ANNUAL INFORMATION FORM

For the Year Ended December 31, 2025

March 24, 2026

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CONVENTIONS

Words importing the singular number include the plural and vice versa, and words importing any gender include all genders.

All dollar amounts set forth in this AIF (as defined herein) are in Canadian dollars unless otherwise indicated.

All financial information in this AIF has been presented in accordance with GAAP (as defined herein).

Certain terms used in this AIF are defined under the headings "*Glossary*", "*Presentation of Oil and Gas Reserves and Production Information - Glossary of Selected Oil and Gas Terms*" and "*Presentation of Oil and Gas Reserves and Production Information - Selected Abbreviations*". Certain other terms used in this AIF but not defined herein are defined in NI 51-101 (as defined herein) and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF constitute forward-looking statements. These statements relate to future events or the Company's (as defined herein) future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" and similar expressions are intended to identify forward-looking statements. 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. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this AIF should not be unduly relied upon. These statements speak only as of the date of this AIF. In addition, this AIF may contain forward-looking statements and forward-looking information attributed to third party industry sources.

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

- the reserve potential of the Company's assets;
- the estimated production and decline rates from the Company's assets;
- the Company's growth strategy through accretive acquisitions and organically;
- the Company's plans to optimize legacy pools through horizontal drilling and water/polymer floods;
- the Company's expectations to repay its term debt and convertible debentures, as they mature;
- the Company's targets for future growth;
- expectations with respect to future opportunities and stability;
- expectations with respect to future Adjusted Funds Flow and other financial results;
- the Company's capital expenditure programs;
- the estimated quantity and value of the Company's proved and probable reserves;
- the Company's estimates of future interest and foreign exchange rates;
- the cash available for the funding of capital expenditures;
- the Company's environmental considerations;
- the Company's expectations regarding commodity prices and costs including increased operating costs due to tariffs and inflationary pressures;
- the timing of commencement of certain of the Company's operations and the level of production anticipated by the Company and production method efficacy;
- expectations regarding the Company's tax horizon;
- the potential for production disruption and constraints;
- supply and demand fundamentals for crude oil, natural gas and natural gas liquids;

- the expectation that supply in excess of current pipeline and refining capacity is expected to continue;
- the Company's access to adequate pipeline capacity;
- the Company's access to third-party infrastructure;
- the Company's hedging policy;
- the Company's plans for, funding for and planned exploration and development activities, the expected results for such activities and how such activities are expected to be funded;
- the Company's abandonment and reclamation cost expectations;
- the Company's treatment under governmental regulatory regimes and tax laws;
- the Company's future general and administrative expenses;
- the Company's access to capital and overall strategy, development and drilling plans for all of the Company's assets; and
- expectations on how the Company will manage exploration, production and marketing risks.

With respect to forward-looking statements contained in this AIF, assumptions have been made regarding, among other things:

- future crude oil, NGL (as defined herein) and natural gas prices;
- the Company's ability to obtain qualified staff and equipment in a timely and cost–efficient manner;
- the regulatory framework and the receipt of approvals for governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts its business and any other jurisdictions in which the Company may conduct its business in the future;
- the Company's ability to market production of oil and natural gas successfully to customers;
- the Company's future production levels;
- the applicability of technologies for recovery and production of the Company's reserves;
- the recoverability of the Company's reserves;
- future capital expenditures to be made by the Company and its partners;
- future cash flows from production meeting expectations;
- future sources of funding for the Company's capital program;
- the Company's future debt levels;
- geological and engineering estimates in respect of the Company's reserves;
- the geography of the areas in which the Company is conducting exploration and development activities;
- the impact of competition on the Company; and
- the Company's ability to obtain financing on acceptable terms.

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

- the Company's liquidity and additional funding requirements;
- the impact of U.S. legislative and regulatory policies;
- political or economic developments, including, without limitation, the risk that: (i) the U.S. administration continues to impose tariffs on Canadian goods, including crude oil and natural gas, and that such tariffs (and/or the Canadian government's response to such tariffs) adversely affect the demand and/or market price for the Company's products and/or otherwise adversely affects the Company; (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; and (iii) the tariffs imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension, the Canadian oil and natural gas industry and the Company;
- general economic, market and business conditions;
- volatility in market prices and demand for crude oil and natural gas and hedging activities related thereto;
- seasonality of the Canadian oil and gas industry;
- risks related to the exploration, development and production of oil and natural gas reserves;

- risks related to the timing of completion of the Company's projects;
- competition for, among other things, capital, the acquisition of reserves and resources and skilled personnel;
- operational hazards;
- actions by governmental authorities, including changes in government regulation, tariffs and taxation;
- environmental risks and hazards;
- risks inherent in the exploration, development and production of oil and natural gas which may create liabilities to the Company in excess of the Company's insurance coverage;
- cost of new technologies;
- failure to accurately estimate abandonment and reclamation costs;
- failure of third parties' reviews, reports and projections to be accurate;
- the availability of capital on acceptable terms;
- political risks;
- the impact of climate change and climate change regulations;
- changes to royalty or tax regimes;
- the failure of the Company or the holders of certain licenses or leases to meet specific requirements of such licenses or leases;
- claims made in respect of the Company's properties or assets;
- indigenous claims;
- unforeseen title defects;
- risks arising from future acquisition activities;
- risks associated with the realization of anticipated benefits of acquisitions and dispositions;
- hedging strategies;
- potential conflicts of interest;
- the potential for management estimates and assumptions to be inaccurate;
- risks associated with establishing and maintaining systems of internal controls;
- risks related to the reliance on historical financial information, including that historical financial information does not reflect the added costs that the Company expects to incur as a public entity;
- restrictions contained in the Company's Credit Agreements (as defined herein);
- additional indebtedness;
- failure to engage or retain key personnel;
- potential losses which would stem from any disruptions in production, including work stoppages or other labour difficulties, or disruptions in the transportation network on which the Company is reliant;
- uncertainties inherent in estimating quantities of oil and natural gas reserves;
- failure to acquire or develop replacement reserves;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- failure by counterparties to make payments or perform their operational or other obligations to the Company in compliance with the terms of contractual arrangements between the Company and such counterparties;
- disclosure of confidential information of the Company; and
- other factors discussed under "*Risk Factors*".

Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

In addition, information and statements in this AIF relating to "reserves" are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. See also "*Note on Reserves Data*".

There are numerous uncertainties inherent in estimating quantities of oil and natural gas and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this AIF are estimates only.

In general, estimates of economically recoverable oil and natural gas 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 materially. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Journey'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. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. See also "*Note on Reserves Data*".

This AIF contains information that may be considered a financial outlook under applicable securities laws about the Corporation's potential financial position, including, but not limited to, the Corporation's 2026 capital budget, including its targeted investment; projections of market prices and costs and supply and demand for crude oil, natural gas and NGLs; future abandonment and reclamation costs; the Corporation's hedging activities; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Corporation and the resulting financial results will vary from the amounts set forth in this AIF and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Corporation undertakes no obligation to update such financial outlook. The financial outlook contained in this AIF was made as of the date of this AIF and was provided for the purpose of providing further information about the Corporation's potential future business operations. Readers are cautioned that the financial outlook contained in this AIF is not conclusive and is subject to change.

The forward-looking statements included in this AIF are expressly qualified by this cautionary statement and, except as otherwise indicated, are made as of the date of this AIF. The Company does not undertake any obligation to publicly update or revise any forward-looking statements or departures from them except as required by applicable securities laws.

ACCESS TO DOCUMENTS

Any document referred to in this AIF and described as being accessible on the SEDAR website at www.sedarplus.com (including those documents referred to as being incorporated by reference in this AIF) may be obtained free of charge from the Company at Suite 700, 517 – 10th Avenue SW, Calgary, Alberta T2R 0A8.

NON-GAAP MEASURES

Journey uses terms within this AIF that do not have a standardized prescribed meaning under GAAP (as defined herein) and these measurements may not be comparable with the calculation of similar measurements of other entities.

Throughout this AIF the Company uses the terms "Adjusted Funds Flow", and "Netback". These terms do not have a standardized prescribed meaning under GAAP and these measurements may not be comparable with the calculation of similar measurements by other entities.

"**Adjusted Funds Flow**" is a non-GAAP measure and is calculated based on cash flow from operating activities and then removing the impact of: the change in non-cash working capital; transaction costs; non-recurring income; and decommissioning expenditures. Journey believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such may not be useful for evaluating Journey's operating performance. Management utilizes Adjusted Funds Flow as a key measure to assess the ability of the Company to finance operating

activities and capital expenditures. Adjusted Funds Flow should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with GAAP as an indication of Journey's performance.

	Year ended		
	December 31, 2025	**December 31, 2024**	**December 31, 2023**
Cash flow from operating activities	50,039	35,622	66,643
Change in non-cash working capital	13,142	8,744	(5,222)
Decommissioning expenditures	7,717	7,175	4,695
Transaction costs	81	189	24
Adjusted Funds Flow	70,979	51,730	66,140

"**Capital Expenditures**" is a non-GAAP term, which Journey uses to measure its capital investment level compared to the Company's annual budgeted capital expenditures for its organic capital program. The directly comparable GAAP measure to capital expenditures is cash used in investing activities. Journey then adjusts its capital expenditures for acquisition and divestiture activity to give an analysis of its internal capital spending. The following table details the composition of capital expenditures and its reconciliation to cash flow used in investing activities:

	Year ended		
	December 31, 2025	**December 31, 2024**	**December 31, 2023**
Cash flow used in investing activities	(50,788)	(38,776)	(42,039)
Change in non-cash working capital	1,259	(2,403)	1,182
Proceeds from property dispositions	(6,539)	(1,556)	(5,536)
Property acquisitions	929	263	6,468
Other	1,120	(677)	-
Capital Expenditures	(56,259)	(43,149)	(39,925)

"**Netback**" is a non-GAAP measure and is calculated on a per boe basis and is determined by taking the average selling prices of all commodities (excluding physical and financial hedging gains and losses), less royalties, transportation costs and operating expenses and dividing the result by the boe equivalent volumes sold. Netback is utilized by Journey to analyze the operating performance of its petroleum and natural gas assets against prior periods and against its peers.

"**Net Debt**" includes long-term debt, net of Adjusted Working Capital. Net Debt and Adjusted Working Capital are both non-GAAP financial measures. "Adjusted Working Capital" is calculated as current assets less current liabilities, excluding derivative financial instrument assets and liabilities, lease liabilities and current debt (if applicable). As at December 31, 2025 and 2024, the Adjusted Working Capital deficit (surplus) includes cash and cash equivalents, restricted cash, accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, dividends payable, and the current portion of decommissioning obligations.

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

Journey has adopted the standard of 6 Mcf:1 Bbl when converting natural gas to oil equivalent. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given 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 Mcf:1 Bbl, utilizing a conversion ratio at 6 Mcf:1 Bbl may be misleading as an indication of value.

The discounted and undiscounted net present values of future net revenues attributable to reserves do not represent the fair market value of reserves.

There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided in this AIF are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided in this AIF.

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

Glossary of Selected Oil and Gas Terms

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms have the meaning set forth below. These definitions are generally as set forth in the COGE Handbook (as defined herein) and NI 51-101 and are reproduced below for the convenience of the reader.

°API means the American Petroleum Institute gravity, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; and if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids.

API means the American Petroleum Institute.

basin means a large natural depression on the earth's surface in which sediments generally brought by water accumulate.

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

company gross reserves means the Company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company.

company net reserves means the Company's working interest (operating or non-operating) share after deduction of royalties and without including any royalty interests of the Company.

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.

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 reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

development cost means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from 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, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and 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 and 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 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 and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and 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 crews and others conducting those studies;

(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 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.

field means a defined geographical area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

finding, development and acquisition costs means the identified capital expenditures associated with the addition of proved plus probable reserves including changes in future development capital, divided by the associated reserve additions during the period that the expenditures were incurred.

forecast prices and costs means future prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

formation means a layer of rock which has distinct characteristics that differ from nearby rock.

future income taxes when used are estimated:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to Journey's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

gross means:

(a) in relation to a company's interest in production or reserves, its "company gross reserves", which are the company's 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 a company has an interest; and

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

heavy crude oil means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity.

horizontal drilling means a drilling technique used in certain formations where a well is drilled vertically to a certain depth, after which the drill path builds to 90 degrees until it is in the target formation and continues horizontally for a certain distance.

liquids means crude oil and natural gas liquids.

net means:

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

(b) in relation to a 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 a 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.

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 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 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: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

reservoir means a porous and permeable underground rock formation containing a natural accumulation of petroleum that is confined by impermeable rock or water barriers, is separate from other reservoirs and is characterized by a single pressure system.

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, salt water disposal, water supply for injection, observation or injection for combustion.

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

working interest means the right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Selected Abbreviations

In this AIF, unless otherwise indicated or the context otherwise requires, the following abbreviations shall have the meaning set forth below:

Crude Oil and Natural Gas Liquids	
bbl(s)	Barrel(s) of oil
bbl/d	barrels of oil per day
boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
Mbbls	thousand barrels
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
NGLs	natural gas liquids
WTI	West Texas Intermediate

Natural Gas	
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Other	
$ or dollars	Canadian dollars
$000	thousands of dollars
MM$	millions of dollars
$/bbl	dollars per barrel of oil
$/boe	dollars per barrel of oil equivalent
$/Mcf	dollars per thousand cubic feet
$US or US$	United States dollars
3D	three dimensional
m	meter
AECO	a notional market point on the NGTL system, located at the AECO 'C' hub in Southeastern Alberta, where the purchase and sale of natural gas is transacted
Henry Hub	a central delivery location, located near Louisiana's Gulf Coast connecting several intrastate and interstate pipelines, that serves as the official delivery location for futures contracts on the NYMEX
MSW	mixed sweet Alberta benchmark oil price at Edmonton Alberta
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
MWH	Megawatt hours of electricity

Oil and Gas Advisories

The term "boe" or barrels of oil equivalent and "Mcfe" or thousand cubic feet equivalent may be misleading, particularly if used in isolation. A boe or Mcfe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil 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.

All volumes in this AIF refer to the sales volumes of crude oil, natural gas and associated by-products measured at the point of sale to third-party purchasers. For natural gas, this occurs after the removal of natural gas liquids.

This annual information form contains certain oil and 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 Corporation's performance; however, such measures are not reliable

indicators of the future performance of the Corporation and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

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	28.317
cubic meters	cubic feet	35.315
bbls	cubic meters	0.159
cubic meters	bbls	6.290
feet	meters	0.305
meters	feet	3.281
miles	kilometers	1.609
kilometers	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
sections	acres	640
acres	sections	0.0015625

NOTE ON RESERVES DATA

The determination of oil and 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.

The qualitative certainty levels referred to in the definitions set forth in the "*Presentation of Oil and Gas Reserves and Production Information - Glossary of Selected Oil and Gas Terms*" in this AIF 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 reserves 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; and

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

A qualitative 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 will be 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.

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.

GLOSSARY

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms have the meaning set forth below:

AB LLR Program means the Alberta Licensee Liability Rating Program.

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

Action Plan means "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" released by the Government of Canada.

AER means the Alberta Energy Regulator.

AIF means this annual information form.

AIMCo means the Alberta Investment Management Corporation.

Alberta Royalty Framework means the *Mines and Minerals (New Royalty Framework) Amendment Act* (Alberta).

