LOGAN ENERGY CORP.

Annual Information Form

For the Year Ended December 31, 2023

March 18, 2024

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APPENDICES

The information in this AIF is given as of December 31, 2023, unless otherwise indicated.

DEFINITIONS

Throughout this Annual Information Form the terms set forth below have the following meanings, unless the context requires or indicates otherwise:

"**A&D**" means Acquisitions and Dispositions;

"**AB IR Program**" means the Alberta Inventory Reduction Program;

"**AB LCA**" means the Alberta Licensee Capability Assessment System;

"**AB LF Program**" means the Alberta Large Facility Liability Management Program;

"**AB LLR Program**" means the Alberta Licensee Liability Rating Program;

"**AB LM Program**" means the Alberta Licensee Management Program;

"**AB LMF**" means the Alberta Liability Management Framework;

"**AB LMR Program**" means the Alberta Liability Management Rating Program;

"**AB OWL Program**" means the Alberta Oilfield Waste Liability Program;

"**ABC**" means Area-Based Closure;

"**ABCA**" means the *Business Corporations Act* (Alberta) R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"**AER**" means Alberta Energy Regulator, an Alberta corporation responsible for regulating the development of energy resources in the province of Alberta;

"**AIF**" or "**Annual Information Form**" means this annual information form dated March18, 2024, for the year ended December 31, 2023;

"**Alberta Methane Regulations**" means the Methane Emission Reduction Regulation;

"**AUC**" means the Alberta Utilities Commission;

"**Bill C-15**" means *An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act*;

"**Bill C-69**" means Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, issued by the Canadian federal government;

"**Board**" or "**Board of Directors**" means the board of directors of Logan;

"**CCAA**" means the *Companies' Creditors Arrangement Act*, R.S.C. 1985, c. C-36;

"**CCUS**" means Carbon Capture, Utilization and Storage;

"**CEA Agency**" means the Canadian Environmental Assessment Agency;

"**CEAA**" means the *Canadian Environmental Assessment Act, 2012* (Canada), S.C. 2012, c. 19, s. 52;

"**Cequence**" means Cequence Energy Ltd.;

"**CER**" means the Canadian Energy Regulator;

"**CERA**" means the *Canadian Energy Regulator Act* (Canada), S.C. 2020, c.28;

"**CETA**" means Comprehensive Economic and Trade Agreement;

"**CFS**" means the Clean Fuel Standard;

"**CFS Regulations**" means the Clean Fuel Regulations;

"**CFTA**" means Canadian Free Trade Agreement;

"**CGL Pipeline**" means Coastal GasLink pipeline;

"**CLA**" means the *Climate Leadership Act*;

"**COGE Handbook**" means the most recent publication of the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means common shares in the capital of Logan;

"**Company**" or "**Logan**" means Logan Energy Corp., a corporation existing under the laws of the Province of Alberta;

"**Conveyance Agreement**" means the conveyance agreement dated June 20, 2023, between Spartan and Logan which provided for the conveyance of the Logan Assets from Spartan to Logan;

"**CO2e**" means carbon dioxide equivalents;

"**CPTPP**" means Comprehensive and Progressive Agreement for Trans-Pacific Partnership;

"**Credit Facility**" means the senior secured revolving demand credit facility of the Company;

"**CUKTCA**" means Canada-United Kingdom Trade Continuity Agreement;

"**Directive 017**" means Measurement Requirements for Oil and Gas Operations;

"**Directive 060**" means Upstream Petroleum Industry Flaring, Incinerating and Venting;

"**Directive 067**" means Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals;

"**Directive 088**" means Licensee Life-Cycle Management;

"**Distribution**" has the meaning ascribed thereto under "*General Development of the Business – Financial Year ended December 31, 2023*";

"**DRIPA**" means the *Declaration on the Rights of Indigenous Peoples Act*;

"**Enbridge**" means Enbridge Inc.;

"**Escrow Agreement**" means the escrow agreement dated July 19, 2023, among Logan, Odyssey Trust Company, as escrow agent, certain brokers, and certain holders of Common Shares;

"**Federal Methane Regulations**" means the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*;

"**Federal Offset Credit Regulations**" means the *Greenhouse Gas Offset Credit System Regulations* (Canada);

"**GAAP**" means Canadian Generally Accepted Accounting Principles, which incorporate International Financial Reporting Standards ("**IFRS**") for public companies;

"**GCA**" means Gas Cost Allowance;

"**GGPPA**" means the *Greenhouse Gas Pollution Pricing Act* (Canada), S.C. 2018, c. 12, s. 186;

"**GHG**" means greenhouse gas;

"**GHG Cap**" means the Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap;

"**GORR Interests**" means Gross Overriding Royalty Interests;

"**HEHE Plan**" means the Healthy Environment and a Healthy Economy Plan;

"**IA Agency**" means the Impact Assessment Agency of Canada;

"**IAA**" means the *Impact Assessment Act* (Canada), S.C. 2019, c. 28, s. 1;

"**IFRS Accounting Standards**" means International Financial Reporting Standards as issued by the International Accounting Standards Board up to March 18, 2024;

"**Interim Guidance**" has the meaning ascribed thereto in "*Industry Factors – Transportation Constraints, Pipeline Capacity and Market Access – Specific Pipeline Updates*";

"**IOGA**" means Indian Oil and Gas Act;

"**IOGC**" means Indian Oil and Gas Canada, a Federal Government agency;

"**LGN**" means the Company's trading symbol for Common Shares on the TSX-V;

"**Logan Assets**" means the assets acquired by Logan from Spartan pursuant to the Conveyance Agreement, consisting of production in the Pouce Coupe and Simonette areas of north-west Alberta, legacy north-east British Columbia production, and undeveloped acres in the Flatrock area of north-east British Columbia;

"**Logan Financing**" means the non-brokered private placement of Common Shares and Units of the Company which closed on July 12, 2023, at a subscription price of $0.35 per Common Share or Unit, as applicable, for aggregate gross proceeds of approximately $48.5 million;

"**Market Price**" means the volume weighted average trading price of the Common Shares on the stock exchange upon which the Common Shares are listed and posted for trading (or if the Common Shares are then listed and posted for trading on more than one stock exchange, on such stock exchange on which the majority of the trading volume and value of the Common Shares occurs) for the ten (10) trading days immediately preceding the particular day, calculated by dividing the total value by the total volume of Common Shares traded for the ten (10) trading day period; or, if the Common Shares are not listed upon a stock exchange in Canada, the Current Market Price in respect of a Common Share shall be determined by the Board acting reasonably and in good faith.

"**McDaniel**" means McDaniel & Associates Consultants Ltd.;

"**McDaniel Report**" means the independent engineering report dated March 18, 2024, and evaluating the crude oil, natural gas and NGL reserves of the Company effective as of December 31, 2023;

"**Modern Slavery Act**" means the Act to enact the Fighting Against Forced Child Labour in Supply Chains Act and to amend the Customs Tariff;

"**Montney**" means the area within the Western Canadian Sedimentary Basin that is north of Whitecourt, Alberta;

"**MRF**" means the Modern Royalty Framework;

"**MRGGA**" means *The Management and Reduction of Greenhouse Gases Act*;

"**NAFTA**" means the North American Free Trade Agreement;

"**NEB**" means the National Energy Board;

"**NEB Act**" means the *National Energy Board Act* (Canada), R.S.C. 1985, c N-7;

"**NGTL System**" means NOVA Gas Transmission Ltd. pipeline network;

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*;

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations*;

"**OBPS**" means the Output-Based Pricing System;

"**OPEC+**" means the Organization of the Petroleum Exporting Countries plus other oil-producing countries;

"**Option Plan**" means the Company's existing stock option plan;

"**Options**" means stock options to purchase Common Shares granted pursuant to the Option Plan;

"**Orphan Fund**" means Alberta's orphan fund to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licensee or working interest participant becomes insolvent or is unable to meet its obligations;

"**Part VI Regulation**" means National Energy Board Act Part VI (Oil and Gas) Regulation;

"**Redwater**" means the SCC's decision in *Orphan Well Association v Grant Thornton*;

"**SCC**" means the Supreme Court of Canada;

"**SEDAR+**" means the System for Electronic Document Analysis and Retrieval Plus;

"**Share Award Incentive Plan**" means the Company's existing share award incentive plan;

"**Sovereignty Act**" means the Alberta Sovereignty Within a United Canada Act;

"**Spartan**" means Spartan Delta Corp., a corporation incorporated under the ABCA;

"**Spartan Shares**" means common shares in the capital of Spartan;

"**Spin-Out**" means the spin-out of the Logan Assets from Spartan to Logan pursuant to the Conveyance Agreement;

"**SSN**" means the Stk'emlupsemc Te Secwepemc Nation;

"**Statement**" has the meaning ascribed thereto in "*Statement of Reserves Data and Other Oil and Gas Information – Date of Statement*";

"**TC Energy**" means TC Energy Corporation;

"**Temporary Service Protocol**" means the CER approved policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network to prioritize deliveries into storage;

"**TIER**" means the Technology Innovation and Emissions Reduction regulation;

"**Transaction Warrant**" means the Common Share purchase warrants issued in connection with the Spin-Out, which warrants were distributed to eligible holders of Spartan Shares pursuant to the Distribution, each Transaction Warrant being non-transferrable and entitling the holder thereof to acquire one (1) Common Share at an exercise price equal to $0.35 per Common Share at any time on or before the close of business on August 14, 2023;

"**TSX-V**" means the TSX Venture Exchange;

"**UNDRIP**" means the *United Nations Declaration of the Rights of Indigenous Peoples*;

"**United States**" or "**U.S.**" means the United States of America and includes its territories and possessions;

"**UNFCCC**" means the United Nations Framework Convention on Climate Change;

"**USMCA**" means the United States Mexico Canada Agreement;

"**Waldron**" means Waldron Energy Corporation; and

"**Warrants**" means the Common Share purchase warrants issued pursuant to the Units subscribed for under the Logan Financing, each Warrant entitling the holder thereof to purchase one (1) Common Share at an exercise price of $0.35 for a period of five years from the date of issuance of such Warrants.

CONVENTIONS

Certain other terms used but not defined in this AIF are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and, unless the context otherwise requires, have the same meanings as ascribed to them in NI 51-101. Unless otherwise indicated, references in this AIF to "$" or "dollars" are to Canadian dollars. All financial information with respect to the Company has been presented in Canadian dollars. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

SELECTED ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
bbls	barrels	MMcf	million cubic feet
Mbbl	thousand barrels	Mcf/d	thousand cubic feet per day
bbl/d	barrels per day	MMcf/d	million cubic feet per day
NGL(s)	natural gas liquid(s)	MMbtu	million British Thermal Units

Other

AECO	Alberta Energy Company "C" Meter Station of the NOVA Pipeline System;
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
km	kilometers

m^3	cubic metres
Mcfe	means 1,000 cubic feet equivalent on the basis of one bbl of crude oil for six Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
MBOE	1,000 barrels of oil equivalent
M$	thousands of dollars
sqkm	square kilometers
US$	United States Dollars
C$	Canadian Dollars
WTI	West Texas Intermediate, price paid in US$ at Cushing, Oklahoma, for crude oil of standard grade

Measurements expressed in BOE or Mcfe may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl and an Mcfe conversion ratio of 1 bbl:6 Mcf are based on an approximate energy equivalency conversion method primarily applicable at 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.

SELECTED CONVERSIONS

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic meters	28.320
Cubic meters	cubic feet	35.315
Bbls	cubic meters	0.159
Cubic meters	bbls	6.290
Feet	metres	0.305
Meters	feet	3.281
Miles	kilometres	1.609
Kilometres	miles	0.621
Acres	hectares	0.405
Hectares	acres	2.471

NOTICE TO READER

Special Note Regarding Forward-Looking Statements

Certain statements contained in this AIF constitute forward-looking statements. These statements relate to future events or the Company's future plans or performance. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements or information is often, but not always, identified by the use of words such as "anticipate", "budget", "continue", "evaluate", "monitor", "can", "able", "potential", "consider", "believe", "could", "estimate", "expect", "forecast", "guidance", "intend", "may", "plan", "predict", "project", "should", "focus", "target", "will", or similar words suggesting future outcomes or language suggesting an outlook. 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's presentation of forward-looking information is based on internally generated budgets relating to drilling plans and related costs, expected results from drilling as well as estimated royalties, operating costs and administrative expenses. Logan bases the commodity pricing for budget purposes on a range of publicly available pricing forecasts and considers general economic conditions. Management believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Such forward-looking statements should not be unduly relied upon.

In particular, this AIF contains forward-looking statements pertaining to the following:

- business strategy, objectives, strength and focus;
- the performance characteristics of the Company's oil and natural gas properties;
- oil and natural gas production levels;
- expectations regarding the Company's growth and risk profile;
- the size of the Company's oil and natural gas reserves;
- projections of market prices and costs, including increased operating and capital costs due to inflationary pressures;
- supply of, and demand for, oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- the ability of the Company to achieve drilling success consistent with management's expectations;
- drilling plans, expectations and timing of drilling;
- the Company's ability to attract and retain qualified personnel;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- treatment under governmental regulatory regimes and tax laws;
- expected effect of regulatory regimes and controls;
- tax horizon and future income taxes;
- use of Credit Facility funds;
- expectations regarding commodity prices in 2024;
- expectations regarding dividends;
- capital expenditure programs and the timing and method of financing thereof; and
- abandonment and reclamation costs.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. See "*Statement of Reserves Data and Other Oil and Gas Information*".

The forward-looking information and statements contained in this AIF reflect management's current views and are based on certain assumptions, including assumptions as to future economic conditions and courses of action, as well as other factors that management believes are appropriate in the circumstances. Such forward-looking statements are subject to risks and uncertainties and no assurance can be made that any of the events anticipated by such statements will occur or, if they do occur, what benefit the Company will derive from them. The Company has made assumptions regarding, among other things:

- the ability of the Company to achieve drilling success consistent with management's expectations;
- the ability of the Company to secure equipment, services, supplies and personnel in a timely manner and at an acceptable cost to carry out its activities;
- the timing and cost of pipeline and facility construction and expansion and the ability of the Company to secure adequate product transportation;
- the timely receipt of required regulatory approvals;
- the ability of the Company to market its oil and natural gas and to transport its oil and natural gas to market;
- the ability of the Company to obtain capital to finance its exploration, development and operations;
- the accuracy of the Company's reserves volumes;
- access to capital and the continued availability of adequate financing proceeds, credit facilities and funds flow to fund the Company's business strategy;
- expectations and assumptions concerning applicable tax laws; and
- future oil and natural gas prices, exchange rates, interest rates and inflation rates.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this AIF:

- volatility in market prices for oil and natural gas;
- lack of transportation and inability to produce oil and natural gas reserves and resources;
- adverse regulatory rulings, orders and decisions;
- liabilities inherent in oil and gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling and processing problems and other problems in producing reserves and resources;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- stock market volatility and market valuations;
- inflationary cost pressures and their impact on the Company's business, including the ability of third parties to manage such cost pressures;
- the impact of climate change and climate change regulations;
- effects of inclement and severe weather events, including fire, drought, flooding and extreme cold temperatures;
- possible renegotiation and replacement of international trade agreements;
- the risks of the oil and natural gas industry both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- the failure to obtain industry partner and other third-party consents and approvals, as and when required;
- the availability of capital on acceptable terms;
- actions by governmental or regulatory authorities including changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry;
- changes in income tax laws or changes in tax laws or trade laws and incentive programs relating to the oil and natural gas industry;
- political uncertainty;
- environmental and Indigenous activism that may result in delays or cancellations of projects;
- global or national health concerns, including the outbreak of pandemic or contagious diseases; and
- the other factors discussed under "*Risk Factors*".

These factors should not be considered as exhaustive. The reader is cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved will vary from the information provided herein and the variations may be material. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there are no representations by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this AIF are made as of the date hereof, and the Company undertakes no obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Non-GAAP Measures and Ratios

This AIF contains certain financial measures and ratios, as described below, which do not have standardized meanings prescribed by IFRS Accounting Standards or GAAP. As these non-GAAP financial measures and ratios are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used. The non-GAAP financial measures and ratios used in this AIF, represented by the capitalized and defined terms outlined below, are used by Logan as key measures of financial performance and are not intended to represent operating profits nor should they be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with IFRS Accounting Standards.

Operating Income and Operating Netback

"**Operating Income**" (non-GAAP financial measure) is a useful supplemental measure that provides an indication of the Company's ability to generate cash from field operations, prior to administrative overhead, financing and other business expenses. "**Operating Income**" is calculated by Logan as oil and gas sales, net of royalties, plus processing and other revenue, less operating and transportation expenses. The Company refers to Operating Income expressed per unit of production as an "**Operating Netback**" which is a non-GAAP financial ratio. Logan considers Operating Netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices.

The components of Logan's Operating Income and Operating Netbacks for the annual periods ended December 31, 2023 and 2022 are outlined below:

(CA$ thousands, except per BOE amounts)	**2023**	**2022**	**2023**	**2022**
			($/BOE)	**($/BOE)**
Oil and gas sales	**78,858**	124,535	**37.19**	54.27
Processing and other revenue	**3,388**	3,325	**1.60**	1.45
Royalties	**(9,528)**	(17,025)	**(4.49)**	(7.42)
Operating expenses	**(31,073)**	(32,458)	**(14.65)**	(14.14)
Transportation expenses	**(8,069)**	(7,583)	**(3.81)**	(3.30)
Operating Income	**33,576**	70,794	**15.84**	30.86

Adjusted Funds Flow

"**Adjusted Funds Flow**" is calculated by Logan as cash provided by operating activities before changes in non-cash working capital and adding back transaction costs (if any). Logan utilizes Adjusted Funds Flow as a key performance measure in the Company's annual financial forecasts and public guidance. Logan believes Adjusted Funds Flow provides useful information to understand the cash flows generated by the Company's operations during the current production period excluding the impact of timing of payments and cash receipts. Transaction costs, which primarily include legal and financial advisory fees, regulatory and other expenses directly attributable to execution of acquisitions and dispositions ("**A&D**"), are excluded to provide a measure representing cash flow generated by the Company's routine business operations. For greater clarity, incremental overhead expenses related to ongoing integration and restructuring post-acquisition (if applicable) are not adjusted and are included in Logan's general and administrative expenses. The Company refers to Adjusted Funds Flow expressed per unit of production as an "**Adjusted Funds Flow Netback**".

