are generally those reserves related to infill drilling locations. If significant capital remains, these can also include wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year but not yet completed or wells further away from Questerre gathering systems. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production.

The McDaniel Report attributes 8.2 MMboe of reserves as “proved undeveloped”. These relate to infill and step-out drilling locations in Kakwa. Questerre has scheduled drilling programs in these areas over the next five years targeting the infill and step-out locations that have been assigned proved undeveloped reserves. Assuming the current pace of drilling by the respective operators at Kakwa remains constant and based on the number of locations, it will take five years to fully develop these locations. There are no proved undeveloped reserves attributed to the Company’s Brazil assets.

Undeveloped Reserves - Probable Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbbls)		Tight Oil (Mbbbls)		Conventional Gas (MMcf)		Shale Gas (MMcf)		Natural Gas Liquids (Mbbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2023	170.9	544.0	—	—	—	—	—	38,371.6	—	4,931.9
2024	—	544.0	—	—	—	—	—	33,090.6	—	4,285.3
2025	—	610.4	—	—	—	—	—	31,594.8	—	3,744.4

In most instances, the probable undeveloped reserves assigned to the Company are those reserves associated with the proven undeveloped reserves using a more optimistic decline analysis and further locations in Kakwa beyond the five-year time frame usually reserved for proved undeveloped locations. Furthermore, undrilled locations in Antler, Saskatchewan are included in this category. Additional production information may result in the reclassification of these reserves into proven developed producing reserves. The McDaniel Report attributes 3.7 MMboe of reserves as “probable undeveloped”. The probable undeveloped locations at Kakwa are similarly based on the assumption that the respective operators maintain their current pace of drilling. The probable undeveloped locations at Antler are based on the successful implementation of the pilot secondary recovery scheme. There are no probable undeveloped reserves attributed to the Company’s Brazil assets.

Development of Undeveloped Reserves

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Questerre’s development plans. Normally, the Company plans to develop its proved and/or probable undeveloped reserves in a responsible manner, that balances the opportunities with its financial resources in the next one to eight years, subject to the current pace of drilling by the operator of its non-operated assets.

A number of factors could result in delayed or cancelled development plans. Such factors include the financial capability of Questerre and its partners, changing economic conditions due to oil and natural gas prices, operating and capital expenditure fluctuations. Changing technical conditions resulting in production anomalies

such as premature water break through or higher than anticipated production declines may result in a delay or cancellation of development plans. In wells that have encountered multiple zones, a prospective zone completion may be delayed until the initial completion is no longer economic. Larger development programs may need to be spread out over several years to optimize capital allocation and facility utilization. Surface access issues associated with landowners, weather conditions or regulatory approvals could also influence development plans.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Questerre's reserves are evaluated by McDaniel and GLJ, each, an independent petroleum engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Questerre's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

In specific, recent production data from wells drilled and placed on production or wells recently equipped with gas lift facilities in the Kakwa area may result in changes to the estimates of reserves. Furthermore, recent production data from wells that may be worked over in the Antler area could also result in changes to the estimates of reserves. Changes to the Company's drilling programs, both on an operated and non-operated basis, may also result in changes to reserve estimates. As the majority of Questerre's reserves in the Kakwa joint venture acreage are non-operated, any changes to the operator's drilling program could impact reserve estimates. The Company may amend the allocation of capital investment between its areas of operation, particularly Kakwa and Antler based on results and commodity prices. With respect to the Company's Brazil assets, the reserves are most sensitive to commodity prices, operating costs and sustaining capital expenditures.

Future Development Costs

Canada

The following table outlines the capital costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) in Canada to those properties evaluated in the McDaniel Report.

CANADA	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Remaining	Total
Development Cost Forecast (M\$)												
Total Proved												
Undiscounted	17	32,226	40,284	41,089	41,911	—	—	—	—	—	—	155,527
Discounted @ 10.0%	17	28,268	32,030	29,701	27,541	—	—	—	—	—	—	117,557
Total Proved + Probable												
Undiscounted	17	32,226	40,284	41,089	41,911	37,764	38,418	39,213	8,258	—	—	279,180
Discounted @ 10.0%	17	28,268	32,030	29,701	27,541	22,552	20,774	19,213	3,683	—	—	183,779
BRAZIL	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Remaining	Total
Development Cost Forecast (M\$)												
Undiscounted	2,600	16,014	2,809	10,294	2,923	17,334	3,041	11,142	3,163	18,763	55,703	143,786
Discounted @ 10.0%	2,574	13,881	2,214	7,374	1,903	10,262	1,636	5,452	1,407	3,163	15,764	65,630
Total Proved + Probable												
Undiscounted	4,101	19,824	11,441	18,418	2,923	17,334	3,041	11,142	3,163	18,763	55,703	165,854
Discounted @ 10.0%	3,910	17,183	9,015	13,194	1,903	10,262	1,636	5,452	1,407	7,587	15,764	87,314

Brazil

The table above outlines the capital costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) in Brazil to those properties evaluated in the GLJ Report.

Questerre estimates that its equity financing along with internally generated cash flow, current cash balances and conventional debt financing should be sufficient to fund the future development costs disclosed above. Questerre typically has available four sources of funding to finance its capital expenditure program: current cash balances, internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favorable terms. Any acquisition opportunities would likely be financed through debt or equity financings. To finance future development costs in the present commodity price environment, the Company anticipates it will need to improve its financial liquidity in the near future through one or all the sources above.

There can be no guarantee that funds will be available or that Questerre will allocate funding to develop all the reserves attributable in the McDaniel Report and GLJ Report. Failure to develop those reserves could have a negative impact on Questerre's future cash flow. Questerre does not anticipate that interest or other funding costs would make further development of any of Questerre's assets uneconomic.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

Questerre has two core areas in Canada and one in Brazil where it currently conducts and expects to conduct the most of its near-term activity: Kakwa, Alberta and Antler, Saskatchewan in Canada and Sao Mateus do Sul in the state of Parana in Brazil. The Company also holds assets prospective for oil shale in the USA, and assets in the St. Lawrence Lowlands, Quebec.

Kakwa, west central Alberta

The Kakwa area is situated approximately 75 kilometres south of Grande Prairie in west central Alberta. Among other zones of interest, the area is prospective for condensate-rich natural gas in the deep, over-pressured fairway of the Montney formation, at a depth of approximately 3,100 metres to 3,600 metres. Economics are enhanced by relatively high liquids content, particularly condensate, and Crown royalty incentives.

Questerre currently holds 40,320 (17,700 net) acres in the area, including a 25% working interest in 10,080 acres ("**Kakwa Central**"), 50% working interest in 4,480 acres ("**Kakwa North**"), a 50% interest in 22,040 acres ("**Kakwa West**") and a 50% interest in 3,840 acres ("**Kakwa South**").

Questerre participated in development drilling at both the Kakwa Central and Kakwa North joint ventures during 2024 and went penalty for the 2025 program at Kakwa Central.

During the year, daily production averaged 2,356 boe/d (2024: 1,452 boe/d) comprising of 7.1 MMcf/d of natural gas (2024: 4.4 MMcf/d) and 1,127 bbl/d of condensate and natural gas liquids (2024: 719 bbl/d).

Capital invested in Kakwa totalled \$18.8 million for the year (2024: \$19.3 million) Total proved and probable reserves as of December 31, 2025, were estimated at 21.1 MMBoe (2024: 22.5 MMBoe) with a before tax NPV-10% of \$124.3 million (2024: \$180.6 million). The Company currently holds 40,320 (17,700 net) acres in the Kakwa area.

At Kakwa North, the operator finalized a three well program during 2025. The wells were brought on-stream in the second quarter. The operator is assessing a follow-up drilling program that could commence in the fall of 2026.

At Kakwa Central, the operator commenced a three well program in the fall of 2025. Questerre elected to forego participation in this entire program due to the proposed inter-well spacing that is expected to impact overall well recoveries.

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

Antler, southeast Saskatchewan

The Antler area is approximately 200 kilometres southeast from Regina in southeast Saskatchewan. The primary target is high quality light oil from the Bakken/Torquay formation, a dolomitic siltstone shale sequence at a depth of between 1,050 metres and 1,150 metres. Secondary targets include the Souris Valley, a carbonate sequence at a depth of approximately 900 metres to 1,000 metres. The Company holds an average 100% working interest in 14,730 acres in this area.

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

\$5.1 million was invested at Antler during the year to expand the pilot secondary recovery scheme and drill two wells. (2024: \$0.8 million). Daily production averaged 207 bbl/d (2024: 250 bbl/d). Total proved and probable reserves as at December 31, 2025, were estimated at 1.2 MMBbls (2024: 1.2 MMBbls) with a before tax NPV-10% of \$17.4 million (2024: \$21.9 million). The Company currently holds 14,730 net acres in the area.

In 2026, the Company expects to continue its work to enhance existing production through workovers and expanding the pilot secondary recovery scheme while assessing future drilling locations.

Oil Shale Mining – Sao Mateus do Sul, Parana, Brazil

Sao Mateus do Sul in the state of Parana, is located approximately 900 kilometres from Sao Paulo in southern Brazil. The primary zone of interest is the Irati oil shale formation. The mined oil shale interval is approximately _m thick consisting of an upper interval of _m and a lower interval of _m separately by _m of limestone interburden. PX Energy's operations in Sao Mateus utilize a technology to produce oil from oil shale developed by an integrated energy company. Its assets include mining, processing and refining operations.

The Acquisition advances the Company's strategy to commercially develop oil shale resources globally. It provides a platform of producing oil shale operations, including mining, processing and refining facilities as well as oil shale reserves and resources. Average daily production from PX Energy for the fourth quarter was 3,768 bbl/d for crude oil and 3.9 MMcf/d of natural gas. Total proved and probable reserves as of December 31, 2025 were 12.6 MMBoe with a before tax NPV-10% of \$372 million.

Oil Shale Mining - Red Leaf Resources Inc.

Red Leaf is a private US-based technology company whose principal assets include its patented HCCO® oil-shale processing technology, oil shale mineral leases in the State of Utah, title to over 7,000 acres in the Uintah Basin in the State of Utah and cash and investments of over US\$9 million. In December 2025, the Company consolidated its ownership of Red Leaf through an exchange of Red Leaf common shares for Common Shares and the acquisition of the Red Leaf preferred shares.

For 2026, the Company plans to optimize the operations of PX Energy to improve profitability and assess options to demonstrate the Red Leaf technology at scale.

Oil Shale Mining – Jordan

In October 2016, Questerre commissioned an independent assessment of its oil shale resources in Jordan (the "**Jordan Resource Assessment**"). The Jordan Resource Assessment was conducted by Millcreek Mining Group, an independent qualified reserves evaluator, as defined by NI 51-101 with an effective date of September 30, 2016. The assessment was prepared in accordance with NI 51-101 and the COGE Handbook. The assessment indicated a best estimate of discovered petroleum initially in place of between 7.8 billion barrels to 12.2 billion barrels. Given the preliminary nature of the Jordan Resources Assessment, it does not contain any estimates regarding the timing or cost to obtain commercial development nor has the Company finalized the specific technology to be used. For more information, please refer to the Company's press release dated October 27, 2016 and the Company's Annual Information Form dated March 24, 2017 available on the Company's website at www.questerre.com or on SEDAR+ at www.sedarplus.ca.

Questerre intends to utilize the Red Leaf technology for its project in Jordan. Discussions with the Government of Jordan for a demonstration of the technology and the related negotiations for the concession agreement for the project remain ongoing. Through the execution of a new agreement with the Government of Jordan, the Company seeks to renew its exclusive rights to this project that expired in 2025.

Quebec

The Quebec Lowlands are situated in Quebec, south of the St. Lawrence River between Montreal and Quebec City. The exploration potential of the Quebec Lowlands is complemented by proximity to one of the largest natural gas markets in North America and a well-established distribution network.

The area is prospective for natural gas in several horizons with the primary target being the Utica. Secondary targets include the shallower Lorraine and the deeper Trenton Black-River carbonate. The majority of

Questerre's acreage lies in the heart of the fairway between two major geological features — Logan's Line, a subsurface thrust fault to the east and the Yamaska growth fault to the west.

Between 2005 and 2010, Questerre and its partner, Repsol, conducted an exploration and commercial appraisal program of the natural gas potential of the Lowlands. In the fall of 2010, the program was suspended while the provincial government initiated an environmental assessment of shale gas development in the province.

Following almost six years of extensive studies and public consultation, in December 2016, the Government of Quebec passed Bill 106, *An Act to implement the 2030 Energy Policy and amend various legislative provisions*. These amendments include the enactment of the *Petroleum Resources Act* to govern the future development of petroleum resources in Quebec. In September 2017, the Ministry of Natural Resources published draft regulations required for the implementation of the *Petroleum Resources Act*.

In the third quarter of 2018, the Government of Quebec enacted the *Petroleum Resources Act* to govern the development of hydrocarbons in the province. It also enacted the associated regulations (the "**Regulations**") which includes restrictions on oil and gas activities, specifically the prohibition of hydraulic fracturing of shale and increasing the minimum setbacks from urbanized areas and bodies from water.

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

In 2019, pursuant to the agreement with a senior exploration and production company, Questerre acquired the exploration rights to 753,000 net acres in the Lowlands, associated wells and equipment, geological and geophysical data and other miscellaneous assets. Consideration included a mutual release for all claims related to outstanding litigation as described in the Company's press release dated June 4, 2018. Other consideration included cash, a contingent payment to the vendor on receipt of Government approval to complete a well and security for the assumption of abandonment and reclamation liabilities. Prior to closing adjustments, the total consideration was estimated at \$67.3 million. The acquisition closed effective December 31, 2019, with requisite government approvals received in early 2020.

As a result of the extensive consultations with stakeholders over the last five years, the Company continued to build support for its project.

The Company's primary objective remains the implementation of a business and political solution for the development of its natural gas discovery in the province. Concurrently, it is protecting its legal rights following the enactment in August 2022 of Bill 21.

Discussions remain ongoing with the Quebec Ministry of Economy, Innovation and Energy, for the Company's carbon storage pilot project application under Bill 21. The project includes a comprehensive program to assess the carbon storage potential including injection and monitoring wells, compression facilities and a pipeline to an adjacent industrial park. The Company is seeking Government funding for this pilot project. The Company is participating in the consultation process for new regulations proposed by the province related to carbon sequestration legislation.

Through the Quebec Energy Association, the Company participated in the public consultation for Bill 69, An Act to ensure the responsible governance of energy resources and to amend various legislative provisions ("**Bill 69**"). Bil 69 included the requirement for an integrated resource management plan to promote energy

development in Quebec. Among other things, it established for electric power and natural gas markets, policy directions, objectives and targets regarding supply, energy infrastructure and innovation. In June 2025, the Government of Quebec enacted Bill 69 under closure.

During the third quarter, the Company was advised that the Supreme Court of Canada declined to hear its application to appeal the decision from the Quebec Court of Appeal on the stay of application of Bill 21. The ruling by the Quebec Court of Appeal in May 2025 annulled a decision by the Quebec Superior Court justice in January 2024 suspending key provisions of Bill 21. The Government of Quebec is now permitted to enforce the specific provisions related to the abandonment and reclamation of existing wells. In March 2026, the Company was advised the Government is seeking proof of solvency for \$11.4 million for the estimated gross abandonment and reclamation costs for these wells. Pursuant to Bill 21, the Government is responsible for 75% of these costs. The Company intends to work collaboratively with the Government to meet its obligations on a reasonable and timely basis.

The Company is also proceeding with the main hearing on the merits of the case in accordance with procedural rules in Quebec, including its debate on the constitutional validity of Bill 21. The questioning of key Government representatives was completed in September and October the fall of 2025. Subject to completion of pre-trial motions and other procedural matters, the Company is seeking a date for the main hearing in 2026.

Wells

As at December 31, 2025, the Company had an interest in 121 gross (74.6 net) producing and 88 gross (69.9 net) non-producing oil and natural gas wells as follows, all of which are onshore.

	Producing				Non-Producing			
	Oil		Natural Gas		Oil		Natural Gas	
Canada	Gross ⁽¹⁾	Net ⁽²⁾	Gross	Net	Gross	Net	Gross	Net
Wells								
Alberta	1.0	1.0	53.0	13.7	5.0	2.5	24.0	10.0
Saskatchewan	56.0	56.0	—	—	45.0	45.0	—	—
Quebec	—	—	—	—	—	—	14.0	12.4
Manitoba	11.0	3.9	—	—	—	—	—	—
Total	68.0	60.9	53.0	13.7	50.0	47.5	38.0	22.4

“Gross” wells mean the number of wells in which Questerre has a working interest or a royalty interest that may be convertible to a working interest.

“Net” wells mean the aggregate number of wells obtained by multiplying each gross well by Questerre’s percentage working interest therein.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Company as at December 31, 2025 and the net area of unproved property for which the Company expects its rights to explore, develop and exploit to expire during the next year. There are no costs or work commitments associated with Questerre’s non-producing properties except for annual lease rentals.

Location	Unproved Properties (acres)		
	Gross ⁽¹⁾	Net ⁽²⁾	Net Area to Expire by December 31, 2026
Alberta	24,480	12,060	100
Saskatchewan	6,498	6,498	—
Manitoba	—	—	—
Quebec ⁽³⁾	1,046,563	951,925	—
Total	1,077,540	970,483	100

(1) "Gross Acres" are the total acres in which Questerre has an interest.

(2) "Net Acres" is the aggregate of the total acres in which Questerre has an interest multiplied by Questerre's working interest percentage held therein.

(3) Subject to the legal claim related to Bill 21.

Significant Factors of Uncertainties Relevant to Properties with No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of Questerre's properties with no attributed reserves. Questerre will be required to make substantial capital expenditures to prove, exploit, develop and produce oil and natural gas from these properties in the future. If Questerre's cash flow from operations or current cash balance is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to Questerre. Failure to obtain such financing on a timely basis could cause Questerre to forfeit its interest in certain properties, miss certain opportunities, and reduce or terminate its operations. The inability of Questerre to access sufficient capital for its exploration and development purposes could have a material adverse effect on Questerre's ability to execute its business strategy to develop these prospects. For further information, see "Risk Factors".

Questerre estimates abandonment and reclamation costs for surface leases, wells and facilities based on its previous experience, current regulations, costs, technology and industry standards. Questerre has estimated the net present value of its total asset retirement obligations for Canada to be \$20 million as at December 31, 2025 based on a total future liability of \$23.4 million.

The McDaniel Report incorporates the Company's current asset retirement obligation, which includes its estimated future abandonment and reclamation costs for wells assigned reserves, and wells not assigned reserves, as well as facilities. These amounts were deducted in determining the aggregate future net revenue. This is summarized below without discount and using a discount rate of 10%. The gross number of wells assigned proved reserves are 165 and the gross number of wells assigned proved plus probable reserves are 138.

CANADA	2026	2027	2028	2029	2030	2031	2032	2033	2034
Abandonment, Decommissioning and Reclamation Cost Forecast (M\$)									
Total Proved									
Undiscounted	270	612	1,411	811	1,360	948	1,514	874	622
Discounted @ 10.0%	269	554	1,161	607	926	586	851	447	289
Total Proved + Probable									
Undiscounted	270	612	1,411	811	1,360	948	1,514	874	622
Discounted @ 10.0%	269	554	1,161	607	926	586	851	447	289
Total Proved		2035	2036	2037	2038	2039	2040	Remaining	Total
Undiscounted		578	359	400	145	206	576	6,798	17,483
Discounted @ 10.0%		244	138	139	46	59	151	741	7,208
Total Proved + Probable									
Undiscounted		578	359	400	145	206	576	10,035	20,720
Discounted @ 10.0%		244	138	139	46	59	151	816	7,283
BRAZIL	2026	2027	2028	2029	2030	2031	2032	2033	2034
Abandonment, Decommissioning and Reclamation Cost Forecast (M\$)									
Total Proved									
Undiscounted	1,099	1,021	1,146	1,063	1,189	1,106	1,241	1,150	1,287
Discounted @ 10.0%	1,047	885	903	761	774	655	668	563	572
Total Proved + Probable									
Undiscounted	1,199	1,123	1,250	1,169	1,297	1,216	1,353	1,265	1,404
Discounted @ 10.0%	1,143	974	985	837	845	720	728	619	625
Total Proved		2035	2036	2037	2038	2039	2040	Remaining	Total
Undiscounted		1,197	1,343	1,245	1,262	1,081	891	25	17,345
Discounted @ 10.0%		484	494	416	383	298	224	6	9,134
Total Proved + Probable									
Undiscounted		1,316	1,465	1,369	1,379	1,184	980	828	19,798
Discounted @ 10.0%		532	539	458	419	327	246	189	10,185

Forward Contracts

Questerre may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. As at December 31, 2025, Questerre had no risk management contracts in place.

Income Tax Horizon

The income tax deducted in the calculation of future net revenue assumes a blow-down scenario whereby Questerre produces out its existing reserves and does not reinvest any capital. Under this scenario, and given Questerre's existing tax pools at December 31, 2025, Questerre does not expect to incur current income taxes prior to 2039.