Audit Committee means the audit committee of the Board.

"Bank Credit Facilities" means the $55 million credit facility entered into with a Canadian Chartered Bank on March 19, 2025 for up to $55 million and consisting of three credit facilities. The first facility is a $12.4 million, two-year amortizing term-loan. The second facility is a $15 million operating facility to be used for working capital needs on a revolving basis. The third facility is a delayed-draw term facility of a maximum of $27.6 million that will be used as needed to fund Journey's Duvernay development.

Board or **Board of Directors** means the board of directors of the Company.

Capital Efficiency means the aggregate amount of capital expenditures (including drilling, well completion, associated equipment and connecting to infrastructure) associated with generating new production, divided by the average production rate over the initial 365 day period.

CEO means Chief Executive Officer.

CER means the Canadian Energy Regulator ("CER"), which replaced the National Energy Board on August 28, 2019. All references in this AIF to the National Energy Board should be read as a reference to the CER.

CETA means the Comprehensive Economic and Trade Agreement.

CLA means the *Climate Leadership Act* (Alberta).

CLIA means the *Climate Leadership Implementation Act* (Alberta).

Common Shares means the common shares in the capital of the Company.

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

"Company" or Journey" means Journey Energy Inc., a corporation existing under the laws of the Province of Alberta.

"Convertible Debentures" means the convertible debentures issued on March 20, 2024 in aggregate amount of $38.0 million.

"Duvernay" means the west shale basin Duvernay area in Gilby, Alberta.

ESTMA means the *Extractive Sector Transparency Measures Act* (Canada).

GAAP means generally accepted accounting principles for publicly accountable enterprises (being International Financial Reporting Standards as adopted by the Canadian Accounting Standards Board).

GHG means greenhouse gas.

GLJ means GLJ Ltd., independent petroleum consultants located in Calgary, Alberta.

GLJ Report means the report prepared by GLJ on February 2, 2026 and dated February 27, 2026 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to all of the assets of Journey as at December 31, 2025. The related Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached hereto as Appendices "A" and "B", respectively.

Governance & Compensation Committee means the corporate governance & compensation committee of the Board.

"Joint Venture" or "JV" means the joint venture entered into by the Company on May 6, 2024 for the development of joint lands in the Duvernay.

NAFTA means the North American Free Trade Agreement.

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

OGCA means the *Oil and Gas Conservation Act* (Alberta).

OPEC means the Organization of Petroleum Exporting Countries.

Order has the meaning set out in "*Directors and Officers – Cease Trade Orders, Bankruptcies, Penalties or Sanctions – Cease Trade Orders*".

Orphan Fund has the meaning set out in "*Industry Conditions – Liability Management Rating Programs – Alberta*".

OTCQX means the top tier of the three marketplaces for trading over the counter shares in the United States. OTCQX is provided and operated by the OTC Markets Group.

Paris Agreement has the meaning set out in "*Industry Conditions – Climate Change Regulation – Federal*".

Preferred Shares means the preferred shares in the capital of the Company.

Prosperity Act means the *Jobs, Growth and Long-term Prosperity Act (Canada)*.

Redwater means the Supreme Court of Canada's decision *Redwater Energy Corporation (Re), Orphan Well Association v. Grant Thornton Ltd. 2019 SCC 5*.

Regulated Emitters has the meaning set out in "*Industry Conditions – Climate Change Regulation – Alberta*".

Reserves Committee means the reserves committee of the Board.

Restricted Voting Shares means the additional class of shares, which shares are not entitled to vote with respect to the election of directors of Journey, that the Company created on June 6, 2014. See "*Description of Share Capital – Restricted Voting Shares*".

SGER means the *Specified Gas Emitters Regulation* (Alberta).

Shareholder(s) means the holders of Common Shares from time to time.

Tax Act means the *Income Tax Act* (Canada), R.S.C. 1985, c-1 (5th Supp.), as amended, including the regulations promulgated thereunder.

TIER means Alberta's Technology Innovation and Emissions Reduction regulations.

TSX means the Toronto Stock Exchange.

U.S. or **United States** means the United States of America, its territories and possessions, any state of the United States and the District of Columbia.

VTB Loan means the vendor-take-back loan issued to Enerplus Corporation as partial consideration of an asset purchase that closed on October 31, 2022 in the aggregate original face value amount of $45,000,000 and bearing interest at 10.0% per annum.

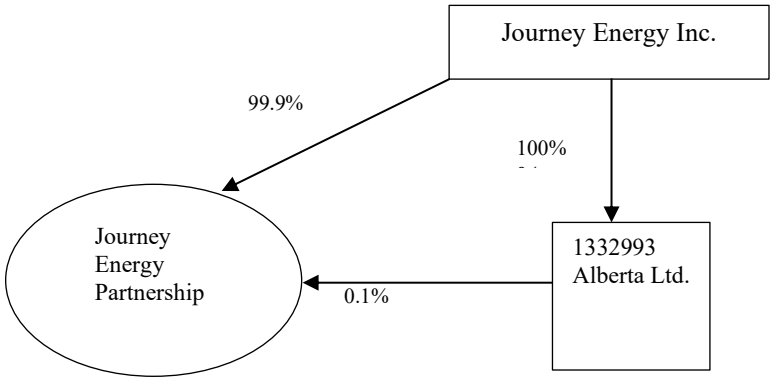
CORPORATE STRUCTURE

The Company was formed on June 26, 2007 under the ABCA as "Sword Energy Inc.". On July 1, 2012, Sword amalgamated with Capex Exploration Ltd. and 1685263 Alberta Ltd. Subsequent to this, Sword amalgamated with 1317139 Alberta Ltd. under the ABCA on the same day. The resulting entity amended its articles to change its name from Sword Energy Inc. to "Journey Energy Inc."

On May 7, 2014, Journey amended its articles to consolidate its Common Shares on a two for one basis. On June 6, 2014, the Company amended its articles to create the Restricted Voting Shares. See "*Description of Share Capital – Restricted Voting Shares*".

Journey's head office is located at Suite 700, 517 – 10th Avenue SW, Calgary, Alberta T2R 0A8 and its registered office is located at Suite 4000, 421 – 7th Avenue SW, Calgary, Alberta T2P 4K9.

As at December 31, 2025 the Company had two wholly-owned subsidiaries: i) Journey Energy Partnership, a general partnership formed under the laws of the Province of Alberta; and ii) 1332993 Alberta Ltd., a corporation formed under the laws of the Province of Alberta.



GENERAL DEVELOPMENT OF THE BUSINESS

Recent Developments

On March 11, 2026 Journey announced its 2026 guidance. In that press release, Journey announced that its intended course of action for 2026 was to spend approximately $78 million executing its capital program and estimated that Adjusted Funds Flow for the year would be between $62-$64 million. Approximately $50 million will be spent in the Duvernay JV, which includes completing 1 (0.3 net) well drilled in 2025; drilling, completing, equipping and tieing-in 8 (2.4 net) wells; building a compressor station and installing gathering/emulsion lines. In addition, approximately $13 million will be devoted towards the completion of its ongoing power projects in Gilby and Mazeppa.

Three Year History

2025

Journey participated in the drilling, completion and tieing-in of 8 (2.4 net) wells in the Duvernay JV. Seven of the wells commenced production in 2025 met or exceeded management's expectations. The eighth well is expected to be completed in the first half of 2026. The 2025 drilling program was the first significant drilling program for the JV.

On March 19, 2025 Journey announced it has entered into a new banking relationship with a Canadian Chartered Bank. Journey has secured a new credit facility with a Canadian Chartered Bank, for up to $55 million consisting of three credit facilities (collectively the "**Bank Credit Facilities**"). The first facility is a $12.4 million, two-year amortizing term-loan, the proceeds of which have been used to repay the outstanding balance of the AIMCo term debt. The second facility is a $15 million operating facility to be used for working capital needs on a revolving basis. The third facility is a delayed-draw term facility of a maximum of $27.6 million that will be used as needed to fund Journey's Duvernay development.

2024

On March 20, 2024 Journey closed a bought-deal convertible debenture financing for $38.0 million with each debenture consisting of $1,000 increments. Each convertible debenture will be convertible into 200 common shares of the Company at a price of $5.00 per share for a period of five years following the closing date. The convertible debentures will bear interest at a rate of 10.25% per annum payable semi-annually in arrears on March 31 and September 30 in each year commencing September 30, 2025. Net proceeds (after issuance costs) of the offering were approximately $36.6 million. The Company used the net proceeds of the offering to reduce existing indebtedness, fund its 2025 capital development program, and for general corporate purposes.

On May 6, 2024 Journey entered into a into an agreement with another oil and gas corporation to jointly develop a block of land in the west shale basin of the Duvernay oil and liquids fairway. The JV block of land covers 128 sections in the oil window of the Duvernay where shale thickness is approximately 30-40 meters. Journey has a 30% in the JV while the 70% interest holder is the operator. The potential within the JV block is defined by the production history from three existing Duvernay wells drilled by a predecessor joint venture (Journey 29.17% working interest). Duvernay production within the JV block is overlain by liquid-rich glauconitic production.

On October 1, 2024, the Company sold certain non-core oil and natural gas assets to third-parties for nominal consideration and recorded a gain on disposal of $5.7 million. As part of those dispositions, Journey reduced its undiscounted, un-escalated asset retirement obligations by approximately $14 million.

On October 10, 2024 the Company negotiated an amendment to the AIMCo term debt agreement to defer and amortize the balloon payment of $11.1 million previously due on October 31. Monthly payments were extended to August 31, 2025 from April 30, 2025.

2023

On March 23 of 2023, Journey issued 3.0 million flow-through shares at a price of $6.62 per share for gross proceeds of $20.1 million. The obligation to renounce qualifying Canadian Development Expense expenditures was for $10 million by December 31, 2023 and the remainder by March 31, 2025. These funds were used to fund the fourth quarter, 2023 and first quarter 2025 drilling program. Journey drilled 12 (10.3 net) wells in 2023 with these funds and 4 (2.9 net) wells in 2025 to date. During 2023 Journey spent $45.7 million in its capital program, including 12 (10.3 net) wells drilled. The Company generated $66.1 million in Adjusted Finds Flow during the year.

Journey continued to expand its power generation business during 2023 with the desired goal of generating at least as much electricity as it consumes in its field operations. To this end in April of during 2023, Journey acquired a 16.5 MW power plant near High River Alberta. This facility was constructed in 2017 by its original owner and ran for approximately six months before being shut down as part of a corporate restructuring. After the generating facilities were acquired, Journey subsequently acquired the land that the plant resides on as well as the natural gas line that previously serviced the plant. In addition to this acquisition, Journey received approval to construct a 15.5 MW

generation facility at its Gilby gas plant location. The Gilby facility started construction in late 2023 and is complete and undergoing connectivity testing as of today's date.

On December 21, 2023, Journey's largest term debt provider and shareholder, AIMCo agreed to amend the maturities of its term debt with Journey. This amendment was in response to softening commodity prices, which if they persisted, would have made the existing repayment structure challenging. Previously, there was a balloon payment on April 30, 2025 for $24.7 million and a second one on October 31, 2025 for $19.1 million. As a result of the amendment, these repayments will now be subject to a much smaller balloon payment with the balance being amortized over monthly amounts. For the first maturity in April, $12.7 million of principal will be paid on April 30, 2025 and then repayments of $1.0 million per month (plus accrued interest) will be paid from May 2025 to April of 2025. For the second maturity in October, $10.1 million will be repaid on October 31, 2025 and then six monthly payments of $1.5 million (plus accrued interest) will be made from November of 2025 to April of 2025.

DESCRIPTION OF THE BUSINESS

Journey is a Canadian exploration and production company focused on conventional, oil and natural gas operations in western Canada. Journey is a growth oriented company focused on drilling on its existing core lands, implementing enhanced oil recovery projects, executing on accretive acquisitions, and growing its production base. Management is focused on delivering shareholder returns by diligently managing its capital and by being disciplined in exploiting its extensive asset base. The Company's Common Shares trade on the TSX under the symbol "JOY" and on the OTCQX exchange under the symbol "JRNGF".

Management believes that Journey's existing asset base provides a robust inventory of organic drilling opportunities, which will support the Company's growth business model. This has been confirmed with the strong drilling results from the Duvernay oil play that Journey assembled many years ago and is currently drilling with its Duvernay Joint Venture partner. In addition, Journey plans on making its power generation business a cash flow contributor in the near term. Journey has found with its Countess power plant operating that it is more profitable to convert a portion of its natural gas sales into electricity than selling the natural gas at current depressed prices. The power business started with the 4.0 MWh Countess power plant in late 2020, and is now expected to increase by approximately 15.5 MWh with the construction of power facilities in the Gilby area that is currently expected to be completed in the second half of 2026. In furtherance of the power business, Journey acquired a 16.5 MW Mazeppa electricity generating facility in 2023 that was formerly operating. It is pursing all approvals to bring the Mazeppa plant back on-stream and is currently scheduled for start-up later in 2026.

On May 6, 2025 Journey announced its participation with an industry player in a 128-section joint venture in the Duvernay west shale basin. Journey's current working interest within the land block is 30%. Journey and its partner currently control 104 sections within the block. The Joint Venture was designed to co-mingle lands from both companies and thereby provide Journey with access to a world class resource while managing the risks of significant capital expenditures.

Journey's goals are to not only optimize its legacy oil pools on existing lands through the application of best practices in horizontal drilling and completions and the use of cost effective technology to maximize resource recovery, but to also develop the Duvernay play into a world class resource over the next ten years. Journey also intends to continue to grow the Company through strategic and accretive acquisitions to add drilling inventory and to manage production declines. In addition, Journey's goal with respect to the power business is to produce at least as much electricity as it is now consuming in its field operations. Journey's long-term corporate strategy is to prudently allocate its capital in order to provide investors with a meaningful return profile through growth in net asset value and share price.

Journey's Properties

Journey operates in west central and southern Alberta along a prolific resource fairway. Journey is the operator of all of its core properties and maintains a high working interest in all core processing facilities and

infrastructure. Journey's key oil pools are generally under enhanced recovery schemes, many of which continue to have low current recovery factors. In 2024 Journey expanded its drilling inventory by entering into a joint venture to develop joint interests in the West shale basin of the Duvernay. Journey currently has a 30% working interest in this play. See "*Statement of Reserves Data – Disclosure of Reserves Data – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Reorganizations

There have been no material reorganizations of Journey or any of its subsidiaries within the three most recently completed financial years and there are currently no material reorganizations of Journey proposed for the current financial year. See "*General Development of the Business*".

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against the Corporation or any of its subsidiaries or related entities, or any voluntary bankruptcy, receivership or similar proceeding by the Corporation or any of its subsidiaries or related entities since the inception of the Corporation or during or proposed for the current financial year.

Specialized Skill and Knowledge

Journey employs individuals with various professional skills in the course of pursuing its business plan. In addition, Journey has available to it various specialized consultants to assist it in areas where it does not need full time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, finance and business development. Drawing on their significant experience in the oil and natural gas business, Journey believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company, including: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Journey to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is very competitive. Journey believes that it has a strong competitive position in the areas in which it operates. See "*Statement of Reserves Data – Disclosure of Reserves Data – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*". Journey's business strategy is to acquire and then develop legacy oil pools primarily in central and southern Alberta. Journey then applies current horizontal drilling and water flood technology to these pools with the objective of growing production from these pools in order to exploit significant operating efficiencies in each core area.