The following table reconciles cash provided by operating activities, as determined in accordance with IFRS Accounting Standards, to Funds from Operations and Adjusted Funds Flow for the annual periods ended December 31, 2023 and 2022:

(CA$ thousands)	**2023**	**2022**
Cash provided by operating activities	**23,954**	67,115
Change in non-cash operating working capital	**5,350**	(3,010)
Add back: transaction costs	**43**	-
Adjusted Funds Flow	**29,347**	64,105

Capital Expenditures

Logan uses "**Capital Expenditures before A&D**" to measure its capital investment level compared to the Company's annual budgeted capital expenditures for its organic drilling program, excluding acquisitions or dispositions. "**Capital Expenditures**" is calculated by adding cash acquisition costs, net of proceeds from dispositions to Capital Expenditures before A&D. The directly comparable GAAP measure is cash used in investing activities. The following table details the composition of capital expenditures and its reconciliation to cash used in investing activities for the annual periods ended December 31, 2023 and 2022:

(CA$ thousands)	**2023**	**2022**
Exploration and evaluation assets	**8,126**	5,611
Property, plant and equipment	**72,280**	2,030
Capital Expenditures before A&D	**80,406**	7,641
Acquisitions	**5,395**	-
Dispositions	**-**	(88)
Capital Expenditures	**85,801**	7,553
Change in non-cash investing working capital	**17,569**	14,562
Cash used in investing activities	**68,232**	22,115

This AIF also contains certain oil and natural gas metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

BACKGROUND

The Company was incorporated pursuant to the ABCA on March 10, 2023 under the name "2499938 Alberta Ltd.", as a wholly-owned subsidiary of Spartan. On March 22, 2023, the Company filed Articles of Amendment changing its name to "Logan Energy Corp." from "2499938 Alberta Ltd.". Logan was incorporated for the purpose of oil and natural gas production, exploration and acquisition in the Pouce Coupe and Simonette areas of north-west Alberta of the Montney resource trend, and in the Flatrock area of north-east British Columbia. As of December 31, 2023 and the date hereof, Logan has no subsidiaries.

On June 20, 2023, pursuant to the terms of the Conveyance Agreement, Logan acquired the Logan Assets from Spartan. At the time of the Spin-Out, the Logan Assets were comprised of approximately 4,000 BOE/d of production in the Pouce Coupe and Simonette areas of north-west Alberta, 500 BOE/d of legacy north-east British Columbia production and 55,769 net undeveloped acres in the Flatrock area of north-east British Columbia. The primary assets transferred to Logan consisted of 193,000 net acres of high working interest 95% Montney Crown land across three properties (Simonette, Pouce Coupe and Flatrock). Pursuant to the terms of the Conveyance Agreement, the Spin-Out was completed for consideration equivalent to the fair market value of the Logan Assets in the aggregate amount of approximately $60.6 million, which was satisfied by the issuance by Logan to Spartan of the Common Shares and the Transaction Warrants, which securities Spartan distributed to eligible holders of Spartan Shares pursuant to the Distribution.

The head office of Logan is located at Suite 1800, 736 – 6th Avenue S.W., Calgary, Alberta T2P 3T7 and its registered office is located at Suite 4200, 888 - 3rd Street S.W., Calgary, Alberta T2P 5C5.

GENERAL DEVELOPMENT OF THE BUSINESS

Logan is a growth-oriented exploration, development and production company formed through the spin-out of Spartan's early stage Montney assets. Logan is founded with a strong initial capitalization and three high-quality and opportunity rich Montney assets located in the Simonette and Pouce Coupe areas of northwest Alberta and the

Flatrock area of northeastern British Columbia. The management team brings proven leadership and a track record of generating excess returns in various business cycles. The following is a summary of the key developments occurring in Logan's business since inception.

Financial Year Ended December 31, 2023

On March 10, 2023, the Company was incorporated under the ABCA under the name "2499938 Alberta Ltd.", as a wholly-owned subsidiary of Spartan. Richard McHardy was appointed as the sole director of the Company on incorporation.

On March 22, 2023, the Company filed Articles of Amendment changing its name to "Logan Energy Corp." from "2499938 Alberta Ltd.".

On June 20, 2023, Logan commenced active operations as a new growth-oriented exploration, development and production company formed through the spin-out (the "**Spin-Out**") of the early stage Montney assets of Spartan. Pursuant to the terms of the Conveyance Agreement, Spartan transferred the Logan Assets to Logan in exchange for one (1) Common Share and one (1) Common Share purchase warrant ("**Transaction Warrant**") for each Spartan Share. At the time of the Spin-Out, the Logan Assets were comprised of approximately 4,000 BOE/d of production in the Pouce Coupe and Simonette areas of north-west Alberta, 500 BOE/d of legacy north-east British Columbia production and 55,769 net undeveloped acres in the Flatrock area of north-east British Columbia. In aggregate, 173,201,341 Common Shares and 173,201,341 Transaction Warrants were issued to Spartan in consideration for the Logan Assets, representing the fair market value thereof in the aggregate amount of approximately $60.6 million. The Common Shares and Transaction Warrants issued to Spartan in connection with the Spin-Out were distributed to eligible holders of Spartan Shares on July 6, 2023, in addition to $9.50 per Spartan Share in connection with the sale of certain assets by Spartan to Crescent Point Energy Corp. effective May 1, 2023 (collectively, the "**Distribution**"). Concurrent with the Distribution, Logan ceased to be a subsidiary of Spartan and is now a stand-alone legal entity. The Transaction Warrants expired on August 14, 2023.

On July 12, 2023, the Company closed a non-brokered private placement for aggregate gross proceeds of approximately $48.5 million (the "**Logan Financing**"). The Logan Financing included:

(a) a non-brokered private placement of 64.3 million units (each, a "**Unit**") at a price of $0.35 per Unit for aggregate gross proceeds of approximately $22.5 million; and
(b) a non-brokered private placement of 74.3 million Common Shares at a price of $0.35 per Common Share for aggregate gross proceeds of approximately $26.0 million.

Each Unit issued pursuant to the Logan Financing was comprised of one (1) Common Share and one (1) Common Share purchase warrant (each, a "**Warrant**"). Each Warrant entitles the holder thereof to purchase one (1) Common Share at a price of $0.35 for a period of five (5) years. The Warrants vested and became exercisable as to one-third upon the Market Price of the Common Shares equaling or exceeding $0.70, an additional one-third upon the Market Price equaling or exceeding $0.7875 and a final one-third upon the Market Price equaling or exceeding $0.875. The Warrants are fully vested and exercisable.

On July 18, 2023, the Company's Common Shares commenced trading on the facilities of the TSX-V under the trading symbol "LGN".

On July 26, 2023, the Company executed a $15.0 million senior secured revolving demand credit facility with National Bank of Canada (the "**Credit Facility**"). The Credit Facility was established to provide the Company with access to additional liquidity.

Recent Developments

On March 18, 2024, the Company’s lender increased the authorized borrowing amount available under the Credit Facility from $15.0 million to $50.0 million.

Significant Acquisitions

Other than pursuant to the Spin-Out, Logan did not complete any significant acquisitions during its mostly recently completed financial year for which disclosure is required under Part 8 of NI 51-102. A business acquisition report was not completed as Logan was not a reporting issuer prior to the completion of the Spin-Out.

DESCRIPTION OF THE BUSINESS

Business Objectives and Strategy

Logan's business strategy is to develop its assets to grow production and cash flow while accumulating and delineating high quality inventory to provide compelling risk adjusted returns to shareholders.

- ***Develop and grow its assets*.** Logan intends to develop its assets to grow production and cash flow. Logan will deploy optimized well designs and development strategies to maximize the capital efficiency of its development drilling. Infrastructure will be built out or expanded as required to support the growth plan.

- ***Identify, acquire and delineate high quality inventory*.** Logan's existing asset base is rich in drilling inventory. Additionally, management has a track record of identifying and acquiring high quality and undervalued inventory and intends to grow the company's drilling inventory as part of the strategy. Management believes that high quality drilling inventory is becoming scarce and believes adding and delineating drilling inventory will contribute to strong equity returns.

- ***Focus on execution and cost discipline*.** While growing, Logan will maintain a focus on reliable execution and well delivery with a focus on cost discipline.

- ***Maintain a high full cycle investment hurdle rate and conservative leverage*.** Logan will evaluate all capital projects and possible acquisitions to ensure that they meet a high rate of return hurdle on a full cycle and risk adjusted basis. Logan will also maintain a conservative balance sheet and contractual commitments that are right sized to enable production growth while protecting downside in a volatile commodity market.

For all capital investments, be it drilling, infrastructure or acquisition opportunities, Logan will evaluate such opportunities to ensure they are expected to deliver risk adjusted returns above Logans weighted average cost of capital. Logan expects to maintain a high investment hurdle rate. The Board may, in its discretion, approve acquisitions that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

Business Strengths

The business strengths of Logan are as follows:

- ***Asset quality*.** Logan has three Montney assets in the Simonette, Pouce Coupe areas of north-west Alberta and in the Flatrock area of north-east British Columbia. Each property has favorable subsurface properties which are expected to deliver compelling well economics and offer different risk-return profiles. Logan intends to maintain a concentrated and high-quality asset base with low abandonment and reclamation obligations.

- ***Inventory depth and growth runway*.** Across 193,000 net acres of high working interest Montney land, management has identified over 500 drilling locations that underpin the growth strategy and decades of drilling inventory.

- ***Management track record*.** The management team has an established track record of creating shareholder value across multiple business cycles and stewarding capital through volatile commodity markets. Additionally, the management team is highly technical with a demonstrated history of identifying and acquiring undervalued assets with significant upside potential.

- ***Fit for purpose capital structure*.** Logan is appropriately capitalized to execute as a growth-oriented producer.

Specialized Skills and Knowledge

It is the belief of management that Logan's officers and employees, who have significant technical and operational oil and gas experience, hold the necessary skill sets to successfully execute the Company's business strategy in order to achieve its corporate objectives. Logan's management team has an established track record of creating value across multiple business cycles in high-growth oil and gas companies through an integrated strategy of acquiring, exploiting and exploring assets.

Competitive Conditions

The oil and gas industry is competitive in all of its phases. Logan competes with numerous other participants in the search for, and the acquisition of, oil, NGLs and natural gas properties, and in the marketing of oil, NGLs and natural gas. Logan's competitors include resource companies which have much greater financial resources, staff and facilities than those of the Company. Competitive factors in the distribution and marketing of oil, NGLs and natural gas include price and methods and reliability of delivery. Logan believes that its competitive position is similar to that of other oil and gas issuers of similar size and at a similar stage of development.

Cyclical and Seasonal Impact of the Industry

The Company's operational results and financial condition will be dependent on the prices received for oil, NGLs and natural gas production. Oil, NGLs and natural gas prices fluctuate widely and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil, NGLs and natural gas regions. Any decline in oil, NGLs and natural gas prices could have an adverse effect on the Company's financial condition.

Economic Diversity

Logan has ensured economic diversity for the Company by not being substantially dependent on any single contract or licence, such as a contract to sell the major part of its products or services or to purchase the majority of its goods, services or raw materials, or any franchise, licence or other agreement to use a patent, formula, trade secret, process or trade name upon which the Company's business depends.

Change to Contracts

Logan does not reasonably anticipate being materially affected by renegotiation or termination of contracts or sub-contracts.

Environmental Policies and Responsibility

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislations. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness.

The operations of Logan are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. Logan is committed to meeting its responsibilities to protect the environment and will be taking such steps as required to ensure compliance with environmental legislation in all jurisdictions in which it operates. Logan believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue, and in continuing to maintain high quality operations, it anticipates making increased expenditures of both a capital and an expense nature as a result of these increasingly stringent environmental protection laws. However, it is not currently possible to quantify any such increased expenditures and it is not anticipated that Logan's competitive position will be adversely affected by current or future environmental laws and regulations governing its oil and natural gas operations.

For a further discussion of the environmental regulations affecting the oil and gas industry, see "*Industry Conditions*" and "*Risk Factors*".

Employees

As at December 31, 2023, Logan employed 19 full time professionals and made use of 3 part-time consultants at its head office in Calgary, Alberta. The Company also employed 1 full time field employee and 10 contract operators located at various field offices in Alberta and British Columbia.

Managing Ongoing Capital Requirements

Logan anticipates that it will make substantial capital investments for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Logan's revenues or reserves decline, it may have limited ability to expend the capital necessary to undertake or complete future drilling programs, and while the Company would seek to finance these activities in the most prudent manner possible, it cannot be assured 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 Logan. Moreover, future activities may require Logan to alter its capitalization significantly. Transactions involving the issuance of securities may be dilutive. The inability of Logan to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects. See "*Risk Factors*" for further discussion of capital requirements.

Governance and Corporate Responsibility

Logan has adopted policies relating to its corporate practices and business conduct, including a code of business conduct & ethics and a whistleblower policy.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The *Statement of Reserves Data and Other Oil and Gas Information* set forth below (the "**Statement**") is dated as of March 18, 2024. The effective date of the Statement is December 31, 2023, and the preparation date of the Statement is March 18, 2024. In compliance with the requirements of NI 51-101, tables below provide the reserves disclosure for Logan as at December 31, 2023, independently evaluated by McDaniel & Associates Consultants Ltd. ("**McDaniel**"). Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Logan believes is important to the readers of this information.

Disclosure of Reserves Data

Logan engaged McDaniel to provide an independent evaluation of Proved Reserves and Proved plus Probable Reserves for all of its properties, which, at the time of the evaluation, were located in the provinces of Alberta and British Columbia. As of the date hereof, Logan owns oil and gas properties in Alberta and British Columbia. The information set forth below is derived from the McDaniel Report, which has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook.

There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and conventional natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable crude oil, NGLs and conventional natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil, NGLs and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGLs and conventional 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 associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the estimates of Future Net Revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained, and variances could be material. The recovery and reserve estimates of the Company's crude oil, NGLs and conventional 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 conventional natural gas reserves may be greater or less than the estimates provided herein. See "*Notice to Reader – Special Note Regarding Forward Looking Statements*".

The following tables set forth certain information relating to the Company's oil, NGL and natural gas reserves, as well as the net present value of the estimated Future Net Revenue associated with such reserves as at December 31, 2023, contained in the McDaniel Report. These tables summarize the data contained in the McDaniel Report, and, as a result, may contain slightly different numbers than the McDaniel Report due to rounding. In addition, numbers in the below tables may not add due to rounding.

The McDaniel Report was based on certain factual data supplied by the Company and McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to McDaniel and accepted without any further investigation. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

The Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached hereto as Appendices "A" and "B", respectively.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Natural Gas Reserves as at December 31, 2023 – Forecast Prices and Costs

	Light and Medium Oil		**Heavy Oil**		**Tight Oil**	
Reserves Category	**Gross[(1)]** (Mbbl)	**Net[(2)]** (Mbbl)	**Gross[(1)]** (Mbbl)	**Net[(2)]** (Mbbl)	**Gross[(1)]** (Mbbl)	**Net[(2)]** (Mbbl)
Proved Reserves						
Developed Producing	-	-	-	-	1,735.8	1,400.7
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	4,711.5	3,935.8
Total Proved	-	-	-	-	6,447.3	5,336.4
Probable	-	-	-	-	6,502.6	4,979.9
Total Proved Plus Probable	-	-	-	-	12,949.9	10,316.3

	Conventional Natural Gas		**Shale Gas**		**Natural Gas Liquids[(3)]**		**Total**	
Reserves Category	**Gross[(1)]** (MMcf)	**Net[(2)]** (MMcf)	**Gross[(1)]** (MMcf)	**Net[(2)]** (MMcf)	**Gross[(1)]** (Mbbl)	**Net[(2)]** (Mbbl)	**Gross[(1)]** (MBOE)	**Net[(2)]** (MBOE)
Proved Reserves								
Developed	-	-	44,186.7	39,637.5	812.4	589.4	9,912.6	8,596.3

Producing								
Developed Non-Producing	-	-	1,323.8	1,220.8	35.6	25.9	256.2	229.3
Undeveloped	-	-	140,719.2	123,120.8	4,992.2	4,002.5	33,156.9	28,458.4
Total Proved	-	-	186,229.7	163,979.2	5,840.2	4,617.7	43,325.7	37,284.0
Probable	-	-	128,744.3	109,583.0	3,495.5	2,488.7	31,455.6	25,732.4
Total Proved Plus Probable	-	-	314,974.1	273,562.1	9,335.7	7,106.4	74,781.3	63,016.5

Notes:
(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.

Net Present Value of Future Net Revenue as at December 31, 2023 – Forecast Prices and Costs

Reserves Category	**Before Income Taxes Discounted at (% / year)**					**After Income Taxes (1) Discounted at (% / year)**				
	0	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**
			(in $ thousands)					(in $ thousands)		
Proved Reserves										
Producing	17,524.6	45,338.4	51,341.0	52,435.6	51,826.2	17,471.7	45,289.2	51,295.2	52,392.7	51,786.0
Non-Producing	1,676.8	1,279.3	997.2	789.6	632.3	1,604.7	1,213.2	936.5	733.6	580.4
Undeveloped	306,199.1	207,000.2	140,284.3	94,429.5	62,157.3	244,223.1	155,725.5	97,287.5	57,936.6	30,846.9
Total Proved	325,400.5	253,617.9	192,622.5	147,654.7	114,615.9	263,299.4	202,228.0	149,519.1	111,062.8	83,213.3
Probable	464,657.1	296,522.7	200,342.0	142,287.0	105,505.1	364,465.8	226,871.5	149,690.5	104,101.6	75,852.2
Total Proved Plus Probable	790,057.6	550,140.6	392,964.5	289,941.7	220,121.0	627,765.2	429,099.4	299,209.7	215,164.4	159,065.5

Note:
(1) The after-tax net present value of Logan's oil and natural gas properties reflects the income tax burden on the properties on a stand-alone basis and takes into account Logan's existing tax pools. It does not consider the business-entity-level tax situation or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The Company's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2023, should be consulted for information at the level of the business entity.