Costs Incurred

The following table summarizes Questerre's property acquisition costs, development costs and exploration costs incurred in Canada and Brazil during the financial year ended December 31, 2025.

Nature of cost	Amount (\$thousands)
Property Acquisition Costs:	
Proved Properties	—
Unproved Properties	—
Development Costs	9,611
Exploration Costs	16,008
Total	25,619

Exploration and Development Activities

The following table summarizes the results of exploration and development activities in Canada and Brazil during the year ended December 31, 2025.

	Gross ⁽¹⁾	Net ⁽²⁾
Development Wells		
Gas	—	—
Oil	2.00	2.00
Service	—	—
Dry	—	—
Exploratory Wells		
Gas	—	—
Oil	—	—
Service	—	—
Dry	—	—
Total Wells	2.00	2.00

(1) "Gross" wells mean the number of wells in which Questerre has a working interest or a royalty interest that may be convertible to a working interest.

(2) "Net" wells mean the aggregate number of wells obtained by multiplying each gross well by Questerre's percentage working interest therein.

The Company's most important current exploration and development activities include the following:

- Continued development of its oil shale project in Sao Mateus do Sul in Parana, Brazil;
- Development drilling for liquids-rich natural gas in the Kakwa area of west central Alberta;
- Implementation of a workover and optimization program and a secondary recovery scheme for light oil in Antler, southeast Saskatchewan;
- Evaluation of the oil shale potential in Jordan; and
- Subject to the securing social acceptability and resolving the legal situation regarding oil and natural gas exploration and exploitation in Quebec, continued assessment of the Utica gas discovery in the St. Lawrence Lowlands, Quebec.

Production Estimates

The following table discloses the estimated average daily sales of products through fiscal 2026 by product type associated with the first year of the gross proved reserves and gross probable reserves estimates reported in the McDaniel Report and the GLJ Report, as applicable, effective December 31, 2025. The Kakwa field accounts for greater than 20 percent of the estimated production disclosed below, with estimated gross proved plus probable reserves production of 2,080.9 boe/d.

Corporation	Light and Medium	Natural Gas	Natural Gas	Combined boe (boe/d)
	Crude Oil (bbl/d)	Natural Gas (Mcf/d)	Liquids (bbl/d)	
Proved				
Kakwa, Alberta	—	5,725.6	772.4	1,726.7
Antler, Saskatchewan	250.9	—	—	250.9
Pierson, Manitoba	35.6	—	—	35.6
Other	2.9	14.2	0.1	5.4
Brazil	1,357.4	962.2	615.3	2,133.1
Total proved	1,646.8	6,702.0	1,387.8	4,151.6
Probable				
Kakwa, Alberta	—	177.8	24.0	53.6
Antler, Saskatchewan	8.0	—	—	8.0
Pierson, Manitoba	0.6	—	—	0.6
Other	—	0.1	0.1	0.1
Brazil	104.5	74.1	87.0	203.9
Total probable	113.1	252.0	111.1	62.3
Total proved plus probable	1,759.9	6,954.0	1,498.9	4,213.9

Netback and Production History

The following table sets forth information respecting the Company's share of average gross daily production, average net product prices received, royalties paid, production costs and the resulting netbacks received by the Company in respect of light crude oil, shale and conventional natural gas and natural gas liquids for the periods indicated.

	Three Months Ended			
	31-Mar 2025	30-Jun 2025	30-Sep 2025	31-Dec 2025
<u>Average Daily Production</u>				
Light Crude Oil and Natural Gas Liquids (bbl/d)	998	1,690	1,512	1,344
Shale Gas and Conventional Natural Gas (Mcf/d)	4,388	8,405	8,485	11,604
Brazilian Crude Oil (bbl/d)	—	—	—	3,768
Total (boe/d)	1,729	3,091	2,926	7,046
<u>Average Net Price Received</u>				
Light Crude Oil and Natural Gas Liquids (\$/bbl)	72.78	102.51	82.96	72.78
Shale Gas and Conventional Natural Gas (\$/Mcf)	2.61	1.41	0.79	2.61
Brazilian Crude Oil (\$/bbl)	—	—	—	85.26
<u>Royalties</u>				
Light Crude Oil and Natural Gas Liquids (\$/bbl)	15.94	8.65	9.16	5.40
Shale Gas and Conventional Natural Gas (\$/Mcf)	(1.57)	(0.32)	(0.37)	(0.15)
Brazilian Crude Oil (\$/bbl)				
<u>Production Costs</u>				
Light Crude Oil and Natural Gas Liquids (\$/bbl)	14.74	12.63	13.90	5.39
Shale Gas and Conventional Natural Gas (\$/Mcf)	3.87	3.10	3.20	2.18
Brazilian Crude Oil (\$/bbl)				39.40
<u>Netbacks Received</u>				
Light Crude Oil and Natural Gas Liquids (\$/bbl)	42.10	81.23	59.90	61.98
Shale Gas and Conventional Natural Gas (\$/Mcf)	0.31	(1.37)	(2.03)	0.57
Brazilian Crude Oil (\$/bbl)	—	—	—	45.86

Note: Natural gas production is predominately shale gas and light crude oil represents approximately 33% of light crude oil and NGLs.

Production Volume by Field

The following table discloses for each significant field and, in total, Questerre's average wellhead production volumes for the period ended December 31, 2025 for each product type.

Field	Light Crude Oil and Natural Gas Liquids (bbl/d)	Shale and Conventional Natural Gas (Mcf/d)	BOE (boe/d)	%
Kakwa-Resthaven, Alberta	1,142	7,250	2,350	63%
Antler, Saskatchewan	207	—	207	6%
Pierson, Manitoba	35	—	35	1%
Other	3	14	6	0%
Brazil	950	977	1,113	30%
Total	2,337	8,241	3,711	70%

Note: Natural gas production is predominately shale gas and light crude oil represents approximately 30% of light crude oil and NGLs.

RISK FACTORS

The business of exploring, developing and producing oil and natural gas reserves is inherently risky. Oil and natural gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Questerre.

Quebec Assets

In August 2022, the Government of Quebec enacted Bill 21-*An Act mainly to end petroleum exploration and production and the public financing of those activities*. The Act is to prohibit exploration for petroleum and production of petroleum and brine. It revokes petroleum exploration and production licences and it provides that the Government establish a compensation program pertaining to the revocation of licences. That Act requires, in particular, the holders of a revoked licence to permanently close wells and restore sites according to the terms and conditions it determines, except wells for which the MERN may authorize pilot projects for the purpose of acquiring geoscience knowledge. The bill validates the regulations made under the authority of the Petroleum Resources Act and 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 has revoked all exploration licenses held by the Company, effectively expropriating its assets in the province for notional compensation. While the Company intends to vigorously defend its legal rights with respect to this expropriation, there can be no certainty it will be successful. See "Other Oil and Gas Information – Oil and Gas Properties – St. Lawrence Lowlands, Quebec", "Risk Factors – Hydraulic Fracturing; and Regulatory" and "Industry Conditions – Environmental Regulation – Quebec" in this AIF.

Liquidity and the Company's Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out

of cash generated 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 the capital markets;
- the Company's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Company's securities in particular.

Further, if the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The recent acquisition of PX Energy and its associated working capital deficit and long term debt as of December 31, 2025, materially increases the Company's liquidity requirements. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The Company may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Additional Funding Requirements

Questerre's adjusted funds flow from its operations may not be sufficient to always fund its ongoing activities. From time to time, Questerre may require additional financing to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Questerre to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and gas industry and/or global economic volatility, the Company may from time to time have restricted access to additional funding.

Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in the Company's revenues from its reserves, which may affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable, or available 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 affected materially and adversely as a result.

If Questerre's adjusted funds flow from operations, current cash balance and available conventional debt capacity is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or be available on favorable terms. Any equity financing may result in a change of control of Questerre or holders of its Common Shares suffering further dilution.

Volatility in the Oil and Gas Industry

Market events and conditions, including global oil and natural gas supply and demand, world health emergencies, actions taken by the Organization of the Petroleum Exporting Countries ("OPEC") and its allies (collectively, "OPEC+") decisions on production growth and space capacity, potential trade disputes involving Canada, Mexico, China, the European Union and the U.S., 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, the occurrence or threat of terrorist attacks in the U.S. or other countries, 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. It is anticipated that the oil and natural gas industry will experience more pressure from investors to take meaningful strides towards combating climate change in the upcoming years, including diversifying their energy portfolios. 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 volatility in the valuation of oil and gas companies. 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 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 unfavorable and highly dilutive terms.

U.S. Tariffs

Since February 2025, multiple tariff measures between the United States, Canada have been threatened, implemented and subsequently adjusted, including with respect to the 10% U.S. tariffs on energy resources and critical minerals from Canada, which have subsequently paused since its announcement. The eventuality, timing, and scope of potential U.S. tariffs, and the ultimate impact of these tariffs on the Canadian oil and gas industry, including the Company's business, remain difficult to predict. However, should a 10% tariff on Canadian energy resources be imposed, it would significantly undermine the competitiveness of Canadian crude oil and natural gas exports to the U.S., which remains the primary export market for Western Canadian producers. Furthermore, such a tariff may reduce demand for Canadian oil and gas and lower realized commodity prices which could negatively impact the Company's revenues and profitability.

Additionally, market uncertainty surrounding U.S.-Canada trade relations and the potential for further trade restrictions could affect the Company's ability to raise capital. There is no assurance that trade tensions between Canada and the U.S. will be resolved favorably or that additional tariffs or trade barriers will not be introduced in the future. Any prolonged or escalated trade dispute could have a material adverse effect on the Company's business, financial condition, and results of operations.

Anti-greenwashing Rules

On June 20, 2024, Bill C-59 received royal assent, thereby enacting certain changes to the *Competition Act* to address "greenwashing", meaning false, misleading, or deceptive environmental claims made for the purpose of promoting a product or a business interest. Under the new rules, certain environmental claims that companies commonly make, including those related to sustainability and forward-looking environmental-related goals, may be problematic. How the new rules will be interpreted and applied is currently unclear. In June 2025, new private rights of action will come into effect, meaning that any person will be able to bring a complaint directly to the Competition Tribunal for an alleged violation of the new greenwashing provisions. The

Competition Bureau has published draft guidance regarding how it will apply the new greenwashing provisions, however the guidance, even once finalized, is not and will not be binding on private parties nor the Competition Tribunal.

On November 17, 2025, the federal government published a Notice of Ways and Means Motion to introduce a bill which proposes to amend the Competition Act by removing the requirement that environmental claims about a business or business activity be “in accordance with internationally recognized methodology” (but still requiring “adequate and proper substantiation”), and by making such business-level claims unavailable to third parties seeking to bring greenwashing complaints to the Competition Tribunal. Companies found to have made representations that violate the rules, intentionally or inadvertently, could be subject to an administrative penalty for the greater of \$10 million for the first order and \$15 million dollars for any subsequent order, and 3% of the Company’s annual worldwide gross revenues. Companies found to have made representations that violate the rules, intentionally or inadvertently, could be subject to an administrative penalty for the greater of \$10 million for the first order and \$15 million dollars for any subsequent order, and 3% of the Company’s annual worldwide gross revenues.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Company’s operating expenses and may impair the Company’s ability to compete. The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system applies in provinces and territories that request it to be implemented or are without their own system that meets federal standards. The federal regime was subject to several court challenges by Alberta, Saskatchewan and Ontario. The final decision from the Supreme Court of Canada was released on October 13, 2023. See “Industry Conditions – Environmental Regulation”.

Any 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 its profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Credit Facilities

The amount authorized under the Company’s credit facilities is dependent on the borrowing base determined by the Company’s lender. The Company is required to comply with covenants under its credit facilities which include certain financial ratio tests. If the Company does not comply with these covenants, the Company’s access to capital could be restricted or repayment could be required. Events beyond the Company’s control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in default under its credit facilities, which could result in the Company being required to repay amounts owing thereunder. Even if the Company can obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under its credit facilities, the lender could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Company’s indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the credit facilities impose certain operating and financial restrictions on the Company including, but not limited to, restrictions on the payment of dividends, repurchase or making of other distributions with respect to the Company’s securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others. In addition, the credit facilities are demand facilities and could be reduced or eliminated by the lender for reasons beyond the control of the

Company. The Company's credit facilities are currently restricted to its Canadian assets, particularly its producing assets in Western Canada.

The Company's Brazilian operations do not currently have access to credit facilities. To date, the Company has been unable to secure third-party financing for PX Energy on acceptable terms. Factors affecting the ability to obtain financing for the Brazilian operations include the outstanding senior secured bonds. Without access to credit facilities, the Brazilian operations are dependent on operational cash flow and support from the Company to fund working capital requirements, capital expenditures, and debt service obligations. There can be no assurance that the Company will be able to secure credit facilities for its Brazilian operations in the future or that such facilities, if obtained, will be on terms acceptable to the Company.

Secured Debt

In connection with the acquisition of PX Energy, the Company assumed US\$80 million in senior secured bonds (the "**Bonds**") issued by FRBH, maturing April 24, 2028, subject to two optional one-year extensions at a 2% fee per extension. The Bonds are secured by a fiduciary assignment of the equity of PX Energy and security over its assets. There can be no assurance the Company will have sufficient funds to repay the principal at maturity or upon acceleration following an event of default. The Bonds contain financial covenants requiring an interest coverage ratio greater than 1.3 times and minimum liquidity of US\$3.2 million. Failure to maintain compliance could trigger an event of default. Upon default, bondholders may enforce their security interests, which could result in the loss of the Company's investment in its Brazilian operations.

The Bonds bear interest at a variable rate linked to Brent crude pricing, ranging from 4% to 20% per annum (capped at 16% over the term). Interest may be paid in kind during 2026 which would increase the principal amount and increase repayment obligations at maturity. There can be no assurance that the Company will be able to refinance the Bonds on acceptable terms or at all. Failure to repay, refinance, or extend the Bonds could have a material adverse effect on the Company's business, financial condition, and results of operations.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, including geopolitical events, all of which are beyond the control of Questerre. World prices for oil and natural gas have fluctuated widely in recent years. Oil and natural gas prices are expected to remain volatile in the near future in response to a variety of factors beyond the Company's control, including but not limited to: (i) global energy supply, production and policies, including the ability of OPEC and OPEC+ countries to set and maintain production levels in order to influence prices for oil; (ii) political conditions, instability, hostilities, epidemics, pandemics and terrorist activities; (iii) global and domestic economic conditions, including currency fluctuations; (iv) the level of consumer demand, including demand for different qualities and types of crude oil and liquids and the availability and pricing of alternative fuel sources; (v) the production and storage levels of North American natural gas and crude oil and the supply and price of imported oil and liquefied natural gas; (vi) weather conditions; (vii) the proximity of reserves and resources to, and capacity of, transportation facilities and the availability of refining and fractionation capacity; (viii) the ability, considering regulation and market demand, to export oil and liquefied natural gas and NGLs from North America; (ix) the effect of world-wide energy conservation and greenhouse gas reduction measures and the price and availability of alternative fuels; (x) government regulations, actions by provincial governments and the Government of Brazil and (xi) the impact of regional and/or global health related events, on economic activity levels and energy demand; and (xii) the implementation of new export tariffs or import taxes on Canadian and/or Brazilian energy resources in the U.S. Certain wells or other projects may become uneconomic because of this decline or any further decline in world oil prices or a decline in natural gas prices, leading to a reduction in the future volume of Questerre's oil and natural gas production. Questerre might also elect not to produce from certain wells or sites at lower prices. All these factors could result in a material decrease in Questerre's future net production revenue, causing a reduction in its oil and natural gas exploration, development and acquisition activities. In addition, bank

borrowings available to Questerre will be in part determined by the borrowing base of Questerre. A sustained material decline in prices from prior relatively higher average prices could reduce Questerre's future borrowing base, therefore reducing the bank credit available to the Company, and could require that a portion of any existing bank debt of the Company be repaid.

Volatility in oil and natural gas prices makes it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers may have difficulty agreeing on the value of such properties. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Questerre assesses the carrying value of its assets to the extent required by International Financial Reporting Standards. If oil or natural gas prices decline, the carrying value of the Company's assets could be subject to downward revision, and the Company's earnings could be adversely affected by any reduction in such carrying value.

In addition to establishing markets for its oil and natural gas, Questerre must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Questerre will be affected by numerous factors beyond its control. Questerre will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Questerre. The ability of Questerre to market natural gas and NGLs may depend upon its ability to acquire space on pipelines which deliver these products to commercial markets. Questerre will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business. Questerre has limited direct experience in the marketing of oil, natural gas and NGLs.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that exploration expenditures by the Company will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones and tools lost in the hole, and changes in drilling plans and locations because of prior exploratory wells or additional seismic data and interpretations thereof. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and on its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able to continue to find satisfactory properties to acquire or participate in. Moreover, the management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of oil and natural gas.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological

and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Restrictions on the availability and cost of materials and equipment may impede the Company's exploration, development, and operating activities as crude oil and natural gas exploration, development, and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment, may impede the Company's exploration, development, and operating activities. The Company may utilize multi-well pad drilling where practicable. Problems affecting a single well could adversely affect production from all of the wells on the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production, or interruption in ongoing production. These delays or interruptions may cause volatility in our operating results.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment, and personal injury.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

In addition, the Company's oil shale mining operations in Brazil are subject to extensive regulatory oversight, including environmental and operational approvals that are more complex and time-consuming than those applicable to conventional oil and gas activities. Oil shale mining involves surface disturbance, industrial processing and waste management, which may result in increased scrutiny by regulatory authorities and longer permitting timelines. Delays in obtaining, renewing or amending permits or licences may adversely affect the timing, cost or scope of the Company's operations.

As is standard industry practice, the Company is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Company could incur significant costs. See "Risk Factors– Insurance" in this AIF.

Political Uncertainty

The Company's results can be adversely impacted by political, legal, or regulatory developments in Canada, Brazil and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact the Company's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits for the Company's activities or restrict the operation of third-party infrastructure that it relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Company's results.

In particular, the recent election of President Donald Trump in the US may result in legislative and regulatory changes that could have an adverse effect on the Company and its financial condition. There is uncertainty regarding U.S. tariffs and support for existing treaty and trade relationships with Canada and Brazil. Implementation of new legislative or regulatory policies by the US government could impose additional costs on the Company, decrease industry activity which would impact demand for the Company's services and could have a material adverse impact on the Canadian or Brazilian economy, the Canadian and Brazilian oil and natural gas industry and the Company's business.

Other government and political factors that could adversely affect the Company's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Company's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for the Company's products.

A change in federal, provincial or municipal governments in Canada or the Government of Brazil may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become increasingly politically polarizing topic in Canada and elsewhere, which has resulted in a rise in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects. Project blockades and demonstrations have the potential to delay and disrupt the Company's activities.

The *Alberta Sovereignty Within a United Canada Act* (the "**Sovereignty Act**") was passed on December 8, 2022, and received Royal Assent on December 15, 2022. The Sovereignty Act, amongst other things, enables the Alberta Government to choose which federal legislation, policies or programs it will enforce in Alberta, providing an overriding right to not enforce those which the Alberta Government deems to be "harmful" to Alberta's interests or infringe on the Federal Constitution and its division of powers. The Sovereignty Act has been opposed by many, including the Alberta New National Democratic Party and various Indigenous groups who have expressed concern as to how the Sovereignty Act will affect Indigenous rights and consultation obligations in Alberta. It is unclear what the effect the Sovereignty Act will have on Alberta, including the petroleum and natural gas industry, Alberta businesses and its federal and interprovincial relationships, including the application of certain federal legislation in Alberta, such as the GGPPA (as defined herein) and the IAA (as defined herein) and the way in which the Alberta Government may address any legislative and policy gaps created. Although the Sovereignty Act has not yet been challenged in court, it is possible the Sovereignty Act's constitutionality will be challenged.

The Federal Government was re-elected in 2025, but in a minority position. The ability of the minority Federal Government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry.

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development particularly with respect to

infrastructure projects. Protests, blockades, and demonstrations have the potential to delay and disrupt the Company's activities.

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Company's net production revenue.

Additionally, some European countries have also experienced the rise of antiestablishment political parties and public protests held against open-door immigration policies, trade, and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Company's ability to market its products internationally, increase costs for goods and services required for third party lessees' operations, reduce their access to skilled labour and as a result, negatively impact the Company's business, operations, financial conditions and the market value of the Common Shares.

In February 2022, Russian military forces invaded Ukraine. The ongoing conflict has materially disrupted oil and gas supply from the region, Canada, the United States, and other jurisdictions have imposed significant financial and trade sanctions on Russia. These sanctions may have far reaching implications for the global economy in addition to their immediate effects on Russia. The duration and outcome of the conflict, as well as the long-term consequences of related sanctions, remain uncertain and may adversely affect regional stability and global economic conditions. Additionally, following the February 2026 missile strikes in Iran, there has been increased instability, including airspace closures in the Middle East, damage to airports and the de facto closure of Strait of Hormuz, a waterway that transports approximately 20% of the world's petroleum. The duration and impact of these ongoing armed conflicts, and the potential of these conflicts spreading to more regions is uncertain, has contributed to increased volatility in global oil and gas markets and may result in sustained increases in energy prices and disruptions to supply.