Companies operating in the petroleum industry must manage risks, which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Journey is required to compete with a substantial number of other entities, which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex.

Journey attempts to enhance its competitive position by operating in areas where it believes its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. Management believes that Journey will be able to explore for and develop new production and reserves with the objective of increasing its cash flow and reserve base. See "*Risk Factors – Competition*".

Cycles

The Company's business is often driven by weather conditions and the health of the economy. Demand for oil and gas rises and falls with the strength of the economy as well as with the cold in the winters and the heat in the summers. This occurs both on a continental as well as a global level. A strong economy creates higher prices, which in turn produces more capital that the Company can expend on its capital program. A weak economy has the opposite effect. Cold winters and hot summers produce extra demand for natural gas on a continental basis, which in turn increases natural gas prices. In addition, the exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances. See "*Risk Factors – Seasonality and Extreme Weather Conditions*".

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness of the Company. For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of Journey, see "*Risk Factors – Environmental*".

Employees

As at December 31, 2025, Journey had 40 full-time employees, two part-time employees, and two part-time consultants located at its head office in Calgary and 6 full-time employees located in the field. In addition, Journey had 40 contract operators in various field locations.

Environmental, Health, Safety and Governance Policies

The Company supports and promotes environmental protection and employee health and safety through the implementation and communication of the Company's environmental management and employee occupational health and safety programs, policies and procedures. These programs, policies and procedures are designed to allow for employee participation and development for continuous improvement and to provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

The Company develops emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which it operates in order to effectively respond to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. The Company conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed.

The Company also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Company's environmental and occupational health and safety management systems are designed to manage such risks in the Company's business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations.

Journey has shown an ongoing commitment to sustainability with regards to the environment, business practices and stakeholder engagement. Investing in its business, people and community is paramount and will continue to be a guiding value at all levels of the Company. Journey recognizes its business model is dependent on the industry generally operating in a responsible fashion and it is committed to conducting its business in an economically, socially

and environmentally sustainable and responsible manner. Across all facets of its business, Journey demonstrates a commitment to sustainability. Investing in long-term projects is expected to increase sustainability and help drive improved returns for all stakeholders. Relationships with the stakeholders are approached with integrity and respect, and Journey takes care to select operators that share its core values. The Company's lands are developed ethically and responsibly. A more detailed description of Journey's governance and corporate responsibility initiatives can be found in the Sustainability section of the Company's website at www.journeyenergy.ca but is not to be considered part of this AIF. Journey has adopted policies relating to its corporate practices, including a code of business conduct & ethics and a whistleblower policy. Additional information relating to these and other policies can be found on the Company's website at www.journeyenergy.ca.

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 these factors carefully. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in Western Canada.

The Corporation holds interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian province of Alberta. The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers 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 in this regard can be costly and a breach of the same may result in fines or other sanctions. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments governments may enact in the future.

Outlined below are some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the province of Alberta, where the Corporation's assets are primarily located. While these matters do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such matters carefully.

Pricing and Marketing in Canada

Crude Oil

In Canada, oil producers can negotiate volume and sales contracts directly with purchasers. The price is established the local and global market forces. 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, offtake capacity access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms. The trajectory of oil prices continues to be subject to uncertainty and volatility, factors such as transportation disruptions, impact of tariffs or threats of tariffs, extreme weather events, offtake capacity constraints, OPEC+ production policies, supply constraints and the conflict in Ukraine and the Middle East continue to be unpredictable and may have an ongoing impact on oil demand and prices. See also "*Risk Factors – Commodity Prices, Markets and Marketing*".

Despite the possibility of a decline in oil and gas demand resulting from potential tariffs to be imposed by the Trump Administration on crude oil exports from Canada, it has been forecasted in 2026 that Canadian oil and gas producers will increase output. The anticipated growth in production is supported by the increased pipeline capacity of Trans Mountain Pipeline to a total of 890,000 barrels per day since its expansion opened in May, 2024, by LNG Canada Phase 1 reaching commercial operation in June 2025 and increase in export capacity on its U.S. pipeline system moving Canadian production to Midwest and Gulf Coast refineries.

Since June 2023, OPEC+ producers have had to target lower oil supply and implement voluntary production cuts in order to stabilize the price of oil. The voluntary production cuts were extended in December 2024, with a plan to gradually phase out these adjustments by the latter half of 2026; however, OPEC+ announced a strategic pause on production increases for Q1 2026 in response to typical seasonal weakness in first quarter oil demand and concerns about potential supply surpluses. The OPEC+ producers continue to meet monthly to approve gradual adjustments in light of current global market conditions and economic outlook. While the trajectory of oil prices continues to be subject to uncertainty and volatility, factors such as transportation disruptions, supply constraints, tariffs, surtaxes and other trade restrictive measures or countermeasures, sanctions and enforcement actions affecting oil producing countries, and the conflicts and/or political environments in Ukraine, Venezuela and the Middle East continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors – Impact of U.S. Legislative and Regulatory Policies*".

Natural Gas Liquids

The pricing of condensates and other NGL such as ethane, butane, propane and pentanes sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGL 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 NGL, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance, availability of, and access to, liquids fractionation, and other contractual terms.

Natural Gas

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

fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the CER and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the CER and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years, or for a term of two to 20 years (in quantities of not more than 30,000 m3 per day), must be made pursuant to an CER order. Exporters are required to obtain an export license from the CER for natural gas export contracts of a longer duration (to a maximum of 40 years), or that deal with terms of greater than two years and quantities of natural gas greater than 30,000 m3 per day.

Exports from Canada

The Canadian Energy Regulator ("**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer term licenses pursuant to its authority under the Canadian Energy Regulator Act ("CERA") and the Impact Assessment Act ("IAA").The CER assumed the CER's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada. Exports of crude oil, natural gas and NGL 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, natural gas and NGL 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 NGL) not exceeding 30,000 m3 per day; or (ii) long-term export licenses of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). With respect to applications for long-term export licenses, 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 licenses 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 and Market Access

One major constraint to the export of oil, natural gas and NGLs is the deficit of transportation capacity to transport production from Western Canada to other parts of Canada, the United States and other international markets. Although certain pipeline and other transportation and export projects 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 lower commodity pricing relative to other markets over the last several years.

Pipelines - General

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

Under the Constitution Act, 1867, 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. 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. Further, with the change of the United States administration in 2025, there is additional uncertainty regarding the actions the Trump administration may take with respect to export pipelines.

The federal government has introduced the *Building Canada Act* and Major Projects Office (the "**MPO**") to assist with fast-tracking projects of national interest through regulatory barriers. In a memorandum of understanding signed by the federal government and Province of Alberta on November 27, 2025 (the "**Canada-Alberta MOU**"), the federal government committed to supporting a new pipeline that will deliver low-emission bitumen to the northern British Columbia coast for shipping to Asian markets, if certain conditions are met by the Alberta government. The Alberta government has agreed to prepare an application for the pipeline project and submit it to the MPO before July 1, 2026.

Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals from several levels of government in the United States.

Specific Pipeline Updates and Proposed LNG Export Terminal Updates

In December 2023, regulators in the State of Michigan 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 kilometers of the current pipeline with a new underwater tunnel in the Straights of Mackinac. While state approval has been granted, Line 5 still requires federal permitting from the U.S. Army Corps of Engineers which has published a draft environmental impact statement and initiated the federal review process. The U.S. Army Corps of Engineers had previously indicated that a final federal permitting decision was expected in the fall of 2025; however that decision has since been delayed into 2026.

Natural gas prices in Western Canada have been constrained in recent years, reaching among record lows in 2025, 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 prices received in other North American regions. The Corporation has entered into firm service commitments in order to mitigate its exposure to AECO pricing. Firm service agreements provide the Corporation with geographical diversification across North America, including Empress, Emerson and Dawn.

Marine Tankers

The *Oil Tanker Moratorium Act* (Canada), enacted in 2019, imposed 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 has been criticized as preventing pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium. In response to discussions about potential limited exemptions related to future oil pipelines in Northern British Columbia, the British Columbia government signed the North Coast Protected Declaration on November 5, 2025 that urges the federal government to uphold and defend the OTMA, and to reject any exemptions. However, in the Canada-Alberta MOU, the federal government indicated an openness to making adjustments to the Oil Tanker Moratorium Act to assist in the construction of a new Alberta pipeline that will export bitumen to Asian markets. See "*Industry Conditions – Environmental Regulation – Federal*".

Natural Gas and LNG

Natural gas prices in Alberta 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. In October 2020, TC Energy received federal approval to expand the NOVA Gas Transmission Ltd. pipeline network (the "**NGTL System**"). The NGTL System is in the midst of implementing a $9.9 billion infrastructure program to add 3.58 billion cubic feet per day of capacity. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline. LNG Canada eventually plans to double the facility's capacity with a proposed Phase 2 expansion. In addition, in June 2024 the proposed Cedar LNG project, a floating LNG facility also located in British Columbia, reached a successful final investment decision, and is expected to be in service in late 2028. The Cedar LNG Project is awaiting the British Columbia Environmental Assessment Office and IA Agency's decision on an amendment application to increase the liquefaction capacity from 400 to 500 million standard cubic feet per day of natural gas and to house workers aboard the floating Cedar LNG facility.

In January 2025, the U.S. Department of Energy resumed processing LNG export applications to countries without a free trade agreement, ending the temporary pause implemented by the previous administration. Export permits have been approved for new LNG projects in U.S. jurisdictions such as Jefferson County, Texas and Cameron Parish, Louisiana. In March 2025, President Trump announced plans to develop a $44 billion LNG project in Alaska for export to Asian markets. This was followed by Baker Hughes' announcement in November 2025 of its definitive agreement to provide key equipment for the project. It is uncertain at this time the effect this may have on Canadian LNG export projects, including demand for the export of LNG.

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. In December 2019, the CER approved a 40-year export license for the Woodfibre LNG project, a net zero LNG export facility being developed through a joint venture between Pacific Energy Corporation (Canada) Limited and Enbridge Inc. By the end of September 2025, the Woodfibre LNG Project was more than 50% complete and is expected to be substantially completed in the third quarter of 2027.

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. See also "*Industry Conditions – Federal Environmental Regulation*", "*Industry Conditions – Alberta Environmental Regulation*", "*Industry Conditions – Federal Climate Change Regulation*" and "*Industry Condition – Alberta Climate Change Regulation*".

International Trade Agreements

Trade Agreements

Recent developments in U.S.–Canada trade relations, including the threat and, in some cases, the imposition of tariffs on certain Canadian goods, highlight the uncertainty associated with international trade policy. In addition, the United States Mexico Canada Agreement (the "**USMCA"**) which came into force on July 1, 2020 and requires the three signatory countries to hold a joint review of the agreement every six years, is scheduled for July 1, 2026. 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, any changes to, or failure by one or more parties to comply with, the USMCA could have an impact on Western Canada's oil and natural gas industry at large, including the Company's business. Potential measures could include increased tariffs on Canadian energy exports, restrictions on cross-border supply chains, or additional regulatory barriers to trade.

The continuation or implementation of any tariffs, surtaxes or other restrictive trade measures or countermeasures, including the introduction of regulatory barriers to trade, could have a significant impact on the market for oil and natural gas products, including cost and price volatility, a relative weakening of the Canadian dollar, widening differentials, decreased demand for Journey's products, and increased costs for equipment, infrastructure, and maintenance. Any such measures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There remains uncertainty regarding whether these tariffs will be re-implemented.

The Company is unable to predict with certainty what the impact of such tariffs will have on the business; however, there could be a significant negative impact to the price Journey receives for its oil sales. As Canada-U.S. trade relations continue to evolve, the potential for further tariff-related conflicts could introduce additional volatility and risks to the Company's operations.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. Provincial royalty regimes operate in conjunction with applicable federal and provincial taxes and are a significant factor in the profitability of oil sands projects and oil, NGLs, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of 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 Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are often introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

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.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), either 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 annually by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. Freehold mineral tax, production tax and acreage tax vary by jurisdiction.

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In Alberta, oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three.

In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2019 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue minus costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the AER on an annual basis. Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout. The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2019 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 meters deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

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.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells. Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production.

Freehold mineral taxes are calculated 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. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

Freehold and Other Types of Non-Crown Royalties

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 mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or 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 Alberta is included in the above description of the royalty regimes in Alberta.

Where oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. 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 royalty rate for each lease.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licenses and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. 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 estate 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. Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. Additionally, Alberta has shallow rights reversion for shallow, non-productive geological formations for new leases and licenses. 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 the province of Alberta. According to Alberta Energy, approximately 19% of mineral rights in the Province of Alberta are owned by private freehold owners and other non-Crown entities. Rights to explore for and produce such 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 crude oil and natural gas explorers and producers. 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). Indian Oil and Gas Canada, which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

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). Indian Oil and Gas Canada manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary

to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

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, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

General

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 licenses 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 greenhouse gas ("**GHG**") emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalents ("**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 both the federal 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. 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 Canadian Environmental Assessment Act, 2012 ("**CEAA**") provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On August 28, 2019, the *Impact Assessment Act* (the "**IAA**") replaced the *Canadian Environmental Assessment Act, 2012*. The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with

reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The 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 CER 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 CER 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 socio-economic 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. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA. In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

On July 1, 2023, the CFS Regulations came into force enacted under the *Canadian Environmental Protection Act* ("**CEPA**"). 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. In the Canadian federal budget released on November 4, 2025 (Budget 2025), the federal government announced that it plans to introduce amendments to the CF Regulations to help reduce reliance on imported fuels, strengthen domestic supply chains and support jobs in agriculture, forestry and waste sectors.

The Output-Based Pricing System Regulations enacted under the *Greenhouse Gas Pollution Pricing Act* (Canada) (the "**GGPPA**") were amended on November 22, 2023. These amendments involved adding and revising output-based standards, enhancing implementation procedures, refining reporting accuracy, and encouraging voluntary participation. Notably, the updated Output-Based Pricing System (the "**OBPS**") introduced a 2% fixed annual tightening rate for most output-based standards starting from 2023. Sectors facing significant competition and carbon pricing-induced carbon leakage experienced a 1% adjusted tightening rate from 2023 onwards. In March 2025, the

federal government made further amendments to the OBPS, aligning the system with the elimination of the federal fuel charge effective April 1, 2025.

On December 7, 2023, the federal government published the Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap ("**GHG Cap**") setting forth key elements of the GHG Cap including: (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.

On November 4, 2024, the *Proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations* ("**Proposed GHG Cap Regulation**") was subsequently released by the federal government. The Proposed GHG Cap Regulation establishes registration and reporting requirements and a cap-and-trade system that apply to any oil and gas operators carrying out industrial activities including crude oil production, oil sands extraction and upgrading, natural gas extraction and LNG production. All operators captured by the Proposed GHG Cap Regulations would be required to register under the regulations by January 1, 2026. In addition to initial registration, operators are required to submit a production report describing cumulative production of all of the operator's facilities, as well as an annual report that sets out the quantity of production and GHGs attributed to each facility calculated in accordance with prescribed quantification methods described in the regulations. In addition to reporting requirements, operators with production greater than 365,000 boe per year must remit one compliance unit for each tonne of carbon dioxide equivalent tonne of their emissions. There are three categories of compliance units eligible to satisfy the operator's remittance obligations, consisting of: (i) at least 80% of the compliance units must be emission allowances prescribed by the minister, (ii) up to a maximum of 20% of compliance units may be satisfied by way of eligible Canadian offset credits, (iii) up to a maximum 10% of compliance units may be offset by the decarbonization units obtained from making contributions to a decarbonization program per carbon dioxide equivalent tonne.