Total Future Net Revenue (Undiscounted) as at December 31, 2023 – Forecast Prices and Costs

	Total Future Revenue (Undiscounted in $ thousands)							
Reserves Category	**Revenue(1)**	**Royalties(2)**	**Operating Costs**	**Development Costs**	**Abandonment and Reclamation Costs(3)**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Total Proved	2,077,491	302,605	880,860	505,073	63,552	325,400	62,101	263,299
Total Proved + Probable	3,846,947	649,638	1,566,165	771,695	69,391	790,058	162,292	627,765

Notes:
(1) Includes all product revenues and other revenues as forecast.
(2) Royalties include any net profits interests paid.
(3) Abandonment and reclamation costs are defined by NI 51-101 as all costs associated with the process of restoring Logan's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

Net Present Value of Future Net Revenue by Production Type as at December 31, 2023 – Forecast Prices and Costs

Reserves Category	**Product Type**	**Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($ thousands)**	**Unit Value Before Income Taxes (Discounted at 10%/Year) (1) ($/bbl & $/Mcf)**

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($ thousands)	Unit Value Before Income Taxes (Discounted at 10%/Year) (1) ($/bbl & $/Mcf)
Proved	Light and Medium Oil (Unit Price $/bbl)	-	-
	Tight Oil (Unit Price $/bbl)	76,340	14.72
	Conventional Natural Gas (Unit Price $/Mcf)	-	-
	Shale Gas (Unit Price $/Mcf)	116,282	1.11
	(All above including associated by-products) (2)		
	Total	192,623	5.17
Proved Plus Probable	Light and Medium Oil (Unit Price $/bbl)	-	-
	Tight Oil (Unit Price $/bbl)	187,862	18.53
	Conventional Natural Gas (Unit Price $/Mcf)	-	-
	Shale Gas (Unit Price $/Mcf)	205,102	1.31
	(All above including associated by-products) (2)		
	Total	392,965	6.24

Notes:
(1) Unit values are based on net reserves.
(2) Includes corporate Gas Cost Allowance, if applicable.

Definitions and Additional Notes to Reserves Data Tables

The determination of oil, NGLs and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of Proved, Probable and Possible Reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

In the tables set forth under the heading "*Statement of Reserves Data and Other Oil and Gas Information*" and elsewhere in this AIF the following definitions and notes are applicable:

> "**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.
>
> "**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.
>
> "**Probable**" or "**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.
>
> "**Proved**" or "**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.
>
> "**Reserves**" or "**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) 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.
>
> "**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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 sub-divide 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.

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve 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 reserve estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

(b) at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and

(c) 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, the majority of 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 the COGE Handbook.

"**Development Costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil, NGLs and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill, complete and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**Development Well**" means a well drilled inside the established limits of an oil or natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**Exploration Costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment, facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical and other crews conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling, completing and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**Exploratory Well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**Future Net Revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs.

"**Gross**" means:

(a) in relation to the Company's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**Net**" means:

(a) in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**Service Well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation or injection for combustion.

"**Abandonment and Reclamation Costs**" represent all costs associated with the process of restoring a company's well sites with booked reserves which have been disturbed by oil and gas activities, existing and to be incurred, to a standard imposed by applicable government or regulatory authorities.

Pricing Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and accounts for inflation with respect to future operating and capital costs. Crude oil, NGL and natural gas benchmark reference pricing, inflation and exchange rates utilized in the McDaniel Report were from the three Consultant Average (McDaniel, GLJ, Sproule) forecast, as at January 1, 2024, as follows:

Year	Crude Oil WTI Cushing Oklahoma (US$/bbl)	Edmonton Light Crude Oil (C$/bbl)	Western Canadian Select (C$/bbl)	Edmonton Ethane (C$/bbl)	Edmonton Propane (C$/bbl)	Edmonton Butane (C$/bbl)	Edmonton Cond. & Natural gasoline (C$/bbl)	Alberta AECO Spot Price (C$/MMbtu)	Capital / Operating Cost Inflation Rate (%/year)	Exchange Rate (US$/C$)(1)
2024	73.67	92.91	76.74	6.88	29.65	47.69	96.79	2.20	0.0	0.752
2025	74.98	95.04	79.77	10.76	35.13	48.83	98.75	3.37	2.0	0.752
2026	76.14	96.07	81.12	13.17	35.43	49.36	100.71	4.05	2.0	0.755
2027	77.66	97.99	82.88	13.44	36.14	50.35	102.72	4.13	2.0	0.755
2028	79.22	99.95	85.04	13.71	36.86	51.35	104.78	4.21	2.0	0.755
2029	80.80	101.94	86.74	14.00	37.60	52.38	106.87	4.30	2.0	0.755
2030	82.42	103.98	88.47	14.28	38.35	53.43	109.01	4.38	2.0	0.755
2031	84.06	106.06	90.24	14.58	39.12	54.50	111.19	4.47	2.0	0.755
2032	85.74	108.18	92.04	14.87	39.90	55.58	113.41	4.56	2.0	0.755
2033	87.46	110.35	93.89	15.17	40.70	56.70	115.67	4.65	2.0	0.755
2034	89.21	112.56	95.77	15.48	41.51	57.83	117.98	4.74	2.0	0.755
Thereafter	Escalation rate of 2%								2.0	0.755

Note:
(1) Exchange rates used to generate the benchmark reference prices in this table.

Logan's weighted average realized sales prices for the year ended December 31, 2023, were $96.33/bbl light and medium crude oil, $97.06/bbl for NGL and $2.94/Mcf for natural gas. The average realized price on a total oil equivalent basis was $37.19/BOE.

Reserves Reconciliation

The below table sets forth a reconciliation of Logan's total Proved, Probable and total Proved plus Probable Reserves (gross) as at December 31, 2023, based on forecast prices and cost assumptions. As the Company did not have any reserves as at December 31, 2022, all additions in the below table are reflected under "Acquisitions". The first reserves acquired by Logan were the Logan Assets acquired on June 20, 2023, pursuant to Spin-Out.

	Light Crude Oil and Medium Crude Oil			Tight Oil		
Factors	Gross(1) Proved Mbbl	Gross(1) Probable Mbbl	Gross(1) Proved Plus Probable Mbbl	Gross(1) Proved Mbbl	Gross(1) Probable Mbbl	Gross(1) Proved Plus Probable Mbbl
December 31, 2022	-	-	-	-	-	-
Extensions & Improved Recovery(3)	-	-	-	5,304.8	6,208.8	11,513.6
Technical Revisions(4)	-	-	-	-	-	-
Acquisitions(5)	-	-	-	1,391.7	293.8	1,685.5
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production(6)	-	-	-	(249.1)	-	(249.1)
December 31, 2023	-	-	-	6,447.3	6,502.6	12,949.9

	Conventional Gas(2)			Shale Gas		
Factors	Gross(1) Proved MMcf	Gross(1) Probable MMcf	Gross(1) Proved Plus Probable MMcf	Gross(1) Proved MMcf	Gross(1) Probable MMcf	Gross(1) Proved Plus Probable Mmcf
December 31, 2022	-	-	-	-	-	-
Extensions & Improved Recovery(3)	-	-	-	147,355.4	120,977.0	268,332.4
Technical Revisions(4)	-	-	-	-	-	-
Acquisitions(5)	-	-	-	44,044.8	7,767.4	51,812.2
Dispositions	-	-	-	-	-	-

Economic Factors	-	-	-	-	-	-
Production[6]	-	-	-	(5,170.6)	-	(5,170.6)
December 31, 2023	-	-	-	186,229.7	128,744.4	314,974.1

	Natural Gas Liquids			Total		
Factors	**Gross[1] Proved Mbbl**	**Gross[1] Probable Mbbl**	**Gross[1] Proved Plus Probable Mbbl**	**Gross[1] Proved MBOE**	**Gross[1] Probable MBOE**	**Gross[1] Proved Plus Probable MBOE**
December 31, 2022	-	-	-	-	-	-
Extensions & Improved Recovery[3]	5,085.1	3,344.3	8,429.4	34,949.1	29,715.9	64,665.0
Technical Revisions[4]	(0.0)	-	(0.0)	0.0	0.0	0.0
Acquisitions[5]	882.5	151.2	1,033.7	9,615.0	1,739.6	11,354.6
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production[6]	(127.4)	-	(127.4)	(1,238.3)	-	(1,238.3)
December 31, 2023	5,840.2	3,495.5	9,335.7	43,325.8	31,455.5	74,781.3

Notes:
(1) Gross Reserves means the Company's working interest reserves before calculation of royalties and before consideration of the Company's royalty interests.
(2) Includes solution gas volumes.
(3) The extensions and improved recovery value includes all new wells drilled and booked during the year.
(4) The technical revisions amount includes all changes in reserves due to well performance and all previously booked wells which were drilled during the year.
(5) The acquisitions amount is the estimate of reserves at December 31, 2023.
(6) Production provided by the Company from June 20, 2023 to December 31, 2023.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following discussion generally describes the basis on which Logan attributes Proved and Probable Undeveloped Reserves and the Company's plans for developing those Undeveloped Reserves. Undeveloped Reserves are attributed by McDaniel in accordance with the standards and procedures contained in the COGE Handbook. Proved Undeveloped Reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable Undeveloped Reserves are those reserves that are less certain to be recovered than Proved Reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of gross Proved Undeveloped Reserves that were attributed in each of the most recent three financial years.

	Light and Medium Oil (Mbbl)		Tight Oil (Mbbl)	
Year	**First Attributed[1]**	**Cumulative at Year End**	**First Attributed[1]**	**Cumulative at Year End**
December 31, 2021	-	-	-	-
December 31, 2022	-	-	-	-
December 31, 2023	-	-	4,711.5	4,711.5

	Conventional Gas (MMcf)		Shale Gas (MMcf)		Natural Gas Liquids (Mbbl)	
Year	**First Attributed[1]**	**Cumulative at Year End**	**First Attributed[1]**	**Cumulative at Year End**	**First Attributed[1]**	**Cumulative at Year End**
December 31, 2021	-	-	-	-	-	-
December 31, 2022	-	-	-	-	-	-
December 31, 2023	-	-	140,719.2	140,719.2	4,992.2	4,992.2

Note:
(1) Refers to reserves first attributed in this fiscal year ending on the effective date.

In most instances Proved Undeveloped Reserves have been assigned, directly offsetting existing producing wells that are producing from either the same or a similar accumulation or pool. Reserves in these areas can be estimated with a high degree of certainty. The majority of the Proved Undeveloped Reserves are planned for development over the next three years, and all will be developed within five years. All Proved Undeveloped Reserves are within the Company's core properties at Simonette and Pouce Coupe targeting the Montney formation. The timeline for drilling the booked undeveloped locations matches Logan's current business plan. A number of factors that could result in delayed or cancelled development include: (a) changing economic conditions such as pricing, operating costs, and capital expenditures; (b) changing technical conditions related to well performance, such as water breakthrough, and or accelerated depletion; (c) capital allocation based on new or other opportunities available to Logan in any given year; and (d) surface access issues (landowners, weather conditions, regulatory approvals).

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of gross Probable Undeveloped Reserves that were attributed in each of the most recent three financial years.

	Light and Medium Oil (Mbbl)		Tight Oil (Mbbl)	
Year	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End
December 31, 2021	-	-	-	-
December 31, 2022	-	-	-	-
December 31, 2023	-	-	6,088.8	6,088.8

	Conventional Gas (MMcf)		Shale Gas (MMcf)		Natural Gas Liquids (Mbbl)	
Year	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End
December 31, 2021	-	-	-	-	-	-
December 31, 2022	-	-	-	-	-	-
December 31, 2023	-	-	119,358.0	119,358.0	3.333.8	3,333.8

Note:
(1) Refers to reserves first attributed in this fiscal year ending on the effective date.

Probable Undeveloped Reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. These reserves can also be a function of the timing of when the reserves are planned to be developed. Reserves not developed within five years can only be considered probable. These Probable Undeveloped Reserves are in the Company's core areas located in and around the Simonette and Pouce Coupe areas of northwest Alberta targeting the Montney Formation. All of these reserves are planned to be on stream within an eight-year timeframe. However, if the economic climate is not conducive to developing these reserves during such timeframe, Logan may, in its discretion, defer the development. There are a number of factors that could result in delays or cancelled development plans, including changing economic and technical conditions, surface access issues, the availability of services and access to pipeline or processing facilities.

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 reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other assumptions that may affect the reserve estimates and the present value, including: (a) historical production in the area compared to offsetting analogous production; (b) initial production and production decline rates; (c) ultimate recovery of reserves; (d) results from future development activities; (e) marketability of production; and (f) effects of government regulations and any government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information.

Logan does not anticipate any significant economic factors or uncertainties will affect any particular components of its reserves data. However, the Company's reserves can be affected significantly by fluctuations in commodity product pricing, capital expenditures, operating costs, royalty regimes and other government restrictions and well performance that are beyond its control. See "*Risk Factors*" for further details. See note 9 of the Company's Financial Statements for the years ended December 31, 2023 and 2022 for Logan's decommissioning obligations. Provisions for the abandonment and reclamation of all of the Company's existing and future wells to a standard imposed by applicable government or regulatory authorities have been included in estimates of the Company's reserves. The McDaniel Report deducted $69.4 million (undiscounted) or a present value of $15.8 million (10% annual discount) for abandonment and reclamation in the total Proved plus Probable category. These abandonment and reclamation costs included all surface leases, wells (including inactive), pipelines and facilities and were supplied by Logan to McDaniel for their evaluation.

Although every reasonable effort is made to ensure that reserves estimates are accurate, reserves estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserves estimates can arise from changes in year-end oil and natural gas prices and reservoir performance. Such revision can be either positive or negative.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Logan's future net revenue attributable to the reserve categories noted below.

	Future Development Costs (Undiscounted) (In $ thousands)	
Year	**Proved Reserves**	**Proved Plus Probable**
2024	79,634	79,634
2025	81,890	81,890
2026	105,299	105,299
2027	104,909	104,909
2028	116,380	116,380
Remaining	16,962	283,584
Total(1)	**505,073**	**771,695**

Note:

(1) Future development costs shown are associated with booked reserves in the McDaniel Report and do not necessarily represent the Company's full exploration and development budget.

Logan expects to fund future development costs through a combination of internally generated Adjusted Funds Flow, debt financing and the issuance of new equity, where and when it believes appropriate.

There can be no guarantee that funds will be available or that the board of directors of Logan will allocate funding to develop all of the reserves attributable in the McDaniel Report. Failure to develop those reserves could have a negative impact on the Company's future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. Logan does not anticipate that interest or other funding costs would make further development of any of the oil and gas assets uneconomic.

Other Oil and Gas Information

Principal Properties

The following is a description of Logan's principal crude oil and natural gas properties as at December 31, 2023. Information in respect of current production is average production, net to its working interest, except where otherwise indicated. Logan has three core areas as at December 31, 2023: the Pouce Coupe property; the Simonette property; and the Flatrock property.

- **Pouce Coupe**

  The Pouce Coupe property is a contiguous asset located in the oil window of the Alberta Montney fairway. As at December 31, 2023, Logan held 46,080 gross (43,892 net) acres of Montney rights in the area. At Pouce Coupe, Logan has ten horizontal Montney wells employing modern high intensity completion designs which have delivered consistently strong results. Production from the Pouce Coupe asset averaged 1,998 boe/d for the year ended December 31, 2023. For the next phase of growth, Logan will construct and operate a 100% owned battery and gas plant which will allow for future growth to 7,500-10,000 boe/d consistent with Logan's development plan.

- **Simonette**

  The Simonette property is located in Alberta, south of Grande Prairie and west of Fox Creek. The large land position includes rights in multiple prospective horizons with the Montney being the main near-term focus for Logan. As at December 31, 2023, Logan held 118,380 gross (111,185 net) acres of Montney rights in Simonette. Logan has 53 operated Montney wells drilled in Simonette with 51 of the wells being drilled before 2017. While these older vintage wells effectively delineate many of the subsurface properties of the asset, Logan is of the view that the landing depth and completion design of the historic wells are suboptimal. Logan drilled two wells in Simonette in 2023, both were completed with higher intensity completion designs and the well in Simonette South was landed lower in the formation when compared to the offsetting legacy wells. To date, these new wells have significantly outperformed the offsetting legacy wells.

  In Simonette, Logan owns a 50% working interest in the 120 mmcf/d gas plant centrally located within the asset base. This facility, along with an extensive network of owned gathering and disposal infrastructure in the area will support the future development and growth plans. Production from the Simonette asset averaged 3,301 boe/d for the year ended December 31, 2023. Logan's development plan includes growing Simonette production to approximately 15,000 boe/d.

- **Flatrock**

  The Flatrock property is a large undeveloped Montney position east of Fort St John in British Columbia. As at December 31, 2023, Logan held 56,165 gross (55,769 net) acres of contiguous Montney rights in Flatrock. Management believes the Flatrock acreage is prospective in two Montney benches with successful wells being drilled in both the Middle Montney and the Upper Montney by operators offsetting the Logan lands. Logan has over 75 sqkm of high quality, proprietary 3D seismic data on the asset. Logan currently has no production or wellbores at Flatrock. The next phase of development will include multiple test wells to hold the lands and prove productivity.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which the Company had a working interest as at December 31, 2023.

		Oil Wells		Natural Gas Wells(1)	
Area	**Category**	**Gross**	**Net**	**Gross**	**Net**
Alberta	Producing	24	19.9	67	60.6
	Non-Producing(2)	8	5.2	74	54.2
British Columbia	Producing	-	-	48	23.4
	Non-Producing(2)	-	-	32	23.6
Total(3)	Producing	24	19.9	115	84.0
	Non-Producing(2)	8	5.2	106	77.8

Notes:
(1) Includes conventional natural gas wells and CBM gas wells.
(2) Non-producing wells include wells that have been shut in and/or suspended.
(3) Excludes abandoned, water source, water injection and disposal wells.

Properties with No Attributable Reserves

As at December 31, 2023, Logan's properties with no attributed reserves contained 90,245 gross (88,215 net) acres. Within these properties, Logan expects that 6,880 gross acres (6,880 net acres) could expire in 2024, however, some of these leases may extend at the discretion of the lessor. The Company has no material work commitments currently scheduled on these lands other than certain decommissioning obligations on some of the non-core properties. Logan reviews the economic viability of these properties on the basis of pricing, capital availability and allocation. There is no guarantee that commercial reserves will be discovered or developed on these properties.

Forward Contracts

Logan is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Logan may use certain derivative financial instruments and foreign exchange contracts to reduce its exposure to fluctuations in commodity prices, increase the certainty of Adjusted Funds Flow and to protect acquisition and development drilling economics. Such financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The Company may be exposed to losses in the event of default by the counterparties to these derivative instruments, but it manages this risk by diversifying its derivative portfolio amongst a number of financially sound counterparties. Logan's Board of Directors will review all derivative and foreign exchange contracts quarterly to ensure such transactions are conducted within risk management tolerances.