See "Industry Conditions – Pipelines", "– Crude Oil and Bitumen by Rail", "– Trade Agreements" and "Climate Change Regulation" in this AIF.

Non-Government Organizations

The oil and natural gas exploration, development and operating activities conducted by the Company may, at times, be subject to public opposition. Such public opposition could expose the Company to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Company will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Company to incur significant and unanticipated capital and operating expenditures.

Changing Investor Sentiment

A number of factors, including the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation, and Indigenous rights have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail

and governmental investors have announced that they are no longer willing to fund or invest in oil and natural gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Company. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Company, or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities even if the Company's operating results, underlying asset values or prospects have not changed.

Global Financial Markets

Market events and conditions, including disruptions in the international credit markets and other financial systems, and the deterioration of global economic conditions caused significant volatility to commodity prices over the last few years. These conditions have resulted in a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and may continue to impact the performance of the global economy going forward.

If the economic climate in the U.S. or the world generally deteriorates further, demand for petroleum products could diminish further and prices for oil and natural gas could decrease further, which could adversely impact the Company's results of operations, liquidity and financial condition.

Adverse Economic Conditions

The demand for energy, including oil and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political development in the US, Europe, or Asia, there could be a significant adverse effect on global financial markets and commodity prices. In addition, hostilities in the Middle East, Ukraine, and other areas and the occurrence or threat of terrorist attacks in the US or other countries could adversely affect the global economy.

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on the Company's business, including changes to the way the Company and its counterparties operate, and on the Company's financial results and condition.

The Company's business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, be adversely impacted as a result of an outbreak of a pandemic, or contagious diseases, and/or decline in commodity prices as a result of: the shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruption or labour shortages caused by infected workers, or government or health authority mandated restrictions on travel by workers or closure of facilities or worksites; suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations; reduced cash flows resulting in less funds from operations being available to fund capital expenditure budgets; reduced commodity prices resulting in a reduction in the volumes and value of reserves; crude oil storage constraints resulting in the curtailment or shutting in of production; counterparties being unable to fulfill their contractual

obligations on a timely basis or at all; the inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate; and the ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

Gathering and Processing Facilities and Pipeline Systems

The Company delivers its products through gathering, processing, and pipeline systems, some of which it does not own. The amount of oil, natural gas and NGLs that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry limiting the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work because of actions taken by regulators could also affect the Company's production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, results of operations and cash flows. Future pipeline projects may be terminated for reasons such as failure to obtain government and/or regulatory support or approval. The direct impact that the termination of such projects will have on the Company is unknown. See "Industry Conditions – Pipelines" in this AIF.

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada leading to increased awareness of and challenges to interprovincial and international infrastructure projects. In 2019, with the passing of Bill C-69, the CERA and the Impact Assessment Act came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency. The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Company's ability to process its production and to deliver the same for sale. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Oil shale mining operations rely on industrial infrastructure, including processing facilities, power supply, water systems, waste disposal facilities and transportation networks. Infrastructure limitations, construction delays, equipment failures or insufficient third-party services may disrupt operations or increase capital and operating costs. Certain specialized processing equipment or replacement parts may not be readily available in Brazil and may require importation.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, electric vehicle mandates, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives (including electric vehicles), which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Questerre to incur costs to remedy such discharge. Recently, the industry has been subject to increased security of and focus on the environmental impact of drilling and completion techniques relating to the exploration for natural gas. Changes to the requirement for drilling and completion techniques could have a material impact on the ability of Questerre to drill and complete wells. Implementation of strategies with respect to climate change and reducing greenhouse gases to meet the limits required by federal or provincial governments could have a material impact on the nature of oil and natural gas operations, including those of Questerre. In November 2024, the federal government published a draft of the proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations, which proposes to cap emissions from certain oil and natural gas activities, implement a cap and trade system, and impose related reporting and remittance obligations. The initial cap would be tied to attributed 2026 emissions, with the first compliance period cap (2030–2032) set at 27% below 2026 levels—an estimated 35% reduction from 2019 emissions. Provinces and industry have criticized the proposal as effectively imposing a production cap, and, if implemented, the regime could materially adversely affect the Company. To date, the Proposed Regulations (as defined herein) have not been brought into force. The federal government under Prime Minister Mark Carney has shifted climate policy toward economic competitiveness, and, under the Canada–Alberta MOU, has committed not to proceed with the Proposed Regulations in light of other commitments made in that agreement.

Oil shale mining activities are subject to stringent environmental regulation in Brazil, including requirements relating to environmental impact assessments, staged licensing, waste disposal, water use, emissions control, land rehabilitation and post-closure monitoring. Environmental licences may include conditions that require substantial capital expenditures, operational modifications or ongoing monitoring. Failure to comply with applicable environmental laws, licence terms or regulatory requirements could result in fines, penalties, operational suspensions, remediation obligations or the revocation of permits.

Oil shale processing typically requires significant volumes of water for extraction and processing. Water abstraction rights are regulated at the state level in Brazil and may be subject to competing industrial, agricultural or community demands, seasonal variability or drought conditions. Restrictions on water availability,

changes in water use regulations, or increased costs associated with water sourcing, treatment or recycling could adversely affect the Company's operations and operating costs.

Oil shale mining generates significant volumes of spent shale, tailings and other processing residues that must be managed, stored and disposed of in compliance with environmental regulations. The Company may be required to establish or expand waste disposal facilities, implement long-term monitoring programs or undertake progressive reclamation during operations. Reclamation and closure obligations may extend beyond the productive life of a project and may require the posting of financial guarantees or result in significant future liabilities.

Brazilian federal and state governments may introduce new or more stringent environmental, climate change or emissions-related regulations applicable to resource extraction and industrial activities. Oil shale mining operations generally have higher energy intensity and greenhouse gas emissions per unit of output compared to conventional oil and gas production, which may increase exposure to future regulatory changes. Compliance with evolving regulatory standards could result in increased costs, operational constraints or reduced project economics.

See "Industry Conditions – Environmental Regulation". Questerre is in material compliance with current environmental laws. No assurance can be given that the application of environmental laws to the business and operations of the Company will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects.

Climate Change

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of greenhouse gases, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "Industry Conditions – Climate Change Regulation" for a summary of Canada's subsequent actions and pledges aimed at reducing Canada's greenhouse gas emissions and environmental impact. As discussed below, the Company faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as greenhouse gas emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of greenhouse gas emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in our profitability and a reduction in the value of our assets.

Claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including us, for alleged personal injury, property damage, or other potential liabilities. While the Company is not a party to any such litigation or proceedings, the Company could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of the Company's securities, impact the Company's operations and have an adverse impact on the Company's financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the financial community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to greenhouse gas-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to oil and natural gas and related infrastructure businesses and projects. The impact of such efforts require our management to dedicate significant time and resources to these climate change- related concerns, may adversely affect our operations, the demand for and price of our securities and may negatively impact our cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, in June 2023 the International Sustainability Standards Board ("ISSB") issued two new international environmental disclosure standards, IFRS S1 and S2, with the aim to develop environmental disclosure standards that are globally consistent, comparable and reliable; in December 2024 the Canadian Sustainability Standards Board ("CSSB") finalized substantially similar new Canadian Standards, CSDS 1 and CSDS 2. The Canadian Securities Administrators which had previously published for comment the Proposed National Instrument 51-107 – Disclosure of Climate-Related Matters intends to incorporate the Canadian Standards into new climate-related disclosure requirements for reporting issuers in Canada. If the Company is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, the business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. As a result of its listing on the Oslo Stock Exchange, the Company is also subject to related reporting requirements including the Corporate Sustainability Reporting Directive that was enacted in January 2023 by the European Union. See "Industry Conditions – Climate Change Regulation".

Physical risks

Based on the Company's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. The Company does not conduct fundamental research regarding the scientific inquiry of climate change, but it does stay abreast of the scientific literature on the subject. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Company's ability to access the Company's properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Company's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Company's assets or cause disruptions to the production and transport of the Company's products or the delivery of goods and services in the Company's supply chain.

Fiscal and Royalty Regime

In addition to federal regulation, each province has legislation and regulations which govern land tenure, drilling and construction permits, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, commodity prices, geographical location, field discovery data and the type or quality of the petroleum product produced.

The royalty regime in Alberta and any other jurisdictions in which the Company's oil and natural gas assets are located, including Quebec, may be subject to further review and changes which could adversely impact the Company's financial condition and operations and make future capital investments less economic. For recent changes see "Industry Conditions - Provincial Royalties and Incentives" in this AIF.

The Company's Brazilian operations are subject to federal, state and municipal taxes, royalties and other levies, which may be amended through legislative, regulatory or administrative action. In addition, Brazil has recently enacted tax reforms and introduced a withholding tax on dividends. Changes in tax laws, royalty rates, fiscal incentives or interpretations by tax authorities could increase the Company's tax burden or reduce after-tax cash flows.

Impact of Future Financings on Market Price

In order to finance future operations or acquisitions opportunities, the Company may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Company cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Company's securities will have on the market price of the Common Shares.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing, transportation, infrastructure and mergers and acquisitions) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. See "Industry Conditions" for further information. These controls and regulations may change from time to time and Questerre's compliance with current and proposed

regulations could have a material adverse impact by substantially increasing its capital expenditures and compliance costs.

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Indigenous consultation, environmental impact assessments, and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. See "Industry Conditions – Production and Operation Regulations" in this AIF.

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Company's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Insurance

Questerre's involvement in the exploration and development of oil and gas properties may result in Questerre becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Questerre will obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Questerre may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to Questerre. The occurrence of a significant event that Questerre is not fully insured against, the Company's inability to obtain insurance coverage against one or more risks at acceptable premium rates or at all or the insolvency of the insurer of such event, could have a material adverse effect on Questerre's financial position, results of operations or prospects.

The Company's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the Company to decide to reduce or possibly eliminate coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the Company's overall risk exposure could be increased and the Company could incur significant costs.

Project Risks

The Company will manage and participate in a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Quebec is a relatively new area for oil and gas development and therefore specialized support services are not locally available. Project cost estimates may not be accurate due to a lack of history of comparable projects. Furthermore, significant project cost over-runs could make a project uneconomic. Higher than expected costs could defer planned operations and set back the anticipated timeline for project development.

The Company's ability to execute projects and market oil, natural gas and NGLs will depend upon numerous factors beyond the Company's control, including: the availability of processing capacity; the availability and

proximity of transportation infrastructure, including pipeline capacity; the availability of storage capacity; the supply of and demand for oil and natural gas; the availability of alternative fuel sources; the effects of inclement weather; the availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; changes in regulations; the availability and productivity of skilled labour; environmental and Indigenous activism or land claims that potentially result in delays or cancellation of projects; litigation and judicial interpretation and application of laws, including with respect to Indigenous rights and historical treaties; and the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

On August 23, 2022, the Government of Quebec enacted Bill 21, An Act mainly to end petroleum exploration and production and the public financing of those activities. Bill 21 revokes petroleum exploration and production licenses, including the 16 exploration licenses held by the Company. It provides that the Government must establish a compensation program pertaining to the revocation of licenses. The Act requires, in particular, the holders of revoked licenses 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 (Quebec), 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. See "Quebec Assets" above.

If the Company's funds flow and funds from external financing sources are not sufficient to cover the capital expenditure requirements, The Company may be required to reallocate available capital among its projects or modify its capital expenditure plans, which may result in delays to, or cancellation or, certain projects or deferral of certain capital expenditures. Any change to the Company's capital expenditure plans could, in turn, have a material adverse effect on the Company's growth objectives and business, financial position and results of operations.

Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

Questerre will actively compete for acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Questerre. Questerre's competitors will include major integrated oil and natural gas companies, numerous other independent oil and natural gas companies and individual producers and operators.

The oil and natural gas industry is highly competitive. Questerre's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities include companies that have greater financial and personnel resources available to them than Questerre.

Questerre's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers, will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Competition may also be presented by alternate fuel sources, additional discoveries of hydrocarbon reserves by the Company's competitors, the cost of production and political and economic factors and other factors outside the Company's control.

Title

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Questerre will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. However, no absolute assurances can be given that title defects do not exist. If title defects do exist, it is possible that Questerre may lose all or a portion of its right, title and interest in and to the properties to which the title defects relate.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs resources, reserves and cash flows to be derived therefrom, including many factors beyond the Company's control. In estimating reserves, the chance of commerciality is effectively 100%.

The reserve and associated cash flow information and estimates represent estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon several variable factors and assumptions, such as commodity prices, historical production from the properties, production rates, and estimated production decline rates, estimated ultimate reserve recovery, changes in technology, timing, amount and effectiveness of future capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods may be less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

Actual future net revenue from the Company's assets will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and revenues derived therefrom will vary from the estimates, and such variations could be material.

Each of the McDaniel Report and the GLJ Ltd. Report are effective as of a specific date and has not been updated and thus does not reflect changes in Questerre's reserves since that date.

Reserve Replacement

Questerre's future oil and natural gas reserves, production and cash flows to be derived therefrom are highly dependent on Questerre successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Questerre may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Questerre's reserves will

depend not only on Questerre's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Questerre's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Capital Markets

As a result of global economic conditions, the Company may have restricted access to capital, bank debt and equity and is likely to face increased borrowing costs. Irrespective of whether the Company's business and asset base change materially, the lending capacity of many financial institutions has diminished, and risk premiums have increased in recent years. As future capital expenditures will be financed out of cash flow from operations, current cash balances, 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 in the Company's securities.

To the extent that external sources of capital become limited or unavailable or available 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 as a result.

Based on current funds available, expected adjusted funds flow from operations and available conventional debt capacity, 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 of or production on the Company's properties. Any properties not proven before expiry will not be available for production leases.

Operational Dependence

Other companies operate some of the assets in which Questerre has an interest. As a result, Questerre will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Questerre's financial performance. Questerre's return on assets operated by others will therefore depend upon multiple factors that may be outside of Questerre's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Company has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner, and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Company has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Company may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Company potentially becoming subject to additional liabilities relating to such assets and the Company having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect the Company's financial and operational results.

Key Employees

The success of Questerre will be largely dependent upon the performance of its management and key employees. Questerre does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Questerre.

Any inability on the part of the Company to attract and retain qualified personnel may delay or interrupt the exploration for, and development and production of, oil and natural gas with respect to the Company's assets. Sustained delays or interruptions could have a material adverse effect on the financial condition and performance of the Company. In addition, rising personnel costs would adversely impact the costs associated with the exploration for, and development and production of, oil and natural gas in respect of the Company's assets, which could be significant and material.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to adequately handle this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licenses and Leases

The Company's properties are held in the form of licenses and leases and working interests in licenses and leases. If the Company or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of the Company's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Company's results of operations and business.

Brazil has an active judicial system in which environmental, land use, Indigenous rights, labour and administrative matters are frequently contested. Licences, permits or approvals granted to the Company may be challenged before administrative tribunals or courts by third parties, including community groups, non-governmental organizations or public prosecutors. Legal proceedings or injunctions could delay or suspend operations, increase costs or result in additional compliance obligations.

Permits and Licenses

The operations of Questerre may require licenses and permits from various governmental authorities. There can be no assurance that Questerre will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its properties. Further, if the Company or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of the Company's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Bitumen and oil shale mining requires access to surface lands for mining, processing facilities, waste disposal and infrastructure. Although concession contracts grant subsurface hydrocarbon rights, surface land access may require agreements with landowners and compliance with land use restrictions. Disputes regarding land access, compensation or surface disturbance may result in operational delays, increased costs or litigation.

Variations in Foreign Exchange Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar and Brazilian Reals/United States dollar exchange rates, which fluctuate over time, consequently, affects the price received by Canadian and Brazilian producers of oil and natural gas. Material increases in the value of the Canadian dollar and/or Brazilian Reals relative to the United States dollar will negatively affect the Company's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Company's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Company receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Company's operations, which may have a negative impact on the Company's financial results.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares of the Company.

With respect to revenues, although the revenues in Brazil are linked to USD benchmark prices, actual invoices for such sales are denominated in R\$, exposing the Company to foreign currency risk.

Credit Facility

The amount authorized under the Company's credit agreement governing the Credit Facility is dependent on the borrowing base determined by its lender. The lender uses the Company's reserves, commodity prices, and other factors, to periodically determine the Company's borrowing base. Lower commodity prices could result in a reduction to the Company's borrowing base, reducing the funds available to the Company under the Credit Facility. This could result in the requirement to repay a portion, or all, of the Company's indebtedness.

The Company is required to comply with certain non-financial covenants under the Credit Facility and in the event that it does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to its failure to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, which could result in the Company being required to repay amounts owing thereunder.

In addition, the Credit Facility may impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to its securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

If the Company's lenders require repayment of all or a portion of the amounts outstanding under the Credit Facility for any reason, including for a default of a covenant, or the reduction of a borrowing base, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under the Credit Facility, it may not be on commercially reasonable terms, or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under its Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

From time to time Questerre may enter into transactions to acquire assets or the shares of other Company's. These transactions may be financed partially or wholly with debt, which may increase Questerre's debt levels above industry standards. Neither Questerre's articles nor its bylaws limit the amount of indebtedness that Questerre may incur. The level of Questerre's indebtedness from time to time could impair Questerre's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Questerre's ability to meet its debt service obligations will depend on Questerre's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Questerre. As certain of the indebtedness of Questerre would bear interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Questerre's interest payment obligations and could have a material adverse effect on Questerre's financial condition and results of operations. Further, Questerre's indebtedness would be secured by substantially all Questerre's assets. In the event of a violation by Questerre of any of its loan covenants or any other default by Questerre on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on Questerre's assets. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Hedging

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production, which is intended to mitigate the effect of commodity price volatility and support the Company's capital budgeting and expenditure plans; however, if commodity prices increase beyond the levels set in such agreements, the Company may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk.

In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

On the other hand, failure to protect against a decline in commodity prices exposes the Company to reduced liquidity when prices decline. A sustained lower commodity price environment would result in lower realized prices for unprotected volumes and reduce the prices at which the Company would enter into derivative contracts on future volumes. This could make such transactions unattractive, and, as a result, some or all of the Company's production volumes forecasted for the current fiscal year and beyond may not be protected by derivative arrangements.

Liability Management

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities, and pipelines in the event a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed

liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Company's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with the Company's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "Industry Conditions - *Liability Management Rating Programs*".

Access Restrictions

The Company's business depends, in part, upon the ability to access its lands to operate, as well as the availability, proximity, and capacity of oil and natural gas gathering systems, pipelines and/or rail transportation systems and processing facilities to provide access to markets for its production. Federal and provincial, regulation of oil and natural gas production and processing and transportation could adversely affect the Company's ability to produce and market oil, natural gas and NGLs. Special interest groups could prevent access to leased land or oppose infrastructure development, resulting in operational delays, or even cancellation of construction of the required infrastructure, both of which frustrate the Company's ability to operate, produce and market its products or restrict shipping of commodities by truck, pipeline or rail.

Availability of Drilling Equipment Access Restrictions

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such equipment may exceed supply thereof and may affect the availability of such equipment to Questerre and may delay the Company's exploration and development activities.

Brazilian concession contracts impose local content requirements relating to goods and services. Oil shale mining operations may require specialized industrial equipment or technologies that are not widely manufactured domestically. Difficulties in sourcing compliant local content, changes in local content measurement rules, or penalties for non-compliance could adversely affect project economics.

Oil shale extraction and processing rely on specialized technologies and industrial processes. Operational underperformance, equipment failures, unplanned maintenance or the inability to optimize processing efficiency could reduce production volumes, increase operating costs or adversely affect recovery rates. The Company may also face challenges in retaining or replacing personnel with specialized technical expertise.

Indigenous Claims

Opposition by Indigenous groups to the conduct of the Company's operations, development or exploratory activities in any of the jurisdictions in which the Company conducts business may negatively impact the Company in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact the Company's progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. It is possible that lands on which the Company operates are, or could in the future become, subject to Indigenous and treaty rights claims (including Indigenous title claims). Any such claims could have a material adverse impact on the Company's ability to operate on such lands when the Company otherwise intends to or at all, which could in turn have a material adverse impact on the Company's financial condition, results of operations and/or growth plans.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Company's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals.