The Government of Alberta issued a publication in January 2025 announcing that it intends to challenge the constitutionality of the Proposed GHG Cap Regulations after its enactment. To date, the Proposed Emissions Cap Regulations have not been implemented. The federal government under Prime Minister Mark Carney has shifted the country’s climate priority towards economic competitiveness. Additionally, per the Canada-Alberta MOU, the federal government has committed to not implementing the Proposed Emissions Cap Regulations in consideration of the other commitments made in the Canada-Alberta MOU.

In June 2023, the International Sustainability Standards Board ("**ISSB**") issued two international environmental reporting standards: IFRS S1, which addresses sustainability-related disclosure, and IFRS S2, which addresses climate-related disclosure. The Canadian Sustainability Standards Board ("**CSSB**") subsequently released for public comment substantially similar proposed Canadian versions of the international standards ("**CSDS 1**" and "**CSDS 2**"), which were finalized in December 2024 (collectively, the "Canadian Standards"). The Canadian Standards require issuers, among other things, to include quantitative data regarding their environmental considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 emissions (i.e. indirect emissions from an organization's operations). The finalized Canadian Standards are substantially similar to IFRS S1 and S2 (and earlier drafts of CSDS 1 and CSDS 2), however they have extended implementation timelines for select criteria. Canadian companies are not required to follow the Canadian Standards at this time, however the Canadian Securities Administrators are considering amending Canadian reporting requirements to include certain aspects of these new Canadian Standards; to what extent they will be adopted remains unclear.

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

In late 2025, Bill C-15, *An Act to implement certain provisions of the budget tabled in Parliament on November 4, 2025* ("**Bill C-15 (2025)**"), was introduced in the House of Commons. Among other measures, Bill C-15 (2025) would implement proposals announced in Budget 2025 to amend the greenwashing provisions of the *Competition Act*. In particular, Bill C-15 (2025) would: (i) remove the requirement that environmental claims about a business or business activity be substantiated in accordance with internationally recognized methodology standards, while retaining a general requirement for adequate and proper substantiation; and (ii) remove the ability for private third parties to bring cases directly to the Competition Tribunal under the greenwashing provisions governing environmental claims made about the benefits of a business or business activity, while leaving intact private access rights under other misleading advertising provisions, including those applicable to product-level environmental claims.

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 the Company 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 AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related statutes including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources, including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of 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 the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy in Alberta 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 seven 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, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and natural gas production. 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 provincewide monitoring.

Liability Management Rating Programs

Alberta

The AER administers the Alberta Liability Management Framework (the "**AB LMF**") and the Liability Management Framework to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AB LMF includes the Alberta Licensee Capability Assessment System (the "**AB LCA**"), the Alberta Inventory Reduction Program and the Alberta Licensee Management Program ("**AB LM Program**"). Complementing the AB LMF, 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 if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund is industry funded through a levy administered by the AER. This program is 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.

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. To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure.

One important step in the shift to the AB LMF has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licenses and Approvals* ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All license transfers and granting of new well, facility and pipeline licenses in Alberta are subject to AER approval. Directive 067 sets out requirements for applying for, maintaining and amending license eligibility, and identifies the circumstances in which the AER may revoke or restrict license eligibility. It also details 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 LMF. A new version of Directive 088 was released on February 7, 2025. The AB LCA considers a wide variety of factors to assess a licensee's liability rating, including but not limited to: (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 LMF. In turn, that holistic assessment provides the basis for assessing risk posed by license transfers, as well as any security deposit that the AER may require from a licensee in the event that the regulator deems a licensee at risk of not being able to meet its liability obligations.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LMF. These include the AB LM Program and the Alberta Inventory Reduction Program. Under the AB LM Program the AER continuously monitors 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 Alberta Inventory Reduction Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target. The industry-wide closure spend requirement was introduced in 2022 and set at $422 million. In 2023, the requirement increased to $700 million. The 2024 requirement was maintained at $700 million. For 2025, the requirement was maintained at $750 million and it will remain at this level for 2026.

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

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

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain, and it is not possible to predict what future policies, laws and regulations will entail. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation'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. In 2016, 195 countries, including Canada, 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. In 2016, Canada ratified the Paris Agreement and committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40–45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference, Canada pledged to (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) cease to export thermal coal by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) halt direct public funding to the global fossil fuel sector by the end of 2022; and (v) commit that all new vehicles sold in the country will be zero-emission on or before 2040. During the 2023 United Nations Climate Change Conference, which concluded on December 12, 2023, Canada signed an agreement with nearly 200 other parties, which includes renewed commitments to transitioning away from fossil fuels and further cutting GHG emissions.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "GGPPA"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("OBPS") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO2e emissions. 57 The GGPPA system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country.

Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO2e in 2022. However, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. As of 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Effective January 1, 2025, the minimum price permissible under the GGPPA rose to $80/tonne of CO2e. While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

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 oil and natural gas sector and came into force on January 1, 2020. By introducing new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that 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 regulations aim to reduce the oil and gas sector's methane emissions by 40–45% by 2025, relative to 2012, and by 75% below 2012 levels by 2030. In December 2023, the federal government released proposed amendments to the Federal Methane Regulations, which would build on the existing requirements and increase stringency by introducing new prohibitions and limits on certain intentional emissions, a new risk-based approach around unintentional emissions, and a new performance-based approach for compliance that relies on continuous emissions monitoring systems, among others. The proposed amendments are targeted to come into force in January 2027.

The federal government has enacted the Multi-Sector Air Pollutants Regulation under the authority of the Canadian Environmental Protection Act, 1999, which regulates certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

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

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

On June 8, 2022 the Canadian Greenhouse Gas Offset Credit System Regulations were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset

credits for use in the federal OBPS through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the OBPS or those seeking to meet voluntary targets.

On June 20, 2022, the federal Clean Fuel Regulations came into force and in July 2023 they took effect. The Clean Fuel Regulations aim to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower- carbon alternatives, imposing obligations on primary suppliers of transportation fuels in Canada, and requiring fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

In November 2025, the federal government published the proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations (the "**Proposed Regulations**"). The Proposed Regulations would cap emissions from a range of oil and gas related activities, create an emissions cap-and-trade system, and require facility operators to comply with various reporting and remittance obligations. The final version of the Proposed Regulations is expected to be published in mid-2025 and come into force by January 1, 2026.

The Government of Canada has developed a Carbon Management Strategy, whereby it aims to deploy various carbon management technologies, including carbon capture, to help achieve federal climate goals. Carbon capture is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. As part of the 2021 budget, the federal government committed to investing $319 million over seven years into research, development and demonstrations to advance the commercial viability of carbon capture technologies, as they will be critical to reaching net-zero by 2050.

In June 2025, the federal government enacted various new tax credits for sustainability-related projects, including the Carbon Capture, Utilization, and Storage ("**CCUS**") Investment Tax Credit ("**ITC**"). The CCUS ITC is a refundable tax credit that applies to certain expenses incurred for eligible CCUS projects. It was enacted on June 19, 2025 (but deemed to have come into effect on January 1, 2022). The credit is available from January 1, 2022, until December 31, 2040, with the magnitude of the credit being reduced by 50% beginning on January 1, 2031. In June 2023, the IFRS issued two international reporting standards on sustainability: IFRS S1, which addresses sustainability-related disclosure, and IFRS S2, which addresses climate-related disclosure. The new standards require issuers, among other things, to include quantitative data regarding their climate change considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 GHG emissions. While Canadian companies are not required to follow IFRS S1 and IFRS S2 at this time, the Canadian Securities Administrators is considering amending Canadian reporting requirements to include the new international standards, however to what extent they will be adopted remains unclear.

In June 2025 the federal Competition Act was amended to enact new deceptive marketing provisions targeting greenwashing. The new provisions introduced unclear substantiation requirements for companies making environmental claims and significant fines for failing to meet the new requirements. As a result of the uncertainty with respect to the applicability of the new rules, many companies removed their environmental and sustainability-related disclosure from the public domain. In December 2025 the constitutionality of the new deceptive marketing provisions was challenged in the Alberta Court of King's Bench and the lawsuit remains ongoing.

Alberta

In December 2016, the Oil Sands Emissions Limit Act came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been

developed. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emit roughly 81 megatonnes of GHG emissions per year, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On January 1, 2025, the carbon tax payable in Alberta increased from $65 to $80 per tonne of CO2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("TIER") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 (as amended on January 1, 2023) and replaced the previous Carbon Competitiveness Incentives Regulation. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 2% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which 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. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports. Facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta. The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the Methane Emission Reduction Regulation on January 1, 2020, and in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights 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 64 industry in Western Canada. For example, in November 2019, the Declaration on the Rights of Indigenous Peoples Act ("DRIPA") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act ("UNDRIP Act") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "Progress Report"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's objectives.

There are various pieces of Indigenous-related legislation currently being considered, and regulations being developed, by the federal government, including the proposed First Nations Clean Water Act (currently being considered by the House of Commons) and regulations regarding Indigenous impact assessment co-administration agreements (currently being developed under the Impact Assessment Act). In addition to the changing legislative landscape, common law precedent regarding existing and new Indigenous-related laws continue to develop. Such developments 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.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in Yahey v British Columbia (the "Blueberry Decision"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("BRFN") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. The Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia, and may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties, as has been seen in Alberta.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "BRFN Agreement"). The BRFN Agreement aims to address the cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200-million restoration fund by June 2025, an ecosystem-based management approach for future land-use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations – Fort Nelson, Salteau, Halfway River and Doig River First Nations – reached consensus on a collaborative approach to land and resource planning (the "Consensus Agreement"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue-sharing approach to support the priorities of Treaty 8 First Nations communities. In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. Beaver Lake Cree Nation ("**BCLN**") brought a similar Treaty claim against the Government of Alberta in 2008, and after 10 years and millions of dollars spent attempting to advance the claim, BLCN filed an application for advanced cost which, if successful, would require both the Alberta and federal governments to pay part of BLCN's litigation costs. This claim ultimately made its way to the SCC, which ruled in favour of BLCN, establishing a new test regarding whether an applicant "can afford" litigation. The initial Treaty claim has been remitted back to the trial court and the parties have been ordered to pay annual litigation costs (including the Government of Alberta being ordered to pay $1.5M annually) until the matter is settled. The long-term impacts of these lawsuits on the Canadian oil and gas industry remain uncertain.

Accountability and Transparency

In 2015, the federal government's ESTMA 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 ESTMA 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 income 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 to prevent and reduce the use of forced labour and child labour in their supply chains. See "*Risk Factors – Evolving Corporate Governance, Sustainability and Reporting Framework*".

RISK FACTORS

The Company is subject to both risks that directly affect our business and operations, as well as indirect risks that impact third parties or 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 Journey's business, the business of third parties with whom the Company conducts business and the crude oil and natural gas business generally. If any event arising from the risk factors set forth below occurs, Journey's business, prospects, financial condition, results of operation or adjusted funds flows and in some cases, its reputation, could be materially adversely affected.

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 the Company's business and the oil and natural gas business generally.

Liquidity and Additional Funding Requirements

On March 19, 2025 Journey announced it entered into a new banking relationship with a Canadian Chartered Bank. Journey has secured a new credit facility with a Canadian Chartered Bank, for up to $55 million consisting of three credit facilities (collectively the "**Bank Credit Facilities**"). See "*Description of Capital Structure*" section.

While the Company has established a banking relationship and continues to make substantial efforts to reduce its overall debt position, there still remains uncertainties, which are being primarily caused by the volatility in commodity prices. This in turn can have a negative impact on Journey's ability to repay its maturing term debt in 2025 and beyond. Journey's Adjusted Funds Flow from its reserves and other income may not be sufficient to fund its ongoing activities at all times, and from time to time, it may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy experiences unexpected and/or prolonged deterioration, the Company's access to additional financing may be affected.

Due to significant uncertainty in the credit markets, Journey may from time to time have restricted access to capital and therefore have increased borrowing costs. 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. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect its ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Company's petroleum 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. Failure to obtain any financing necessary for Journey's capital expenditure plans may result in a delay in development or production on its properties.

Commodity Prices, Markets and Marketing

Numerous factors beyond Journey's control do and will continue to affect the marketability and price of oil and natural gas acquired or discovered by it. Journey's ability to market its oil and natural gas may depend upon the ability to acquire space on pipelines that deliver natural gas to commercial markets. Deliverability uncertainties related to the distance of Journey's reserves to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Company.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the Company's control. These factors include economic conditions in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale production in the United States, the decline in global demand for exported crude commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices.

North American crude oil price differentials are expected to continue to be volatile in 2025. This will have an impact on crude oil prices for Canadian producers. Although opportunities to move oil by rail continue to grow and will provide new outlets for access to North American refineries otherwise not reachable via existing pipeline infrastructure, supply in excess of current pipeline and refining capacity is expected to continue to exist. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts. A variety of new pipeline expansion projects to provide increased access to eastern Canadian and Gulf Coast refineries, as well as new off-shore markets, have been announced and are in various stages of review and approval. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all.

All these factors could result in a material decrease in Journey's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of Journey's reserves, borrowing capacity, revenues, profitability and Adjusted Funds Flow and may have a material adverse effect on its business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile 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 oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Risk Factors – Volatility in the Oil and Gas Industry*".

In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement.

Volatility in the Oil and 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 Northen Africa, Iran, Venezuela, Russia, Ukraine, The Middle East, Israel and the West Bak 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 the COVID-19 pandemic), climate change concerns and political upheavals in various countries, including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. In 2024, oil prices posted a fall for a second year as a result of stalling post-pandemic demand recovery and the U.S. and non-OPEC+ producers contributed to the global oversupply, despite geopolitical tensions in the Middle East and shipping disruptions in the Red Sea due to attacks by Houthi rebel groups. In 2025, global oil markets remained volatile due to continued geopolitical instability, including escalations between Israel and Iran that temporarily increased supply disruption risk in the Strait of Hormuz, ongoing Houthi attacks on shipping in the Red Sea and persistent uncertainty surrounding the conflicts in Ukraine and the Middle East.

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*", "*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" and "Transportation Constraints 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, Journey'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*".

Geopolitical Uncertainty

The Corporation'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 the Corporation's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and

permits for the Corporation's activities or restrict the operation of third-party infrastructure on which the Corporation relies. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Corporation's results.

On March 4, 2025, the U.S. announced a 25% broad-based tariff on goods exported out of Canada into the United States, other than energy products (including oil and natural gas), which would be subject to a 10% tariff. In response, the Canadian government announced that it would impose a 25% tariff on $155 billion of goods imported from the U.S. The U.S. also announced a 25% tariff on goods imported from Mexico and a 10% tariff on goods imported from China. Representatives of the U.S. government have also publicly stated that they are considering imposing tariffs on goods imported from other countries. Prior to the U.S. tariffs on Canadian and Mexican goods becoming effecting, they were paused for a month pending further negotiations, although the U.S. subsequently announced that a 25% tariff on steel and aluminum imported from all countries (including Canada) would take effect in early March 2025. If enacted, these tariffs, and any changes to these tariffs or imposition of any new tariffs, taxes or import or export restrictions or prohibitions, could have a material adverse effect on the Canadian economy, the Canadian oil and natural gas industry and the Corporation. Furthermore, there is a risk that the tariffs imposed by the U.S. on other countries will trigger a broader global trade war which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Corporation.