The Company did not have any derivative financial instruments as at or during the year ended December 31, 2023. Logan entered into certain commodity price risk management contracts subsequent to the reporting period, which are summarized in note 19 of the Notes to the Financial Statements for the years ended December 31, 2023 and 2022.

Tax Horizon

Logan was not required to pay income taxes during the year ended December 31, 2023, as the Company had sufficient income tax deductions available to shelter taxable income. As at December 31, 2023, Logan had approximately $119.4 million of tax pools available. Logan does not expect to pay cash income taxes until 2025 based upon current legislation, the Company's planned capital expenditures, production rates and commodity price forecasts, and various other assumptions. A higher (lower) level of capital expenditures than those currently contemplated, decreases (increases) in production rates, decreases (increases) in commodity price assumptions, as well as potential future acquisitions (dispositions), could further extend (reduce) the estimated tax horizon.

Costs Incurred

The following table summarizes Logan's corporate and property acquisition costs, exploration costs and development costs, before property dispositions, for the year ended December 31, 2023. The amounts reported as exploration costs are consistent with capital expenditures classified as exploration and evaluation assets under IFRS Accounting Standards. The amounts reported as development costs are consistent with capital expenditures classified as property, plant and equipment under IFRS Accounting Standards.

Capital Expenditures(1)

Nature of Cost	Amount (M$)
Exploration Costs	8,126
Development Costs	72,280
Capital Expenditures before A&D(1)	80,406
Property Acquisition Costs	5,395
Corporate Acquisition Costs	-
Acquisitions	5,395
Dispositions	-
Capital Expenditures(1)	85,801

Notes:
(1) "Capital Expenditures" and "Capital Expenditures before A&D" do not have standardized meanings under IFRS Accounting Standards therefore these amounts may not be directly comparable to measures for other companies where similar terminology is used. Logan uses "Capital Expenditures before A&D" to measure its capital investment level compared to the Company's annual budgeted capital expenditures for its organic drilling program, excluding acquisitions or dispositions. "Capital Expenditures" is calculated by adding cash acquisition costs, net of proceeds from dispositions to Capital Expenditures before A&D. The directly comparable GAAP measure is cash used in investing activities. Refer to "*Notice to Reader - Non-GAAP Measures and Ratios*" for a reconciliation to cash used in investing activities.

Exploration and Development Activities

The following table sets forth the gross and net development wells completed by Logan during the financial year ended December 31, 2023.

	Development Wells		Exploration Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	-	-
Tight Oil[1]	4.0	4.0	-	-
Shale Gas[2]	1.0	1.0	-	
Service	-	-	-	-
Dry and Abandoned	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	5.0	5.0	-	-

Notes:
(1) Includes 1 Montney oil well in Simonette North and 3 Montney wells in Pouce Coupe completed in 2023
(2) Includes 1 Montney gas well at Simonette South completed in 2023

See "*Principal Properties*" above for a description of Logan's exploration and development plans.

Production Estimates

The following table sets out the first-year production forecast of volumes of Logan's working interest (Company Gross) production for each product type estimated by McDaniel for the year ended December 31, 2024, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosures of Reserves Data*".

	Crude Oil [1] (bbl/d)	Natural Gas Liquids (bbl/d)	Natural Gas[2] (Mcf/d)	Gross Barrel of Oil Equivalent (BOE/d)
Proved				
Pouce Coupe	1,478	124	12,392	3,668
Simonette	506.6	897.8	22,476.0	5,150
BC Minors	-	67.2	2,417.0	470
Total	1,985.0	1,088.9	37,284.9	9,288
Proved Plus Probable				
Pouce Coupe	1,574.0	130.8	13,075.2	3,884
Simonette	529.6	976.7	23,898.7	5,489
BC Minors	-	68.0	2,448.5	476
Total [3]	2,103.7	1,175.5	39,422.4	9,850

Notes:
(1) Crude Oil is inclusive of "Light Crude Oil and Medium Crude Oil", "Heavy Oil" and "Tight Oil" reserve classifications.
(2) Natural Gas is inclusive of "Conventional Natural Gas" and "Shale Gas" reserve classifications.
(3) Includes working interest production before royalty deductions.

2023 Production History

The following tables disclose, on a quarterly basis for the year ended December 31, 2023, Logan's share of average daily production volumes (working interest before royalties), average selling prices, royalty expenses, transportation and operating expenses incurred and Operating Netbacks on a per unit of volume basis for each product type.

	Three Months Ended				Year Ended
	31-Mar-23	30-Jun-23	30-Sep-23	31-Dec-23	31-Dec-23
Average Daily Production					
Crude Oil(6) (bbl/d)	752	660	782	1,844	1,012
NGLs (bbl/d)	479	456	516	818	568
Natural Gas(7) (Mcf/d)	24,351	23,396	24,573	29,116	25,370
Total (BOE/d)	**5,290**	**5,015**	**5,394**	**7,515**	**5,808**
Average Realized Prices(1)					
Crude Oil(6) ($/bbl)	101.64	92.41	108.60	90.40	96.33
NGLs ($/bbl)	78.59	71.66	76.36	79.91	77.17
Natural Gas(7) ($/Mcf)	3.99	2.43	2.67	2.72	2.94
Total ($/BOE)	**39.94**	**30.01**	**35.24**	**41.44**	**37.19**
Processing and Other Revenue(2)					
Crude Oil(6) ($/bbl)	1.72	1.83	1.76	1.25	1.60
NGLs ($/bbl)	1.72	1.83	1.76	1.25	1.60
Natural Gas(7) ($/Mcf)	0.29	0.31	0.29	0.21	0.27
Total ($/BOE)	**1.72**	**1.83**	**1.76**	**1.25**	**1.60**
Royalties(3)					
Crude Oil(6) ($/bbl)	(24.40)	(21.55)	(25.78)	(9.61)	(17.41)
NGLs ($/bbl)	(19.69)	2.66	(16.27)	(6.35)	(9.59)
Natural Gas(7) ($/Mcf)	(0.30)	0.02	(0.12)	(0.08)	(0.12)
Total ($/BOE)	**(6.64)**	**(2.49)**	**(5.85)**	**(3.37)**	**(4.49)**
Transportation Expenses					
Crude Oil(6) ($/bbl)	(10.28)	(12.05)	(13.88)	(7.34)	(9.92)
NGLs ($/bbl)	(2.97)	(4.24)	(5.91)	(5.84)	(4.94)
Natural Gas(7) ($/Mcf)	(0.34)	(0.34)	(0.40)	(0.37)	(0.37)
Total ($/BOE)	**(3.30)**	**(3.58)**	**(4.41)**	**(3.87)**	**(3.81)**
Operating Expenses(4)					
Crude Oil(6) ($/bbl)	(16.52)	(15.77)	(15.80)	(11.82)	(14.65)
NGLs ($/bbl)	(16.52)	(15.77)	(15.80)	(11.82)	(14.65)
Natural Gas(7) ($/Mcf)	(2.75)	(2.63)	(2.63)	(1.97)	(2.44)
Total ($/BOE)	**(16.52)**	**(15.77)**	**(15.80)**	**(11.82)**	**(14.65)**
Operating Netbacks (1)					
Crude Oil(6) ($/bbl)	52.16	44.87	54.90	62.88	55.95
NGLs ($/bbl)	41.13	56.14	40.14	57.15	49.59
Natural Gas(7) ($/Mcf)	0.88	(0.21)	(0.19)	0.51	0.27
Total ($/BOE)	**15.20**	**10.00**	**10.94**	**23.63**	**15.84**

Notes:

(1) "Average Realized Prices" are a non-GAAP financial ratio calculated by dividing sales revenue into production volumes by product type. Average Realized Prices are presented before gains or losses on derivative financial instruments.

(2) Processing and other revenue primarily relates to fees earned for third party use of the Company's infrastructure and is not directly attributable to individual products. The total is allocated pro-rata based on production volumes by product type for purposes of this table.

(3) Royalties are presented net of Gas Cost Allowance ("**GCA**"). For purposes of this table, total corporate GCA credits are allocated to NGLs and natural gas royalties pro-rata based on gross royalties before GCA. During the second quarter of 2023, natural gas and NGLs royalties are positive due to a true-up of annual GCA from the previous year.

(4) The Company's operating expenses are not directly attributable to individual products. Total operating expenses are allocated pro-rata based on production volumes by product type for purposes of this table.

(5) "Operating Netback" is a non-GAAP financial measures which may not be directly comparable to other issuers. "Operating Income " is calculated as average selling prices, net of royalties, plus processing and other revenue, less operating and transportation expenses. See "*Notice to Reader - Non-GAAP Measures and Ratios*" for more information.

(6) Crude Oil is inclusive of "Light Crude Oil and Medium Crude Oil", "Heavy Oil", and "Tight Oil" reserve classifications.

(7) Natural Gas is inclusive of "Conventional Natural Gas" and "Shale Gas" reserve classifications.

The following table sets forth the average daily production volumes for the year ended December 31, 2023, for each of the important properties comprising Logan's assets. In calculating average daily production over the 365-day year ended December 31, 2023.

Property	Crude Oil[1] (bbl/d)	Natural Gas Liquids (bbl/d)	Natural Gas[2] (Mcf/d)	Total (BOE/d)
Alberta				
Pouce Coupe	672	74	7,510	1,998
Simonette	340	417	15,260	3,301
British Columbia				
BC Minors	-	76	2,600	509
Total	**1,012**	**568**	**25,370**	**5,808**

Notes:
(1) Crude Oil is inclusive of "Light Crude Oil and Medium Crude Oil", "Heavy Oil", and "Tight Oil" reserve classifications.
(2) Natural Gas is inclusive of "Conventional Natural Gas" and "Shale Gas" reserve classifications.

DESCRIPTION OF SHARE CAPITAL

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares, issuable in series. As at the date hereof there are 465,537,090 Common Shares and nil Preferred Shares issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attached to such securities.

Common Shares

The holders of Common Shares are entitled to receive notice of and attend all meetings of shareholders of Logan (except meetings at which only holders of a specified class or series of shares are entitled to vote) and are entitled to one vote per Common Share. Subject to the prior rights of holders of Preferred Shares, holders of Common Shares are entitled to dividends, if, as and when declared by the Board, and, in the event of the liquidation, dissolution or winding-up of Logan, or any other distribution of assets among its shareholders for the purpose of winding-up its affairs, to receive on a pro-rata basis all of the remaining property of Logan.

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 determined by the Board, who may fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. The Preferred Shares of each series shall, with respect to dividends, 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 the shares of any other class ranking junior to the Preferred Shares. The Preferred Shares of any series may also be given such other preferences and priorities over the Common Shares and any other shares of the Company ranking junior to such series of Preferred Shares. As of the date hereof, the Company has authorized only one series of Preferred Shares which are non-voting, redeemable and retractable, none of which are outstanding.

Warrants

The Warrants were issued to subscribers of Units under the Logan Financing. Each Warrant entitles the holder to purchase one (1) Common Share at a price of $0.35 per Common Share for a period of five (5) years. The Warrants will vest and become exercisable as to one-third upon Market Price equaling or exceeding $0.70, an additional one-third upon the Market Price equaling or exceeding $0.7875 and a final one-third upon the Market Price equaling or exceeding $0.875. The Warrants are fully vested and exercisable. As at December 31, 2023, there were 64,286,100 Warrants outstanding and as at the date hereof, there are 64,286,100 Warrants outstanding.

Stock Options

Pursuant to the Option Plan, the total number of Common Shares reserved for issuance pursuant to the Options granted and outstanding under the Option Plan and other share compensation arrangements, including but not limited to the Share Award Incentive Plan, shall not exceed a number of Common Shares equal to 10% of the number of issued and outstanding Common Shares. As at December 31, 2023, there were 22,695,000 Options outstanding and as at the date hereof, there are 22,670,000 Options outstanding.

Share Awards

Pursuant to the Share Award Incentive Plan, the total number of Common Shares reserved for issuance pursuant to the Share Awards granted and outstanding under the Share Award Incentive Plan and other share compensation arrangements, including but not limited to the Option Plan, shall not exceed a number of Common Shares equal to 10% of the number of issued and outstanding Common Shares. As of the date of this AIF, no Share Awards have been granted.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares commenced trading on the TSX-V under the trading symbol "**LGN**" on July 18, 2023. The following table sets forth the market price ranges and the trading volumes of the Common Shares for the financial year ended December 31, 2023, as reported by the TSX-V.

Month	High ($)	Low ($)	Volume
December 2023	$0.93	$0.78	5,577,223
November 2023	$1.02	$0.88	6,589,641
October 2023	$1.05	$0.99	6,282,857
September 2023	$1.10	$0.99	20,655,573
August 2023	$1.17	$0.98	17,743,270
July 18 – 31, 2023	$1.24	$0.73	37,663,393

Prior Sales

During the year ended December 31, 2023, no securities have been issued by the Company that are outstanding, but not listed or quoted on a marketplace, except the Warrants issued pursuant to the Logan Financing and Options granted under the Company's Option Plan. During the financial year ended December 31, 2023, Logan granted 22.7 million Options with an average exercise price of $0.89 per Common Share. Each Option entitles the holder thereof upon exercise to acquire one (1) Common Share for the stated exercise price in accordance with the Option Plan. In addition, the Company issued 173,201,341 Transaction Warrants pursuant to the Spin-Out (which expired on August 14, 2023) and 64,286,100 Warrants pursuant to the Logan Financing. Please see "*General Development of the Business – Financial Year ended December 31, 2023*" for more information. No awards were granted in 2023 under the Company's Share Award Incentive Plan. Additional information is provided in note 11 of Logan's Financial Statements for the years ended December 31, 2023 and 2022.

ESCROWED SECURITIES

Pursuant to an escrow agreement (the "**Escrow Agreement**") dated July 19, 2023, among Logan, Odyssey Trust Company, as escrow agent, certain brokers, and certain securityholders of Logan, 35,514,516 Common Shares are presently subject to escrow conditions, as shown in the table set forth below.

Designation of Class	Number of Securities Held in Escrow / Subject to Contractual Restrictions on Resale[(1)]	Percentage of Common Shares
Common Shares	35,514,516[(2)]	7.63%[(3)]

Notes:

(1) Securities are contractually restricted or held in escrow by Odyssey Trust Company, the Corporation's transfer agent. Of the 71,029,030 escrowed securities originally subject to the Escrow Agreement, the first 25% of the escrowed securities were released on July 14, 2023, and a further 25% were released on January 14, 2023. Of the 35,514,516 remaining escrowed securities, as set forth in the above table, 50% are scheduled to be released on July 14, 2024, and the remaining 50% is scheduled to be released on January 14, 2025, in accordance with additional customary terms and conditions set forth in the Exchange's Form 5D – Escrow Agreement (Value Security).

(2) Comprised of Common Shares that were issued to Principals (as such term is defined in TSXV Policy 1.1) of Logan under the Logan Financing.

(3) Percentage is based on 465,537,090 Common Shares issued and outstanding as at March 18, 2024.

DIVIDEND POLICY

The Company has not declared or paid any dividends since inception. It is the intention of Logan to retain any earnings to finance the growth and development of the Company's business, and, therefore Logan does not anticipate paying any dividends in the immediate or foreseeable future.

DIRECTORS AND EXECUTIVE OFFICERS

The following table lists the names of the directors and officers, their municipalities of residence, positions and offices with the Company and principal occupations. All directors have been elected to serve as such until the Company's next annual meeting of shareholders, or until his or her successor is duly elected, unless his or her office is vacated earlier in accordance with the by-laws of the Company or applicable law.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Richard F. McHardy *Alberta, Canada*	President, Chief Executive Officer & Director since March 10, 2023	Director, President, and Chief Executive Officer of Logan Energy Corp. since March 10, 2023. Prior thereto, Mr. McHardy acted as Executive Chairman of Spartan from December 19, 2019 until July 6, 2023 and President, Chief Executive Officer and a director of Spartan Energy from December 2013 to May 2018.
Brendan Paton *Alberta, Canada*	Vice President, Engineering & Chief Operating Officer	Vice President, Engineering and Chief Operating Officer of Logan since June 20, 2023. Vice President, Engineering, of Spartan from March 2021 to July 2023. Prior thereto, Manager (Engineering) of Spartan from December 2019 to March 2021; President of Canoe Point Energy Ltd. from June 2018 to December 2019; and Production Engineer at Shell Canada Limited from July 2011 to June 2018.
Ashley Hohm *Alberta, Canada*	Vice President, Finance & Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Logan since June 20, 2023. Vice President, Finance and Controller of Spartan from March 2021 to July 2023. Prior thereto, Controller of Spartan from December 2019 to March 2021 and Vice President, Finance of Kelt Exploration Ltd. from March 2016 to April 2018.
Craig Martin *Alberta, Canada*	Vice President, Operations	Vice President, Operations, of Spartan from December 2019 to July 2023. Prior thereto, Professional Engineer with Vermilion Energy Inc. from May 2018 to October 2019. Prior thereto, Manager, Drilling and Completions, at Spartan Energy from February 2014 to May 2018.
Fotis Kalantzis[(2)] *Alberta, Canada*	Chairperson & Director since June 19, 2023	President and Chief Executive Officer of Spartan since December 19, 2019. Prior thereto, Senior Vice President, Exploration, of Spartan Energy Corp. from March 2016 to May 2018; Vice President, Exploration, of Spartan Energy from December 2013 to March 2016.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Geri Greenall(1)(3) *Alberta, Canada*	Director since June 19, 2023	Chief Financial Officer of Spartan from December 19, 2019 through December 31, 2023. Independent director of Kelt Exploration Ltd. from December 2017 to September 2023. Co-founder and Chief Financial Officer of Camber Capital Corp., a fund manager offering private client and institutional fund management services, from May 2011 to December 2019.
Reginald J. Greenslade(2) *Alberta, Canada*	Director since June 19, 2023	Independent businessman and Director of Spartan and Cleantek Industries Inc. Director of Spartan Energy from December 2013 to May 2018.
Donald Archibald(1)(3) *Alberta, Canada*	Director since June 19, 2023	Independent businessman; President of Cypress Energy Corp., a private investment company, since March 2008. Mr. Archibald also serves on the board and various committees of Spartan, Palisade Capital, Panorama Mountain Resort, Petronas Energy Canada, Serafina Energy Ltd. and Willow Biosciences Inc.
Pat Ward(2)(3) *Alberta, Canada*	Director since June 19, 2023	President, CEO and director of Aqua Solutions Inc., a private, green, mid-stream company, since August 2021. Previously, he was the founder, director, President and CEO of Painted Pony Energy Ltd. from May 2007 to October 2020, when it was acquired by Canadian Natural Resources Limited.
Ron Hozjan(1) *Alberta, Canada*	Director since June 19, 2023	Vice President, Finance and Chief Financial Officer of Aureus Energy Services Inc., an environmental, social and governance focused water management company, since January 2020. Prior thereto, Vice President, Finance and Chief Financial Officer of Tamarack Valley Energy Ltd. from June 2010 until January 2020.
Sony Gill *Alberta, Canada*	Corporate Secretary	Partner at Stikeman Elliott LLP, a national law firm, practicing primarily in the areas of corporate finance, securities and mergers and acquisitions transactions. Prior thereto, partner at another national law firm.