For example, regulatory authorities in British Columbia ceased granting approvals, and, in some cases, revoked existing approvals, for, among other things crude oil and natural gas activities relating to drilling, completions, testing, production, and transportation infrastructure following a British Columbia Supreme Court decision that the cumulative impacts of government-sanctioned industrial development on the traditional territories of a Indigenous group in northeast British Columbia breached that group's treaty rights. Following that decision, the Government of British Columbia signed an implementation agreement with that Indigenous group to address cumulative effects of development on that group's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. These measures, which are expected to form the basis of similar arrangements with other Indigenous groups in British Columbia, are expected to remain in place while a long-term cumulative effects management regime is implemented. While the Company believes that the regulatory authorities will resume granting and reinstate approvals for oil and natural gas activities on time frames and terms and conditions consistent with past practice, the long-term impacts of, and associated risks with the decision and arrangements with Indigenous groups to address the cumulative effects of development on claimed lands on the Canadian oil and natural gas industry and the Company remain uncertain.

In addition, the federal government has introduced legislation to implement the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See "Industry Conditions – Indigenous Rights".

Geopolitical Risks

The marketability and price of oil and natural gas that may be acquired or discovered by Questerre is and will continue to be affected by political events throughout the world that cause disruptions to the supply of oil. Geopolitical developments in the Middle East and other areas of the world can have a significant impact on the price of oil and natural gas. Any event could result in a material decline in prices and therefore result in a reduction of Questerre's net production revenue.

In addition, Questerre's expected oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of Questerre's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Questerre. Questerre does not have insurance to protect against the risk from terrorism.

Conflicts of Interest

Directors and officers of Questerre may also be directors and officers of other companies involved in oil and gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of Questerre and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to, such other procedures and remedies as apply under the ABCA.

Dilution

Questerre may make future acquisitions or be involved in financings or other transactions involving the issuance of securities of Questerre which may be dilutive to existing holders of Common Shares and/or Series2 Preferred Shares.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing infrastructure are in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Company's exploration and development activities, which could in turn have a material adverse impact on the Company's business, operations and prospects.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing has resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. Any new laws, regulations, or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third-party or governmental claims, and could increase the Company's costs of compliance and doing business, as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions or bans on hydraulic fracturing in the areas where the Company operates could result in it being unable to economically recover its oil and gas reserves and reserves, which would result in a significant decrease in the value of the Company's assets.

Water is an essential component of the Company's drilling and hydraulic fracturing processes. Limitations or restrictions on the Company's ability to secure enough water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Company is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on the Company's financial condition, results of operations, and cash from operating activities.

In addition, the Company must dispose of the fluids produced from oil and natural gas production operations, including produced water, which it does directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

Government authorities may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Company or by commercial disposal well vendors that it may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity

could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Company or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Company or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Company's business, financial condition, and results of operations. In September 2018, MERN enacted the final hydrocarbon Regulations in Quebec, including restrictions on oil and gas activities, specifically the prohibition of hydraulic fracturing of shale and increasing setbacks for activity from urbanized areas and bodies of water.

Third Party Credit Risk

The Company is, or may be, exposed to third party credit risk through contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Company may be exposed to third party credit risk from operators of properties in which the Company has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company and its cash flow from operations. In addition, poor credit conditions in the oil and natural gas industry and consequently of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying aspects of the program and the Company's anticipated results thereof until the Company is able to find a suitable alternative partner, if at all. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's financial and operational results.

Dividends are Discretionary

The Company is not obligated to pay dividends on the Common Shares. The payment of dividends is at the sole discretion of the Company's board of directors, and it may decide to eliminate or reduce any dividends paid on the Common Shares or retain cash otherwise available for dividends for investment in our business. In addition, certain of its agreements may restrict its ability to pay dividends, and thus the Company's ability to pay dividends on its Common Shares will depend on, among other things, the Company's level of indebtedness at the time of the proposed dividend and whether it is in compliance with such agreements. Any reduction or elimination of dividends could cause the market price of the Common Shares to decline and could further cause the Common Shares to become less liquid, which may result in losses to shareholders.

For a description of the dividend rights attributable to the Series 2 Preferred Shares, see "Description of Share Capital – Preferred Shares – Series 2 Preferred Shares – Dividend Rights" below

Future Sales of Common Shares and Series 2 Preferred Shares

The Company may issue additional Common Shares and/or Series 2 Preferred Shares in the future, which may dilute a shareholder's holdings in the Company. The Company's articles permit the issuance of an unlimited number of Common Shares, Class B Shares (as defined herein) and Preferred Shares (as defined herein), and shareholders will have no pre-emptive rights in connection with such further issuances. The directors of the Company have the discretion to determine the provisions attaching to any series of Preferred Shares and the price and the terms of issue of further issuances of Common Shares or Class B Shares. Also, additional Common Shares and/or Series 2 Preferred Shares may be issued by the Company on the exercise of stock options issued under the Company's stock option plan.

Emission Regulation

The Company's exploration and production facilities and other operations and activities emit greenhouse gases ("GHGs") and require them to comply with GHG emissions legislation in force in those provinces and states in which it operates or that may be enacted in provinces and states in which it operates. The Company and its customers may also be required to comply with the regulatory schemes for GHG emissions ultimately adopted by the federal governments in Canada and the United States. See "Industry Conditions – Environmental Regulation and Climate Change Regulation" in this AIF.

Technology

While the Company has not licensed the technology to date, the commercial scalability of Red Leaf's process has not been demonstrated and is therefore unproven commercial technology relative to oil shale extraction. There can be no assurance that the process will perform as expected, at scale, or that the costs to construct or operate the technology will not be significantly higher than anticipated.

Possible Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

As part of its ongoing strategy, the Company may complete acquisitions of assets or other entities in the future. Achieving the benefits of completed and future acquisitions depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses and entities requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships and deficiencies in internal controls or information technology controls, that may adversely affect the Company's ability to achieve the anticipated benefits of any acquisitions. In addition, non-core assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, may realize less than their carrying value on the financial statements of the Company.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company. There can be no assurance that the Company will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Company or implemented in the future may become obsolete. In such a case, the Company's business, financial condition, and results of operations and cash flows could be materially adversely affected. If the Company is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

Risks Associated with Interests in Brazil

Changes in government may alter the level of support for oil and gas activities, potentially resulting in revisions to existing oil and gas regulations in Brazil or to tax or other laws that could adversely affect the Company. There can be no certainty as to the outcome of any resulting change in regulations or laws within Brazil. Additional uncertainties that can apply to developing countries include, but are not limited to, changes in energy

and environmental policies and the administration of such, social instability, corruption, revolution, border disputes, expropriation or nationalization of assets without fair compensation or marketable compensation, renegotiations or modification of existing contracts, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, limits on allowable levels of production, currency exchange controls, labour disputes and other uncertainties arising out of foreign government sovereignty over the Company's operations in Brazil. The Company's operations may also be adversely affected by changes in applicable laws and policies of Brazil, which could have a negative impact on Company.

The Company's international and Canadian operations may also be adversely affected by laws and policies of Canada, including as they pertain to oil and gas development, foreign trade, taxation and investment or political relations with Brazil and imposed economic sanctions.

Income tax and other tax laws affecting the Company may change in the future or be interpreted in a manner that adversely affects the Company. In 2025, Brazil introduced a new 10% withholding tax on dividends effective January 1, 2026 which will result in additional taxes in the future on any dividends paid by our Brazilian subsidiary to Canada. While there are no restrictions or taxes owing on any repatriations of capital, the new withholding tax on dividends will result in increased costs to the Company. Changes in foreign exchange regulations, further restrictions on repatriation of funds from Brazil or the imposition of additional income taxes, withholding or other taxes on repatriations may adversely affect the Company's ability to obtain cash from its Brazil subsidiaries to meet obligations within Canada, including the payment of dividends. The impact on future cash flows may be material.

The majority of the Company's operations are conducted in Portuguese and the Company may enter into significant contracts in Portuguese which may give rise to uncertainties. The Company manages this risk through the employment and involvement of qualified personnel within Brazil in all local operations. The majority of personnel in Brazil belong to a labour union which has defined requirements with respect to compensation and benefits for employees. Although this has not been an issue for PX Energy, an employee strike could cause disruption of PX Energy's operations and have an adverse financial impact.

Risks Associated with Interests in Jordan

Certain of Questerre's assets and operations are located in Jordan. Political, economic, legal and social conditions in Jordan, as well as in the Middle East (including Turkey) and surrounding areas could materially and adversely affect Questerre's business as it is subject to political, economic and other uncertainties that are not within its control. These include, but are not limited to, the uncertainty of negotiating with foreign governments, changes in government policies and legislation, adverse legislation or determinations or rulings by governmental authorities, currency fluctuations, currency devaluations, currency controls, high inflation, disputes between various levels of authorities, arbitrating and enforcing claims against entities that may claim sovereignty, authorities claiming jurisdiction, potential implementation of exchange controls and/or royalty regimes and increases in the government's share and other risks arising out of Jordanian sovereignty over Questerre's Jordanian assets.

Questerre's operations may also be adversely affected by social instability, changes in crude oil or natural gas pricing policy (or in the personnel administering such policy), availability of oil transport infrastructure, availability of Jordanian pipeline export infrastructure, the necessary political approvals, finding acceptable gas conservation solutions, the risks of war, terrorism, guerrilla activities, insurrections, border disputes, military repression, civil disorder, crime, abduction, expropriation of property without fair compensation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, economic or other sanctions (imposed by other countries or regions), the imposition of specific drilling obligations, oil export or pipeline restrictions and the development and abandonment of fields.

While Jordan has historically been regarded as relatively stable compared to other countries in the region, the evolving geopolitical environment in the Middle East, including conflicts in neighboring jurisdictions, tensions involving regional and extra-regional actors, and the potential for escalation or spillover effects, may increase security, operational and compliance risks. There can be no assurance that regional instability, including acts of terrorism or other security incidents, will not adversely impact Jordan or the Company's operations therein.

The threat of terrorism and politically motivated violence remains a risk in the region. Transnational and domestic extremist or militant groups have, from time to time, demonstrated the capability to plan and conduct attacks in Jordan and neighboring countries. Heightened regional tensions, including those related to ongoing conflicts and shifting security dynamics, may increase the risk of terrorist or criminal actions, civil unrest or other security-related disruptions within Jordan.

Any such events could result in delays or interruptions to operations, increased security or compliance costs, damage to assets or third-party infrastructure, constraints on the availability of contractors, service providers or skilled personnel, or, in extreme circumstances, the loss of operating control or limitations on the Company's ability to extract, transport or sell hydrocarbons. Any of these outcomes could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Companies operating in countries such as Jordan may be targets for criminal or terrorist actions including those of ISIS. Criminal or terrorist action against Questerre, its properties or facilities or third-party infrastructure, could have a material adverse effect on the Company's business, results of operations and financial condition. In addition, the possible threat of criminal or terrorist actions against it could have a material adverse effect on the ability of Questerre to adequately staff its operations or could materially increase the costs of doing so.

Furthermore, Questerre is exposed to the risk of a change in government relations.

Although Questerre has good relations with the Government of Jordan, there can be no assurance that the actions of present or future governments will not materially adversely affect the business or financial condition of Questerre. Questerre and its co-venturers may be unable to obtain or renew required drilling rights, licenses, permits and other authorizations and/or such rights, licenses, permits and other authorizations may be suspended, terminated or revoked prior to their expiration.

Any significant delay in obtaining or renewing a license, permit or other authorization including approval of development plans, may result in a delay of the Company's planned activities in Jordan and the future development of any associated oil and gas resources. In addition, any of Questerre's existing and future drilling rights and licenses, permits and other authorizations may be suspended, terminated or revoked if Questerre fails to comply with the relevant requirements of the Government of Jordan and its agencies. If Questerre or its co-ventures' fail to fulfill the specific terms of any of its existing or future rights, licenses, permits and other authorizations or operates its business in a manner that violates applicable law in Jordan, government regulators may impose fines or suspend or terminate the relevant right, license, permit or other authorization, any of which could have a material adverse effect on the value of Questerre's assets in Jordan.

Tax Matters

It is expected, based upon current legislation, the projections contained in the McDaniel Report, the GLJ Report and various other assumptions that no cash income taxes are to be paid by Questerre in the near future. A lower level of capital expenditures than those contained in the McDaniel Report or the GLJ Report or should the assumptions of Questerre in respect thereof prove to be inaccurate, Questerre may be required to pay cash income taxes sooner than anticipated, which could materially reduce cash flow available to Questerre.

The taxation of corporations is complex. In the ordinary course of business, Questerre may be subject to ongoing audits by tax authorities. While Questerre believes that its tax filing positions are appropriate and

supportable, it is possible that tax matters, including the calculation and determination of revenue, expenditures, deductions, credits and other tax attributes, taxable income and taxes payable, may be reviewed and challenged by the tax authorities. In addition, the previous tax filing positions of businesses acquired by Questerre may be reviewed and challenged by tax authorities. If such challenge were to succeed, it could have a material adverse effect on Questerre's tax position. Further, the interpretation of and changes in tax laws, whether by legislative or judicial action or decision, and the administrative policies and assessing practices of taxation authorities, could have a material adverse effect on Questerre's tax position.

Internal Controls

Effective internal controls are necessary for Questerre to provide reliable financial reports and to help prevent fraud. Although Questerre undertakes several procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, Questerre cannot be certain that such measures will ensure that Questerre will maintain adequate control over financial processes and reporting.

Failure to implement the required new or improved controls, or difficulties encountered in their implementation, could harm Questerre's results of operations or cause it to fail to meet its reporting obligations. If Questerre or its independent auditors discover a material weakness in such controls, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in Questerre's financial statements and materially reduce the market price of the Common Shares.

Litigation

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, securities laws matters, employment matters, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of the Company. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's business from a breach of confidentiality cannot presently be quantified but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Volatility of Market Price of Common Shares

The market price of the Common Shares may be volatile. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Market price fluctuations in the Common Shares may be due to the Company's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Company or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "Forward Looking Statements and Information May Prove Inaccurate" in this

AIF. In addition, the market price for securities in the stock markets, including the TSX, has recently experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that are often unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares.

Information Technology Systems and Cyber-Security

The Company relies heavily on information technology, such as computer hardware and software systems, to properly operate its business. In the event the Company is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data, compromise confidential customer or employee information, result in the disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage. In addition, information systems could be damaged or interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on the Company's business, financial condition, results of operations and cash flows.

In the ordinary course of business, the Company collects, uses and stores sensitive data, including intellectual property, proprietary business information and personal information of the Company's employees and third parties. Despite the Company's security measures, its information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions. Any such breach could compromise information used or stored on the Company's systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties or other negative consequences, including disruption to the Company's operations and damage to its reputation, which could have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course of operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to business activities, or the Company's competitive position. In addition, cyber-phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, credit card and banking details, or approval of wire transfer requests by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. Increasingly, social media is used as a vehicle to carry out cyber-phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to penetrate the Company's systems and obtain confidential information. As social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Company may not be able to properly regulate social media use and preserve adequate records of business activities. If the Company becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber-phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the

email or request recipients to send a password or other confidential information through email or to download malware.

To date the Company has not experienced any material losses relating to cyber-attacks or other information security breaches. However, there can be no assurance that the Company will not incur such losses in the future. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties or other negative consequences, including disruption to the Company's operations and damage to its reputation, which could have a material adverse effect on the Company's business, financial condition, results of operations and cash flows. Although the Company maintains a risk management program, it does not include an insurance component that provides coverage for the operational impacts from an attack to, or breach of, Questerre's information technology and infrastructure, including process control systems.

Additionally, the Company's information technology systems may incorporate the use of artificial intelligence ("AI") and development of such capabilities remain ongoing. As with new innovations, AI presents risks, challenges and unintended consequences that could affect its adoption, and therefore the Company's business. AI algorithms and training methodologies may be flawed. The use of AI to support business operations of the Company, its partners, vendors, suppliers, contractors, or others carries inherent risks related to data privacy and cybersecurity, such as intended, unintended, or inadvertent transmission of proprietary or sensitive information, as well as challenges related to implementing and maintaining AI tools, including the development and maintenance of appropriate datasets for such support. Dependence on AI without adequate safeguards to make certain business decisions may introduce additional operational vulnerabilities, by producing inaccurate outcomes based on flaws or deficiencies in the underlying data or other unintended results. Further, AI tools or software may rely on data sets to produce derivative work which may contain content subject to license, copyright, patent or trademark protection or sensitive personal information and can produce outputs that infringe intellectual property rights or compromise privacy of individuals or organizations, raising concerns about data privacy. As AI is an emerging technology for which the legal and regulatory landscape is not fully developed, including potential liability for breaching intellectual property or privacy rights or laws, new laws and regulations applicable to AI initiatives remains uncertain, and the Company's obligation to comply with such laws could entail significant costs, negatively affect the Company's business or limit the Company's ability to incorporate certain AI capabilities into the Company's operations.

Firm Commitment Transportation and Processing Arrangements

The Company may be unable to satisfy its obligations under its firm commitment transportation and processing arrangements. If this occurs, the Company will be required to satisfy the financial obligations under such firm commitment transportation and processing arrangements and, as a result, will incur the notional cost of transporting volumes of oil, NGLs and/or natural gas that exceed the Company's production, which would adversely affect its financial condition.

Inflation and Cost Management

The Company's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash from operating activities. The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects, and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the

services and equipment necessary to the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and cash from operating activities.

Reputation Risk

The Company relies on its reputation to build and maintain positive relationships with stakeholders, to recruit and retain staff, and to be a credible trusted company. Any actions that Questerre takes that causes a negative public opinion has the potential to negatively impact the Company's reputation which may adversely impact its share price, development plans or its ability to continue operations.

Forward-Looking Statements and Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking statements and information. By its nature, forward-looking statements and information involve numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties related to forward-looking statements and information are found under the heading "Forward-Looking Statements" in this AIF.

INDUSTRY CONDITIONS

Brazil

Brazil, located on the east coast of South America, is a federal republic characterized by a large and growing domestic market, a diversified economy and a significant oil and natural gas industry. Brazil has a population of approximately 218 million and is the world's eleventh largest economy. As at 2024, Brazil had proven oil reserves of approximately 17 billion barrels and proven natural gas reserves of approximately 17 trillion cubic feet, as reported by the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis ("**ANP**"), the National Agency of Petroleum, Natural Gas and Biofuels, an agency of the Brazilian government. The growth of Brazil's hydrocarbon sector reflects continued exploration success and a regulatory framework that permits private investment.

Hydrocarbon exploration in Brazil began in the 1930s, with the first commercial discovery occurring in 1939 in the Recôncavo Basin in the State of Bahia. Substantial growth in production did not occur until the late 1970s, when Petróleo Brasileiro S.A. ("**Petrobras**"), the state-owned oil company, expanded operations offshore. In the Campos Basin, a series of deep-water discoveries were made during the 1980s and 1990s. Subsequent discoveries of the "pre-salt" reservoirs—located beneath extensive salt layers—in the Santos Basin have become the principal focus of Brazil's offshore hydrocarbon development and have been a key factor in Brazil's emergence as a significant oil exporter.

In addition to pre-salt offshore resources, Brazil also offers opportunities beyond conventional shallow- and deep-water prospects, including mature onshore and coastal basins that have not yet benefited from next-generation exploration and development technologies. Onshore basin opportunities include new exploration models, unconventional or tight oil and gas plays, and enhanced recovery techniques applied to existing accumulations.

Certain onshore hydrocarbon activities in Brazil, including the extraction of hydrocarbons from oil shale or bituminous rock through surface mining and retorting processes, differ operationally and regulatorily from conventional oil and natural gas exploration and production. These activities are often referred to in Brazil as

“xisto” or oil shale operations and may be subject to overlapping oil and gas, mining and environmental regulatory regimes.

Brazil - Hydrocarbon Law & Concessions Regime

Until 1995, oil and gas activities in Brazil were monopolized by Petrobras. Constitutional Amendment No. 09 (1995) modified this monopoly by permitting the Brazilian government to contract with state-owned and private entities to conduct various oil and gas activities. This framework is primarily governed by Federal Law No. 9,478 of 1997 (the “**Petroleum Law**”).

Under the concession regime established by the Petroleum Law, the ANP has conducted 17 bidding rounds, as well as open acreage auctions under the Permanent Offer System, to grant concession contracts for onshore and offshore exploration and production blocks. These concession contracts (each, a “**Concession Contract**”) confer exclusive exploration and production rights, subject to compliance with contractual and regulatory requirements.

In addition to the concession regime, Brazilian legislation has established a production sharing contract regime, which applies to the licensing of defined pre-salt areas and certain other areas designated by the federal government as strategic. The Company’s exploration and production rights are governed exclusively by the concession regime.

Although the Company’s exploration and production rights are governed by concession contracts issued pursuant to the Petroleum Law, oil shale and bitumen mining activities may also engage regulatory concepts typically associated with mining operations, including surface land use, waste disposal and industrial processing regulation.

Regulatory Authorities

Oil and gas activities in Brazil are primarily regulated by the following authorities:

- Conselho Nacional de Política Energética (“**CNPE**”) – the National Council of Energy Policy, responsible for establishing guidelines for national energy policy, fostering the rational use of energy resources, and ensuring the proper functioning of Brazil’s energy framework;
- Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (“**ANP**”) – the national regulatory agency responsible for regulating, **contracting** and supervising activities relating to oil, natural gas and biofuels, and for establishing applicable technical and operational standards; and
- Ministério de Minas e Energia (“**MME**”) – the Ministry of Mines and Energy, responsible for formulating public policies and promoting investment in mining and energy activities.