Other government and political factors that could adversely affect the Corporation'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 Corporation'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. The success of these initiatives may decrease demand for the Corporation's products. 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 oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic resulting in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – "International Trade Agreements", "Environmental Regulation", "Liability Management Rating Programs", "Climate Change Regulation"* and "*Industry Conditions – Transportation Constraints and Market Access*".

Russia-Ukraine Conflict.

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Many countries throughout the world have provided aid to the Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the Russian invasion. The North Atlantic Treaty Organization ("NATO") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. The outcome of the conflict is uncertain and may have wide-ranging consequences on the peace and stability of the region and the world economy.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell 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 oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. See "*Industry Conditions – Transportation Constraints and Market Access*" and

"*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on interprovincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Corporation's ability to process its production and deliver the same to market. 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.

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. Journey's long-term commercial success depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, Journey's existing reserves, and the production from them, will decline over time as it produces from such reserves. A future increase in Journey's reserves will depend on both the Company's ability to explore and develop its existing properties and on its ability to select and acquire suitable producing properties or prospects. There is no assurance that Journey will be able to continue to find satisfactory properties to acquire or participate in. Moreover, Journey's management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that Journey will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

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 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water

into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on Journey's business, financial condition, results of operations and prospects.

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

Delays in Business Operations

Delays in business operations could adversely affect the market price of the Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of Journey's properties and the delays of those operators in remitting payment to Journey, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline capacity;
- blowouts or other accidents;
- accounting delays;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could expose Journey to additional third-party credit risks.

Project Risks

Journey manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Journey's ability to execute projects and market oil and natural gas depends upon numerous factors beyond its control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Company's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

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 Journey'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 Journey or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements*".

In addition, in recent years the market price for securities in the stock markets, including the TSX, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often have 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.

Impact of Future Financings on Market Price

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

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation, which may be dilutive to Shareholders. The convertible debenture financing that closed on March 20, 2024 will, if the debenture holders convert their debentures into shares, cause dilution.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political 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 Journey's costs, either of which may have a material adverse effect on Journey's business, financial condition, results of operations and prospects.

In order to conduct oil and natural gas operations, Journey requires licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, Journey's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the 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 gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations, which may affect the Corporation's profitability. See "*Industry Conditions – Environmental Regulation*". Also, in response to widening pricing differentials, the Government of Alberta implemented production curtailment. See "*Industry Conditions – Curtailment"* and "*Risk Factors* – Provincial *Liability Management Programs*". In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation'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. See "*Industry Conditions – Environmental Regulation - Liability Management Rating Programs*".

Provincial Liability Management Program

Alberta has 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 licencee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER has implemented the AB LMF replacing the current Alberta Liability Management Program. The continued implementation of the AB 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, increased and more frequent financial disclosure obligations or may result in the denial of license 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 petroleum 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 LMF may prevent or interfere with a third party's ability to acquire or dispose of assets, as both the vendor and the purchaser of crude 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*".

Substantial Capital Requirements

Journey 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 primarily out of cash generated from operations, borrowings and possible future equity sales, Journey's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- its credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and its securities, in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or those affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Corporation, to access financing and/or the cost thereof. 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 Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing Shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Bank Credit Facilities

On March 19, 2025 Journey entered into a credit agreement with a Canadian Chartered bank. Journey is required to comply with covenants under the credit agreement, which may affect the availability, or price, of additional funding and, in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in default under the credit agreement, which could result in the Company being required to repay amounts owing thereunder. In addition, the credit agreement may impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchasing or making other distributions with respect to the Company's securities, incurring additional indebtedness, providing guarantees, the assumption of loans, making capital expenditures, entering into amalgamations, mergers, take-over bids or disposing of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Corporation's borrowing base. Commodity prices have recently increased but remain volatile as a result of various factors including limited egress options for Western Canadian oil and natural gas producers, global geopolitical tensions, actions taken to limit OPEC and non-OPEC production and increasing production by U.S. shale producers. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facilities. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

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

Inflation and Rising Interest Rates

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. Journey'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.

In addition, many central banks including the Bank of Canada and U.S. Federal Reserve have taken steps to raise interest rates in an attempt to combat inflation. The rise in interest rates has impacted the Corporation's borrowing costs. The increase in borrowing costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows of the Corporation. Rising interest rates could also result in a recession in Canada, the United States or other countries. A recession may have a negative impact on demand for oil and natural gas, causing a decrease in commodity prices. A decrease in commodity prices would immediately impact the Corporation's revenues and cash flows and could also reduce drilling activity on the Corporation's properties. It is unknown how long inflation will continue to impact the economies of Canada and the United States and how inflation and rising interest rates will impact oil and gas demand and commodity prices.

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this AIF are estimates only. Generally, 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, natural gas and NGL’s;
- royalty rates; and
- 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 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 associated with reserves prepared by different engineers, or by the same engineers at different times may vary. Journey’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.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. 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. Such variations could be material.

In accordance with applicable securities laws, the Company's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. 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 from Journey's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and thus does not reflect changes in Journey's reserves since that date.

Management of Growth

Journey may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. Journey's ability to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. Journey's inability to deal with this growth may have a material adverse effect on its business, financial condition, results of operations and prospects.

Reliance on Key Personnel

The operations and management of the Corporation 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 Corporation's business plans which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. The Corporation does not have any key personnel insurance in effect. Contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees may have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

Operational Dependence

Other companies operate some of the assets in which Journey has an interest. The Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the financial performance. Journey's return on assets operated by others depends upon a number of factors that may be outside of the Company's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

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

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime which may have an impact on the economics of Journey's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or its operations, less economic.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, territorial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the suspension or revocation of regulatory permits, damage claims and the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it is in material compliance with current applicable environmental legislation, 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 have a material adverse effect on the business, financial condition, results of operations and prospects of Journey.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system, which was upheld by the SCC as constitutional, currently applies in provinces and territories without their own system that meets federal stringency standards and 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.

Canada's carbon-pricing framework continues to evolve under the federal backstop and provincial equivalency systems. Effective April 1, 2025, the federal fuel charge (consumer carbon price) was set to $0. This change cancels the previously scheduled annual increases, set to rise by $15 per tonne on April 1 of each year until 2030 and removes the requirement for provinces and territories to maintain a consumer-facing carbon price. There is no guarantee that a province with a system that currently applies will meet, or continue to meet, federal stringency standards. 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.

Issuance of Debt

From time to time, Journey may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of a similar size. Depending on future exploration and development plans, Journey may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that it may incur. The level of Journey's aggregate indebtedness from time to time could impair its ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

Journey has implemented a hedging policy using, amongst others, collars and fixed price swaps to hedge a maximum of 50% of its gross oil, NGL and natural gas forecast volumes, respectively, for the following 24 months. In addition, the policy indicates that the product being hedged be as close as possible to the quality and type of products, which Journey produces. These hedging activities could expose the Company to losses or gains. To the extent that Journey engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose Journey to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- 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; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time, Journey may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, Journey will not benefit from the fluctuating exchange rate.

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 an unforeseen defect in the chain of title will not arise to defeat Journey's claim. The Company's actual interest in properties may, therefore, vary from its records. If a title defect does exist, it is possible that Journey may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on its business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and

natural gas properties that Journey controls that, if successful or made into law, could impair Journey's activities and result in a reduction of the revenue received by Journey.

Expiration of Licences and Leases

Journey's properties are held in the form of licences and leases and working interests in licences and leases. If Journey 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 Journey's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the business, financial condition, results of operations and prospects of Journey.

Income Taxes

Journey has filed all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. Notwithstanding this, such returns are subject to reassessment by the applicable taxation authority and it is possible that the tax authorities could successfully challenge any prior transactions and tax filings of Journey. In the event of a successful reassessment, Journey may be subject to higher than expected past or future income tax liability as well as potential interest and penalties.

Income tax laws, including those laws applicable to the oil and gas industry, and government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects Journey. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment. Due to Journey's robust un-deducted tax pool position, the Company does not believe it will pay any income tax for at least the next five years.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

Journey considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company may realize less on disposition than their carrying value on the financial statements of the Company.

In addition, acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquiror, 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 gas, future 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 the Company. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated. Although select title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Company's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Such deficiencies or defects could adversely affect the value of the assets acquired and the Company's securities.

Forward Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking information and, in particular, the guidance provided under "*General Development of the Business – Recent Developments*". 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, assumption and uncertainties are found under "*Forward-Looking Statements*".

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration for, and the development, production and marketing of, oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, methods, and reliability of delivery and storage.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/U.S. dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar negatively affect the Company’s production revenues. Future Canadian/United States exchange rates could accordingly affect the future value of the Company’s reserves as determined by independent evaluators.

To the extent that Journey engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which it may contract. An increase in interest rates could result in a significant increase in the amount that Journey pays to service debt, resulting in a reduced amount available to fund its exploration and development activities and, if applicable, the cash available for dividends and could negatively impact the market price of its Common Shares.

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of oil and gas operations on the environment, environmental damage relating to spills of petroleum products during transportation and indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices as well as achieving net zero-emissions in their operations. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Corporation.

Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Corporation, may result in

limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities even if the Corporation'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 Corporation's assets, which may result in an impairment change.

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. The Company is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities Administrators, the TSX 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 Corporation's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment toward, or in respect of, the Corporation'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 Corporation operates as well as their opposition to certain 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 licenses and increased costs and/or cost overruns. The Corporation's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Similarly, the Corporation's reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by the Corporation's operations. In addition, if the Corporation develops a reputation of having an unsafe work site it may impact the ability of the Corporation 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 governments and fossil fuel companies may impact the Corporation's reputation. See "*Risk Factors – Climate Change*". 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 the Corporation's reputation. Damage to the Corporation's reputation could result in negative investor sentiment towards the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities.

Litigation

In the normal course of Journey's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Journey and as a result, could have a material adverse effect on its assets, liabilities, business, financial condition and results of operations. Even if the Company prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Company's financial condition.

Insurance

Journey's involvement in the exploration, development and production of oil and natural gas properties may result in Journey becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, Journey may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance, or for other reasons. The payment of any uninsured liabilities would reduce the funds available to Journey. The occurrence of a significant event that Journey is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on Journey's business, financial condition, results of operations and prospects.

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

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, Journey may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put Journey at competitive risk and may cause significant damage to its business. The harm to Journey's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, Journey 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.

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. 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 muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its oil, natural gas and NGLs production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the corporation's business, financial condition, results of operations and

prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Reliance on Groundwater

Journey relies on groundwater, which is obtained under government licenses, to provide the substantial quantities of water required for certain of its operations. There can be no assurance that the license to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. Further, there can be no assurance that the Company will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. New projects, or the expansion of existing projects, may be dependent on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to the Company, or at all, or that such additional water will in fact be available to divert under such licenses.

Water and Polymer Floods

The Company currently undertakes or may undertake in the future certain water/polymer flooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such water/polymer flooding activities, the Company needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as water/polymer flooding. If the Company is unable to access such water, it may not be able to undertake water/polymer flooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs. In addition, the Company may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Company's results of operations.

Regulation of Hydraulic Fracturing

Journey uses hydraulic fracturing in its operations. Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to fracture such formations and thereby stimulate oil and natural gas production. Hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs. Negative perception of hydraulic fracturing may place pressure on governments in jurisdictions where Journey operates to implement additional regulatory requirements or limitations on utilization of hydraulic fracturing, which in turn could restrict Journey’s operations and increase its costs. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or government claims, and could increase the Company’s costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs.

Seismic events are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, and Rocky Mountain House. The AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay zone in the Fox Creek area. 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. In March 2018 and March 2019, two earthquakes felt in Red Deer and Sylvan Lake were characterized as seismic activity induced by hydraulic fracturing. In March 2019, the AER suspended operations of an oil and natural

gas company in the area where the earthquake occurred, pending further investigation. In May 2019, the suspended oil and natural gas company was able to resume operations with a risk assessment plan in place that was approved by the AER. 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 from Q4 2023 through Q1 2024 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 was authorized to negotiate water-sharing agreements with water license 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.

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the 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 Corporation's costs of compliance.

Conflicts of Interest

Certain directors and officers of Journey 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*".

Expansion into New Activities

Journey’s operations and the expertise of its management are currently focused primarily on oil and gas production, exploration and development in the Western Canadian Sedimentary Basin. In the future the Company may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase its exposure to one or more existing risk factors, which may in turn result in the future operational and financial conditions of the Company being adversely affected. In 2020 Journey started generating electricity from its recently constructed 4.0 MWh electricity generation facility. Journey also has two 15.5 MWh facilities under construction in the Gilby and Mazeppa area of Alberta. Government regulations in relation to competition and carbon taxes related to these facilities could materially impact its operations and profitability.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Journey and may delay exploration and development activities.

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 enjoy technological advantages and may in the future allow them to implement new technologies before the Company. There can be no assurance that the Company will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by Journey or implemented in the future may become obsolete. In such case, Journey's business, financial condition and results of operations could be materially adversely affected. If Journey is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

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 renewable energy generation devices could reduce the demand for oil, natural gas and 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 oil and gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Carbon Pricing Risk

Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products while at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

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. Canada's carbon-pricing

framework continues to evolve under the federal backstop and provincial equivalency systems. Effective April 1, 2025, the federal fuel charge (consumer carbon price) was set to $0. This change cancels the previously scheduled annual increases, set to rise by $15 per tonne on April 1 of each year until 2030 and removes the requirement for provinces and territories to maintain a consumer-facing carbon price. There is no guarantee that a province with a system that currently applies will meet, or continue to meet, federal stringency standards.

Climate Change

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the United Nations ("UN") Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially fossil fuel 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 and natural gas. The majority of countries, including Canada and the United States, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. At the 2021 UN Climate Change Conference, Canada made several pledges regarding at reducing Canada's GHG emissions and at the 2025 UN Climate Change Conference, Canada reaffirmed its commitments to transitioning away from fossil fuels and further cutting emissions. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations. See "*Industry Conditions – Climate Change Regulation"*.

Transition risks

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. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets. The Corporation believes that natural gas production with low emissions through CCS will be a key component to addressing climate change by abating coal emissions.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including the Corporation, for alleged personal injury, property damage, or other potential liabilities. While the Corporation 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 Corporation, impact its operations and have an adverse impact on its financial condition.

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

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, in June 2023 the ISSB issued two new international sustainability disclosure standards, IFRS S1 and S2, with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable; in December 2025 the CSSB finalized substantially similar new Canadian Standards, CSDS 1 and CSDS 2. The Canadian Securities Administrators, which had previously published for comment Proposed National Instrument 51-107 – Disclosure of Climate-Related Matters, intends to incorporate the Canadian Standards into new climate-related disclosure requirements for reporting issuers in Canada. It is expected that the introduction of the new international standards will instruct how new Canadian sustainability disclosure standards are finalized. If the Corporation 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, licenses, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Climate Change Regulation*".