Notes:
(1) The Company's Audit Committee is comprised of Mr. Hozjan (Chair) and Mr. Archibald and Ms. Greenall.
(2) The Company's Reserves, Environment and Health and Safety Committee is comprised of Mr. Greenslade (Chair) and Messrs. Kalantzis and Ward.
(3) The Company's Corporate Governance and Compensation Committee is comprised of Mr. Ward (Chair) and Ms. Greenall and Mr. Archibald.

As of the date hereof, the directors and executive officers of the Company as a group beneficially own, directly or indirectly, or exercise control or direction over, an aggregate of 94.3 million Common Shares, representing approximately 20% of the Common Shares issued and outstanding on a non-diluted basis.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as set forth below, to the knowledge of management of Logan:

(a) no director or executive officer is, or within the ten years prior to the date hereof has been, a director, chief executive officer or chief financial officer of any other issuer that, while that person was acting in that capacity: (i) was the subject of a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or (ii) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemptions under securities legislation that was issued after the director or 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;

(b) no director, executive officer or any shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, or a personal holding company of any such person: (i) is, or within the ten years prior to the date hereof has been, a director or executive officer 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 (ii) has, within the 10 years preceding the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual; and

(c) no director, executive officer or any shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, within the last 10 years, has: (i) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or (ii) been subject to 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.

Mr. Archibald was a director of Waldron Energy Corporation ("**Waldron**") from December 31, 2009 to August 17, 2015. On August 6, 2015, the secured subordinated lender of Waldron demanded repayment in full of all amounts owed to it under its credit facility and gave notice of its intention to enforce its security. This repayment demand created a cross-default between Waldron and its secured bank lender, which subsequently demanded repayment in full of all amounts owed to it under its credit facility and also gave notice of its intention to enforce its security. After various discussions between Waldron and both its lenders, Waldron consented to the appointment of a receiver and manager on August 13, 2015. On August 17, 2015, a receiver and manager was appointed over the assets, undertakings and property of Waldron pursuant to an order of the Court of Queen's Bench of Alberta.

Mr. Archibald was Chairman of Cequence Energy Ltd. ("**Cequence**") from July 30, 2009 to September 28, 2020. Pursuant to an amended and restated initial order of the Court of Queen's Bench of Alberta on June 11, 2020, Cequence was granted authority to file with the Court a plan of compromise or arrangement under the CCAA. On September 28, 2020, Cequence implemented a plan of compromise and arrangement which was sanctioned on September 17, 2020 by order of the Court of Queen's Bench of Alberta, and which marked the conclusion of the CCAA proceedings.

Mr. Hozjan was appointed as a director of 763997 Alberta Ltd. (formerly known as Target Capital Inc.) on September 16, 2020. On September 15, 2020, the Alberta Securities Commission (“ASC"), as principal regulator, issued a management cease trade order against Target Capital’s Chief Executive Officer and Chief Financial Officer for failure to file the required period disclosure, being annual filings for the financial year ended March 31, 2020. On November 5, 2020, due to the continued delay in respect of such filings, the ASC issued a cease trade order against Target Capital, replacing the management cease trade order. On April 16, 2021, Target Capital’s Chief Executive Officer and Chief Financial Officer resigned and were replaced with new interim officers and a refreshed board of directors, which includes Mr. Hozjan, appointed to restore public reporting. On April 18, 2022, Target Capital Inc. filed the outstanding period disclosure and submitted an application to the ASC to revoke the cease trade order. The cease trade order was revoked on May 8, 2023.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Company will be subject in connection with the operations of Logan. In particular, certain directors and officers of Logan 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 Logan. 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 a 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. As at the date of this AIF, Logan is not aware of any existing or potential material conflicts of interest between the Company and any director or officer of Logan.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of crude oil and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian petroleum and natural gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. While it is not expected that any of these controls or regulations will affect the operations of the Company in a manner materially different than they would affect other oil and gas corporations of similar size, investors should consider such legislation, regulations and agreements carefully. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which means that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand, but regional market and transportation issues also influence prices. Specific prices that a producer receives will depend, in part, on oil quality, prices of competing fuels, distance to market, access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms. Following the COVID-19 pandemic, the oil markets began to rebalance in 2021 with oil prices reaching their highest levels in six years. The rebound continued into 2022 with a surge in oil prices in early 2022. This was primarily driven by the impact of the Russian invasion of Ukraine and the OPEC+ decision to adhere to previously agreed-upon production cuts. Additionally, the global economic conditions and outlook improved due to reducing and easing COVID-19 restrictions. In June 2023, OPEC+ producers agreed to target lower oil supply up until the end of 2024 in order to stabilize the price of oil. In anticipation of a potential surplus, in November 2023, OPEC+ producers agreed to a voluntary cut in output for the first quarter of 2024.

While the trajectory of oil prices continue to be subject to uncertainty and volatility, factors such as transportation disruptions, supply constraints and the conflict in Ukraine continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

During the early summer months of 2023, wildfire activity impacted Canadian crude production throughout the second quarter. In addition, many facilities experienced lengthy maintenance updates, which resulted in lower overall production. Despite the setbacks, it has been forecasted that Canadian oil and gas producers will drill 8% more wells in 2024, taking advantage of greater access to pipelines, signaling a ramp-up in growth and demand for crude oil production in the country. The anticipated growth in exports and crude oil prices is supported by the progress of the Trans Mountain Pipeline which is expected to increase the pipeline's capacity by 590,000 barrels per day, to a total of 890,000 barrels per day.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane, propane and pentane plus sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural gas prices are expected to remain subdued for the first few months of 2024 in light of the predicted warmer 2024 winter. Exceptionally high production levels in both Canada and the U.S., alongside storage reserves in Europe and North America, have collectively contributed to maintaining lower natural gas prices.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (Canada), R.S.C. 1985, c N-7 ("**NEB Act**") with the *Canadian Energy Regulator Act* (Canada), S.C. 2020, c.28; ("**CERA**"), the *Canadian Environmental Assessment Act, 2012* (Canada), S.C. 2012, c. 19, s. 52; ("**CEAA**") with the *Impact Assessment Act* (Canada), S.C. 2019, c. 28, s. 1 ("**IAA**") and replacing the National Energy Board ("**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, NGLs and natural gas from Canada. The legislative regime relating to exports of crude oil, NGLs and natural gas.

Exports of crude oil, NGLs and natural gas from Canada are subject to CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**") until such time as the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, NGLs and natural gas exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas (other than NGLs) not exceeding 30,000 m^3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGLs). With respect to applications for long-term export licences, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes are not greater than Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

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.

Transportation Constraints, Pipeline Capacity and Market Access

As discussed in more detail below, one major constraint to the export of crude oil, NGLs and natural gas is the deficit of transportation capacity to transport production from Western Canada to the U.S. and other international markets. Although certain pipeline and other transportation and export projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due in part 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.

Pipelines

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. 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 and the price received.

Under the Canadian Constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, construction of interprovincial and international pipelines (new or expansion capacity) will require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty such that, even when projects are approved they often face delays due to actions taken by provincial and municipal governments, public interest groups 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 of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian petroleum and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, NGLs and natural gas, 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.

Specific Pipeline Updates

The Enbridge Inc. ("**Enbridge**") Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, experienced permitting difficulties in the United States. However, Minnesota regulators approved the final required permit for the project in November 2020 and received confirmation of such approval from the Minnesota Court of Appeals in June 2021. On September 29, 2021, Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement's in-service date was October 1, 2021, and Line 3 transports 760,000 barrels per day at full capacity. In October 2022, a Minnesota District Court upheld approvals given to the Line 3 Replacement, which were challenged on the basis that the U.S. Army Corps of Engineers should have taken into consideration how the broader project would impact climate change. The U.S. Army Corps of Engineers limited their environmental review of the project only to the impacts of construction in Minnesota rather than downstream concerns like greenhouse gas ("**GHG**") emissions from the ultimate burning of the crude oil carried in the pipeline.

In December 2023, Michigan Regulators approved Enbridge's Line 5 Tunnel Replacement Project, marking the end of a more than three year long evaluation process. Line 5 is seen as crucial infrastructure supplying Michigan, Ontario and Quebec. This approval begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straights 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.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the federal government's Indigenous consultations. The federal Court of Appeal quashed the approval and directed Cabinet to correct these deficiencies. Following a reconsideration by the NEB and enhanced consultation efforts led by the federal government, Cabinet reapproved the Trans Mountain Pipeline expansion. Subsequent challenges to the approval were rejected by the Federal Court of Appeal in February 2020 and the SCC in July 2020.

The Trans Mountain Pipeline expansion project faced a series of construction-related challenges throughout the third and fourth quarters of 2023. In September 2023, Trans Mountain faced a potential nine-month delay over a reroute approval in the Jacko Lake area near Kamloops, British Columbia, due to difficulties identified during the tunnel drilling process. The request was opposed by the Stk'emlupsemc Te Secwepemc Nation (the "**SSN**") First Nation, whose territory the pipeline crosses. The SSN argued that changing the route would disturb lands that hold "profound spiritual and cultural significance". After a three day hearing, the CER approved the route change request on a 1.3-kilometer section of the pipeline. Following the CER's release of the reasons for its decision, the SSN has not filed an appeal or a variance request.

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and mechanical completion of the project is now expected to occur in the second quarter of 2024. In November 2023, Trans Mountain faced another regulatory hearing on a pipeline variance request of a section of pipeline between Hope and Chilliwack, British Columbia. Trans Mountain applied for a variance request due to very challenging conditions, including the hardness of the rock that needed to be drilled. Trans Mountain requested permission to change the diameter, wall thickness, and coating for a 2,300-meter stretch of the pipeline, differing from its initial approval. The CER ordered Trans Mountain to attend an oral hearing in November of 2023 to provide further information or justification. In early December 2023, the CER denied the variance request, causing a potential two-year delay and additional losses. On January 12, 2024, the CER reversed its decision, approving the request for change, allowing construction to continue.

The United States presidential election is set to occur in the fall of 2024, which may result in a shift in the political agenda in the United States in the coming years, including a change in control of the house and/or the senate. Uncertainty remains as to the advancement of pipeline projects between Canada and the United States.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGLs or persistent crude oil products in excess of 12,500 metric tonnes along British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbl/d of crude oil out of the province to help alleviate the transportation constraints impacting Canadian oil prices.

In the spring of 2019, the Government of Alberta announced it would cancel the program and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020, that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in early April 2020 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits announced in February 2020 within metropolitan areas, with further mandatory speed reductions applying outside of metropolitan areas during winter months (November 15 to March 15). As of February 2024, no permanent rules have been approved.

Natural Gas and LNG

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which is generally lower than the price received in other North American markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy Corporation ("**TC Energy**") on its NOVA Gas Transmission Ltd. pipeline network (the "**NGTL System**") to prioritize deliveries into storage (the "**Temporary Service Protocol**"). The change stabilized supply and pricing, particularly during periods of maintenance on the system. Construction began on the NGTL System in 2021 with a majority of the project components reaching in-service for firm contracts in early 2023. It is anticipated that all project components will reach in-service in the first quarter of 2024.

In July 2020, the Explorers and Producers Association of Canada applied to extend the Temporary Service Protocol, which was opposed by NGTL and ultimately denied by the CER in February 2021.

In January 2022, the CER issued its decision denying NGTL's application for a proposed firm transportation linked service from receipt points along the North Montney Mainline in Northeast British Columbia to the proposed Willow Valley Interconnect delivery point. In its decision the CER stated the tolling methodology proposed would result in unjust and unreasonable tolls.

In August 2023, TC Energy sought regulatory approval for a potential minority interest sale of its NGTL System. The sale would result in a restructuring in order to facilitate potential future minority ownership of the system, including possible participation from Indigenous groups. As of the date of this AIF, no decision has been announced. TC Energy has begun discussions with Indigenous groups regarding a potential sale.

Development of both provincial and federal frameworks may also impose restrictions on natural gas and LNG projects in Canada, particularly as provincial and federal governments work to achieve emissions reduction targets.

On January 26, 2024, the Biden Administration announced a temporary pause on pending decisions on exports of LNG to non free trade agreement countries until the Department of Energy can update the underlying analysis for authorizations, which may increase the need to use Canadian infrastructure to fill the gap, of which the projects are still in development.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, opposition from environmental and Indigenous groups and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. The Coastal GasLink pipeline (the "**CGL Pipeline**") was built by TC Energy, construction of which began in November 2018. In May 2020, TC Energy sold its 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline faced intense legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays to construction activities on the CGL Pipeline, although construction is proceeding.

In October 2023, it was announced that the 670 kilometre pipeline installation had been completed ahead of the year-end target. The project will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the CGL Pipeline. Once in service, 17 First Nations that are situated along the pipeline route have signed an agreement for the option to buy a 10% stake in the project.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited, a subsidiary of Woodside Petroleum Ltd.

The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia, and owned by Woodfibre LNG Limited a subsidiary of Singapore-based Pacific Oil and Gas Ltd. The BC Oil and Gas Commission (BC Commission) approved a project permit for the Woodfibre LNG Project, in July 2019. In April 2022, a Notice to Proceed was issued, instructing the contractor to begin work required to move the project toward major construction commencement in 2023. In July 2022, Pacific Energy Corporation Limited and Enbridge entered into a partnership agreement to jointly invest in the construction and operation of the Woodfibre LNG Project. In November 2022, proposals were made to amend the conditions listed in the project's Decision Statement (which informs the proponent about the determination made by the Minister or the Governor in Council), concerning technical feasibility. These proposed amendments were then issued for public comment. On November 9, 2023, the British Columbia Environmental Assessment Office approved the amendment to the environmental assessment certificate for the Woodfibre LNG Project to allow for a temporary floating worker accommodation, or 'Floatel', as well as its associated mooring, access infrastructure, and onshore drinking-water treatment facility. The 'Floatel' is expected to arrive in 2024. On July 31, 2023, the project officially commenced construction on the first of the proposed eighteen modules for the project. The Woodfibre LNG Project is expected to be substantially completed in the third quarter of 2027.

GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026; however, on February 7, 2022, the IA Agency concluded that the project was likely to cause an adverse environmental impact. Although the federal government has rejected the initial plan, GNL Quebec Inc. is not prevented from submitting a new or revised project proposal for authorization. As of the date of this AIF, no revised proposal has been submitted.

The United States Mexico Canada Agreement and Other Trade Agreements

NAFTA / USMCA

On July 1, 2020, the North American Free Trade Agreement ("**NAFTA**"), a free trade agreement among the governments of Canada, the United States and Mexico, was replaced by a new trade agreement, widely referred to as the USMCA, and sometimes referred to as the United States Mexico Canada Agreement. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, NGLs and natural gas from Canada, the implementation of the USMCA could have an impact on Western Canada's petroleum and natural gas industry at large, including the Company's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach other international markets.

Other Trade Agreements

Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among: Canada, Australia, Japan, Mexico, New Zealand, Vietnam, Singapore, Peru Malaysia, Chile and Brunei Durussalam.

Canada has also pursued a number of other international free trade agreements with countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. 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 crude oil and natural gas products to the European Union. Although CETA has not received full ratification by 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, which received royal assent on March 17, 2021. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021, and CUKTCA came into force on April 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 August 2023, an updated version of the Canadian Free Trade Agreement ("**CFTA**") was published, aiming to revamp the Agreement on International Trade to create a more robust and equitable trade environment within Canada.

While it is uncertain what effect CETA, CPTPP, CUKTCA CFTA 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.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments (i.e. the Crown). Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral rights owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage. Oil and natural gas located in such provinces 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.

Each of the provinces in Western Canada 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 licence. In addition, Alberta 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 licences. For leases and licences issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or licence. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown. Such reversionary rights may impact any gross overriding royalty interests ("**GORR Interests**") granted out of Crown leases.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by the federal government on behalf of First Nations or national parks and by private freehold owners, such as the Company. Rights to explore for and produce privately owned crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop crude oil and natural gas reserves.

An additional category of mineral rights ownership includes ownership by the Canadian Federal Government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). The IOGC, which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for the exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, crude oil and natural gas activities conducted on Indian reserve lands were governed by the Indian Oil and Gas Act (the "**IOGA**") and the Indian Oil and Gas Regulations, 1995. In 2009, Parliament passed An Act to Amend the Indian Oil and Gas Act, amending and modernizing the IOGA, however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying regulations. The amended and modernized IOGA and the accompanying regulations came into force on August 1, 2019.

The GORR Interests are royalty interests that are granted or carved out of leasehold interests (created through the issuance of a lease by the Crown or fee simple mineral title owner). As such, the continued existence and value of the GORR Interests is dependent upon the validity and terms of the leasehold interest out of which they were granted.

In respect of the GORR Interests granted out of Crown leases, in addition to the varying terms and conditions set forth in provincial legislation, as discussed above, the provinces of Alberta, British Columbia, Saskatchewan and

Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to non-productive geological formations at the conclusion of the primary term of a lease or licence.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of crude oil, NGLs, sulphur 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, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of production. 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 have established incentive programs for exploration and development. Such programs often provide for volume-based incentive programs, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low. The incentive programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. In addition, incentive programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, NGLs and natural gas, or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the petroleum and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the petroleum and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada.

Producers and working interest owners of oil and natural gas rights may also create additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests, the terms of which are subject to negotiation.

Alberta

In Alberta, provincially set royalty rates apply to Crown-owned mineral rights and crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis.