Environmental regulation is also applicable to oil and gas activities, and certain environmental licences and permits are required. Depending on the nature of the activity, licensing may be regulated at the federal or state level. In the State of Bahia, where the Company operates, environmental licensing for oil and gas activities is overseen by the Instituto do Meio Ambiente e Recursos Hídricos (“**INEMA**”).

Oil shale and bitumen mining activities are subject to enhanced environmental scrutiny due to the surface-based nature of extraction, the generation of spent shale and tailings, water consumption, and associated industrial processing. Environmental licensing typically requires the issuance of preliminary, installation and operating licenses and may impose detailed conditions relating to waste management, water use, emissions, reclamation and long-term monitoring.

Concession Regime – Exploration and Production Phases

Under the concession regime, oil and gas blocks are awarded through bidding rounds and open acreage auctions conducted by the ANP. The ANP determines which blocks are offered and publishes the applicable tender documentation, which specifies the technical, legal and financial qualification requirements for participation.

Bid evaluation criteria include the signature bonus, the minimum exploration program, and local content commitments. Federal, state and municipal governments receive revenues through government takes, which consist of:

- Signature Bonus – a lump-sum payment due upon execution of the concession contract;
- Royalties – monthly payments based on production volumes;
- Special Participation – extraordinary compensation payable in cases of high production volumes or high profitability; and
- Area Occupation or Retention Fees – annual payments for the occupation or retention of exploration areas.

Foreign investors may participate directly or indirectly in Brazilian oil and gas activities, provided they incorporate a Brazilian company with head office and management in Brazil and satisfy ANP qualification requirements. There are no statutory preference rules favouring domestic participants.

Concession operations are divided into an exploration phase and a development and production phase. For mature blocks, the exploration phase generally extends for five years, while frontier blocks may have terms of up to eight years. The Company's blocks have a five-year exploration term comprising two phases of three and two years, respectively. The minimum exploration program for the first phase consists of the work program bid during the auction, while the second phase typically requires the drilling of at least one exploration well.

If a hydrocarbon discovery is made, the concessionaire must notify the ANP and submit a Development Assessment Plan (“**PAD**”), which may include a request for a long-term production test. Upon completion of the assessment period, a Final Discovery Assessment Report is submitted, after which the concessionaire may declare commerciality. A Development Plan must be submitted within six months of the commerciality declaration. Once approved by the ANP, the concessionaire enters the development and production phase, which has a term of 27 years from the declaration of commerciality and may be extended with ANP approval. At the conclusion of the production term, abandonment and reclamation obligations must be fulfilled before the area reverts to the ANP.

Government Initiatives – Oil Shale (Xisto) Mining and Processing

The Incentive and Revitalization Program for Exploration and Production Activities (“**Potencializa E&P**”) is a federal initiative intended to support sustainable development of hydrocarbon resources, including oil shale mining and processing activities in frontier areas and projects with marginal or higher-cost economic profiles. In the context of oil shale, the program is aimed at encouraging private sector investment, revitalizing legacy mining and industrial assets, promoting the development and application of unconventional resource technologies, streamlining licensing and permitting processes, strengthening domestic supply chains, supporting emissions mitigation initiatives, and improving geological and technical understanding of Brazilian sedimentary basins containing oil shale resources, including the Paraná Basin.

Local Content Requirements

All concession contracts contain local content requirements established during the bidding process. Compliance is assessed at the end of each exploration or development phase. Failure to meet committed

levels may result in penalties imposed at the project or expenditure level. Concessionaires must submit quarterly local content reports to the ANP.

In 2018, the ANP introduced revised regulations reducing local content requirements for all blocks and fields held by the Company to 50%. As at December 31, 2025, the Company had not accrued or estimated any local content penalties.

Royalties, Taxes and Government Takes

Royalties are payable on the production of oil, condensate and natural gas. The standard royalty rate under the Petroleum Law is 10%, which may be reduced by the ANP to no less than 5% under certain circumstances. In 2018, the ANP introduced a mechanism permitting reduced royalty rates of up to 5% on incremental production from mature fields.

All of the Company's concession contracts were originally subject to a 10% royalty rate. In 2021, the ANP introduced reduced royalty rates for medium and small producers. The Company received approval to reduce the royalty rate applicable to the Mina de Xisto field to 7.5%, effective May 1, 2022.

Landowners are also entitled to royalties ranging from 0.5% to 1% of production, as determined by the ANP. The Company's concession contracts are subject to a landowner royalty of 1%. Certain third parties are entitled to a 2.5% gross overriding royalty on revenues from portions of the Mina de Xisto field, net of government royalties and revenue-based taxes.

Sales revenues are subject to federal social contributions (PIS and COFINS) at a combined rate of 9.25%. Natural gas revenues are also subject to state-level ICMS. In Bahia, the ICMS rate on natural gas is 12%. Under the Company's gas sales agreement, product prices are grossed up to account for these taxes. Applicable tax credits may offset amounts payable.

Brazil enacted comprehensive tax reform legislation in 2023, which will gradually replace existing federal, state and municipal consumption taxes with a dual value-added tax system by 2033. No immediate changes to tax rates or application were effective as at 2026.

Special Participation

Special participation is an extraordinary compensation payable on onshore fields that achieve high production volumes or profitability. Production below prescribed thresholds is exempt. Based on current forecasts, special participation is not expected to apply to the Company's reserves.

	M ³ /Quarter (in equivalent oil cubic metres)	boe/d	Special Participation
Year 1	450,000	31,450	(RLP – RLP*450/VPF)*SP%
Year 2	350,000	24,461	(RLP – RLP*350/VPF)*SP%
Year 3	250,000	17,472	(RLP – RLP*250/VPF)*SP%
Year 4 and thereafter	150,000	10,483	(RLP – RLP*150/VPF)*SP%

Where:

- (1) RLP is Net profit per quarter
- (2) VPF is production per quarter, measured in thousands of cubic metres of equivalent oil for each field
- (3) SP% is the applicable special participation rate between 10% and 40% depending on the quarterly production volume, increasing at higher levels of production.

The net profit corresponding to each field of a given concession area equals the gross revenue from production from the field deducting the corresponding amount of the royalties, exploration investments, operational costs, depreciation and taxes directly related to the field operations, that have been actually disbursed during the concession agreement term, until it is assessed, and which have been determined according to the ANP rules, all divided by the volume of production produced. For the purposes of the calculations described under this "Special Participation" section, all amounts are computed in R\$.

When the net profit of a determined field is negative, it may be offset against the calculation of the special participation owed for that same field, for the following quarters.

In case of fields which extend over two or more concession areas, the assessment of the special participation shall be based on the net profit and the total production volume of the fields.

Corporation Taxes

The Company is subject to Brazil's actual profit tax regime. The statutory corporate income tax rate is 34%. Tax losses may be carried forward indefinitely, subject to utilization limits.

Brazil implemented a 10% withholding tax on dividends effective January 1, 2026, which may affect future distributions from the Company's Brazilian subsidiary.

Canadian Government Regulation

The Canadian oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government all of which should be carefully considered by investors in the oil and gas industry. Outlined below are some of the more significant aspects of the relevant legislation and regulations.

Pricing and Marketing – Oil

Producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, price of competing oils, distance to market, the value of refined products, the supply/demand balance and contractual terms of sale.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of oil and gas from the region. Certain countries, including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near-term effects on Russia. The long-term impacts of the conflict remain uncertain.

Pricing and Marketing – Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon a producer's own arrangements (whether long or short-term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

Pricing and Marketing – Natural Gas Liquids

In Canada, the price of NGL sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such pricing depends, in part, on the quality of the NGL, prices of competing chemical feedstock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms.

Exports from Canada

On August 28, 2019, the *Canadian Energy Regulator Act* (Canada) (the “**CERA**”) came into force. The CER has assumed the NEB’s responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime. See “*Industry Conditions - Environmental Regulation – Federal*” in this AIF.

Exports of crude oil, natural gas and NGL from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the “**Part VI Regulation**”). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Company does not directly engage in contracts to export the Company’s production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under Canadian constitutional law, the development and operation of interprovincial and international pipelines fall within the federal government’s jurisdiction and, under CERA new interprovincial and international pipelines require a federal regulatory review and approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty in this regard, such that, even when projects are approved at a federal level, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government’s duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals from several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

The federal government has introduced the Building Canada Act and created the Major Projects Office (the "MPO") to help advance projects designated as being of national interest by coordinating federal regulatory processes. In addition, under a memorandum of understanding between the federal government and the Province of Alberta dated November 27, 2025 (the "Canada-Alberta MOU"), the federal government has expressed support for a proposed pipeline intended to transport low-emission bitumen to the northern British Columbia coast for export to Asian markets, subject to certain conditions being met by Alberta. Under the Canada-Alberta MOU, Alberta has committed to preparing and submitting an application for the proposed pipeline to the MPO by July 1, 2026.

The Trans Mountain Pipeline expansion received approval of the cabinet of the Canadian federal government in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Budget increases and in-service date delays have been attributed to, among other things, high global inflation, global supply chain challenges, widespread flooding in British Columbia in late 2021 and unexpected major archeological discoveries.

Construction of the Trans Mountain Pipeline expansion was completed in April 2024, and service began in May 2024. The original pipeline and the newly completed expansion now operate collectively. With the expansion completed, the system's nominal capacity increased from approximately 300,000 to 890,000 barrels per day, and the expansion included three new berths at Westridge Marine Terminal in British Columbia.

In 2021, the Biden administration in the U.S. revoked certain permits required for the construction of the Keystone X.L. pipeline, resulting in the projects cancellation by TC Energy.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, potentially forcing the lines comprising this segment of the pipeline system to be shut down by May 2021. Enbridge Inc. stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General intends to appeal the decision.

In September 2022, the District Court of Wisconsin ruled in favour of the Bad River Band in its dispute with Enbridge Inc. over the Enbridge Line 5 pipeline in that state. Stopping short of ordering the system to be shut down, the Court ruled that the Bad River Bend is entitled to financial compensation and ordered Enbridge Inc. to reroute the pipeline around Bad River territory within five years.

In December 2023, Michigan Public Service Commission approved Enbridge's Line 5 Tunnel Replacement Project. This approval begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straits of Mackinac. The pipeline will be housed within a concrete tunnel beneath the lakebed. The tunnel project must first be approved by the U.S. Army Corps of Engineers at the United

States federal level before construction can commence. The U.S. Army Corps of Engineers has initiated an environmental impact assessment, which is expected to be completed by 2026.

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system transporting crude oil.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. On November 26, 2021, the CER issued its Reasons for Decision in Enbridge Pipelines Inc. RH-001-2020, denying the application to introduce firm service on the Canadian Mainline. If approved, the application would have made 90% of the Canadian Mainline's currently uncommitted capacity subject to firm contracts for priority access, with contract terms ranging from eight to 20 years. Contracts for firm service were to be awarded through an open season process put forward as part of the application.

Crude Oil and Bitumen by Rail

In February 2020, the federal government announced that trains hauling more than 20 cars carrying crude oil or diluted bitumen, would be subject to reduced speed limits following two derailments that led to fires and oil spills in Saskatchewan. The orders were updated in April 2020 and were intended to remain in effect on an interim basis while Transport Canada worked with industry to develop permanent regulatory measures. Subsequent amendments to the Rules Respecting Key Trains and Key Routes and the Track Safety Rules have since been implemented, incorporating permanent safety enhancements related to train speeds, winter operations, and track inspection and maintenance.

Trade Agreements

The United States-Mexico-Canada Agreement ("**USMCA**") replaced the North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. Under the USMCA, energy export restrictions are no longer subject to the requirement that they do not reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36-month period. In addition, the USMCA includes a change to the rules of origin for crude oil that should make it easier for exporters to qualify for duty-free treatment on shipments to other USMCA parties. In particular, the origin of the diluent that is used to facilitate the transportation of crude petroleum oils is disregarded, provided that the diluent constitutes no more than 40 per cent by volume of the goods. The United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, therefore the implementation of the USMCA could impact Western Canada's oil and gas industry at large, including Questerre's business.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union ("**Brexit**") on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"). On December 9, 2020, the Government of Canada introduced Bill C-18, an Act to Implement the Trade Continuity Agreement. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021. The CUKTCA

replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

In addition, Canada and ten other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership (“**CPTPP**”) on March 8, 2018, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP has been ratified by seven countries, including Canada. As other countries ratify the agreement, they are added to the annexes. The CPTPP facilitates temporary entry to Canada for certain categories of business persons who are citizens of other countries which are signatories to the CPTPP.

In August 2023, an updated version of the Canadian Free Trade Agreement was published, aiming to revamp the Agreement on International Trade to create a more robust and equitable trade environment within Canada.

Recent developments in U.S.-Canada trade relations have increased uncertainty regarding the stability of the USMCA. In light of the evolving nature of U.S.-Canada trade relations and the potential for policy shifts, there is no assurance that the current trade framework will remain in place or that future negotiations will result in favorable terms for the Canadian energy sector. Furthermore, a renegotiation of USMCA which is anticipated to begin in July 2026, old result in terms that are unfavorable to Canadian energy exports could result in increased tariffs, quotas, or regulatory barriers, in turn reducing market access which could negatively affect the Company’s business.

While it is uncertain what effect CETA, CPTPP, CUKTCA or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Extractive Sector Transparency Measures Act

The Extractive Sector Transparency Measures Act (“**ESTMA**”), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state-owned entities, made by Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state-owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds \$100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Failure to comply with the reporting obligations under ESTMA are punishable upon summary conviction with a fine of up to \$250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over \$90,000,000 in total liability.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates and other matters. The royalty regime in each province is a significant factor in the profitability of crude oil, NGL, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from

time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

On January 1, 2017, the Royalty Review Advisory Panel's recommendations for a new royalty regime, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "MRF"), took effect. The MRF applies to non-oil sands wells drilled on or after that date, while wells drilled prior to January 1, 2017 remain subject to Alberta's prior royalty framework until January 1, 2027, unless a producer elects to opt into the MRF. The *Royalty Guarantee Act* (Alberta), which came into force in 2019 provides a commitment that no major changes will be made to Alberta's oil and natural gas royalty structure for a minimum of 10 years.

The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the drilling and completion cost allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. The Mid-Life phase royalty rate will range from 5% to 40% on all production, depending on the commodity price of oil. This royalty rate is intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 Mcf/d for gas, the royalty rate will move to a sliding scale formula (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, were released in the second half of 2016.

Royalties, for wells drilled prior to January 1, 2017, are paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework" until January 1, 2027, unless the Company has elected to opt-in to the MRF. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 36%. Royalties on NGLs are levied at a flat rate of 30% of the sales volume for propane and butane and 40% for pentanes plus with field condensate at a rate equivalent to oil.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the

assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling.

The impact on the Company of any changes to applicable royalty regimes will be dependent on several factors, but an increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic.

Saskatchewan

In Saskatchewan, taxes ("**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and natural gas operations. A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations.

The amount payable as a Crown royalty or a freehold production tax in respect of oil is paid on a well-by-well basis and depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. The royalty reserved to the Crown depends on the categorization and classification of the oil, monthly production and a prescribed reference price determined monthly by the Saskatchewan Ministry of Energy and Resources ("**SMER**") formerly the Saskatchewan Ministry of Economy. The base royalty rate ranges from 5% - 20% and the marginal royalty rate ranges from 25% - 45%.

The amount payable as a Crown royalty in respect of natural gas depends on the vintage of the gas, the type of gas production, the quantity of gas produced in a month, and the price of the gas. For both provincial Crown royalty and freehold production tax purposes, natural gas is categorized as either non-associated gas or associated gas, the former being gas produced from gas wells and the latter being gas produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as "fourth tier gas", "third tier gas", "new gas", or "old gas". The royalty reserved to the Crown depends on the categorization and classification of the natural gas, monthly production, and a reference price prescribed by the SMER. As an incentive for the production and marketing of natural gas which may otherwise have been flared, the royalty rate on associated gas is less than on non-associated natural gas. The base royalty rate ranges from 0% - 20% and the marginal royalty rate ranges from 30% - 45%.

The Government of Saskatchewan currently provides a number of targeted incentive programs, These include both royalty reduction and incentive volume programs, with targeted programs for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells. As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the SMER implemented a five year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. The moratorium is in connection

with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane-based GHG emissions by 40% to 45% between 2021 and 2025, The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of \$1.50 per acre owned regardless of whether or not there is production from the lands.

Manitoba

In Manitoba, the royalty amounts payable on oil produced from Crown lands depends on the classification of the oil which is dependent on the date of drill, re-entry, enhanced recovery project implementation date, or various other key dates. Royalty rates are calculated on a sliding scale formula and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations. The Crown royalty on an oil well can be up to 43% of monthly production from a well or allocated to a spacing unit or unit tract, as applicable. The Crown royalty payable on natural gas production is a flat 12.5% of the monthly revenue.

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale between 0% and approximately 40% and is based on monthly production volume and varies with the classification of the oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month.

Land Tenure

Crude oil and natural gas is owned predominantly by the respective provincial governments, except for Manitoba where private ownership accounts for approximately 80% of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated between the parties to such lease.

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses

issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or intermediate term of the license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. To conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat production and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

On a Federal level and pursuant to the *Prosperity Act*, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On August 28, 2019, the CERA and the *Impact Assessment Act* ("**IAA**") came into force. In addition, the Impact Assessment Agency of Canada (the "**IA Agency**") replaced the Canadian Environmental Assessment Agency.

The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered

by the IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IAA. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75km of new right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. In 2022, the Alberta Court of Appeal found significant portions of the IAA to be unconstitutional. The decision was appealed, and on October 13, 2023, the Supreme Court of Canada held that the IAA was unconstitutional in part, concluding that certain provisions exceeded federal jurisdiction by capturing projects otherwise within provincial authority.

The Court affirmed, however, that Parliament has jurisdiction to regulate federal effects and to impose impact assessments where a sufficient federal nexus exists. In response to the Supreme Court's decision, the Government of Canada introduced and enacted amendments to the IAA intended to narrow the scope of federal assessments and align the legislation with constitutional limits, while maintaining federal oversight of effects within federal jurisdiction.

On December 3, 2020, the Government of Canada tabled Bill C-15 (as defined below). Bill C-15 is the Government of Canada's response to requests to implement the United Nations Declaration of the Rights of Indigenous Peoples as a framework for reconciliation in Canada. On June 21, 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act received Royal Assent and immediately came into force.

Alberta

The Alberta Energy Regulator (the "AER") is the principal regulator for oil, natural gas and oil sands development in Alberta. It derives its authority from the Responsible Energy Development Act and a number of related statutes including the *Oil and Gas Conservation Act*, the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources, including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Land and Property Rights Tribunal, as well as the Alberta Ministry of Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning and cumulative effects arrangements to support responsible resource development. Alberta's land-use framework is primarily implemented under the *Alberta Land Stewardship Act*, which contemplates the development of region-specific land-use plans to manage the combined effects of existing and future land use activities. While the AER is the primary regulator for energy resource development, land-use and environmental matters may also involve Alberta Environment and Protected Areas, the Ministry of Energy and Minerals, Indigenous Relations, and other provincial authorities, depending on the nature of the activity.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock

and stimulate oil and natural gas production. The Company routinely conduct hydraulic fracturing in its drilling and completion programs. In recent years, hydraulic fracturing has been linked to increased seismicity in certain areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in Subsurface Order Nos. 2, 6, and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the “**Seismic Protocol Regions**”). Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a “traffic light” reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

Alberta’s Liability Management Framework (“**AB LM Framework**”) was introduced in July 2020 and has now been substantially implemented through binding AER directives and rules. As of 2024–2025, the framework is fully operational and governs financial assessment, licence eligibility, closure spending, security requirements, and enforcement for conventional oil and gas activities in Alberta.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* (“**SKOGCA**”), the act governing the regulation of resource development operations in the province, which came into force on April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* (“**OGCR**”) and *The Petroleum Registry and Electronic Documents Regulations* (“**Registry Regulations**”). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan’s energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented several operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers and procedural aspects including those related to Saskatchewan’s participation as partner in the Petroleum Registry of Alberta.

Manitoba

In Manitoba, the Petroleum Branch of Innovation, Energy and Mines develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Oil and gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (“**MBOGA**”) and *The Oil and Gas Production Tax Act*, and related regulations and guidelines.

Liability Management Rating Programs

Alberta

The AER administers the AB LM Framework and the Liability Management Rating Program (the “**AB LMR Program**”) to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. This change was effected under key new AER directives in 2021, and further updates were released in 2022.

Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the fully operational and governs financial assessment, licence eligibility, closure spending, security requirements, and enforcement for conventional oil and gas activities in Alberta. The AB LM Framework include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program (the "**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including Alberta's former Liability Management Rating ("**LMR**") and Licensee Liability Rating ("**LLR**") based programs have been replaced under the AB LM Framework, and the AER has indicated that the LMR is no longer calculated or used for any regulatory purpose. In addition, the AER has rescinded the Oilfield Waste Liability Program (the "**AB OWL Program**"), program and the Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under program as part of implementing the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the AB LM Framework and the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if where a licensee or working interest participant becomes insolvent or is otherwise unable to meet its obligations and no responsible party can be identified. Licensees in the AB LLR Program and the AB OWL Program fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately \$335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered \$113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LF Program. A separate orphan levy applies to persons holding licences subject to the AB LF Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. In March 2025, the Alberta government approved a \$144.5 million levy to fund the Orphan Well Association's 2025/26 operating budget.

As a result of the Supreme Court of Canada's decision in Orphan Well Association v Grant Thornton (also known as the Redwater decision), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed Bill 12: The Liabilities Management Statutes Amendment Act. Bill 12 places the burden of a defunct licensees' abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes came into force in June 2020.

In response to the increase in orphaned crude oil and natural gas sites and the environmental risks associated therewith, the AER has issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. For example, the AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("**Directive 067**"), which deals with

licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director or officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences remain subject to AER approval with transfers assessed on a non-routine, risk-based basis. Transfers are now evaluated through a holistic assessment of licensee capability rather than numerical liability ratios. As part of this approach, transferees must demonstrate to the satisfaction of the AER that they financially and operationally capable of meeting abandonment, remediation and reclamation obligations.

Alongside changes to Directive 067, the AER also introduced Directive 088: Licensee Life-Cycle Management (“**Directive 088**”) in December 2021 under the AB LM Framework. Directive 088 replaces, to an extent, the AB LLR Program with the AB LCA. Whereas the AB LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee’s deemed asset value relative to the deemed liability value of its oil and gas wells and facilities, the AB LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. Such factors are wide reaching and include: (i) a licensee’s financial health; (ii) its established total magnitude of liabilities, (iii) the remaining lifespan of its mineral resources and infrastructure; (iv) the management of its operations; (v) the rate of closure activities and spending and pace of liability growth; and (vi) its compliance with administrative and regulatory requirements. These various factors then feed into a broader holistic assessment of a licensee under the AB LM Framework. In turn, that holistic assessment provides the basis for assessing risk posed by licence transfers, as well as any security deposit that the AER may require from a licensee in the event that the regulator deems a licensee at risk of not being able to meet its liability obligations.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program, the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee’s proportion of provincial inactive liabilities and the licensee’s level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target. The AER also implemented a closure nomination program (the “**CN Program**”) in 2023. Under the CN Program, those who qualify may nominate certain oil and gas sites for closure.

The AER has also implemented the Inactive Well Compliance Program , which addresses legacy non—compliant inactive wells in under Directive 013:and concluded in 2021 following extension to the final compliance deadline.

The Government of Alberta followed the announcement of the AB LM Framework with amendments to the Oil and Gas Conservation Rules and the Pipeline Rules in late 2020. The changes to these rules fall into three principal categories: (i) they introduce “closure” as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER’s authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

On February 7, 2025, the AER released Bullet 2025-04, providing for new editions of four directives: Directive 001: Requirements for Site-Specific Liability Assessment; Directive 011: Estimated Liability; Directive 068: Security Deposits and Directive 088: Licensee Life-Cycle Management.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary area-based closure (“ABC”) program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the “**SK LLR Program**”). The SK LLR Program is designed to assess and manage the financial risk that a licensee’s well and facility abandonment and reclamation liabilities pose to an orphan fund (the “**SK Orphan Fund**”) established under the SKOGCA. The SK Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

On January 1, 2023, the Financial Security and Site Closure Regulations (the “Closure Regulations”), came into force. Pursuant to the Closure Regulations, changes to the oil and gas liability framework included: (i) changes to the formula for determining if a licensee poses a financial risk; (ii) annual spend targets for closure activities by licensees, commencing in 2023; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer.

Manitoba

To date, Manitoba has not implemented a liability management rating program like those found in the other western provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the Drilling and Production Regulations. In certain circumstances, a performance deposit may be refunded. The MBOGA also establishes the Abandonment Fund Reserve Account (the “**Abandonment Fund**”). The Abandonment Fund is a source of funds that may be used to operate or abandon a well when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred as well as annual levies for inactive wells and batteries.

Climate Change Regulation

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the “**UNFCCC**”) since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. On January 20, 2021, President Biden of the United States signed an executive order to rejoin the Paris Agreement. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada.

In 2016, the Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada made several pledges aimed at reducing Canada’s GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be

zero-emission on or before 2035. At the 2025 UN Climate Change Conference, Canada advanced carbon market initiatives and adaptation finance, but faced scrutiny for LNG expansion and uncertainty around its approach to oil and gas emission gaps.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of \$20/tonne of carbon dioxide equivalent ("**CO₂e**") emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. This ensures that there is a uniform price on emissions across the country. Originally under current federal plans, this price will escalate by \$10 per year until it reached a price of \$50/tonne of CO₂e in 2022. On December 11, 2020, however, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO₂e will increase by \$15 per year until it reaches \$170/tonne of CO₂e in 2030. On March 15, 2025, the Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act and the Fuel Charge Regulations (SOR/2025-107) were published. Pursuant to these amendments, effective April 1, 2025, the Government of Canada reduced all fuel-charge rates under Part 1 of the GGPPA to zero, thereby eliminating the consumer-facing carbon tax. The amendments also removed the requirement for provinces and territories to maintain a consumer-facing carbon price, with the result that previously scheduled rate increases—including the planned increase to \$95 per tonne on April 1, 2025—no longer apply. All administrative obligations associated with the Part 1 fuel charge cease with respect to reporting periods after March 31, 2025, and the Canada Carbon Rebate, which was funded by proceeds from the Part 1 charge, has been discontinued.

On April 26, 2018, the federal government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas industry and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities); well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

In December 2023, the federal government released proposed amendments to the Federal Methane Regulations in order to further reduce upstream methane emissions and to contribute to Canada meeting its international climate-related commitments. The proposed amendments would build on the existing requirements and increase stringency by introducing new prohibitions and limits on certain intentional emissions, a new risk-based approach around unintentional emissions, and a new performance-based approach for compliance that relies on continuous emissions monitoring systems, among other things. The proposed amendments are targeted to come into force in January 2027.

In the November 23, 2021, Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis, to protect nature and the traditional

knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The Canadian Net-Zero Emissions Accountability Act (the "**CNEAA**") received royal assent on June 29, 2021 and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions-reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada introduced its 2030 Emissions Reduction Plan (the "2030 ERP") on March 29, 2022. In the 2030 ERP, the Government of Canada proposes a roadmap for Canada's reduction of GHG emissions to 40-45% below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the oil and gas sector, among other measures.

On June 8, 2022, the Canadian Greenhouse Gas Offset Credit System Regulations were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal output-based pricing system through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the output-based pricing system or those seeking to meet voluntary targets.

On June 20, 2022, the Clean Fuel Regulations came into force, establishing Canada's Clean Fuel Standard. The Clean Fuel Standard will replace the former Renewable Fuels Regulation, and aims to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives. The requirement to comply with the Clean Fuel Standard began on July 1, 2023, imposing obligations on primary suppliers of transportation fuels in Canada and require fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

On November 22, 2023, the federal government published amendments to the Output-based Pricing System (the "OBPS"). These regulations are made under the Greenhouse Gas Pollution Pricing Act (the "GGPPA"). These changes involve adding and revising output-based standards ("Standards"), enhancing implementation procedures, refining reporting accuracy, and encouraging voluntary participation. Notably, the updated OBPS introduces a 2% fixed annual tightening rate for most Standards starting from 2023. Sectors facing significant competition and carbon pricing-induced carbon leakage will experience a 1% adjusted tightening rate from 2023 onwards. Additionally, the publication of the Quantification Methods for the Output-Based Pricing System Regulations (the "OBPS QM"), detailing emissions quantification methods, was released on December 12, 2023. The OBPS QM establishes the required methods for quantifying greenhouse gases, heat ratios, and electricity generated within the OBPS framework.

On December 7, 2023, the federal government published the Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap ("GHG Cap"). Under the GHG Cap, LNG projects would be captured by cap-

and trade system. The provincial and federal governments aim to work together to ensure the regulations and programs complement each other to minimize additional administrative requirements. The key elements of the GHG Cap include: (i) a decline of emissions to meet net-zero by 2050; (ii) creating the legal upper bound on emissions (being the maximum emissions the whole sector may be allowed to emit per year) in a manner responsive to technically achievable emissions reductions and the global demand for oil and gas; (iii) minimal administrative burden; and (iv) ongoing monitoring and regular review of the standards.

In November 2024, the federal government published the proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations (the “**Proposed Regulations**”).

The Proposed Regulations would cap emissions from a range of oil and natural gas related activities, create an emissions cap-and-trade system, and require facility operators to comply with various reporting and remittance obligations. The final version of establish registration and reporting obligations, as well as a cap-and-trade regime, applicable to oil and gas operators engaged in industrial activities including crude oil production, oil sands extraction and upgrading, natural gas extraction, and liquefied natural gas production. All operators captured by the Proposed Regulations is expected to be published in mid-2025 and come into force would be required to register by January 1, 2026. Under the proposed cap-and-trade framework, the federal government would set an annual maximum emissions threshold and issue emissions allowances, free of charge, in an amount equal to that cap. The initial cap would be determined with reference to 2026 emissions, attributed in accordance with the formula set out in the Proposed Regulations. For the first compliance period, spanning 2030 to 2032, the cap would be set at a level 27% below 2026 attributed emissions for affected facilities, which is anticipated to correspond to an approximate 35% reduction relative to 2019 emission levels. The Proposed Regulations have been criticized by provinces and industry stakeholders on the basis that the cap-and-trade system effectively operates as a production cap. If implemented, the cap-and-trade regime could have a material adverse effect on the Company’s business, financial condition, results of operations, and prospects.

To date, the Proposed Regulations have not been implemented. The federal government under Prime Minister Mark Carney has shifted the country’s climate priority towards economic competitiveness. Additionally, per the Canada-Alberta MOU, the federal government has committed to not implementing the Proposed Regulations in consideration of the other commitments made in the Canada-Alberta MOU.

The Government of Canada has developed a Carbon Management Strategy, whereby it aims to deploy various carbon management technologies, including carbon capture, to help achieve federal climate goals. Carbon capture is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. As part of the 2021 budget, the federal government committed to investing \$319 million over seven years into research, development and demonstrations to advance the commercial viability of carbon capture technologies.

In June 2024, the federal government enacted various new tax credits for sustainability-related projects, including the Carbon Capture, Utilization, and Storage (“**CCUS**”) Investment Tax Credit (“**ITC**”). The CCUS ITC is a refundable tax credit that applies to certain expenses incurred for eligible CCUS projects. It was enacted on June 19, 2024 (but deemed to have come into effect on January 1, 2022). The credit is available from January 1, 2022, until December 31, 2040, with the magnitude of the credit being reduced by 50% beginning on January 1, 2031.

On November 17, 2025, the federal government published a Notice of Ways and Means Motion to introduce a bill which proposes to amend the *Competition Act* by removing the requirement that environmental claims about a business or business activity be “in accordance with internationally recognized methodology” (but still

requiring “adequate and proper substantiation”), and by making such business-level claims unavailable to third parties seeking to bring greenwashing complaints to the Competition Tribunal.

The Canadian Standards require issuers, among other things, to include quantitative data regarding their climate change considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 GHG emissions (i.e., indirect emissions from an organization’s operations). The finalized Canadian Standards are substantially similar to IFRS S1 and S2 (and earlier drafts of CSDS 1 and CSDS 2), however they have extended implementation timelines for select criteria. Canadian companies are not required to follow the Canadian Standards at this time, however, the Canadian Securities Administrators are considering amending Canadian reporting requirements to include certain aspects if these new Canadian Standards; to what extent they will be adopted remains unclear.

In June 2024 the federal Competition Act was amended to enact new deceptive marketing provisions targeting “greenwashing”. The new provisions introduced unclear substantiation requirements for companies making environmental claims and significant fines for failing to meet the new requirements. As a result of the uncertainty with respect to the applicability of the new rules, some companies removed their environmental and sustainability-related disclosure from the public domain. In December 2024 the constitutionality of the new deceptive marketing provisions was challenged in the Alberta Court of King’s Bench and the lawsuit remains ongoing.

In general, there is uncertainty with regard to the impact of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on Questerre’s operations and cash flow.

Alberta

Alberta Climate Leadership Plan

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the “**CLP**”). Under this strategy, the *Climate Leadership Act* (the “**CLA**”) came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The CCIR remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of \$20/tonne. In accordance with the GGPPA, this will increase to \$30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta’s proposed Technology Innovation and Emissions Reduction (“**TIER**”) regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The provisions of the TIER regulation required that an interim review of the regulation be completed by December 31, 2022 giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of the carbon pricing systems for 2023 to 2030. Following the comment period, the Technology Innovation and Emissions Amendment Regulation was adopted with certain amendments to the TIER Regulation becoming effective January 1, 2023. These amendments include meeting the federal standards for Alberta’s carbon pricing system, the creation of sequestration credits for CCUS projects and amendments to the number of credits that can be used to meet emission targets. The TIER regulation is set to undergo another review by December 31, 2026.

The TIER regulation operates differently than the former facility based CCIR and instead applies to industrywide to emitters that emit more than 100,000 tonnes of CO₂e per year in 2016 or any subsequent year. The 2020

target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high performance benchmarks. Certain facilities, such as those in the electricity sector, are compared against the good-as-best gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000-tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO₂e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower committed to lowering its annual methane emissions by 45% by 2025. Pursuant to this goal, the and reached this target three years early. The Government of Alberta enacted the Methane Emission Reduction Regulation (the "**Alberta Methane Regulations**") on January 1, 2020, and in. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta. On September 26, 2025, the Minister of the Environment and the Government of Alberta entered into a written agreement recognizing the equivalency between the Federal Methane Regulations and Alberta Methane Regulations under the *Environmental Protection and Enhancement Act* (Alberta). This equivalency agreement has a term of five years, applying until 2030. On October 23, 2025, the federal government made an order declaring the Federal Methane Regulations do not apply in Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed \$1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies will begin exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest \$40 million in 11 carbon capture and storage hub projects through Emissions Reduction Alberta.

In February 2023, the TIER regulation was amended to, among other things, amend the opt-in thresholds for emissions-intensive and trade-exposed industries, tighten facility-specific benchmarks, revise the credit use limits and expiration periods as well as create sequestration credits for carbon capture, utilization and storage projects. The TIER regulation will be subject to a subsequent review which must be completed by December 31, 2026.

On August 3, 2023, the Alberta Ministry of Affordability and Utilities announced that the Alberta Utilities Commission was directed to pause approvals of new renewable electricity generation projects until February 29, 2024. The announcement was in response to the need to review and consider policy changes in relation to renewable development. The review of the policies for renewable resource development will include a public inquiry, after which the Alberta Utilities Commission must submit a report on the findings no later than March 29, 2024 to the Minister of Affordability and Utilities. It is unknown at this time what effect the renewable pause and corresponding inquiry may have on the energy market in Alberta.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any additional programs or additional regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

In October 2024, the Government of Alberta announced that it made an application to the Federal Court for a judicial review in respect of the federal carbon tax regime.

Saskatchewan

In May 2009, the Government of Saskatchewan announced the Management and Reduction of Greenhouse Gases Act (the "**MRGGA**") to regulate GHG emissions in the province. The government subsequently released Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy ("**Prairie Resilience**"), outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, *The Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program.

On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO₂e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40-45% by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO₂e emissions by 2025, with a total reduction of 38.2 million tonnes of CO₂e by 2030.

The MRGGA and the Saskatchewan O&G Emissions Regulations meet the federal benchmark stringency requirements for certain industrial sectors, but the federal backstop continues to apply to emissions sources not covered in Saskatchewan's emissions legislation. The federal fuel charge continues to apply in Saskatchewan.

In April 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the Province's progress on goals set out under Prairie Resilience. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030. According to its 2020 and 2021 reports, the province generates nearly 26% of its electricity from renewable energy sources, an increase of 1.6% since 2019. To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented Directive PNG017: *Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and Directive PNG036: *Venting and Flaring Requirements*, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had

finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Saskatchewan. In furtherance of these goals and agreements, in March 2021, the Government of Saskatchewan announced it would provide \$500,000 to support innovative research and technology for measuring and monitoring gas volumes and emissions, which will be overseen by the Saskatchewan Research Council.

In January 2021, the Government of Saskatchewan announced support for three projects expected to reduce methane emissions, including a new flare-gas-to-power project, an expansion of gas processing facilities, and a new gas fractionation plant. The Saskatchewan Petroleum Innovation Incentive ("SPII") and Oil and Gas Processing Investment Incentive ("OGPII") give this support. The SPII and OGPII provide a percentage of transferable royalty credits after private funding has been obtained and the facilities have been built. In September 2021, Saskatchewan's Energy and Resource Minister announced that one of the government's key priorities would be to increase investment in CCUS through enhanced oil recovery CCUS projects.

Manitoba

The Government of Manitoba commenced public consultations with respect to the development of a cap-and-trade system to reduce GHG emissions in 2010. The enactment of *The Climate Change and Emissions Reductions Act* (Manitoba) set emission reduction targets as of December 31, 2012 at six per cent below 1990 emissions and detailed the commitment of the Government of Manitoba to various initiatives in an effort to reduce GHG emissions. On December 3, 2015, the Government of Manitoba announced Manitoba's Climate Change and Green Energy Action Plan to address climate change and create green jobs. One component of this plan involved cutting GHG emissions by one-third of its 2005 levels by 2030, in part by implementing a cap and trade program for large emitters. Following this announcement, on December 7, 2015, the Government of Manitoba announced that it has signed a memorandum of understanding with Quebec formalizing the intent of these provinces to link their respective cap and trade systems. However, no legislation has been enacted to implement the initiatives outlined in Manitoba's Climate Change and Green Energy Action Plan or the memorandum of understanding.

In June 2019, the Government of Manitoba announced a GHG emissions reduction target of one megatonne for the 2018-2022 period. In July 2020, Manitoba unveiled the Conservation and Climate Fund (now referred to as the Climate Action Fund), which provides grants for green projects and initiatives. In October 2021, Manitoba announced \$1 million in grants through the **Conservation and Climate Fund** to various organizations and projects, including methane clean technology development and vehicle and infrastructure electrification initiatives.

In October 2025, the Government of Manitoba released *Manitoba's Path to Net Zero*, a high-level policy strategy outlining the province's objective of achieving net-zero GHG emissions by 2050. The strategy emphasizes government leadership, collaboration with Indigenous governments, expansion of clean electricity and transportation infrastructure, and the development of future sector-specific action plans. The Path to Net Zero is a policy framework rather than binding legislation and does not, in itself, establish enforceable emissions limits or new regulatory obligations.

Quebec

Pursuant to the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere*, Quebec facilities emitting more than 10,000 tonnes CO₂ equivalent of greenhouse gases a year, subject to certain exceptions, must record and report those emissions to the MDDELCC. Pursuant to the *Regulation Respecting a Cap-and-trade System for Greenhouse Gas Emission Allowances*, certain targeted emitters of greenhouse gas in a quantity equal to or greater than 25,000 metric tonnes CO₂ equivalent annually, subject to certain exceptions, have been required since 2013 to cover all their greenhouse gas emissions with emission allowances obtained by a combination, as applicable, of free distribution and auction, as well as

emissions reduction units from offset projects or recognized compliance units from other jurisdictions. These requirements are related to the Government of Quebec's goal of reducing greenhouse gas emissions in the province by 20% of 1990 emission levels by 2020 and 37.5% by 2030.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to UNDRIP and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the Declaration on the Rights of Indigenous Peoples Act ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, UNDRIP came into force in Canada. Similar to British Columbia's DRIPA, UNDRIP requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of UNDRIP (the "**Progress Report**"). The Progress Report provides that, as of June 2022, the federal government has sought to implement UNDRIP by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of UNDRIP has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of UNDRIP.

On June 29, 2021, the British Columbia Supreme Court issued its judgement in the *Yahey v British Columbia* (the "**Blueberry Decision**") with respect to a claim brought forth by the Blueberry River First Nation ("**BRFN**") against the province of British Columbia regarding the cumulative impact of industrial development within the BRFN treaty claim area. The Blueberry Decision found that the Province of British Columbia breached the Treaty 8 rights of the BRFN by allowing extensive industrial development on the BRFN's traditional territory without first assessing the cumulative impacts of this development on the ability of the members of the BRFN to exercise their Treaty 8 rights to hunt, fish, and trap on their traditional territory. The Blueberry Decision calls for the province of British Columbia to pause some development in the BRFN traditional area pending the results of an investigation into the cumulative impacts of industrial development in the BRFN's traditional territory. The Blueberry Decision gave six months for the Government of British Columbia and the BRFN to negotiate changes to the regulatory regime that recognizes and respects treaty rights.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "**BRFN Agreement**"). The BRFN Agreement aims to address the cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a \$200-million restoration fund by June 2025, an ecosystem-based management approach for future land-use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas

activities. The BRFN will receive \$87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations –Fort Nelson, Salteau, Halfway River and Doig River First Nations –reached consensus on a collaborative approach to land and resource planning (the "**Consensus Agreement**"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue-sharing approach to support the priorities of Treaty 8 First Nations communities.