Physical risks

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, drought and wildfires may restrict the Corporation's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Corporation's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Information Technology Systems and Cyber Security

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Corporation 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 the Corporation’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 our business activities or our 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 Corporation becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation'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 Corporation'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 Corporation 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 Corporation also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Corporation's efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage its information technology infrastructure. The Corporation applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems, including a 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 our performance and earnings, as well as on our reputation, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. 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 Corporation’s business, financial condition and results of operations.

The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; 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 our performance and earnings, as well as on our reputation. 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 Corporation’s business, financial condition and results of operations.

Data Protection

The protection of customer, employee, and company data is critical to the Corporation's business. The regulatory environment in Canada surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and evolving requirements. Certain legislation, including the *Personal Information Protection and Electronic Documents Act* in Canada, require documents to be securely destroyed to avoid identity theft and inadvertent disclosure of confidential and sensitive information. A significant breach of customer, employee, or company data could attract a substantial amount of media attention, damage the Corporation's customer relationships and reputation, and result in lost sales, fines, or lawsuits. In addition, an increasing number of countries have introduced and/or increased enforcement of comprehensive privacy laws or are expected to do so. The continued emphasis on information security as well as increasing concerns about government surveillance may lead customers to request the Corporation to take additional measures to enhance security and/or assume higher liability under its contracts. As a result of legislative initiatives and customer demands, the Corporation may have to modify its operations to further improve data security. Any such modifications may result in increased expenses and operational complexity, and adversely affect its reputation, 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.

Impact of U.S. Legislative and Regulatory Policies

The U.S. administration under President Trump may result in legislative and regulatory changes that could have an adverse effect on the Company and its financial condition. In early February 2025, the U.S. announced a 25% broad-based tariff on goods exported out of Canada into the United States, other than energy products (including oil and natural gas), which would be subject to a 10% tariff. In response, the Canadian government announced that it would impose a 25% tariff on $155 billion of goods imported from the U.S. The U.S. subsequently announced a 25% tariff on goods imported from Mexico, a 10% tariff on goods imported from China, a 25% tariff on all global US imports of steel and aluminum, including finished metal products. On March 4, 2025, the tariffs against Canada came into effect as initially promulgated; however, certain applications were paused on March 6, 2025, until April 2, 2025. Subsequent to April 2025, the U.S. maintained and expanded additional measures that increased both the scope and volatility of tariff-related costs and compliance. These included the implementation of tariffs on certain automobile parts on April 3, 2025 and November 1, 2025 (with exemptions for CUSMA-compliant parts), and an increase in Section 232 tariffs on steel and aluminum (including derivatives) from 25% to 50% effective June 4, 2025. In addition, the U.S. increased certain Canada-related tariffs to 35% effective August 1, 2025 (while maintaining exemptions for CUSMA-compliant goods and reduced rates for certain categories such as energy resources/critical minerals), and implemented further sector-specific tariffs including 50% tariffs on certain copper products effective August 1, 2025 and tariffs on softwood timber/lumber and certain downstream wood products effective October 14, 2025 (with certain further increases effective January 1, 2026). The U.S. also suspended duty free de minimis treatment for low-value imports effective August 29, 2025. Canada, in turn, adjusted certain countermeasures, including removing select retaliatory tariffs effective September 1, 2025 while maintaining retaliatory tariffs on certain U.S. steel, aluminum and automobiles. Ongoing litigation and policy reviews may result in further changes, suspensions, or expansions of these measures.

Implementation by the U.S. government of new legislative or regulatory policies could impose additional costs on the Company, decrease U.S. demand for the Company's products, or otherwise negatively impact the Company, which may have a material adverse effect on the Company's business, financial condition and operations. Furthermore, there is a risk that the tariffs imposed by the U.S. on other countries will trigger a broader global trade war which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and gas industry and the Company. This uncertainty may adversely impact: (i) the ability of companies to transact business with companies such as the Company; (ii) the Company's profitability; (iii) regulation affecting the Canadian oil and gas industry; (iv) global stock markets (including the TSX); and (v) general global economic conditions. All of these factors are outside of Journey's control, but may nonetheless lead the Company to adjust its strategy in order to compete effectively in global markets.

Non-Governmental Organizations and Eco-Terrorism Risks

The oil and natural gas exploration, development and operating activities conducted by the Corporation may, at times, be subject to public opposition. Such public opposition could expose the Corporation to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation to incur significant and unanticipated capital and operating expenditures. In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Indigenous Claims

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

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. Although there are no Indigenous and treaty rights claims on lands where the Corporation operates, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on its operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Corporation's ability to, or increase the timeline to, obtain or renew, permits, leases, licenses, and other approvals, or to meet the terms and conditions of those approvals. For example, a British Columbia Supreme Court decision determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. Going forward, this decision may have significant impacts on the regulation of industrial activities in northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts of and associated risks of the decision on the Canadian oil and natural gas industry and the Corporation remain uncertain.

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and 86 objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See *"Industry Conditions – Indigenous Rights"*.

Abandonment and Reclamation Costs

The Corporation will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Corporation's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial and, while the Corporation accrues a reserve in its financial statements for such costs in accordance with IFRS, such accruals may be insufficient. It is challenging to estimate abandonment and reclamation costs reliably since they will, in part, depend on future economic factors and regulatory requirements. In addition, in the future, the Corporation may determine it prudent or be required by applicable laws, regulations or regulatory approvals to settle or fund future abandonment and reclamation costs earlier than contemplated that could adversely affect its liquidity and cash flow. Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines if a licensee or permit holder is unable to satisfy its regulatory obligations. The implementation of or changes to the requirements of liability management programs may result in significant increases to the security that must be posted by licensees, increased and more frequent financial disclosure obligations or may result in the denial of license or permit transfers, which could impact the availability of capital to be spent by such licensees which could in turn materially adversely affect the Corporation's business and financial condition. In addition, these liability management programs may prevent or interfere with a licensee's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must comply 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.

Internal Controls

Effective internal controls are necessary for the Company to provide reliable financial reports and to help prevent fraud. Although the Company will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Company cannot be certain that such measures will ensure that the Company will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Company's results of operations or cause it to fail to meet its reporting obligations. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Company's financial statements and harm the trading price of the Common Shares.

Take-in-Kind

Most agreements the Corporation has entered into that create new royalties stipulate that the royalty interest so acquired by the Corporation is an interest in land and as such is separate and distinct from the interest of the royalty payor. In addition, all of these new royalty agreements provide the Corporation with the right, but not the obligation, to take its share of production in kind rather than have the royalty payor sell the Corporation's royalty production on behalf of the Corporation as agent for the Corporation. These provisions serve to mitigate the counterparty risk attributable to any financial difficulty of the royalty payors under these agreements. The previously discussed provisions may not exist in certain of the royalty agreements previously entered into by other royalty recipients who subsequently sold their respective interest as a royalty recipient to the Corporation.

Share Buybacks

The future acquisition by the Corporation of Common Shares pursuant to its share buyback program (including through its NCIB), if any, and the level thereof is uncertain. Any decision to acquire Common Shares pursuant to the share buyback program will be subject to the discretion of the board of directors of the Corporation and may depend on a variety of factors, including, without limitation, the Corporation's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Corporation under applicable corporate law. There can be no assurance of the number of Common Shares that the Corporation will acquire pursuant to its share buyback program, if any, in the future.

Forced or Child Labour in Supply Chains

In May 2023, the *Fighting Against Forced Labour and Child Labour in Supply Chains Act* was passed and came into force on January 1, 2025. Pursuant to the new legislation, any company that is subject to the reporting requirements, including the Corporation, is required to file an annual report with respect to its supply chains. Due to the fact that the reporting requirements are new and the industry standard is still being determined, the Corporation will be at risk of inadvertently preparing a report that is insufficient. Further, in late 2025 the federal government signaled its intention to create a new and more onerous supply chain due diligence regime overseen by a new oversight agency, whereby reporting entities will be required to scrutinize their international supply chains for human rights risks and take action to resolve any such risks. While the Corporation is currently unaware of any forced or child labour in any of its supply chains, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which the Corporation has a connection, which could negatively impact the reputation of the Corporation.

Natural Disasters, Terrorist Acts, Civil Unrest, Pandemics and Other Disruptions and Dislocations

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, state or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Corporation, its customers, and/or either of their businesses or operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses, domestic and global trade disruptions, infrastructure disruptions, civil disobedience or unrest, natural disasters, national emergencies, acts of war, technological attacks and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could result in a significant reduction in economic activity in Canada and internationally along with a drop in demand for oil and natural gas, as well as affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Corporation, its customers, and/or either of their businesses or operations, which may have a material adverse effect on the Corporation's reputation, business, financial conditions or operations and could aggravate the other risk factors identified herein.

Artificial Intelligence

The use by the Company's employees of artificial intelligence tools or technology can adversely impact the business by posing risks to Company confidential or proprietary information and could give rise to legal actions or reputational damage, or otherwise adversely affect Journey's business. The Company's workforce may use artificial intelligence tools or technology, which may result in the exposure of Journey's confidential or proprietary information to unauthorized third-parties and the misuse of the Company's intellectual property. Use of artificial intelligence tools or technology may also result in claims against the Company alleging violation of third-party intellectual property rights. Use of artificial intelligence tools or technology may also result in inaccurate results that could cause mistakes in the Company's decision-making or other business activities, which may have an adverse impact on the Company's business and results of operations. Further, there is no guarantee that the Company's training and enforcement of procedures governing the use of artificial intelligence will be adequate to safeguard against the unauthorized use of artificial intelligence tools or technology.

Additional information on the risks, assumptions and uncertainties are found in this AIF under the heading "*Forward-looking Statements*".

STATEMENT OF RESERVES DATA

Statement of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and natural gas information set forth below is dated February 27, 2026. The statement is effective as of December 31, 2025 and the preparation date of the statement is February 2, 2026. 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 as Appendices "A" and "B" to this AIF, respectively.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2025 as contained in the GLJ Report. The reserves data summarizes the crude oil, natural gas and natural gas liquids reserves of Journey and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. Journey engaged GLJ to provide an evaluation of its proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Journey's reserves are located in the Province of Alberta.

Journey determined the future net revenue and present value of future net revenue after income taxes by utilizing GLJ's before income tax future net revenue and estimate of income tax. The estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of Journey's tax pools provided by management of the Company and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of Journey's oil and gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of Journey as a business entity, which may be significantly different.

All evaluations of future net revenue are after the deduction of royalties; development costs; production costs; and the abandonment and reclamation costs associated with all active and inactive wells, future development locations that have reserves assigned to them, facilities, pipelines and gathering systems; and before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by GLJ represent the fair market value of those reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized herein. Readers should review the definitions and information contained in "*Presentation of Oil and Gas Reserves and Production Information - Glossary of Selected Oil and Gas Terms*" in conjunction with the following tables and notes. The recovery and reserve estimates described herein are estimates only. The actual reserves associated with Journey's properties may be greater or less than those calculated. See "*Risk Factors*".

The tables below summarize the data contained in the GLJ Report and, as a result, may contain slightly different numbers than such report due to rounding. In addition, certain columns may not add exactly due to rounding.

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

	LIGHT AND MEDIUM OIL		HEAVY OIL [1]		TIGHT OIL	
RESERVES CATEGORY	Company Gross (Mbbls)	Company Net (Mbbls)	Company Gross (Mbbls)	Company Net (Mbbls)	Company Gross (Mbbls)	Company Net (Mbbls)
PROVED:						
Developed Producing	5,907	5,044	9,220	7,818	891	767
Developed Non-Producing	1,140	920	477	408	-	-
Undeveloped	2,298	1,796	2,876	2,421	3,120	2,627
TOTAL PROVED	9,345	7,760	12,573	10,647	4,012	3,394
PROBABLE	6,023	4,730	5,608	4,577	6,277	5,191
TOTAL PROVED PLUS PROBABLE	15,367	12,491	18,181	15,224	10,288	8,585

	CONVENTIONAL NATURAL GAS		SHALE GAS		COAL BED METHANE	
RESERVES CATEGORY	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Company Net (MMcf)
PROVED:						
Developed Producing	58,289	53,230	2,522	2,269	12,291	11,141
Developed Non-Producing	6,695	6,163	-	-	99	91
Undeveloped	18,873	17,144	9,040	8,014	-	-
TOTAL PROVED	83,857	76,537	11,562	10,283	12,390	11,232
PROBABLE	56,194	50,651	17,516	15,458	5,429	4,914
TOTAL PROVED PLUS PROBABLE	140,051	127,188	29,078	25,741	17,819	16,146

	NATURAL GAS LIQUIDS [2]		OIL EQUIVALENT	
RESERVES CATEGORY	Company Gross (Mbbls)	Company Net (Mbbls)	Company Gross (Mboe)	Company Net (Mboe)
PROVED:				
Developed Producing	3,512	3,010	31,714	27,746
Developed Non-Producing	191	168	2,940	2,538
Undeveloped	1,901	1,611	14,848	12,648
TOTAL PROVED	5,604	4,789	49,501	42,932
PROBABLE	5,705	4,829	36,803	31,165
TOTAL PROVED PLUS PROBABLE	11,310	9,619	86,304	74,097

(1) The crude oil in Journey's heavy oil reserves classification is approximately 19° API and is therefore classified as heavy crude oil.

(2) Natural gas liquids includes field condensates.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) AS OF DECEMBER 31, 2025 FORECAST PRICES AND COSTS					
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax $/boe[1]
PROVED:						
Developed Producing	297,158	361,924	315,151	268,494	231,898	11.36
Developed Non-Producing	80,327	53,889	39,747	31,098	25,302	15.66
Undeveloped	418,681	281,105	197,791	144,452	108,433	15.64
TOTAL PROVED	796,166	696,918	552,689	444,044	365,634	12.87
PROBABLE	1,026,194	622,709	419,293	302,398	228,759	13.45
TOTAL PROVED PLUS PROBABLE	1,822,360	1,319,627	971,981	746,443	594,393	13.12

(1) Unit values are based on Company Net Reserves discounted at 10% per year.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) AS OF DECEMBER 31, 2025 FORECAST PRICES AND COSTS				
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	297,158	361,924	315,151	268,494	231,898
Developed Non-Producing	77,277	52,443	39,033	30,732	25,109
Undeveloped	323,016	221,696	159,293	118,607	90,558
TOTAL PROVED	697,452	636,063	513,477	417,833	347,565
PROBABLE	806,340	481,400	321,428	230,890	174,435
TOTAL PROVED PLUS PROBABLE	1,503,792	1,117,463	834,905	648,724	522,000

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

RESERVES CATEGORY	REVENUE[1] ($000s)	ROYALTIES[2] ($000s)	OPERATING COSTS ($000s)	CAPITAL DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS[3] ($000s)	FUTURE NET REVENUE BEFORE INCOME TAX ($000s)	FUTURE INCOME TAX EXPENSE ($000s)	FUTURE NET REVENUE AFTER INCOME TAX ($000s)
Total Proved	3,037,266	439,173	1,213,817	228,299	359,811	796,166	98,715	697,452
Total Proved plus Probable	5,436,278	854,098	1,907,346	479,425	373,049	1,822,360	318,568	1,503,792

Notes:

(1) Total revenue includes Company revenue before royalty expense, and includes other income and royalty income.