In January 2016, the Government of Alberta announced further changes to the Alberta Royalty Framework. Under the new modern royalty framework (the "**MRF**"), the sliding scale royalty concept will be maintained, but will be achieved with a greater degree of simplicity. The new royalty percentage will be applied to the gross revenue generated from all hydrocarbons, with no differentiation between produced substances, and wells will be charged a flat 5% royalty rate until revenues exceed a normalized well cost allowance, which will be based on vertical well depth and lateral length. The calculation of this cost allowance, and other details regarding the various parameters within the new formula under the MRF was announced in 2016 and was fully implemented as of January 1, 2017. Prior to January 1, 2017, the former royalty framework continued to apply to any wells drilled prior to that date, and thereafter for a period of 10 years following which, such wells will be transitioned into the MRF. Any changes to the royalty regime in Alberta may have a material effect on the Company. See "*Risk Factors*".

In addition to any negotiated royalty amount payable to the freehold mineral owner, 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 percent of revenues reported from fee simple mineral title properties.

In July 2019, the Government of Alberta enacted the *Royalty Guarantee Act* which provides certainty that no major changes will be made to the current oil and gas royalty structure for a period of at least ten years.

British Columbia

In May 2022, the government of British Columbia introduced a new royalty framework that is set to come into effect September 1, 2024 with a two-year transition period beginning on September 1, 2022. The new royalty framework will be based on a revenue-minus cost royalty system with price-sensitive royalty rates designed to reflect the value of the resource and achieve a return of 50% of profits after production costs are accounted for. New wells will pay a flat royalty of 5% until the capital spent on drilling and completions is recovered, following which, the well will move to a price-sensitive royalty rate between 5% and 40%. The range of the rate will vary by commodity type. During the transition period, any new wells which are spud on or after September 1, 2022 are not eligible for the deep-well royalty program, the marginal well royalty program or the ultra-marginal royalty program. Wells that are spud on or after September 1, 2022 will pay a 5% royalty rate for the equivalent of the first 12 production months, following which the wells will pay royalties based on the current royalty framework until September 1, 2024 when all the wells transition to the new framework. Wells drilled prior to September 1, 2022 shall continue to pay royalties based on the current royalty framework until the new framework takes effect on September 1, 2024.

Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales.

The Crown royalty rate for oil can be as high 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells, including low productivity wells, to reflect higher per-unit costs of exploration and extraction. The Crown royalty rate for natural gas and NGLs in British Columbia varies depending on the characteristics of the specific substance and can be as high as 27%, depending on factors such as whether the gas is classified as conservation gas or non-conservation gas, the applicable reference price and select price.

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 British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

For oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

The Ministry of Energy, Mines and Low Carbon intends to create a mechanism that will begin in early 2023 to allow producers to repurpose unused deep well entitlements by transferring them to a Healing Land and Emission Reduction Pool. Once allocated to a producer's pool, the deep well credits will no longer be available to reduce royalties on the well they were originally allocated to.

Freehold and Other Types of Non-Crown Land Royalties and Taxes

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the freehold mineral owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay Freehold Mineral Taxes or production taxes. Freehold Mineral Taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the Freehold Mineral Taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on Indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between Indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of Indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the terms.

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. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, Logan 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.

Regulatory Authorities and Environmental Regulation

The Canadian 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 restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in suspension or revocation of necessary licences and authorizations, civil liability 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 (typically measured in terms of their global warming potential and expressed in terms of CO2e, may impose further requirements on operators and other companies in the petroleum and natural gas industry).

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The CERA and the CEAA provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the CEAA were repealed. As part of the regulatory transition, the IA Agency replaced the CEA Agency.

The enactment of the CERA and IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. However, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. Despite this structural change, the CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

The IAA is similar to the repealed CEAA 2012 in that it 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 socioeconomic factors, climate change and impacts to Indigenous rights. It also requires an expanded public interest assessment, including Indigenous consultation, as applicable. The impact assessment must look at the direct result of the project's construction and operation. Designated projects specific to the petroleum and natural gas industry include pipelines that require more than 75 km 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 response to the publication of the IAA, the Government of Alberta submitted a reference question to the Alberta Court of Appeal regarding its constitutionality. On May 10, 2022, the Alberta Court of Appeal released its opinion stating that the IAA went beyond the federal Parliament's constitutional authority and reached into areas of exclusive provincial authority. The federal Government appealed the Alberta Court of Appeal's opinion to the SCC. On October 13, 2023, the SCC issued its judicial reference opinion, concluding that the "designated projects" component of the IAA is beyond the legislative authority of the federal government and therefore unconstitutional.

However, the SCC reached a unanimous decision affirming the constitutional validity of the section within the IAA that pertains to projects conducted or funded by federal authorities on federal lands or abroad. The SCC found that "designated projects" under the IAA was unconstitutional as it was seen as overreaching federal authority. This portion of the IAA was criticized for regulating entire projects, rather than focusing solely on areas falling under federal jurisdiction.

This decision has significant implications for the development of natural resources, energy and infrastructure projects in Canada. While the federal government works to bring the IAA into compliance with the guidance as set out by the SCC, the Impact Assessment Act (the "**Interim Guidance**") was enacted, and will remain in place until the IAA is revised. During this interim period, the federal government will not be using its discretionary process to designate projects under the IAA until the legislation has been revised. The Federal Minister of Environment announced it will work with the provinces and Indigenous groups to ensure the impact assessment process works for all. The revisions to the IAA will require that only those projects that can result in adverse federal effects are targeted. Until such time as the revised IAA has been released, proponents must comply with the Interim Guidance. The potential effects that the Interim Guidance, or the revised IAA, may have on the oil and gas industry is unknown.

On July 1,2023, the CFS Regulations came into force. The objective of the clean fuel standard is to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The CFS Regulations requires liquid fossil fuel primary suppliers (i.e. producers and importers) to reduce the carbon intensity ("**CI**") of the liquid fossil fuels they produce in, and import into, Canada. The CFS Regulations has also established a credit market, whereby the annual

CI reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the CI of the fossil fuel throughout its lifecycle; (ii) supplying low-carbon fuels; and (iii) specified end-use fuel switching in transportation.

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, detailing emissions quantification methods, was released on December 12, 2023. The OBPS regulations 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 2024, the federal government plans to publish proposed regulations for a 60-day public comment period. Formal written comments will also be sought on the proposed regulations at that time. The final regulations are expected to be published by 2025. The initial reporting responsibilities could come into effect as early as 2026, while the complete system requirements are set to be gradually implemented between 2026 and 2030.

On June 21, 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act ("**Bill C-15**") received Royal Assent and immediately came into force. 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.

Alberta

The discharge of crude 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 Logan to incur costs to remedy such discharge in the event that they are not covered by the Company's insurance. Although the Company maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. 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.

The Alberta Energy Regulator ("**AER**") is the principal regulator responsible for all energy development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related statutes including the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER ensures 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 (the "**AUC**") and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental, and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, increased seismicity 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 crude oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the 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 crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity 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). Crude 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 crude 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 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.

British Columbia

In British Columbia, the Oil and Gas Activities Act (the "**OGAA**") regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the OGAA, the BC Commission has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The Environmental Protection and Management Regulation establishes the government's environmental objectives and requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the Petroleum and Natural Gas Act, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The Drilling and Production Regulation requires a producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

An updated Environmental Assessment Act came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the Environmental Assessment Act, the Government of British Columbia enacted the accompanying Reviewable Projects Regulation, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the British Columbia Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project.

Liability Management Rating Programs

Alberta

The AER administers the Alberta Liability Management Framework (the "**AB LMF**") and the new Liability Management Framework that replaced the Alberta Liability Management Rating Program (the "**AB LMR Program**") and its constituent programs to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. 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 AB LMF include a new Alberta Licensee Capability Assessment System (the "**AB LCA**"), a new Alberta Inventory Reduction Program (the "**AB IR Program**") and a new Alberta Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Alberta Oilfield Waste Liability Program (the "**AB OWL Program**"), the Alberta Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Alberta Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under 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 LMF and the AB LMR Program, Alberta's *Oil and Gas Conservation Act* 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 a licensee or working interest participant becomes insolvent or is unable to meet its obligations. 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. 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. Under the new AB LMF, the Orphan Well Association has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

The SCC's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision) provides the backdrop for Alberta's approach to liability management. As a result of 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*, which came into force on proclamation. The *Liabilities Management Statutes Amendment Act* 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.

One important step in the shift to the AB LM Framework has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and granting of new well, facility and pipeline licences in Alberta are subject to AER approval. Previously under the AB LMR Program, as a condition of transferring existing AER licences, approvals and permits, all transfers required transferees to demonstrate that they had a liability management rating of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021, to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

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; (iv) the management of its operations; (v) the rate of closure activities for its liabilities; and (vi) and 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. However, the liability management rating under the LLR Program is still in effect for other liability management programs such as the AB OWL Program and the AB LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

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. During the summer of 2022, the AER announced that it would increase spend targets for liabilities in 2023 from $422 million to $700 million and released forecasted targets through 2027, each of which are expected to increase annually by 9%.

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.

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. The ABC, together with the inventory reduction program implemented under the AB LMF, which implements mandatory closure spend targets over a 5-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

On November 16, 2023, the AER provided an update on the ongoing implementation of the AB LMF. The process to implement the AB LMF involves updating various regulatory instruments and establishing a new security framework under the OGCA. The changes aim to improve risk assessment, ensure fair responsibility for cleanup in active sites, and streamline regulations. The new security framework will consider factors beyond the LLR, such as the entire energy development life cycle and the polluter-pay principle. Stakeholder engagement is planned for 2024 before releasing draft documents for public comment.

British Columbia

The BC Commission previously oversaw a Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. In the spring of 2019, the BC Commission introduced a Comprehensive Liability Management Plan ("**CLMP**"). The purpose of the CLMP is to ensure that 100% of the costs associated with the reclamation of oil and natural gas sites is paid by industry, rather than the Government of British Columbia or residents of British Columbia. Pursuant to the CLMP, the BC Commission is implementing a Permittee Capability Assessment ("**PCA**") program. Similar to the framework to be implemented in Alberta, the PCA program is intended to be a holistic evaluation of permittees throughout the development life cycle and is intended to replace the BC LMR Program. The PCA program is intended to mitigate risk and minimize pressure on the Orphan Site Reclamation Fund.

In the spring of 2019, a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BC Commission to impose more than one levy in a given calendar year.

The *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan. The BC Commission is currently drafting proposed amendments to expand the Dormancy Regulation to include pipelines, facilities and related activities. The comment period on the draft policy changes ended on July 30, 2022. It is unknown when the amended regulation is expected to be implemented.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. These funds were administered by regulatory authorities in each province and disbursed through various provincial programs.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the regulation of the oil and natural gas industry in Canada. These impacts are uncertain and it is 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 the Company's operations and cash flow.

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 changes 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 December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees' delaying decisions about a prospective carbon market and emissions cuts until the next climate conference. The result of the 2021 United Nations Climate Change Conference, more commonly referred to as COP26, was the Glasgow Climate Pact, negotiated through consensus of the representatives of the 197 attending parties. Owing to late interventions from India and China, which weakened a move to end coal power and fossil fuel subsidies, the conference ended with the adoption of a less stringent resolution than some anticipated. The Glasgow Climate Pact reaffirms the long-term global goals (including those in the Paris Agreement) to hold the increase in the global average temperature to below 2.0° Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5° Celsius above pre-industrial levels.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, but indicated in the recent Speech from the Throne (also referred to as the Throne Speech) that it expects to implement policy changes to exceed this target. Specific details have not yet been announced. In connection with this target, 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. In March 2022, the Government of Canada also introduced Canada's 2030 Emissions Reduction Plan (the 2030 Reduction Plan), which provides the building blocks for the Canadian economy to achieve 40% to 45% emissions reductions below 2005 levels by 2030. The 2030 Reduction Plan includes $9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress of the 2030 Reduction Plan will be reviewed and produced in reports in 2025 and 2027, with additional targets to be developed for 2035 and 2050.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the **"HEHE Plan"**) which builds on the Pan-Canadian Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a $3-billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels. Also of relevance to the petroleum and natural gas industry, in June 2022, the federal government introduced the Single-use Plastics Prohibitions Regulations. The regulations prohibit, subject to certain exemptions, the manufacture, import and sale of single-use plastic checkout bags, cutlery, foodservice ware made from or containing problematic plastics, ring carriers, stir sticks and straws. The prohibitions on manufacture and import for sale in Canada and sale and manufacture, import and sale for export come into force on a rolling basis between December 2022 and December 2025.

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050. Canada joined over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. The Canadian Net-Zero Emissions accountability Act became law in June 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation also sets rolling five-year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrine greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (Canada), S.C. 2018, c. 12, s. 186 ("**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: the OBPS and a regulatory fuel charge imposing an initial price of $20/tonne of CO_2e 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. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country.

The price is set to increase to \$50/tonne of CO_2e on April 1, 2022. In addition, on March 5, 2021, the federal government introduced for comment the *Greenhouse Gas Offset Credit System Regulations* (Canada) (the "**Federal Offset Credit Regulations**"). The proposed Federal Offset Credit Regulations are intended to establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS. The final Federal Offset Credit Regulations are expected to be put in place before the end of 2021.

Alberta, Saskatchewan, Ontario and Manitoba each challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the SCC and on March 25, 2021, the majority ruled that the GGPPA is constitutional.

Manitoba also made an appeal to the Federal Court stating that the federal government did not act properly in imposing a minimum price on carbon because Manitoba was planning to use its own lower price. In October of 2021, the Federal Court rejected Manitoba's argument, stating that the federal government's actions were consistent with the purpose of the GGPPA as was upheld by the SCC.

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards or federal benchmarks. Currently, the provincial systems, together with the federal fuel charge apply in each of Alberta, Saskatchewan, Ontario, New Brunswick, Nova Scotia and Newfoundland and Labrador. The provincial plans in each of British Columbia, Quebec and the Northwest Territories apply in full in those jurisdictions while the OBPS and federal fuel charge apply in each of Yukon, Nunavut, Manitoba and Prince Edward Island. For so long as the provincial systems in Alberta (under the *Technology Innovation and Emissions Reduction ("**TIER**")* regulation) British Columbia and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

On October 29, 2020, the federal government launched the \$750 million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies. Part of this fund is directed towards methane reduction.

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 petroleum 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 the 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. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

On December 4, 2023, the Minister of Environment and Climate Change announced amendments to the Federal Methane Regulations that seek to further cut emissions. These amendments closely mirror those in the United States and echo the International Energy Agency's call to curtail methane emissions from the oil and gas sector by 75% by 2030. These amendments signify a significant reinforcement to Canada's methane strategy. The draft amendments are undergoing consultation until mid-February 2024. The Government of Alberta has opposed the amendments, stating it will take measures to ensure the amended regulations are not implemented in Alberta. It is unknown at this time what the potential effects of the amended Federal Methane Regulations may be.

The federal government announced that it will proceed with the development and implementation of a Clean Fuel Standard ("**CFS**") that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. On December 18, 2020, the federal government published proposed CFS regulations, with the Clean Fuel Regulations ("**CFS Regulations**") which came into force on June 21, 2022, which implements the CFS. The CFS Regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS Regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to gradually reduce the amount of carbon in their product. Beginning in 2023, the carbon intensity reduction requirement will start at 3.5gCO2e/MJ, increasing by 1.5 gCO2e/MJ each year and reaching 14 gCO2e/MJ in 2030. The standard applies to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The regulations offer compliance credits, tracked via the Credit and Tracking System, and created a market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

On August 10, 2023, the federal government released a draft of the Clean Electricity Regulations which will help drive progress towards a net-zero electricity grid by 2035. The Clean Electricity Regulations are part of a suite of measures by the Government of Canada from the 2030 Emissions Reduction Plan to transition to clean energy. Developed under CERA, these regulations establish stringent pollution emission standards without prescribing specific technologies. This technology-neutral stance aims to grant flexibility to provincial, territorial, and municipal authorities as they transition to clean energy.

The Alberta Government has contested the constitutionality of the draft Clean Electricity Regulations and urged the federal government to support Alberta's plan for achieving carbon neutrality by 2050. On November 27, 2023, the Government of Alberta issued notice of its intention to invoke a resolution under the Alberta Sovereignty within a United Canada Act (the "**Sovereignty Act**") in response to the draft Clean Electricity Regulations. This resolution directs specific provincial entities from enforcing or complying with the Clean Electricity Regulations "to the extent legally permissible." Consequently, there is a strong possibility that once implemented, the Clean Electricity Regulations will face constitutional challenges.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

The federal government has enacted the Multi-Sector Air Pollutants Regulation under the authority of CERA, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream petroleum and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

On July 24, 2023, the Minister of Environment and Climate change released the Inefficient Fossil Fuel Subsidies Government of Canada Self-Review Assessment Framework and the Inefficient Fossil Fuel Subsidies Government of Canada Guidelines. The documents will support the federal government's focus on clean energy and net-zero initiatives and the de-carbonization of Canada's oil and gas sector. Pursuant to the Framework, subsidies are deemed "inefficient" unless they satisfy certain criteria, which include, but are not limited to: supporting clean energy, clean technology, or renewable energy; providing essential energy service to a remote community; providing short term support for emergency response; supporting Indigenous economic participation in fossil fuel activities; or supporting abated production processes, such as carbon capture, utilization, and storage, or projects that have a credible plan to achieve net-zero emissions by 2030.

On June 13, 2023, Bill S-5 Strengthening Environmental Protection for a Healthier Canada Act to amend CERA, received royal assent. The amendments include changes to the preamble of CEPA, which now recognizes that every individual in Canada has a right to a healthy environment. Section 2 of CEPA now requires that the federal government protect this right, and that an implementation framework be developed to consider how this right will be administered under CEPA, which is anticipated to be published by 2025. Further amendments include creating a risk assessment Plan of Chemical Management Priorities, setting out a multi-year assessment of substances and activities, and a commitment to consider the cumulative effects of these assessments on vulnerable populations.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan. Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge that was compliant with federal requirements. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites. In June 2019, the Government of Alberta repealed the CLA and the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $65/tonne of CO2e and will increase to $80/tonne on April

1, 2024. In December 2019, the federal government approved Alberta's TIER regulation which applies to large emitters and those who have opted-in. The TIER regulation came into effect on January 1, 2020 and replaced the previous Carbon Competitiveness Incentives Regulations.