In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by the BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. The long-term impacts of the Blueberry Decision and the Duncan's First Nation lawsuit on the Canadian oil and gas industry remain uncertain.

DIVIDENDS OR DISTRIBUTIONS

Questerre has not paid any dividends or made any distributions on its Common Shares or Series 2 Preferred Shares since incorporation. Dividends or distributions on its Common Shares will be paid solely at the discretion of Questerre's board of directors after considering the financial condition of Questerre and the economic environment in which it is operating. No dividends or distributions are expected to be paid on the Common Shares in the foreseeable future. For a description of the dividend rights attributable to the Series 2 Preferred Shares, see "**Description of Share Capital – Preferred Shares – Series 2 Preferred Shares – Dividend Rights**" below.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of Common Shares, an unlimited number of Class B Common voting shares ("Class B Shares") and an unlimited number of preferred shares, issuable in one or more series ("Preferred Shares"). As at the date hereof, 512,213,454 Common Shares, 452,213,454 Series 2 Preferred Shares and no Class B Shares were issued and outstanding. The following is a description of the rights, privileges, restrictions and conditions attaching to the Common Shares, the Class B Shares and the Preferred Shares.

Common Shares and Class B Shares

The holders of Common Shares and Class B Shares are entitled to receive notice of and to attend at and to vote one vote per Common Share or Class B Share, at meetings of shareholders of the Company, except meetings at which only holders of a specified class of shares are entitled to vote. In addition, the holders of Common Shares are entitled to receive dividends declared on the Common Shares, subject to the rights of the holders of shares ranking prior to the Common Shares, and the holders of Class B Shares are entitled to receive dividends declared on the Class B Shares, subject to the rights of the holders of shares ranking prior to the Class B Shares. Holders of Common Shares and Class B Shares are entitled to receive pro rata the remaining property of the Company upon dissolution in equal rank with the holders of other Common Shares and Class B Shares.

Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each series consisting of a number of Preferred Shares as may be determined by the board of directors of the Company who may also fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. Unless the directors otherwise specify in the articles of amendment designating a series of Preferred Shares, the holder of each series of Preferred Shares shall not, as such, be entitled to receive notice of or vote at any meeting of shareholders, except as otherwise specifically provided in the ABCA. The Preferred Shares of each series shall, with respect to payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary, or any other distribution of the assets of the Company among its shareholders for the purpose of winding-up its affairs, be entitled to preference over the Common Shares and Class B Shares and over any other shares of the Company ranking by their terms junior to the Preferred Shares of that series.

Series 2 Preferred Shares

Voting Rights

Other than as set forth below, the holders of Series 2 Preferred Shares shall have no right to receive notice of or to be present at or vote either in person or by proxy, at any meeting of the shareholders of the Company by virtue of or in respect of their holding of Series 2 Preferred Shares.

Holders of Series 2 Preferred Shares:

- may vote as a separate class on Articles of Amendments or changes to their rights, privileges, restrictions, or conditions; and
- notwithstanding any other approval requirements under the Company's Articles, at any time when at least 50,000,000 Series 2 Preferred Shares are outstanding, the following decisions of the Company must be approved by a majority of the holders of Series 2 Preferred Shares:
 - at each meeting of the shareholders of the Company at which directors of the Company are to be elected, the election of the three (3) members of the Oversight Committee (as defined in the Series 2 Share Terms);
 - liquidating, dissolving or winding-up the business and affairs of the Company, effect any amalgamation or consolidation or any other Deemed Liquidation Event (as defined in the Series 2 Share Terms), or consent to any of the foregoing;
 - amending, altering or repealing any provision of the Articles or the By-laws of the Company in a manner that adversely affects the powers, preferences or rights of the Series 2 Preferred Shares; and
 - creating or issuing any shares in the capital of the Company having preferential or equal treatment as to dividends, returns of capital or sharing of assets in respect of the Quebec Business on a liquidation in relation to the existing issued and outstanding Series 2 Preferred Shares.

Dividend Rights

Subject to applicable law and to any required withholding tax deductions, the holders of the Series 2 Preferred Shares shall be entitled to share pro rata:

- subject to the conversion rights of the Company, if the Litigation (as defined in the Series 2 Share Terms) results in proceeds to the Company, in a cash dividend on the Series 2 Preferred Shares equal to the Series 2 Litigation Dividend Amount (as defined in the Series 2 Share Terms); and
- if the Litigation results in the reinstatement or reissuance of the Company's Petroleum and Natural Gas Exploration Licenses and/or Royalty Interests on the Farmout Lands or a similar result, in the

Series 2 Operational Dividend Amount (as such terms are defined in the Series 2 Share Terms) for the immediately preceding fiscal year.

Prior to payment of the Series 2 Litigation Dividend Amount, the Company will be entitled to: (i) expense reimbursement related to fees and expenses related to the Litigation, the estimated asset-retirement obligations related to the Quebec Business, as well as expenses of the Technical Committee and expenses paid or payable to the Oversight Committee; and (ii) an amount equal to the sum of 5% of the Litigation Proceeds.

The Series 2 Operational Dividend Amount is based on the Quebec Business Distributable Cash, which is equal to 50% of the Operating Revenue (as such terms are defined in the Series 2 Share Terms), for the applicable fiscal year if the Company has drilled and completed ten (10) Test Wells in accordance with the Series 2 Share Terms, or 100% of the Operating Revenue for the applicable fiscal year otherwise.

The holders of the Series 2 Preferred Shares shall not be entitled to any dividend other than or in excess of the dividends provided for above. The determination of both the Series 2 Litigation Dividend Amount and the Series 2 32 Operational Dividend Amount also take into consideration the rate of tax, expressed as a percentage, under Part VI.1 of the Tax Act that the Company determines will be applicable to that dividend or other distribution.

Conversion by the Company

Provided the conclusion of the Litigation does not include the reinstatement or reissuance of the Company's Petroleum and Natural Gas Exploration Licenses and/or Royalty Interests on the Farmout Lands or a similar result, at the option of the Company (upon approval by the Board, including the approval of the Preferred Director) and subject to the policies of the TSX and the Oslo Stock Exchange, or such other stock exchange(s) as the New Common Shares are then trading, the Series 2 Preferred Shares shall be convertible into such number of fully paid and non-assessable New Common Shares (prior to an in lieu of payment of the Series 2 Litigation Dividend Amount) as is determined by dividing:

- on the first \$280,000,000 of Series 2 Litigation Proceeds Amount (as defined in the Series 2 Share Terms), the lesser of (1) \$280,000,000; and (2) the Series 2 Litigation Proceeds Amount; and+
- on the balance, if any, of the Series 2 Litigation Proceeds Amount, the amount determined by the formula:

$$A \times (1 - B)$$

where

"A" is the balance, if any, Series 2 Litigation Proceeds Amount; and

"B" is the Ordinary Combined Tax Rate (as defined in the Series 2 Share Terms);

by the by the ninety (90) day volume weighted trading price of the New Common Shares on the principal exchange on which they are traded on the last business day preceding the Litigation Proceeds Payment Date (or such other lower price as may be required by the principle exchange on which the New Common Shares are traded).

Liquidation Rights

In the event of any liquidation, dissolution or winding-up of the Company or Deemed Liquidation Event, the holders of the Series 2 Preferred Shares then outstanding are entitled to be paid out of the assets of the Company available for distribution to its shareholders or out of the consideration payable to shareholders in such Deemed Liquidation Event, as applicable, before any payment is made to the shareholders of the

Company by reason of their ownership of Common voting shares of the Company, a pro rata an amount equal to: the Unpaid Series 2 Dividends (as defined in the Series 2 Share Terms) as at the date of liquidation, dissolution or winding up of the Company or Deemed Liquidation Event; plus the amount to which they would be entitled as a Series 2 Operational Dividend Amount if the reference in the definition of Series 2 Operational Dividend Amount to “Quebec Business Distributable Cash for the Relevant Year” were read to also include any Net Proceeds (without duplication of any amount included in the Series 2 Litigation Dividend Amount or the Series 2 Operational Dividend Amount), (the “**Series 2 Liquidation Amount**”). If upon any such liquidation, dissolution or winding up of the Company or Deemed Liquidation Event, the assets of the Company available for distribution to its shareholders are insufficient to pay the holders of Series 2 Preferred Shares the full amount of the Series 2 Liquidation Amount, the holders of Series 2 Preferred Shares shall share ratable in any distribution of the assets available for distribution in proportion to the respective amounts which would otherwise be payable in respect of the Series 2 Preferred Shares held by them upon such distribution if all amounts payable on or with respect to such shares were paid in full.

In the event of any voluntary or involuntary liquidation, dissolution or winding up of the Company, after the payment in full of all Series 2 Liquidation Amounts required to be paid to the holders of Series 2 Preferred Shares, the remaining assets of the Company available for distribution to its shareholders or, in the case of a Deemed Liquidation Event, the remaining consideration, shall be distributed among the holders of the Company’s Common voting shares in accordance with the share terms for such Common voting shares.

The holders of the Series 2 Preferred Shares shall not, as such, be entitled, upon the liquidation, dissolution or winding-up of the Company or on the sale of the Core Business, to share in any proceeds received by the Company from the disposition of the Core Business.

The Company shall not have the power to effect a Deemed Liquidation Event unless the agreement or plan of arrangement for such transaction provides that the consideration payable to the shareholders of the Company in such Deemed Liquidation Event shall be allocated to the holders of shares of the Company in accordance with the foregoing.

Funding of Litigation

The *Company* is required to pay legal fees and disbursements in respect of the Litigation (including any class action support arrangement entered into by the *Company* with respect to any legal proceeding or claim related to the curtailment of operations on the Farmout Lands) up to \$1,000,000 (the “**Required Litigation Funding Amount**”).

In addition, provided the Company believes the Litigation continues to be commercially viable, the Company may pay legal fees and disbursements in respect of the Litigation above the Required Litigation Funding Amount.

Oversight Committee

The Company retains the sole and exclusive authority to direct the conduct of the Litigation. However, its ability to enter into any settlement agreement is subject to the written consent of the Oversight Committee. Before agreeing to any settlement, the Company must promptly notify the Oversight Committee in writing when settlement discussions begin or upon receipt of any settlement offer. The Company and the Oversight Committee are required to consult in good faith regarding all settlement offers, proposals, and discussions, including whether to accept, reject, or counter any settlement offer. If the Oversight Committee determines that a proposed settlement may adversely affect the holders of Series 2 Preferred Shares, it may withhold its consent.

If the conclusion of the Litigation includes the reinstatement or reissuance of the Company's Petroleum and Natural Gas Exploration Licenses and/or Royalty Interests on the Farmout Lands or a similar result, the Oversight Committee will also be entitled to receive certain financial and operational information related to the Quebec Business and will also be entitled to appoint a representative to the technical committee (the "**Technical Committee**"). The role of the Technical Committee shall be to advise the Board on technical and financial matters, with respect to the Quebec Business, including but not limited to Farmout Operations that are necessary or desirable to properly explore, appraise, develop, produce from and otherwise exploit the Farmout Lands in a manner appropriate in the circumstances.

Cancellation of Series 2 Preferred Shares

From and after the business day after the date that is five (5) years from the date of issuance of the last issued Series 2 Preferred Share, if the conclusion of the Litigation does not include the reinstatement or reissuance of the Company's exploration license agreements in Quebec or a similar result, the Series 2 Preferred Shares shall be deemed to be redeemed by the Company for no additional consideration after payment of the Series 2 Litigation Dividend Amount, if any, or if there are no Litigation Proceeds, on the conclusion of the Litigation.

MARKET FOR SECURITIES

Price Range and Volume of Trading of Common Shares

The following tables set forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares of Questerre on each of the Toronto Stock Exchange and the Oslo Stock Exchange as reported by sources Questerre believes to be reliable for the periods indicated:

Toronto Stock Exchange

	Price Range (C\$)		Trading Volume
	High	Low	
2025			
January	0.25	0.22	449,899
February	0.29	0.24	547,761
March	0.33	0.26	403,423
April	0.29	0.25	506,271
May	0.27	0.21	533,771
June	0.32	0.24	713,538
July	0.35	0.28	559,386
August	0.45	0.30	904,915
September	0.38	0.30	1,081,376
October	0.38	0.29	476,650
November	0.35	0.30	268,577
December	0.32	0.29	603,208
2026			
January	0.33	0.27	1,476,246
February	0.29	0.23	1,131,292
March	0.32	0.25	1,325,734

Oslo Stock Exchange

	Price Range (NOK)		Trading Volume
	High	Low	
2025			
January	2.03	1.69	16,918,678
February	2.29	1.75	30,461,139
March	2.40	1.96	39,630,957
April	2.03	-	17,839,540
May	1.93	-	22,917,350
June	2.33	-	24,716,318
July	2.61	2.00	28,402,485
August	3.25	2.15	50,122,823
September	2.64	2.03	16,505,639
October	2.72	2.15	16,344,396
November	2.25	2.05	9,238,267
December	2.41	-	10,422,820
2026			
January	2.42	1.87	17,013,236
February	1.98	1.67	15,415,297
March	2.39	1.77	45,361,460

The Series 2 Preferred Shares are not listed for trading on any stock exchange.

PRIOR SALES

The following table sets forth, for each class of securities of the Company that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the financial year ended December 31, 2025 and the number of securities of the class issued at that price and the date on which the securities were issued.

Class of Securities	Issue Price or Exercise Price	Number of Securities Issued	Date of Issue
Stock Options	\$ 0.23	6,675,000	January 27, 2025

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at the date hereof, except as disclosed below the Company does not have any securities in escrow or that are subject to contractual restrictions on transfer.

DIRECTORS AND OFFICERS

The following table sets forth the names and residences of the current officers and directors of the Company, their position and offices with the Company, the periods during which they have served as officers or directors of the Company and their principal occupations for the past five years.

Name and Municipality of Residence	Offices Held and Time as Director or Officer	Principal Occupation During the Last Five Years
Michael R. Binnion ⁽⁵⁾ President, Chief Executive Officer and Director Calgary, Alberta, Canada	President, Chief Executive Officer and director since November 2000	President, Chief Executive Officer and Director of Questerre.
Dennis F. Sykora ⁽²⁾⁽³⁾⁽⁵⁾ Director Calgary, Alberta, Canada	Director since March 2013	Independent businessperson. Director and Chair of the Audit Committee of Dominion Lending Centres Inc., a TSX listed company that is the largest independent mortgage broker in Canada
Bjorn Inge Tonnessen ⁽²⁾⁽³⁾⁽⁴⁾ Chairman Oslo, Norway	Director since November 2007	Independent businessperson. Executive Chair of Transitus Energy, a private energy transition company. Executive Chair of Geothermal Energy Nordic. CEO and CFO of Edge Petroleum, a private exploration and production company focused on the Norwegian Continental Shelf from June 2017 to March 2021.
Hans Jacob Holden ⁽²⁾⁽³⁾⁽⁵⁾ Director Oslo, Norway	Director since April 2017	Independent businessperson. Business Development at AF Gruppen a leading Norwegian contracting and industrial group from January 2018 to March 2022.
Jauvonne Kitto ⁽⁴⁾⁽⁵⁾ Director Calgary, Alberta	Director since February 2024	Independent businessperson. Chief Executive Officer of the Saa Dene Group, a holding company for several Indigenous-owned or controlled businesses since May 2019.
John Brodylo, P. Geol Vice President, Exploration Calgary, Alberta, Canada	Vice President, Exploration since January 2004	Vice President, Exploration of Questerre since January 2004.
Jason D'Silva Chief Financial Officer Calgary, Alberta, Canada	Chief Financial Officer since 2005	Chief Financial Officer of Questerre since 2005.
Jyoti Parmar Vice President, Finance Calgary, Alberta, Canada	Vice President, Finance since December 2025	Vice President, Finance of Questerre since December 2025. Vice President, Finance, CarbonAI Group of Companies, a technology company focused on carbon credit market solutions from October 2023 to November 2025. Prior thereto, Corporate Controller for Maha Petroleum an international exploration and production company from October 2017 to October 2023.

Name and Municipality of Residence	Offices Held and Time as Director or Officer	Principal Occupation During the Last Five Years
Rick Tityk Vice President, Land Calgary, Alberta, Canada	Vice President, Land since November 2005	Vice President, Land of Questerre since November 2005.
David Pellegrin Vice President, Operations Calgary, Alberta, Canada	Vice President, Operations since September 2025	Vice President, Operations of Questerre since September 2025 and Senior Petroleum Engineer since October 2024. Prior thereto, Senior Petroleum Engineer at a select group of energy advisory and private and public exploration and production companies.
Filippo Segatori Vice President, Oil Shale Calgary, Alberta, Canada	Vice President, Oil Shale since February 2026	Vice President, Oil Shale since February 2026. Vice President Projects, Red Leaf Resources from January 2023 and President since April 2025. Prior thereto, Lead, Project Management (Shale Gas & Oil Sands), PetroChina Canada Ltd. from June 2021 to December 2023.

Notes:

- (1) The term of office of each director will expire at the end of the next annual meeting of shareholders of Questerre, or until successors are elected or directors vacate the offices in accordance with Questerre's by-laws.
- (2) Audit Committee member.
- (3) Reserve Committee member.
- (4) Compensation and Nominating Committee member.
- (5) Oversight Committee.

The directors and officers of Questerre, as a group, beneficially own, directly or indirectly, or exercise control or direction over 32,809,725 Common Shares or approximately 7.3% of the outstanding Common Shares at the date of this AIF.

The information as to shares beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to the Company by the respective individuals indicated.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

None of the directors or executive officers of the Company (nor any personal holding company of any of such persons) is, as of the date of this AIF, or was within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including Questerre), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "Order") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

None of the directors or executive officers of the Company (nor any personal holding company of any of such persons), or security holder holding a sufficient number of our securities to affect materially the control of Questerre is, as of the date of this AIF, or has been within the ten years before the date of this AIF, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation

relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets or has, within the ten years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

No director or executive officer of the Company (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

Under National Instrument 52-110 *Audit Committees*, the Company is required to include in its AIF the disclosure required under Form 52-110F1 with respect to its Audit Committee, including the text of its audit committee charter, the composition of the Audit Committee and the fees paid to the external auditor. This information is provided in Appendix D and Appendix E attached hereto.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than set forth in this AIF, management of the Company is not aware of any material interests, direct or indirect, of any directors or executive officers of the Company, any person or company which beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares of the Company, or any known associate or affiliate of such persons, in any transaction within the last three financial years of the Company, or during the current financial year which has materially affected or is reasonably expected to materially affect the Company.

TRANSFER AGENT AND REGISTRAR

The transfer agents and registrars for the Common Shares of Questerre are Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario and DNB Bank ASA at its principal office in Oslo, Norway.

MATERIAL CONTRACTS

Except for contracts entered in the ordinary course of business, there are no material contracts entered into by Questerre and still in effect as at the date hereof that can be reasonably regarded as presently material other than the Share Purchase Agreement dated as of July 28, 2025 between the Company, Forbes & Manhattan Limited and the former shareholders of FRBH, as amended by an amendment, Waiver and Undertaking dated September 26, 2025 between Forbes & Manhattan Inc., Forbes & Manhattan Limited, the former shareholders of FRBH, Forbes & Manhattan Resources Inc., Forbes Participações Ltda., the Company and 2744026 Alberta Ltd. (the "**Acquisition Agreement**").

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report, valuation or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by Questerre during, or related to, the year ended December 31, 2025 other than McDaniel, Questerre's independent qualified reserves

evaluator, GLJ Ltd. reserve evaluators for PX Energy, and Ernst & Young LLP, Questerre and PX Energy's auditors. To Questerre's knowledge, none of the principals of McDaniel or GLJ Ltd. had any registered or beneficial interests, direct or indirect, in any securities or other property of Questerre or of Questerre's associates or affiliates either at the time they prepared the statement, report, valuation or opinion prepared by it, at any time thereafter or to be received by them.

The Company's auditors are Ernst & Young LLP, Chartered Professional Accountants, who have prepared an independent auditor's report dated March 31, 2026, in respect of the Company's consolidated financial statements as at and for the year ended December 31, 2025. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Questerre or any associate or affiliate of Questerre.