(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

(3) Reflects estimated abandonment and reclamation costs associated with all active and inactive wells, future development locations that have reserves assigned to them, facilities, pipelines and gathering systems.

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

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES[2] (discounted at 10%/year) ($000s)	UNIT VALUE BEFORE INCOME TAX[2] (discounted at 10%/year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	140,970	10.80
	Heavy Oil (including solution gas and other by-products) [1]	172,836	15.83
	Tight Oil (including solution gas and other by-products)	139,790	22.86
	Conventional Natural Gas (including by-products but excluding solution gas)	87,305	7.96
	Shale Gas (including by-products but excluding solution gas)	0	0.00
	Coal Bed Methane (including by-products but excluding solution gas)	11,788	6.30
	Total	552,689	12.87
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	257,682	12.05
	Heavy Oil (including solution gas and other by-products) [1]	246,497	15.83
	Tight Oil (including solution gas and other by-products)	325,010	20.39
	Conventional Natural Gas (including by-products but excluding solution gas)	127,139	6.87
	Shale Gas (including by-products but excluding solution gas)	0	0.00
	Coal Bed Methane (including by-products but excluding solution gas)	15,652	5.82
	Total	971,981	13.12

Note:
(1) The crude oil in Journey's heavy oil reserves classification is approximately 19° API and is therefore classified as heavy crude oil.
(2) Other Company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on the Company net reserves.

Pricing Assumptions

The forecast cost and price assumptions below assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The following crude oil and natural gas benchmark reference pricing, inflation and exchange rates were utilized in the GLJ Report and are the average of the published forecasts for GLJ, Sproule Ltd. and McDaniel & Associates Consultants Ltd.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF JANUARY 1, 2026
FORECAST PRICES AND COSTS

	OIL				NATURAL GAS		NATURAL GAS LIQUIDS				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton MSW Oil Price 40° API ($Cdn/bbl)	WCS Crude Oil Stream Hardisty ($Cdn/bbl)	Heavy Crude Oil Hardisty ($Cdn/bbl)	AECO Gas Price ($Cdn/MMBtu)	NYMEX Henry Hub ($US/MMBtu)	Edmonton Propane ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Edmonton Pentanes Plus ($Cdn/bbl)	INFLATION RATE [1] %/Year	EXCHANGE RATE [2] ($US/$Cdn)
2026	59.92	77.54	65.12	60.09	3.00	3.74	25.10	36.95	80.01	0.00	0.728
2027	65.10	83.60	70.43	64.94	3.30	3.78	27.28	39.79	86.19	2.00	0.737
2028	70.28	90.18	76.90	71.16	3.49	3.85	29.67	42.87	92.83	2.00	0.740
2029	71.93	92.32	78.71	72.84	3.58	3.93	30.37	43.89	95.05	2.00	0.740
2030	73.37	94.17	80.29	74.30	3.65	4.01	30.98	44.77	96.94	2.00	0.740
2031	74.84	96.06	81.90	75.80	3.72	4.09	31.60	45.67	98.89	2.00	0.740
2032	76.34	97.98	83.53	77.32	3.80	4.17	32.23	46.58	100.87	2.00	0.740
2033	77.87	99.93	85.20	78.87	3.88	4.26	32.87	47.51	102.88	2.00	0.740
2034	79.42	101.93	86.91	80.46	3.95	4.34	33.53	48.46	104.94	2.00	0.740
2035	81.01	103.97	88.65	82.07	4.03	4.43	34.20	49.43	107.04	2.00	0.740
2036	82.63	106.05	90.42	83.71	4.11	4.52	34.89	50.42	109.18	2.00	0.740
2037	84.29	108.17	92.23	85.39	4.20	4.61	35.58	51.43	111.36	2.00	0.740
2038	85.97	110.34	94.07	87.10	4.28	4.70	36.30	52.46	113.59	2.00	0.740
2039	87.69	112.54	95.95	88.84	4.36	4.79	37.02	53.51	115.86	2.00	0.740
2040	89.45	114.79	97.87	90.61	4.45	4.89	37.76	54.58	118.18	2.00	0.740
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.00	0.740

Notes:
(1) Inflation rates for forecasting prices, operating costs and capital costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by Journey for the year ended December 31, 2025 were $79.46/bbl for light and medium crude oil; $78.86/bbl for tight oil; $71.77/bbl for heavy crude oil; $46.03/bbl for natural gas liquids; $1.50/Mcf for conventional natural gas; $1.43/mcf for shale gas; and $1.44/mcf for CBM natural gas.

Reserves Reconciliation

The following table sets forth the reconciliation of our gross reserves as at December 31, 2025, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2025 include working interest reserves before royalties payable and without including gross royalties receivable. Key highlights include:

- Total Proved technical revisions were 918 Mboe due to improved performance at various properties.
- Total Proved plus Probable technical revisions were positive 794 Mboe.
- Total natural gas liquids shown below includes associated natural gas liquids from both conventional and shale/tight reservoirs.

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE / FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			TIGHT OIL		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2024	10,615	6,340	16,954	13,184	5,846	19,030	1,623	3,731	5,354
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	201	188	389	19	5	24	2,542	1,378	3,920
Technical Revisions	411	(52)	359	338	(105)	232	202	1,167	1,370
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(882)	(422)	(1,303)	(53)	(8)	(61)	-	-	-
Economic Factors	(75)	(31)	(106)	(161)	(130)	(291)	-	-	-
Production	(926)	-	(926)	(753)	-	(753)	(356)	-	(356)
December 31, 2025	9,345	6,023	15,367	12,573	5,608	18,181	4,012	6,277	10,288

	CONVENTIONAL NATURAL GAS			SHALE GAS			COALBED METHANE		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2024	101,309	66,531	167,840	5,326	12,137	17,463	12,638	5,863	18,502
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	1,353	1,733	3,086	6,934	3,588	10,522	-	-	-
Technical Revisions	(3,155)	(8,537)	(11,692)	30	1,790	1,821	1,116	(324)	791
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(6,803)	(3,268)	(10,071)	-	-	-	-	-	-
Economic Factors	(1,329)	(264)	(1,593)	-	-	-	(7)	(109)	(116)
Production	(7,519)	-	(7,519)	(728)	-	(728)	(1,357)	-	(1,357)
December 31, 2025	83,857	56,194	140,051	11,562	17,516	29,078	12,390	5,429	17,819

	TOTAL NATURAL GAS LIQUIDS			BOE		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2024	5,125	4,921	10,046	50,425	34,927	85,352
Discoveries	0	0	0	0	0	0
Extensions and Improved Recovery	823	832	1,655	4,965	3,291	8,256
Technical Revisions	302	45	347	918	(124)	794
Acquisitions	-	-	-	-	-	-
Dispositions	(153)	(56)	(209)	(2,222)	(1,030)	(3,252)
Economic Factors	(50)	(37)	(87)	(508)	(260)	(768)
Production	(443)	-	(443)	(4,078)	-	(4,078)
December 31, 2025	5,604	5,705	11,310	49,501	36,803	86,304

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty to be recoverable where significant expenditure is required to render them capable of production. Probable undeveloped reserves are those additional reserves that are less certain to be recovered than proved reserves where significant expenditure is required to render them capable of production. The GLJ Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGE Handbook.

Journey plans to develop substantially all of the proved and probable undeveloped reserves in the GLJ Report over the next five years. Journey allocates development capital annually as part of an annual budgeting process. Risk can be reduced by technically reviewing prior year's results before committing additional capital. Optimal pace of development and allocation of capital will lead to development time frame exceeding two years for Journey's undeveloped reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years.

	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
Year	First Attributed[1]	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2023	26	2,865	633	3,098	1,148	26,590	102	1,257
2024	426	2,689	116	2,901	1,874	21,533	427	1,367
2025	63	2,298	-	2,876	-	18,873	472	1,901

Year	Tight Oil (Mbbls)		Shale Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed[1]	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2023	-	-	-	-	952	11,652
2024	1,224	1,224	3,976	3,976	3,168	12,432
2025	1,740	3,120	5,028	9,040	3,113	14,848

Note:
(1) First Attributed refers to reserves first attributed at the year-end of the corresponding fiscal year.

GLJ has assigned 14,848 Mboe of proved undeveloped reserves in the GLJ Report under forecast prices and costs, which includes $197.1 million of associated undiscounted future development capital. Forecast spending for the next two years is $120.4 million.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were attributed in each of the most recent three financial years.

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed[1]	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2023	-	4,408	235	3,155	463	44,052	44	3,332
2024	309	3,808	29	3,003	813	41,806	805	3,969
2025	22	3,683	-	2,984	-	35,275	1,396	4,695

Year	Tight Oil (Mbbls)		Shale Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed[1]	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2023	-	-	-	-	356	18,237
2024	3666	3666	11909	11909	6929	23,399
2025	3,038	5,993	8,242	16,718	5,830	26,020

Note:
(1) First Attributed refers to reserves first attributed at the year-end of the corresponding fiscal year.

GLJ has assigned 26,020 Mboe of probable undeveloped reserves in the GLJ Report under forecast prices and costs which includes $251.0 million of associated undiscounted future development capital. Forecast spending for the next two years is approximately $99.1 million.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in forecast commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on the Company's reserves and, in particular, the development of our undeveloped reserves unless future development costs are adjusted at the same time. Other than the foregoing and the factors disclosed or described in the tables above, Journey does not anticipate that any significant economic factors or significant uncertainties will affect any particular components of its reserves data. However, Journey's reserves can be significantly affected by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes, abandonment and reclamation costs and well performance that are beyond the Company's control. See "*Risk Factors*".

Abandonment and Reclamation Costs

The costs to abandon and reclaim all of Journey's producing and non-producing wells, gas plants, pipelines, batteries, and other facilities have been estimated by Journey in consultation with industry consultants who are knowledgeable in these matters. No estimate of salvage value is netted against these estimated costs. The Company's model for estimating the amount of future abandonment and reclamation expenditures is done at the well and facility levels. Estimated costs for each well, pipeline segment and facility are based on an external consultant's estimates and then adjusted by internal technical personnel to take into account specific additional information that is unique to those properties. Each well, pipeline and facility is assigned a cost for abandonment and reclamation that is unique to the type of property, taking into account its geographic location, well depth, and producing zones, among other factors. The timing of the expenditures is based on the end of the productive life for the specific wells as estimated by a third party consultant, and also taking into account governmental requirements. Facility reclamation costs are generally scheduled to begin shortly after the end of the reserve life for the specific field for the associated reserves.

As at December 31, 2025 there were 2,167 gross (1,619.6 net) wells for which Journey expects to incur abandonment and reclamation costs; and 640 gross (440.2 net) wells for which abandonment work is complete but the sites require reclamation work only.

The GLJ Report deducted $373.0 million (undiscounted) for abandonment and reclamation costs associated with all active and inactive wells, future development locations that have reserves assigned to them, facilities, pipelines and gathering systems, in estimating the future net revenues disclosed above. A comprehensive estimate of future abandonment and reclamation costs for all of Journey's existing wells, facilities, surface leases, and pipelines is provided for in the financial statements of Journey. These amounts are described in Note 11 of the December 31, 2025 audited, annual financial statements.

Future Development Costs

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

	FUTURE DEVELOPMENT COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2026	56,939	77,197
2027	77,110	155,480
2028	48,662	91,531
2029	18,393	47,433
2030	10,130	41,079
Thereafter	17,065	66,705
Total (Undiscounted)	228,299	479,425
Total (Discounted at 10%)	187,836	379,167

Journey expects to fund the development costs of its reserves through a combination of internally generated Adjusted Funds Flow, debt and equity issuances. There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves could have a negative impact on Journey's future Adjusted Funds Flow.

Interest or other costs of external funding are not included in Journey's reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. Journey does not anticipate that interest or other funding costs would make development of any of its properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

Gilby, Alberta

The Greater Gilby area is located just northwest of Red Deer, Alberta. Production from the area comprises gas and associated liquids from the Glauconite formation; oil from the Mannville formation; and Duvernay shale oil and associated gas.

Glauconite gas and associated liquids produces from the Hoadley barrier island sandstone trend. This extensive gas field has been developed in phases over the past 30 years, initially with vertical wells, and more recently with horizontal wells. The formation varies in reservoir quality, but is generally low permeability, gas charged and slightly over-pressured. Journey's lands are partially developed with both vertical and horizontal wells, but a significant inventory of low risk horizontal wells remain to be drilled. Oil production at Gilby is predominantly from the Gilby Mannville B Unit, which is a medium gravity (26˚ API) water flood where Journey holds 100% working interest.

Duvernay shale oil has emerged as the immediate focus of the Company. The Duvernay is a silty carbonaceous shale, oil prone, highly over pressured and undeveloped on most of Journey's land base. As of the end of 2025, Journey has, through its Duvernay Joint Venture delineated and proven up the play with 12 producing wells, and significant ongoing development activity. Average 2025 production in the Greater Gilby area was 2,810 boe/d (59% light oil and NGL's).

Medicine Hat, Alberta

The Medicine Hat property is located just east of Medicine Hat, Alberta. At Medicine Hat production is from the Basal Quartz formation, which produces from a stacked braided fluvial system with low gravity oil (16˚ API). The pool currently has active water and polymer flood, with further upside in expansion of the polymer flood and infill horizontal wells. Average 2025 production from the Medicine Hat area was 1,604 boe/d (97% oil and NGL's).

Countess, Alberta

The Greater Countess area is located adjacent to Brooks, Alberta. Countess production is comprised of shallow gas from the Milk River/Medicine Hat formations, coal bed methane from Belly River coal formations. The Milk River and Medicine Hat sequence is dominated by marine sandstones. Substantially all of Journey's shallow gas wells have been additionally completed up-hole in the coal units of the Belly River formation. Average 2025 production at the Greater Countess area was 953 boe/d (97% natural gas).

Matziwin, Alberta

The Matziwin property is located approximately 50 kilometers north of Brooks, Alberta. Matziwin is characterized by its large oil in place, low recovery medium gravity oil (30˚ API) and associated natural gas production. In the area, production is primarily from the Glauconitic formation, dominated by shore-face sandstone deposits. These fine grained sandstone reservoirs were originally developed with vertical wells, and have since been further exploited with horizontal multi-frac drilling. A significant inventory of development drilling locations and subsequent water flood comprises the bulk of the upside of this asset. Average 2025 production at Matziwin was 1,007 boe/d (44% light oil and NGL's).

Crystal, Alberta

The Greater Crystal area is located approximately 90 kilometers southwest of Edmonton, Alberta and production is mainly from properties at Crystal, Poplar Creek, and Westerose. At the Crystal property, oil production is from the Viking formation (40˚ API), which produces from an estuarine valley fill sandstone reservoir. Further upside exists in

the exploitation of the Viking sandstone by drilling horizontal, multi-frac wells in the lower permeability portions of the pool, and expanding the existing water flood beyond the heart of the pool. At Poplar Creek and Westerose, Belly River oil (34˚ to 37˚ API) production occurs in several pools, producing from delta front shore face sandstone reservoirs, many of which are currently water flooded. Upside exists with infill horizontal multi-frac drilling, pool expansion and water flood expansion in several Belly River pools. The Westerose Banff B Unit is a stable, long life oil pool (29˚ API) currently under a gas reinjection scheme. Production occurs from the vuggy dolomite reservoir of the Banff Clarks member. Further drilling is contemplated for this pool to optimize recovery. Journey has consolidated a notable land position in Westerose for Glauconitic gas, and foresee significant horizontal drilling in this play over time. Average 2025 production from the Greater Crystal area was 1,116 boe/d (64% light oil and NGL's).