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, among others, meeting the federal standards for Alberta's carbon pricing system, the creation of sequestration credits for Carbon Capture, Utilization and Storage ("**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 applies 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, with a further 1% reduction for each subsequent year. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high performance benchmarks. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard. 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. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. The amendments reduced the threshold for those to opt-in from 10,000 tonnes of CO2e to 2,000 tonnes of CO2e per year. 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 TIER regulation will continue to apply in Alberta for so long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

In furtherance of global emissions reductions targets, the Government of Alberta had announced a goal to lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the Methane Emission Reduction Regulation (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* ("**Directive 060**"). The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* ("**Directive 017**") that took effect in December 2018. In November 2023, it was announced that Alberta had achieved its goal of reducing methane emissions by 45% by 2025, years ahead of schedule.

In November 2020, the Government of Canada and the Government of Alberta reached an equivalency agreement with respect to the Alberta Methane Regulations. Through the Equivalency Agreement and Directive 060 and Directive 017, Alberta maintains jurisdiction over the regulation of the upstream oil and gas industry. Should amendments to the Federal Methane Regulation come into effect and the Government of Alberta challenges such amendments, the potential effects of such legislation in Alberta, or the effects of any potential challenge to their implementation by the Government of Alberta is unknown.

Alberta was 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 through 2025 to fund two commercial-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. Both projects will help reduce the CO_2 emissions from the oil sands and fertilizer sectors and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which 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. This legislation is intended to encourage new carbon capture and storage projects in Alberta.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization. The AUC also released its Hydrogen Inquiry Report in September 2022 which reviewed the viability and impacts of hydrogen blending into natural gas distribution systems in 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 AUC 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 polices for renewable resource development will include a public inquiry, after which the AUC 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.

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 CCUS hub projects through Emissions Reduction Alberta.

British Columbia

In August 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge is currently set at \$50/tonne of CO_2e. As noted above, the pollution pricing system in British Columbia currently meets the federal stringency requirements, and in order to maintain its application, the fuel charge will increase to \$65/tonne of CO_2e in 2023 to maintain compliance with the federal benchmark.

In January 2016, the *Greenhouse Gas Industrial Reporting and Control Act* (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

In December 2018, the Government of British Columbia announced an updated clean energy plan, ("**CleanBC**"), which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of oil and natural gas production; (v) reducing 45% of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles. On July 6, 2021, the Government of British Columbia released the B.C. Hydrogen Strategy, which lays out a framework for the province to utilize hydrogen in support of its CleanBC plan. The Strategy sets out 63 actions to be undertaken over three periods of time: (i) short term (2020-2025), (ii) medium term (2025-2030) and (iii) long term (2030-beyond).

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "**CleanBC Roadmap**"), aimed at helping British Columbia achieve its 2030 emission reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90% of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries and for increased support for clean hydrogen and negative emissions technology. Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

In January 2019, the BC Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia. The equivalency agreement will be in place for a period of five (5) years.

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 the *United Nations Declaration of the Rights of Indigenous Peoples* ("**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 December 2020, the federal government introduced *Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act*. Similar to British Columbia's DRIPA, the intention of Bill C-15 is to establish a process whereby the Government of Canada will 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. Bill C-15 received royal assent and was passed into law on June 21, 2021.

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 Bill C-15 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.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to the *Extractive Sector Transparency Measures Act* must report payments over $100,000 made to any level of a Canadian or foreign government (including Indigenous groups), including royalty payments, taxes (other than consumption taxes and personal taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

Bill S-211, An Act to enact the Fighting Against Forced Child Labour in Supply Chains Act and to amend the Customs Tariff (the "**Modern Slavery Act**") received royal assent on May 11, 2023 and came into force on January 1, 2024. Pursuant to the Modern Slavery Act, entities that meet certain criteria are required to file public reports annually on the steps they have taken prevent and reduce the use of forced labour and child labour in their supply chains. Corporations that meet the requirement to comply with the obligations under the Modern Slavery Act will be required to submit their first annual report by May 31, 2024. The Company will be required to comply with the reporting obligations under the Modern Slavery Act and is preparing its first report. See "Risk Factors – Evolving Corporate Governance, Sustainability and Reporting Framework".

The Company is subject to both risks that directly affect Logan's business and operations, as well as indirect risks that impact third parties or the industry generally. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with Logan's business, the business of third parties with whom the Company conducts business and the crude oil and natural gas business in general. If any event arising from the risk factors set forth below occurs, Logan's business, prospects, financial condition, results of operation or cash flows and in some cases, its reputation, could be materially adversely affected.

Volatility in the Petroleum and Natural Gas Industry

Market events and conditions, including global excess crude oil and natural gas supply, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, Russia and the Ukraine, the Middle East, Israel and the West Bank and Gaza Strip, and Yemen, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, conflict between the United States and Iran, isolationist and punitive trade policies, increased United States shale production, sovereign debt levels, world health emergencies (including global pandemics) and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. Following extreme supply/demand imbalance in 2020, the crude oil and natural gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. However, the ongoing war in the Ukraine and price caps and sanctions on oil from Russia have impacted demand and oil prices throughout the latter half of 2022 which continued throughout 2023. 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. These events and conditions have caused a significant decrease in the valuation of crude oil and natural gas companies and a decrease in confidence in the petroleum and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Royalties and Incentives*", "*Regulatory Authorities and Environmental Regulation*" and "*Climate Change Regulation*" in *"Industry Conditions*". In addition, difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the petroleum and natural gas industry in Western Canada and cross-border with the United States has led to additional downward price pressure on crude oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the petroleum and natural gas industry in Western Canada (see "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access*").

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, and are anticipated to continue to reduce, the Company's cash flow which could result in a reduced capital expenditure budget. 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. See "*Risk Factors - Reserve Estimates*". A prolonged period of adverse market conditions may impede the Company's ability to refinance its Credit Facility or arrange alternative financing when the Credit Facility becomes due or if the lending limits under the Credit Facility are reduced upon periodic review. See "*Risk Factors - Credit Facility Arrangements*". 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 or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Logan's cash flow may not be sufficient to continue to fund operations and to satisfy obligations when due and will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds from asset sales to discharge its obligations. See "*Risk Factors - Additional Funding Requirements*".

Commodity Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired, discovered or produced by Logan is, and will continue to be, affected by numerous factors beyond its control. The Company's ability to market its crude oil and natural gas may depend upon its ability to acquire space on pipelines that deliver oil and natural gas to commercial markets or contract for the delivery of crude oil by rail (see "*Industry Conditions – Pricing and Marketing in Canada" and "Risk Factors – Volatility in the Petroleum and Natural Gas Industry").* The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines, railway lines processing and storage facilities; and operational problems affecting such pipelines, railway lines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas and many other aspects of the crude oil and natural gas business.

The prices of crude oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. Any material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of Logan's anticipated net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of Logan's reserves. Logan might also elect not to produce from certain wells at lower prices. See "*Industry Conditions - Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access*" and "*Risk Factors – Volatility in the Petroleum and Natural Gas Industry*".

Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers, sellers, lessors and lessees have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities. See *"Risk Factors – Volatility in the Petroleum and Natural Gas Industry".*

All of these factors could result in a material decrease in Logan's expected net production revenue and a reduction in its future crude oil and natural gas acquisition, exploration, development and production activities. Any substantial and extended decline in or continued low crude oil and natural gas prices would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business and financial condition.

In addition, bank borrowings available to Logan may, in part, be determined by Logan's borrowing base. A sustained material decline in prices from historical average prices could reduce Logan's borrowing base, therefore reducing the bank credit available to Logan which could require that a portion, or all, of Logan's bank debt be repaid.

Project Risks

The Company manages a variety of small and large projects in the conduct of its business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Logan's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the following: processing capacity availability; availability and proximity of pipeline capacity; availability of storage capacity; availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing; the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations; effects of inclement weather; availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; regulatory changes; political uncertainty; availability and productivity of skilled labour; environmental and Indigenous activism or land claims that potentially results in delays or cancellations of projects; litigation and judicial interpretation and application of laws, including with respect to Indigenous rights and historical treaties; and litigation and regulation of the oil and natural gas industry by various levels of government and governmental agencies.

These factors could result in Logan being unable to execute projects on time, on budget, or at all and may be unable to effectively market its oil and natural gas products.

Reliance on Operators, Management and Key Personnel

The operations and management of the Company require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Company's business plans which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Logan's success will be, in part, dependent on the performance of its key managers and consultants. Failure to retain the managers and consultants, or to attract or retain additional key personnel, with the necessary skills and experience could have a materially adverse impact upon Logan's growth and profitability. Logan does not carry key person insurance. The contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company. In addition, Logan may not be the operator of certain oil and natural gas properties in which it acquires an interest. To the extent Logan is not the operator of its oil and natural gas properties, Logan will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators.

Third-Party Credit Risk and Delays

Logan is or may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, suppliers and other parties. In the event such entities fail to meet their contractual obligations to Logan, such failures could have a material adverse effect on Logan and its Adjusted Funds Flow. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Logan's ongoing capital program, potentially delaying the program and the result of such program until Logan finds a suitable alternative partner.

In addition to the usual delays in payments by purchasers of oil and natural gas to Logan or to the operators, and the delays by operators in remitting payment to Logan, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale of delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of Logan in a given period and expose Logan to additional third-party credit risks. To the extent that any 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 business and financial condition.

Alternatives to, and Changing Demand for, Petroleum Products

Fuel conservation measures, alternative fuel requirements, 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, 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 crude oil and natural gas products. Logan cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a negative effect on Logan's business, financial condition, results of operations and cash flows.

Variations in Foreign Exchange Rates and Interest Rates

Operating costs incurred by Logan are generally paid in Canadian dollars. World crude oil and natural gas prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which fluctuates over time. Material increases in the value of the Canadian dollar negatively impact Logan's production revenues. Future Canadian/U.S. exchange rates could accordingly impact the future value of Logan's reserves as determined by independent reserves evaluators. Although a low value of the Canadian dollar relative to the U.S. dollar may positively impact the price the Company receives for crude oil and natural gas production it could also result in an increase in the price of certain goods used in operations which may have a negative impact on the Company's financial results.

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

An increase in interest rates could result in a significant increase in the amount Logan pays to service debt, which could negatively impact the market price of the Common Shares, which negative impact could prove to be material over time.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Logan depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Logan may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Logan's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Logan will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Logan may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Logan.

Future oil and natural 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 diligent 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.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and the shutting-in of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect production, which may reduce the Company's revenue.

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 hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including geological and seismic risks, 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 could have a negative effect on future results of operations, liquidity and financial condition, which could prove to be material over time.

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

Gathering and Processing Facilities, Pipeline Systems and Rail

The products Logan produces must be delivered through gathering, processing and pipeline systems, some of which are not owned by the Company, and in certain circumstances, by rail. The amount of crude oil and natural gas produced and sold from Logan's assets is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits, and limits on availability of capacity in gathering and processing facilities continues to affect the petroleum and natural gas industry and limits the ability to transport produced crude oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of crude oil and natural gas companies to export oil and natural gas. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Company's business and financial condition.

As a result, producers have considered rail lines as an alternative means of transportation. 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 and challenges to interprovincial and international infrastructure projects. On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the CEAA 2012 were repealed. In addition, the IA Agency replaced the CEA Agency. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Federal*". 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 Logan's production is processed through facilities owned by third parties over which the Company has no 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 third party facility operations could have a materially adverse effect on Logan's production and ability to deliver the same for sale, which, in turn, would indirectly reduce the Company's revenues. 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.

Regulatory

Crude oil and natural gas operations (exploration, development, production, pricing, marketing, transportation and infrastructure) are subject to extensive controls and regulations imposed by various levels of government and may be amended from time to time. Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of crude oil and natural gas and infrastructure projects. Amendments to these controls and regulations, including changes to royalty regimes or the calculation of production and mineral taxes, may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". 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, or make certain projects on the Company's assets uneconomic, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Further, the ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime as the implementation of the orders can be delayed resulting in uncertainty and interruption to business of the crude oil and natural gas industry. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and natural gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact crude oil and natural gas operations and may affect the Company's business and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Logan's operations require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that Logan will be able to obtain all necessary permits, licences, registrations, approvals and authorizations to carry out exploration and development at its projects. In addition, certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) could negatively affect the Company's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. It is not expected that any of these controls or regulations will affect the operations of Logan in a manner materially different from how they would affect other oil and natural gas companies of similar size. Logan *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs".*

Environmental Regulation

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities* and *Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of such legislation may result in the imposition of fines or other penalties, some of which may be material, as well as the responsibility to remedy environmental problems caused by Logan's operations. See "*Industry Conditions — Regulatory Authorities and Environmental Regulation*". Should Logan be unable to fully fund the cost of remedying an environmental problem, Logan might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities and the potential for 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 Logan to incur costs to remedy such discharge. Although Logan believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws 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 Logan's financial condition, results of operations or prospects. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

Stakeholders, the public and provincial and federal governments are becoming increasingly concerned about habitat and species protection, including degradation to biodiversity caused by economic activity. Accordingly, governments at various levels are increasing the rigour of existing acts and regulations and issuing changes aimed at improving environmental protection.

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 that a licensee or permit holder becomes defunct. Alberta and the AER continue to implement the Alberta LMF, completing the remaining amendments to the necessary directive and regulations to entirely phase out the AB LMR Program. The implementation of the New Alberta LMF Program, or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by such third parties, or may result in the denial of licence or permit transfers, which could impact the availability of capital to be spent by them which could in turn materially adversely affect the Company's business and financial condition. The impact and consequences of the SCC's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program 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 natural 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 – Regulatory Authorities and Environmental Regulation"* and *"Industry Conditions – Liability Management Rating Programs*".

Royalty Regimes

There can be no assurance that the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or Logan's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. British Columbia introduced a new royalty framework in May 2022 that came into effect on September 1, 2024, with a number of incentives ending for any wells spudded after September 1, 2022. See "*Industry Conditions – Royalties and Incentives*".

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 GHG, 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 and the United States, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact.

Chronic Climate Change Risks

The Company's exploration and production facilities and other operations and activities emit GHG's and require the Company to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There is no guarantee the current provincial regimes in place will continue to meet federal stringency requirements and their continued application is subject to achieving the stringency standards as required by the federal government.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian petroleum and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. See "*Risk Factors – Seasonality and Extreme Weather Conditions*". In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Company to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chains, transport needs and employee safety, which may in turn have a material adverse effect on the Company. Specifically, in the event of water shortages or sourcing issues, the Company may not be able to, or will incur greater costs to, carry out hydraulic fracturing.

Foreign and domestic governments continue to evaluate and implement policy, legislation and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing operating expenses on the Royalty Properties, and, in the long-term, potentially reducing the demand for crude oil and natural gas and related products, resulting in a decrease in the Company's profitability and a reduction in the value of its assets. See "*Risk Factors – Non-Governmental Organizations and Eco-Terrorism Risks*" and "*Risk Factors – Reputational Risk*".

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which influenced investors' willingness to invest in the petroleum and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENVironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. The application was denied and ENVironment JEUnesse appealed to the Appeal Court of Quebec on February 23, 2021. The appeal was dismissed on December 31, 2021. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Given the perceived elevated long-term risks associated with regulatory changes or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, 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 GHG 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 crude oil and natural gas and related infrastructure businesses and projects. The impact of such efforts may require the Company's management to dedicate significant time and resources to these climate change related concerns, may adversely affect the Company's operations, the demand for and price of the Company's securities and may negatively impact the Company's cost of capital and access to the capital markets, which negative impact could prove to be material over time.

Claims have been made against certain energy companies alleging that GHG emissions from crude 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 crude oil and natural gas companies, for alleged personal injury, property damage or other potential liabilities. While the Company is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Company, impact its operations and have an adverse effect on its financial condition, which could prove to be material.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term, potentially reducing the demand for crude oil and natural gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or requiring impairments for financial statement purposes. See "*Industry Conditions - Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations and Eco-Terrorism Risks*", "*Risk Factors – Reputational Risk*" and "*Risk Factors – Changing Investor Sentiment*".

Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards and alternative energy incentives and mandates. There has also been increased activism, including threats of culpability, legal action against oil and gas producers, and public opposition to fossil fuels and the oil and gas industry in which the Company operates. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 - *Disclosure of Climate-Related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. 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, its 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.

Acute Climate Change Risks

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or could interfere with the Company's operations, increasing its costs and otherwise negatively impacting its operations. Over the last several years, certain areas of Alberta and British Columbia have been negatively impacted by wildfires, and most recently with extreme flooding in British Columbia causing temporary interruption to both pipeline systems and railway lines. Extreme weather conditions may lead to disruptions in the Company's ability to transport produced oil and natural gas as well as goods and services in its supply chains. The Company's assets are located in locations that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Company is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting the Company's operations.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under high pressure into rock formations to stimulate the production of crude oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. 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 costs of compliance and doing business as well as delay the development of crude oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of crude oil and natural gas that is ultimately produced from the reserves associated with Logan's assets and, therefore, could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Seismic events are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Red Deer and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek and the Red Deer region, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Formation in the Fox Creek area in February 2015 and subsequently in the Red Deer region in December 2019. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements will remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Water is an essential component of the Company's drilling and hydraulic fracturing processes. Limitations or restrictions on the Company's ability to secure sufficient amounts of 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. For instance, significantly reduced mountain snowpack and below-average precipitation over the past number of months has led to extremely low reservoir levels and record-low river levels in certain areas of Alberta. As such, for the first time since 2001, Alberta's Drought Command Team has been authorized to negotiate water-sharing agreements with water licence holders to manage water use and mitigate the risks of drought. If the Company is unable to obtain water to use in its operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which ultimately may have a detrimental effect on the Company's financial condition, results of operations, and cash flows.

Pandemic Risk

Severe disruptions in regional economies and the world economy can be caused by the outbreak of a contagious illness. Such pandemics and efforts to contain them could result in international, national and local border closings, travel restrictions, significant disruptions to business operations, supply chains, customer activity and demand, service cancellations, reductions and other changes, significant challenges in healthcare service preparation and delivery, and quarantines, as well as considerable general concern and uncertainty, all of which could negatively affect the economic environment and may in the future have further impacts, as was the case for the COVID-19 pandemic. It is not possible to predict what measures and restrictions may be imposed by governmental authorities and the period of time during which those measures and restrictions may apply. Economic and supply chain disruptions, including temporary staff shortages resulting from a pandemic, could further materially affect the Company's financial results and operations. A pandemic could also further and significantly impact global economic activity, including demand for hydrocarbons, and cause increased market volatility, continued changes to the macroeconomic environment and commodity prices in connection with ensuing economic disruption, supply shortages, trade disruption, temporary staff shortages and temporary closures of facilities in geographic locations more importantly impacted by the outbreak. The scope and severity of such disruptions and their impact on the Company's financial results and operations could be material.