CONFLICTS

There are potential conflicts of interest to which the directors and officers of Questerre will be subject in connection with the operations of Questerre. In particular, certain of the directors and officers of Questerre are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Questerre or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Questerre. See "Directors and Officers". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

LEGAL PROCEEDINGS

To the knowledge of the Company, there are no legal proceedings material to the Company to which the Company is or was a party to or of which any of its property is or was the subject of, during the financial year ended December 31, 2025 except the Company's legal proceedings against the Government of Quebec.

REGULATORY ACTIONS

To the knowledge of the Company, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the Company's last financial year; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority during the last financial year.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remunerations, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions is contained in the Company's management information circular filed in December 2025 relating to its most recent annual meeting of shareholders of the Company. Additional financial information is contained in the Company's comparative financial statements and management's discussion and analysis for the year ended December 31, 2025. Additional information relating to the Company may be found on SEDAR+ at www.sedarplus.ca and the Company's web site at www.questerre.com.

Additional copies of this AIF, the materials listed in the preceding paragraph, any interim financial statements which have been issued by the Company and any other document incorporated herein by reference will be available upon request by contacting the Chief Financial Officer of the Company at its offices at Suite 1650 AMEC Place, 801 Sixth Avenue S.W., Calgary, Alberta T2P 3W2, Phone: (403) 777-1185 or Fax: (403) 777-1578.

SELECTED ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbls/d	barrels per day
API	American Petroleum Institute
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
Bcf	billion cubic feet
MMbtu	million British thermal units
GJ	gigajoule
GJ/d	gigajoules per day
m ³	cubic metres

Other

boe	barrel of oil equivalent converting six Mcf of natural gas to one barrel of oil (6:1)
boe/d	barrels of oil equivalent per day
MMcfe/d	Million cubic feet of natural gas Equivalent converting 1 barrel of oil to six Mcf of natural gas
Mboe	thousand barrels of oil equivalent
M\$	thousands of dollars
MMboe	million barrels of oil equivalent
NPV	net present value

In this AIF the calculation of barrels of oil equivalent (boe) is calculated at a conversion rate of six thousand cubic feet (6 Mcf) of natural gas for one barrel (bbl) of oil based on an energy equivalency conversion method. Boe may be misleading particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a 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 equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF and in certain documents incorporated by reference into this AIF, constitute forward-looking statements. These statements relate to future events or the Company's 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 words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "potential", "targeting", "intend", "could", "might", "should", "believe", "prospect", "future", "possible", "can", "speculative", "perhaps"

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. The Company believes that 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, or incorporated by reference into, this AIF should not be unduly relied upon. These statements speak only as of the date of this AIF or as of the date specified in the documents incorporated by reference into this AIF, as the case may be.

Forward-looking information and statements are included throughout this AIF (and the documents incorporated by reference herein) and include, but are not limited to, statements pertaining to the following:

- the impacts of Bill 21 enacted by the Government of Quebec;
- Questerre's corporate strategy;
- the scalability and impact of Questerre's projects;
- Questerre's competitive position;
- Questerre's reserves and resources;
- any estimate of present value or future net cash flow;
- drilling inventory, drilling plans and timing of drilling, completion and tie-in of wells;
- plans for facilities and infrastructure construction;
- the assessment of the design of the oil shale project in Jordan;
- negotiation of the concession for the oil shale project in Jordan;
- assessment of the Utica shale gas discovery in the St. Lawrence Lowlands, Quebec;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- joint venture participation;
- drilling, completion and facilities costs;
- results of various projects, current and anticipated, of Questerre;
- the implementation of processing, transportation and marketing agreements;
- regulatory approvals;
- Questerre's development plans;
- the tax horizon and taxability of Questerre;
- properties with no attributed reserves;
- abandonment and reclamation costs;
- Questerre's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of governmental regulation on Questerre;
- projections of commodity prices and costs;
- expectations regarding the ability to raise capital;
- Questerre's ability to finance future development costs;
- expected royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses including, but not limited to, financial commitments;
- the evaluation of the proprietary process developed by Red Leaf;
- capital expenditure programs;
- treatment under current, new and proposed government regulation and fiscal regimes, including those in Quebec;
- the Company's dividend policy;
- potential conflicts of interest; and
- expectations regarding the risk factors faced by Questerre, including mitigation thereof and the potential effects thereof.

The Company's 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 AIF:

- Quebec's Bill 21 and compensation prescribed therein;
- volatility in market prices for oil, natural gas liquids and natural gas due to, among other things, the production agreements between OPEC and its allies, including Saudi Arabia and Russia, on production levels, the war in Ukraine, and conflict in the Middle East;
- trade disputes involving Canada, Mexico, China, the European Union and the United States;
- general economic conditions in Canada, the United States and globally including reduced availability of debt and equity financing generally;
- industry conditions, including fluctuations in the price of oil, NGLs and natural gas;
- governmental regulation of the oil and natural gas industry, including environmental regulation;
- adverse judicial rulings, regulatory rulings, orders and decisions;
- fluctuation in foreign exchange or interest rates;
- liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- uncertainties associated with estimating oil and natural gas reserves;
- insufficient advancement by Red Leaf in the engineering of its process;
- incorrect assessments of the value of acquisitions;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to realize anticipated benefits of acquisitions;
- failure to obtain industry partner and other third-party consents and approvals, when required;
- stock market volatility and market valuations;
- geopolitical instability;
- availability of financing on acceptable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped land, and skilled personnel;
- competition for and inability to retain drilling rigs and other services;
- rights to surface access;
- the need to obtain required approvals from regulatory authorities;
- general business and market conditions; and
- the other factors considered under "Risk Factors" in this AIF and other risk factors identified in other documents incorporated herein by reference.

These factors should not be considered exhaustive. Statements relating to "reserves" and "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future. With respect to forward-looking statements contained or incorporated by reference in this AIF, Questerre has made assumptions regarding: future exchange rates; energy markets and the price of oil and natural gas; the impact of increasing competition; condition of general economic, commodity and financial markets; availability of drilling and related equipment; availability of skilled labour; availability of prospective drilling rights; current technology; cash flow; commodity prices; production rates; effects of regulation and environmental and tax laws; future operating costs and the Company's ability to obtain financing on acceptable terms. In addition, forward-looking statements in documents incorporated by reference herein may be based on additional assumptions as disclosed in such documents. Readers are cautioned that the foregoing list of factors is not exhaustive.

The above summary of assumptions and risks related to forward-looking information has been provided in this AIF and the documents incorporated by reference herein to provide readers with a more complete perspective

on Questerre's future operations and prospects. Readers are cautioned that this information may not be appropriate for other purposes.

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

The forward-looking statements contained in this AIF and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The Company does not intend, and does not assume any obligation, to update or revise these forward-looking statements except as required pursuant to applicable securities laws.

NON-GAAP MEASURES

This AIF uses "netback" which does not have standardized meanings prescribed by generally accepted accounting principles and therefore may not be comparable measures to other companies where similar terminology is used. Netback denotes petroleum and natural gas revenue less royalties, operating expenses and transportation and marketing expenses.

PRESENTATION OF OIL AND GAS INFORMATION

All oil and gas information contained in this AIF and the documents incorporated by reference herein, has been prepared and presented in accordance with NI 51-101. The actual oil and gas reserves and future production will be greater than or less than the estimates provided herein. The estimated value of future net revenue from the production of the disclosed oil and gas reserves does not represent the fair market value of these reserves. There is no assurance that the forecast prices and costs or other assumptions made in connection with the reserves disclosed herein will be attained and variances could be material.

For more information on reserves categories, see Appendix C – *Definitions Used for Reserves Categories*.

**APPENDIX A
FORM 51-101F2
REPORT ON RESERVES DATA
BY AN INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

To the Board of Directors of Questerre Energy Company (the “Company”):

1. We have evaluated the Company’s reserves data as at December 31, 2025. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the “COGE Handbook”) maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2025, and identifies the respective portions thereof that we have evaluated and reported on to the Company’s Board of Directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net revenue \$M (before income taxes, 10% discount)			
			Audited	Evaluated	Reviewed	Total
McDaniel	December 31, 2025	Canada	—	133,346.00	—	133,346.00

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd.
2000, 525 – 8th Avenue SW
Calgary, Alberta T2P 1G1

Per: Signed “Michael Verney”
Michael J. Verney, P.Eng.
Executive Vice President

Calgary, Alberta, Canada
March 9, 2026

**APPENDIX B
FORM 51-101F2
REPORT ON RESERVES DATA
BY AN INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

To the Board of Directors of Questerre Energy Company (the “Company”):

1. We have evaluated the Company’s reserves data as at December 31, 2025. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025 estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the “COGE Handbook”) maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2025, and identifies the respective portions thereof that we have evaluated and reported on to the Company’s Board of Directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net revenue \$M (before income taxes, 10% discount)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	December 31, 2025	Brazil	—	371,951.00	—	371,951.00

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Inc.
1920, 401 -9 Avenue SW
Calgary, Alberta T2P 3C5

Per: Signed “Wendy Akins”

Executive Vice President

Calgary, Alberta, Canada
March 23, 2026

APPENDIX C
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Questerre Energy Company (the “**Company**”) is responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company’s reserves data. The report of the independent qualified reserves evaluators is presented above.

The Reserves Committee of the board of directors of the Company has

- (a) reviewed the Company’s procedures for providing information to the independent qualified reserves evaluators;
- (b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors has reviewed the Company’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserve Committee, approved

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data, contingent resources data and prospective resources data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary, and the variations may be material.

(signed) “Michael Binnion”
Michael Binnion
President and Chief Executive Officer

(signed) “David Pellegrin”
David Pellegrin
Senior Production Engineer

(signed) “Hans Jacob Holden”
Hans Jacob Holden
Director

(signed) “Bjorn Inge Tonnessen”
Bjorn Inge Tonnessen
Director

March 31, 2026

APPENDIX D DEFINITIONS USED FOR RESERVE CATEGORIES

The following reserves definitions are set out by the Canadian Securities Administrators in CSA Staff Notice 51-324 and are derived from Section 5 of Volume 1 of the COGE Handbook (Second Edition, September 1, 2007). Readers should consult a current edition of the COGE Handbook for updates and for additional explanation and guidance.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates

- (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
- (c) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Development and Production Status

Each of the reserve categories (proved, probable and possible) may be divided into developed and undeveloped categories:

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
 - (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
 - (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest-level sum of individual entity estimates for which reserves estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, most reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5 of the *COGE Handbook*.

**APPENDIX E
AUDIT COMMITTEE INFORMATION
REQUIRED IN AIF**

The Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Appendix E.

Composition of the Audit Committee

The following table sets forth the names of each current member of the Audit Committee, whether such member is independent, whether such member is financially literate and the relevant education and experience of such member:

<u>Name</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Dennis Frank Sykora, Chair	Yes	Yes	<p>Mr. Sykora is an independent businessperson.</p> <p>Director and Chair of the Audit Committee of Dominion Lending Centres Inc., a TSX listed corporation that is Canada's leading network of mortgage professionals with over 8500 agents across Canada.</p> <p>Mr. Sykora was formerly a director of High Arctic Energy Services Inc. ("High Arctic"), a TSX listed oilfield services company from 2007 to 2016. He was also employed in various executive positions at High Arctic, including Chief Executive Officer, Executive Vice President, General Counsel and Chief Restructuring Officer.</p> <p>Mr. Sykora was a director and member of the Audit Committee for Canadian First Financial Group and CFF Bank from 2012 to 2014.</p> <p>Prior to joining High Arctic, Mr. Sykora was President of Roll'n International Group from 1996 to 2007.</p>

Name	Independent	Financially Literate	Relevant Education and Experience
Hans Jacob Holden	Yes	Yes	<p>Mr. Sykora is both a Chartered Professional Accountant and a lawyer and a member of the Law Society of Alberta. He practiced with Felesky Flynn LLP from 1991 to 1996 and with Ernst & Young from 1981 to 1990.</p> <p>Mr. Sykora holds a Bachelor of Commerce from the University of Saskatchewan and a Bachelor of Laws from the University of Calgary.</p> <p>Mr. Holden is an independent businessperson. Previously, a business development advisor at AF Gruppen a leading contracting and industrial group based in Norway from January 2018 to March 2022.</p> <p>Mr. Holden served as a Director of Seatankers Group from January to November 2017.</p> <p>Mr. Hans Jacob Holden served as Section Manager of the Reservoir Department of Saga Petroleum ASA.</p> <p>Mr. Holden has over twenty-five years' experience in the international oil and natural gas industry, with a focus on corporate finance, in the last sixteen years. From 2004 to 2016, Mr. Holden was employed by Pareto Securities AS.</p>

Name	Independent	Financially Literate	Relevant Education and Experience
Bjorn Inge Tonnessen	Yes	Yes	<p>Mr. Tonnessen is an independent businessman, Executive Chair of Transitus Energy, a private energy transition company and Executive Chair of Geothermal Energy Nordic. He was formerly CEO and CFO of Edge Petroleum AS from 2017 to 2021. From June 2012 to May 2017, he was President of Spike Exploration, a private Norwegian exploration and production company. Prior thereto, he was Managing Director in Norway and Executive Vice President License Management for the Svenska Group, a private Swedish based exploration and production company.</p> <p>He was formerly the senior energy analyst with DNB NOR Markets ASA from January 2003 to July 2007 and an equity analyst with Handelsbanken Capital Markets from October 2001 to November 2002. Prior thereto he was employed by the Svenska Group in a variety of progressively more senior roles including exploration and production manager for a large part of the company's portfolio. Mr. Tonnessen has also been working as an offshore drilling engineer for several years.</p> <p>Mr. Tonnessen holds a Bachelors' degree in Petroleum Engineering from Stavanger University in Norway and an MBA equivalent degree from Stockholm University in Sweden.</p>

Pre-Approval of Policies and Procedures

As of the date hereof the Audit Committee has not adopted specific policies or procedures in respect of the provision of non-audit services to the Company.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were \$529,215-\$569,215 in 2025 and \$195,698 in 2024.

Audit – Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Company's external auditor that are reasonably related to the performance of the audit or review of the Company's financial statements that are not reported under "Audit Fees" above were \$15,750 and \$15,750 in 2025 and 2024.

Tax Fees

The aggregate fees billed in 2025 for professional services rendered by the Company's external auditor for tax compliance, tax advice and tax planning were \$35,129 (2024: \$17,082).

All Other Fees

There were no additional fees for products and services provided by the Company's auditors other than services reported above.

APPENDIX F
AUDIT COMMITTEE MANDATE
AND TERMS OF REFERENCE
CHARTER

A. Composition and Process

- 1) The Audit Committee shall be composed of a minimum of three directors, all of whom shall be independent as that term is defined in National Instrument 52-110, Audit Committees (“NI 52-110”). An independent member of the audit committee is a member who has no direct or indirect material relationship with the Company. A material relationship means a relationship which could, in the view of the Company’s board of directors, reasonably interfere with the exercise of the member’s independent judgment. Pursuant to NI 52-110, a person who is or has been, or whose immediate family member is or has been:
 - i) an officer or employee of the Company, a subsidiary or affiliate;
 - ii) an affiliate, partner or employee of a current or former internal/external auditor of the Company;
 - iii) employed as an executive officer of an entity if any of the Company’s current executives serve or have served on the entity’s compensation committee;
 - iv) a person who accepts or has accepted, directly or indirectly, a consulting, advisory or compensatory fee from the issuer or subsidiary of the Company;
 - v) a person who is an affiliate of the Company or subsidiary of the Companyis considered to have a material relationship with the Company unless the period prescribed by NI 52-110 has elapsed.
- 2) Members shall serve one-year terms and may serve consecutive terms, which are encouraged to ensure continuity of experience.
- 3) The Chairperson shall be appointed by the Board of Directors for a one-year term and may serve any number of consecutive terms.
- 4) All members of the Audit Committee shall be financially literate. Financial literacy is the ability to read and understand a balance sheet, income statement and cash flow statement that present a breadth and level of complexity comparable to the Company’s financial statements.
- 5) The Chairperson shall, in consultation with management and the external auditor and internal auditor (if any), establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the members with sufficient time for study prior to the meeting. The external auditor will also receive notice of all meetings of the Audit Committee. The Audit Committee may employ a list of prepared questions and considerations as a portion of its review and assessment process.
- 6) The Audit Committee shall meet at least four times per year and may call special meetings as required. A quorum at meetings of the Audit Committee shall be its Chairperson and one of its other members or the Chairman of the Board of Directors. The Audit Committee may hold its meetings, and members of the Audit Committee may attend meetings, by telephone conference if this is deemed appropriate.

- 7) The minutes of the Audit Committee meetings shall accurately record the decisions reached and shall be distributed to Audit Committee members with copies to the Board of Directors, the Chief Executive Officer, the Chief Financial Officer and the external auditor.
- 8) The Audit Committee reviews, prior to their presentation to the Board of Directors and their release, all material financial information required by securities regulations.
- 9) The Audit Committee enquires about potential claims, assessments and other contingent liabilities.
- 10) The Audit Committee periodically reviews with management, depreciation and amortization policies, loss provisions and other accounting policies for appropriateness and consistency.
- 11) The Charter of the Audit Committee shall be reviewed by the Board of Directors on an annual basis.

B. Authority

- 12) Appointed by the Board of Directors pursuant to provisions of the *Business Corporations Act* (Alberta) and the bylaws of the Company.
- 13) Primary responsibility for the Company's financial reporting, accounting systems and internal controls is vested in senior management and is overseen by the Board of Directors. The Audit Committee is a standing committee of the Board of Directors established to assist it in fulfilling its responsibilities in this regard. The Audit Committee shall have responsibility for overseeing management reporting on internal controls. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the Audit Committee to ensure that management has done so.
- 14) The Audit Committee shall have unrestricted access to the Company's personnel and documents and will be provided with the resources necessary to carry out its responsibilities.
- 15) The Audit Committee shall have direct communication channels with the internal auditors (if any) and the external auditors to discuss and review specific issues as appropriate.
- 16) The Audit Committee shall have the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties.
- 17) The Audit Committee shall set and pay the compensation for any advisors employed by the Audit Committee.

C. Relationship with External Auditors

- 18) An external auditor must report directly to the Audit Committee.
- 19) The Audit Committee is solely responsible for overseeing the work of the external auditor including the resolution of disagreements between management and the external auditor regarding financial reporting.
- 20) The Audit Committee shall implement structures and procedures to ensure that it meets with the external auditor on a regular basis in the absence of management.

D. Accounting Systems, Internal Controls and Procedures

- 21) Obtain reasonable assurance from discussions with and/or reports from management, and reports from external auditors that accounting systems are reliable and that the prescribed internal controls are operating effectively for the Company and its subsidiaries and affiliates.
- 22) The Audit Committee shall review to ensure to its satisfaction that adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company's financial statements and will periodically assess the adequacy of those procedures.
- 23) The Audit Committee shall review with the external auditor the quality and not just the acceptability of the Company's accounting principles.
- 24) Direct the external auditor's examinations to particular areas.
- 25) Review control weaknesses identified by the external auditors, together with management's response.
- 26) Review with external auditors their view of the qualifications and performance of the key financial and accounting executives.
- 27) In order to preserve the independence of the external auditor the Audit Committee will:
 - i) recommend to the Board of Directors the external auditor to be nominated;
 - ii) recommend to the Board of Directors the compensation of the external auditor's engagement; and
 - iii) review and pre-approve any engagements for non-audit services to be provided by the external auditors or its affiliates, together with estimated fees, and consider the impact on the independence of the external auditor.
- 28) Review with management and with the external auditor any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material to financial reporting.
- 29) The Audit Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.
- 30) The Audit Committee shall establish a periodic review procedure to ensure that the external auditor complies with the Canadian Public Accountability Regime under National Instrument 52-108-Auditor Oversight.
- 31) The Audit Committee will review and approve the Company's hiring policies with regards to partners, employees and former partners and employees of the present and former auditor of the Company.

E. Statutory and Regulatory Responsibilities

- 32) Annual Financial Information - review the annual audited financial statements, including Letter to Shareholders and related press releases and recommend their approval to the Board of Directors, after

discussing matters such as the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates with management and the external auditor.

- 33) Annual Report - review the management's discussion and analysis ("MD&A") section and all other relevant sections of the annual report to ensure consistency of all financial information included in the annual report.
- 34) Interim Financial Statements - review the quarterly interim financial statements, including the Letter to Shareholders and related press releases and recommend their approval to the Board.
- 35) Earnings Guidance/Forecasts - review forecasted financial information and forward-looking statements.
- 36) Review the Company's financial statements, MD&A and earnings press releases before the Company publicly discloses this information.

F. Reporting

- 37) Report, through the Chairperson of the Audit Committee, to the Board of Directors following each meeting on the major discussions and decisions made by the Committee.
- 38) Report annually to the Board of Directors on the Committee's responsibilities and how it has discharged them.
- 39) Review the Committee's Charter annually and propose recommended changes to the Board.

G. Other Responsibilities

- 40) Investigating fraud, illegal acts or conflicts of interest.
- 41) Discussing selected issues with corporate counsel or the outside auditor or management.