Volatility of Market Price of Common Shares

The trading price of securities of crude oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the crude oil and natural gas market. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of crude oil and natural gas commodity prices, and the securities of issuers involved in the crude oil and natural gas business, has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. Similarly, recent market prices in the securities of crude oil and natural gas issuers relative to other industry sectors have led to lower crude oil and natural gas representation in certain key equity market indices. The volatility, trading volume and market price of crude oil and natural gas have been impacted by increasing investment levels in passive funds that track major indices and only purchase securities included in such indices and subsequently dispose of those securities if they are excluded from such indices. In addition, many institutional investors, pension funds and insurance companies, including government sponsored entities, have implemented investment strategies increasing their investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. These factors have impacted the volatility and liquidity of certain securities and put downward pressure on the market price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Similarly, the market price of the Common Shares may be due to Logan'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 Logan or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Notice to Reader – Special Note Regarding Forward-Looking Statements*". In addition, in recent years the market price for securities in the stock markets, including the TSX-V, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Credit Facility Arrangements

The amount authorized under the Credit Facility is dependent on the borrowing base determined by the lender to Logan under the Credit Facility. The Company is required to comply with covenants under the Credit Facility, which from time to time, either affect the availability, or price, of additional funding and in the event that the Company does not complete therewith, the Company's access to capital could be restricted or repayment could be required. The failure of the Company to comply with such covenants, which may be affected by events beyond the Company's control, could result in the default under the Credit Facility which could result in the Company being required to repay amounts owing thereunder. Even if the Company is able to 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, 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 and cross-acceleration provisions. In addition, the Credit Facility may, from time to time, 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 the Company's securities, incurring of additional indebtedness, 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.

Borrowing

From time to time, Logan may acquire assets or the shares of other corporations or otherwise finance its ongoing operations using debt, which may increase Logan's debt levels above industry standards. Further, a significant decrease in crude oil and natural gas prices, hedging losses or lower than expected production from Logan's properties may cause the Company's debt-to-cash flow ratio to rise above its peer standards. The level of Logan's indebtedness or debt-to-cash flow ratio from time to time could impair Logan's ability to obtain additional financing in the future on a timely basis and could affect the market price of the Common Shares.

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. Logan's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on the Company's financial performance and Funds from Operations.

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 its financial performance and funds from operations.

Substantial Capital Requirements

Logan 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 Logan'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 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. Logan 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 its business financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, Logan may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Company 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 natural gas industry and/or global economic and political volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. 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.

As a result of global economic and political volatility, Logan may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If revenues from the Company's reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Logan'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. In addition, the future development of Logan's properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing could be highly dilutive to existing shareholders. Failure to obtain any financing necessary for Logan's capital expenditure plans may result in a delay in development or production on the Company's properties.

Changing Investor Sentiment

A number of factors, including the effects of the use of fossil fuels on climate change, GHG emissions reduction, the impact of crude oil and 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 crude oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount of their investments of such entities 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 be costly 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 crude 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 Common Shares, even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Company's assets which may result in an impairment charge.

Evolving Corporate Governance, Sustainability and Reporting Framework

The Company's business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Company's securities. Logan is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities Administrators, the TSX-V and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Company's efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

Reputational Risk

The Company's business, financial condition, operations or prospects may be negatively impacted as a result of any negative public opinion toward the Company or as a result of any negative sentiment toward or in respect of the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain crude oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and increased costs and/or cost overruns.

Any environmental damage, loss of life, injury or damage to property caused by Logan's operations could damage the reputation of the Company in active operational areas. The Company's reputation could be affected by actions and activities of other corporations operating in the crude oil and natural gas industry, over which the Company has no control. If the Company, either directly or indirectly, develops a reputation of having unsafe work sites it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against fossil fuel companies may indirectly harm the Company's reputation. In addition, environmental damage, loss of life, injury or damage to property caused indirectly by the Company's operations could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital and decreasing the price and liquidity of the Common Shares.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which 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.

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, NGLs and natural gas reserves and cash flows to be derived therefrom, including many factors beyond Logan's control. The information concerning reserves and associated cash flow set forth in this AIF represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as: historical production from the properties; production rates; ultimate reserve recovery; timing and amount of capital expenditures; marketability of oil and natural gas; royalty rates; the assumed effects of regulation by governmental agencies; and future operating costs, all of which may vary from actual results.

For those 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. Logan's actual production, revenues, taxes and 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 the 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 are generally 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. Many of Logan's producing wells have a limited production history and thus there is less historical production on which to base the reserves estimates. In addition, a significant portion of Logan's reserves may be attributable to a limited number of wells and, therefore, a variation in production results or reservoir characteristics in respect of such wells may have a significant impact upon Logan's reserves.

In accordance with applicable securities laws, McDaniel has used forecast price and cost estimates based on averages from three different independent evaluators' price forecasts in calculating reserves quantities. See "*Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions*". Actual future net cash flows 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 cash flows derived therefrom will vary from the estimates contained in the McDaniel Report and such variations could be material. The McDaniel Report is based in part on the assumed success of activities Logan intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the McDaniel Report will be reduced to the extent that such activities do not achieve the level of success assumed in the McDaniel Report. The McDaniel Report is effective as of December 31, 2023, with a preparation date of March 18, 2024, and, except as may be specifically stated or required by applicable securities laws, has not been updated and, therefore, does not reflect changes in reserves since that date.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. The actual interest of the Company in properties may accordingly vary from Logan's records. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Company's title to the oil and natural gas properties Logan controls that could impair the Company's activities on them and result in a reduction of the revenue received by Logan.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

Logan may engage in the acquisitions and dispositions of businesses and assets in the ordinary course of business. Acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of Logan. All such assessments involve a measure of geologic, engineering, facility operations, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Logan'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 may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of so that Logan 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 Logan, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Hedging

From time to time, Logan may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. Similarly, the Company may enter into agreements to fix the differential or discount pricing gap which exists, and may fluctuate between different grades of crude oil, NGLs and natural gas and the various market prices received for such products. However, if commodity prices or differentials increase beyond the levels set in such agreements, Logan may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. In addition, if the Company enters into hedging arrangements it may be exposed 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; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or a sudden unexpected material event impacts crude oil and natural gas prices.

Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to U.S. dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Company will not benefit from the fluctuating exchange rate.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Logan will actively compete for capital, skilled personnel, access to rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations.

The Company competes with other exploration and production companies, any of whom may have more financial resources, staff or political influence than the Company. Logan's ability to increase its production in the future will depend not only on its ability to develop the Company's properties, but also on its ability to select other suitable assets for further exploration and development.

In addition, the Company competes with numerous other entities in the search for, and the acquisition of, petroleum and natural gas properties and in the marketing of petroleum and natural gas. In particular, the Company competes with other companies for the acquisition of royalty interests in petroleum and natural gas properties. Other companies may have access to substantially greater financial resources, staff and facilities than those of the Company and who may have lower costs of, and better access to, capital. The Company's ability to increase its reserves in the future will depend partially on its and its partners' and royalty payors' ability to explore and develop its present properties but will primarily depend on its ability to acquire royalty interests in suitable producing properties or properties with future reserve or resource potential.

Political Uncertainty

The Company's results can be adversely impacted by political, legal, or regulatory developments in Canada 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 Logan's existing operations and planned projects. This includes actions by regulators or other political factors to delay or deny necessary licences and permits for the Company's activities or restrict the operation of third-party infrastructure that the Company relies on. Additionally, changes in environmental regulations, assessment processes or other laws, while increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact Logan's results.

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 Logan's products.

The federal government was re-elected in 2019, but in a minority position. Another federal election was held on September 20, 2021 and the federal government was re-elected again 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 petroleum 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. A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the petroleum and natural gas industry including the balance between economic development and environmental policy. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry, which effect could prove to be material over time. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access – Specific Pipeline and Proposed LNG Export Terminal Updates*" and "*Industry Conditions – The United States Mexico Canada Agreement and Other Trade Agreements*".

Following former Alberta Premier Jason Kenney's resignation on May 18, 2022, Danielle Smith was elected as Premier on October 11, 2022. Shortly after her appointment, Premier Smith introduced Bill 1: The Alberta Sovereignty Within a United Canada Act (the Sovereignty 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 New 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 and the IAA 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.

Geopolitical Risks

The marketability and price of oil and natural gas that may be acquired or discovered by Logan 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 outside of Canada, including changes in political regimes or parties in power, may have a significant impact on the price of crude oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of Logan's net production revenue.

The level of geo-political risk escalates at certain points in time. While the specific impact on the global economy would depend on the nature of the event, in general, any major event could result in instability and volatility. Current areas of concern include: global uncertainty and market repercussions due to the spread of global pandemics; Russia's military invasion of Ukraine; the Israeli-Hamas conflict and rising civil unrest and activism globally.

Non-Governmental Organizations and Eco-Terrorism Risks

The crude oil and natural gas industry may, at times, be subject to public opposition. The oil and natural gas industry has become increasingly politically polarizing in Canada, which has resulted in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects. Such public opposition could expose Logan 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 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, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and direct legal challenges, including the possibility of climate-related litigation (see "*Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access*"). 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 significant and unanticipated capital and operating expenditures which may negatively impact the Company's business, financial condition, results of operations and prospects.

In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack which may have a material adverse effect on its business, financial condition, results of operations and prospects. Logan does not have insurance to protect against the risk of terrorism.

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from crude oil and natural gas wells are subject to ongoing regulatory review by federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the costs of compliance for Logan which may impact the economics of certain projects and in turn impact activity levels and new capital spending on the Company's properties.

Cost of New Technologies

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

Availability and Cost of Equipment, Material and Qualified Personnel

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment, including drilling and related equipment and qualified personnel in the particular areas where such activities will be conducted. The oil and natural 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. Demand for such limited equipment and qualified personnel may affect the availability of such equipment and qualified personnel to Logan and may delay Logan's exploration and development activities. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. In addition, the costs of qualified personnel and equipment in the areas where Logan's assets are located are very high due to the availability of, and demands for, such qualified personnel and equipment.

Management of Growth

Logan may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Logan to manage future growth and integration of additional lands, assets and acquisitions effectively will require it to continue to implement and improve its operations and financial systems and to expand, train and manage its employee base. The inability of Logan to deal with this integration growth could have a material adverse impact on its business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

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

Income Taxes

Logan files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act (Canada)* and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable. Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that affects the Company. Furthermore, tax authorities having jurisdiction over Logan may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Conflicts of Interest

Certain directors and officers of Logan are also, or may in the future be, directors or officers of other crude oil and natural gas companies, that may compete or be counterparties to agreements with the Company and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA and the Company's policies which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract, or material transaction, or proposed material transaction, with the Company disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. The Company also has additional policies in place which require management to seek approvals of independent directors in certain situations where there may be a perceived or potential conflict of interest arising due to interlocking directorships, despite the transaction being within management's authorization levels and not otherwise requiring Board approval. See "*Directors and Officers – Conflicts of Interest*".

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may make the ground unstable, limit access and, as a result, cause reduced operations or a cessation of operations.

Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict access to Logan's properties and cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas typically fluctuates during cold winter months and hot summer months.

Dilution

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive.

Indigenous Claims

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. Claims and protests of Indigenous peoples may disrupt or delay third-party operations, new development or new project approvals on the Company's properties. Logan is not aware that any claims have been made in respect of Logan's assets; however, if a claim arose and was successful this could have an adverse effect on Logan and its operations. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a negative effect on the Company's business, financial condition, results of operations and prospects, whereby negative effect could prove to be material over time.

Moreover, in recent years there has been increasing litigation regarding historical treaties with Indigenous peoples in Canada. Judicial interpretation of such historical treaties, and in particular the rights granted thereunder to Indigenous nations to manage and use the lands in a manner consistent with their ancestral practices, may impact future resource and industrial development in and around these lands. While the potential impact of current and future judicial decisions is uncertain at this time, it is possible that such decisions may have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time. See "*Industry Conditions - Indigenous Rights*".

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system, which was upheld by the SCC, currently applies in provinces and territories without their own system that meets federal stringency standards. Provinces with their own system are subject to continued compliance with the federal system. There is no guarantee that a province with a system that currently applies will meet, or continue to meet, federal stringency standards. See "*Industry Conditions –Climate Change Regulation*". The taxes placed on carbon emissions may have the effect of decreasing the demand for crude oil and natural gas products and at the same time, increasing the operating expenses of crude oil and natural gas companies, each of which may have a material adverse effect on the Company's revenue. 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.

Insurance

Logan's involvement in the exploration for and development of oil and natural gas properties may result in Logan becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Logan has obtained 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, Logan may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Logan. The occurrence of a significant event that Logan is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Logan's financial position, results of operations or prospects.

Litigation

In the normal course of Logan'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, relating to personal injuries, property damage, property taxes, land rights, environmental issues and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Logan and as a result, could have a material adverse effect on Logan's assets, liabilities, business, financial condition and results of operations. Even if Logan prevails in any such legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition.

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 Logan. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information by the Company, a breach could put Logan 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 solely in monetary 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, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Information Technology Systems and Cyber-Security

Logan has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure, and its ability to expand and continually update this infrastructure, to conduct daily operations. Various information technology systems are relied upon to estimate reserve quantities, process and record financial data, manage the land base, manage financial resources, analyze seismic information, administer contracts and communicate with employees and third-party partners.

The Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of Logan'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 its business activities or competitive position. In addition, cyber-phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. 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.

The Company maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber security risk assessments. The Company also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Company's efforts to mitigate such phishing attacks through education and training, phishing activities remain a serious problem that may damage Logan's information technology infrastructure. The Company applies technical and process controls in line with industry-accepted standards to protect its information assets and systems, including written incident response plan for responding to a cyber security incident. However, these controls may not adequately prevent cyber-security breaches.

Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company's performance and earnings, as well as reputation. Logan applies technical and process controls in line with industry-accepted standards to protect information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Social Media

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 gain entry into the Company's systems and obtain confidential information. The Company periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, 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 and client communications conducted through the use of social media platforms.

Limited Ability of Residents in the U.S. to Enforce Civil Remedies

The Company is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of Logan's directors and officers and the representatives of the experts who provide services to Logan (such as the Company's auditors and independent reserve engineers), and all of Logan's assets and all or a substantial portion of the assets of such persons are located outside the U.S. As a result, it may be difficult for investors in the U.S. to effect service of process within the U.S. upon such directors, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments of the U.S. courts based upon civil liability under the U.S. federal securities laws or the securities laws of any state within the U.S. There is doubt as to the enforceability in Canada against the Company or against any of Logan's directors, officers or representatives of experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts of liabilities based solely upon the U.S. federal securities laws or securities laws of any state within the U.S.

Forward-Looking Information May Prove Inaccurate

Current and prospective investors are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks 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 are found in this AIF under the heading "*Notice to Reader – Special Note Regarding Forward-Looking Statements*".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was a subject of, during the most recently completed financial year that were or are material to the Company, nor are any such legal proceedings known to the Company to be contemplated which could be deemed material to the Company.

To the knowledge of management of the Company, there have not been any penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the most recently completed financial year, nor have there been any other 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, and the Company has not entered into any settlement agreement before a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described below, to the knowledge of the directors and officers of the Company, none of the directors or executive officers of the Company, nor any person or Company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares, nor any of their respective associates or affiliates, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years or during the Company's current year or in any proposed transaction which has materially affected or is reasonably expected to materially affect the Company.

Sony Gill, the Corporate Secretary of the Company, is a partner of the national law firm Stikeman Elliott LLP, which rendered legal services to the Company.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the Common Shares of the Company is Odyssey Trust Company at its office in Calgary, Alberta.

MATERIAL CONTRACTS

Other than contracts entered into in the ordinary course of business, there have been no material contracts entered into by the Company within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

Reserves estimates contained in this AIF were derived from the McDaniel Report prepared by McDaniel & Associates Consultants Ltd., an independent reserves evaluator. As of December 31, 2023, to the knowledge of the Company, the directors, officers, employees and consultants of McDaniel who participated in the preparation of the McDaniel Report who were in a position to directly influence the preparation or outcome of the preparation of the McDaniel Report as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares. In addition, none of the officers, directors, employees or consultants of McDaniel are currently expected to be elected, appointed or employed as a director, officer or employee of the Company or any of the Company's associates or affiliates.

PricewaterhouseCoopers LLP is the auditor of the Company and has confirmed that it is independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

Other than as set out above, no other experts (whose profession or business gives authority to a report, valuation, statement or opinion made by them) were named in any securities disclosure document filed by the Company pursuant to NI 51-102 in the most recently completed financial year.

ADDITIONAL INFORMATION

Additional information regarding Logan may be found on SEDAR+ at www.sedarplus.ca. Additional information, including directors' and officers' remuneration and indebtedness, the principal holders of Common Shares and the securities authorized for issuance under equity compensation plans, will be contained in the Company's management information circular relating to the upcoming annual meeting of shareholders. Additional financial information is available in the annual audited financial statements of the Company and the related management's discussion and analysis for the financial year ended December 31, 2023.

APPENDIX "A"

Form 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Logan Energy Corp. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2023. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2023, 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, 2023, 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 rate)			
			Audited	Evaluated	Reviewed	Total
McDaniel	December 31, 2023	Canada	-	392,964.5	-	392,964.5

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 reports 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 judgements 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.

(signed) *"Michael J. Verney"*

Michael J. Verney, P.Eng.
Executive Vice President
Calgary, Alberta, Canada
March 18, 2024

APPENDIX "B"

FORM 51-101F3
Report of management and directors on oil and gas disclosure

Management of Logan Energy Corp. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated and reviewed the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

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 evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation and, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and natural gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves 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) *"Richard McHardy"*
Richard McHardy
President, CEO & Director

(signed) *"Brendan Paton"*
Brendan Paton
VP Engineering & Chief Operating Officer

(signed) *"Reginald Greenslade"*
Reginald Greenslade
Director

(signed) *"Fotis Kalantzis"*
Fotis Kalantzis
Chairperson & Director

(signed) *"Pat Ward"*
Pat Ward
Director

March 18, 2024