Pine Creek Alberta

The Greater Pine Creek area is located approximately 200 kilometers northwest of Edmonton, Alberta where production is mainly from properties at Ante Creek and Carrot Creek. At the Ante Creek property, oil production is from the Montney formation (35˚ API), which produces from silty dolomitic sandstone layers interbedded with high permeability streaks of sandstone/coquina. Further upside exists from the expansion of the existing waterflood. Carrot Creek production is dominated by Ellerslie liquid rich gas production and legacy Cardium oil pools (36˚ API). The Ellerslie is comprised of series of stacked lithic channels which are being developed using horizontal, multi-stage frac'd wells. The Cardium is comprised of smaller deposits of low permeability sandstone, occasionally overlain with streaks of conglomerate. Further Ellerslie development drilling is planned at Carrot Creek. Average 2025 production at the Greater Pine Creek area 2,101 boe/d (60% light oil and NGL's).

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Journey had a working interest as at December 31, 2025 and does not include 255 gross (201.1 net) service wells (injection, disposal, source water or observation wells), and 640 (440.2 net) abandoned wells (cut and capped but not reclaimed yet).

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	460	367.2	332	251.5	838	628.0	282	171.8
Total	460	367.2	332	251.5	838	628.0	282	171.8

Developed and Undeveloped Land Holdings

The following table sets out the developed and undeveloped land holdings of Journey as at December 31, 2025.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	389,929	286,631	288,135	173,811	678,063	460,443
Total	389,929	286,631	288,135	173,811	678,063	460,443

Of the properties set out above 12,233 gross (6,344 net) acres are scheduled for expiry in 2026. Journey closely monitors land expiries and plans its development program with the strategy of minimizing expiries of undeveloped lands. Development of the Corporation's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under "*Industry Conditions"* and *"Risk Factors"* herein.

Forward Contracts

Journey uses risk management contracts in order to reduce its exposure to fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The following risk management contract are currently outstanding:

a) Electricity supply

Commodity	Contract	Volume	Reference Price	Strike	Remaining Term - December 31, 2025
Electricity	Fixed price	5 MWh	AESO Monthly	$78.97	January 1, 2025 to December 31, 2026
Electricity	Fixed price	2 MWh	AESO Monthly	$77.83	January 1, 2025 to December 31, 2026

b) Natural gas sales

Commodity	Contract	Volume	Price	Remaining Term - December 31, 2025
Natural gas	Fixed price	10,000 gj/d	$3.06/mcf CAD	January 1, 2026 to March 31, 2026

c) Crude Oil sales

Commodity	Contract	Volume	Price	Remaining Term - December 31, 2025
Crude Oil	Put	2,000 bbl/d	$50 USD	Jan 1, 2026 to Mar 31, 2026
Crude Oil	Call	2,000 bbl/d	$85 USD	Jan 1, 2026 to Mar 31, 2026
Natural Gas	Swap	5,000 GJ/d	$2.90 CAD	Jan 1, 2026 to Mar 31, 2026
Crude Oil	Collar	500 bbl/d	$55-$68.45 USD	Jan 1, 2026 to Mar 31, 2026
Crude Oil	Collar	500 bbl/d	$60-$72.50 USD	Jan 1, 2026 to Mar 31, 2026
Crude Oil	Collar	750 bbl/d	$$72.50-$98 CAD	Apr 1, 2026 to Dec 31, 2026
Crude Oil	Collar	750 bbl/d	$60-$72.15 USD	Apr 1, 2026 to Sep 30, 2026
Crude Oil	Swap	500 bbl/d	$67.57 USD	Apr 1, 2026 to Dec 31, 2026
Crude Oil	Collar	300 bbl/d	$61.55-$75 USD	Apr 1, 2026 to Mar 31, 2027
Crude Oil	Swap	750 bbl/d	$75 USD	Apr 1, 2026 to Jun 30, 2026
Natural Gas	Swap	10,000 gj/d	$2.90 CAD	Jan 1, 2026 to Mar 31, 2027

Tax Horizon

Journey was not required to pay income taxes during the year ended December 31, 2025, as the Company had large undeducted income tax deductions available to shelter taxable income. As at December 31, 2025, the Company had approximately $658 million of tax pools available for deduction in the future. Journey does not expect to pay cash income taxes for at least the next five years based upon current legislation, the Company's planned capital expenditures, production rates and commodity price forecasts, and various other assumptions. A higher (or 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) and their assumed tax pools, could further extend (reduce) the estimated tax horizon.

Costs Incurred

The following table summarizes the capital costs incurred by Journey for the year ended December 31, 2025.

	Year ended December 31, 2025 ($000s)
Development costs	38,194
Mineral rights acquisition/retention	1,557
Power generation asset construction	16,508
Property dispositions	(6,821)
Administrative	91
Total	49,529

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Journey participated during the year ended December 31, 2025.

	Development		Exploratory	
	Gross	Net	Gross	Net
Natural Gas	-	-	-	-
Oil	7	2.1	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	7	2.1	-	-

For 2026, Journey is currently planning to spend approximately $79 million including: $38 million for drilling, completing, equipping and tie-ing in 9 (2.7 net) Duvernay wells; $13 million advancing its power generation business; $17 million on facility costs; $8 million on abandonments; and $3 million on land acquisitions.

Production Estimates

The following table sets out for each product type the gross volume of production estimated for 2026 in the estimates of gross proved reserves and gross probable reserves disclosed in the tables above. The Gilby, Duvernay property is the only area that accounts for 20 percent or more of the total gross proved plus probable reserves production for 2026.

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)[2]	Tight Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids[1] (bbl/d)	Oil Equivalent (boe/d)
Proved								
Gilby Duvernay	-	-	1,410	-	3,722	-	423	2,453
Other Alberta	2,465	2,115	-	19,295	-	4,094	867	9,345
Total Proved	2,465	2,115	1,410	19,295	3,722	4,094	1,290	11,798

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)[2]	Tight Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids[1] (bbl/d)	Oil Equivalent (boe/d)
Probable								
Gilby Duvernay	-	-	-	-	-	-	-	-
Alberta	144	55	610	674	1,596	74	172	1,372

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)[2]	Tight Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids[1] (bbl/d)	Oil Equivalent (boe/d)
Total Probable	144	55	610	674	1,596	74	172	1,372
Total Proved plus Probable	2,609	2,170	2,021	19,968	5,318	4,168	1,462	13,170

Notes:

(1) Natural gas liquids includes field condensates.

(2) The crude oil in Journey's heavy oil reserves classification is approximately 19° API and is therefore classified as heavy crude oil.

Production History

The following tables summarize certain information in respect of the production, product prices received (excluding revenues from physical hedges), royalties paid, operating expenses and the resulting Netback for the periods indicated below.

	Quarter Ended in 2025				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2025
Average Daily Production [1]					
Light and Medium Oil (bbl/d)	2,731	2,578	1,695	2,412	2,545
Tight Oil (bbl/d)	440	646	2,173	1,262	974
Heavy Oil (bbl/d)	2,160	2,103	2,053	2,070	2,064
Conventional Natural Gas (MMcf/d)	22,044	21,919	19,735	18,649	20,892
Shale Gas (MMcf/d)	910	1,273	4,124	2,903	1,996
Coal-bed methane natural gas (MMcf/d)	3,891	3,663	3,791	3,531	3,718
Natural Gas Liquids (bbl/d)	1,192	1,147	1,333	1,301	1,244
Combined (boe/d)	10,997	10,950	11,862	11,226	11,261
Average Sales Prices Received [2]					
Light and Medium Oil (bbl/d)	89.19	78.25	79.38	70.04	79.46
Tight Oil (bbl/d)	92.27	83.29	84.45	65.24	78.86
Heavy Oil (bbl/d)	79.71	69.30	73.27	64.74	71.77
Conventional Natural Gas (MMcf/d)	2.00	1.51	0.51	2.03	1.50
Shale Gas (MMcf/d)	2.15	1.48	0.46	2.14	1.43
Coal-bed methane natural gas (MMcf/d)	1.89	1.42	0.43	2.08	1.44
Natural Gas Liquids (bbl/d)	51.81	39.64	43.57	32.46	41.68
Combined (boe/d)	51.94	45.36	45.32	42.66	46.03
Royalties Paid					
Light and Medium Oil (bbl/d)	20.37	17.22	18.71	14.81	17.84
Tight Oil (bbl/d)	1.79	11.91	15.02	8.85	11.02
Heavy Oil (bbl/d)	16.91	14.00	16.87	13.80	15.37
Conventional Natural Gas (MMcf/d)	0.02	(0.20)	0.16	(0.05)	(0.02)
Shale Gas (MMcf/d)	0.08	0.20	0.08	0.17	0.13
Coal-bed methane natural gas (MMcf/d)	0.24	0.01	0.07	0.21	0.13
Natural Gas Liquids (bbl/d)	6.12	(12.19)	1.55	(3.65)	(1.90)
Combined (boe/d)	9.24	7.24	7.75	6.33	7.63

Production Costs [3][4]					
Light and Medium Oil (bbl/d)	42.40	38.15	44.76	41.99	41.80
Tight Oil (bbl/d)	2.25	6.57	2.14	6.19	4.21
Heavy Oil (bbl/d)	22.42	23.43	24.48	23.98	23.56
Conventional Natural Gas (MMcf/d)	1.04	0.90	1.05	1.09	1.02
Shale Gas (MMcf/d)	0.21	(0.05)	0.26	1.39	0.62
Coal-bed methane natural gas (MMcf/d)	1.50	2.17	1.71	0.69	1.52
Natural Gas Liquids (bbl/d)	12.96	11.43	11.01	10.38	11.40
Combined (boe/d)	19.06	17.58	17.24	17.73	17.88
Transportation Costs					
Light and Medium Oil (bbl/d)	1.26	1.83	1.41	1.33	1.46
Tight Oil (bbl/d)	0.84	0.90	0.96	3.04	1.61
Heavy Oil (bbl/d)	2.99	2.08	3.44	3.19	2.92
Conventional Natural Gas (MMcf/d)	-	-	0.01	0.01	-
Shale Gas (MMcf/d)	-	-	-	-	-
Coal-bed methane natural gas (MMcf/d)	-	-	-	-	-
Natural Gas Liquids (bbl/d)	1.07	0.37	0.67	8.23	2.69
Combined (boe/d)	1.05	0.92	1.57	1.66	1.31
Netback Received [5]					
Light and Medium Oil (bbl/d)	25.16	21.05	14.50	11.91	18.36
Tight Oil (bbl/d)	87.39	63.91	66.33	47.16	62.02
Heavy Oil (bbl/d)	37.39	29.79	28.48	23.77	29.92
Conventional Natural Gas (MMcf/d)	0.94	0.81	(0.71)	0.98	0.50
Shale Gas (MMcf/d)	1.86	1.33	0.12	0.58	0.68
Coal-bed methane natural gas (MMcf/d)	0.15	(0.76)	(1.35)	1.18	(0.21)
Natural Gas Liquids (bbl/d)	31.66	40.03	30.34	17.50	29.49
Combined (boe/d)	22.59	20.15	17.44	16.94	19.21

Notes:

(1) Realized prices exclude the gains and losses from physical hedging.
(2) Before the deduction of royalties.
(3) Production costs are composed of direct costs incurred to operate both oil and natural gas wells. A number of assumptions are required to allocate these costs between product types. In addition, these include facility operating costs, net of third-party recoveries including processing, treating and water disposal.
(4) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(5) See "*GAAP and Non-GAAP Measures*".

The following table indicates the average daily production from the important fields for the year ended December 31, 2025.

	Light/ Medium Crude Oil (bbl/d)	Tight Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (mcf/d)	CBM Natural Gas (mcf/d)	NGLs (bbl/d)	Boe (boe/d)
Gilby	106		974	4,885	1,996	-	583	2,810
Pine Creek	868	-	-	5,076	-	-	387	2,101
Medicine Hat	-	-	1,562	251	-	-	-	1,604
Crystal	544	-	-	2,406	-	-	171	1,116
Matziwin	417	-	-	3,376	-	-	28	1,007
Countess	23	-	-	1,857	-	3,718	1	953
Other	587	-	1,562	251	-	-	-	1,604
Total	2,544	974	2,064	20,895	1,996	3,718	1,244	11,261

DIVIDENDS AND DIVIDEND POLICY

Journey does not anticipate paying dividends in the foreseeable future and will instead direct cash flow to its capital programs and reasonable debt levels.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of the Company as of the date hereof consists of an unlimited number of Common Shares, an unlimited number of Restricted Voting Shares and an unlimited number of Preferred Shares. As of the date of this AIF, there were 67,481,185 Common Shares issued and outstanding and no Restricted Voting Shares or Preferred Shares issued and outstanding. Following is a description of the rights, privileges, restrictions and conditions attaching to Journey's share capital.

Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

> *Voting Rights*: Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of the Shareholders (except meetings at which only holders of a specified class of shares are entitled to vote).
>
> *Dividends*: Holders of Common Shares are entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class, subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company and provided that no dividend shall be declared on the Common Shares unless a dividend in the same per share amount is declared on the Restricted Voting Shares.
>
> *Ranking*: In the event of any liquidation, dissolution or winding-up of Journey, whether voluntary or involuntary, or any other distribution of Journey assets among its Shareholders for the purpose of winding-up Journey's affairs, and subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company, holders of Common Shares are entitled to receive the remaining property of the Company upon dissolution in the same per share amount with the holders of Restricted Voting Shares.

The Common Shares also contain tag along rights to the benefit of the Restricted Voting Shares, which provide that in the event that an Exclusionary Offer (as defined below) is made, then an offer to acquire the Restricted Voting Shares must be made that is identical to the Exclusionary Offer in terms of price per share, percentage of outstanding shares to be taken up and in all other material respects. An "Exclusionary Offer" is defined as an offer to purchase Common Shares which must be made, by reason of applicable law or by the regulations or policies of any stock exchange on which the Common Shares are listed, to all or substantially all of the holders of Common Shares.

As at the date hereof, to the knowledge of the Company, there is one shareholder owning more than 10% of the Common Shares of Journey: AIMCo with 13,980,070 Common shares (representing 20.7% of the outstanding Common Shares).

Restricted Voting Shares

On June 6, 2014, the Company amended its articles to create the Restricted Voting Shares. The Restricted Voting Shares have the same rights, privileges, restrictions and conditions as the Common Shares set out above (and will rank equally with the Common Shares in respect to the right to receive dividends as and when declared by the Board of Directors and the right to receive Journey assets in the event of any liquidation, dissolution or winding-up of Journey), except holders of Restricted Voting Shares shall not be entitled to vote in respect of the election of directors of the

Company and the Restricted Voting Shares shall automatically be converted into Common Shares on a 1:1 basis upon the sale of such Restricted Voting Shares to any third party and for no consideration payable in connection thereof.

A holder of Restricted Voting Shares shall have the right at any time or from time to time, upon providing notice to the Company, to convert all or any number of the outstanding Restricted Voting Shares held by such holder into Common Shares on the basis of one Common Share for each Restricted Voting Share, without payment of any additional consideration by such holder.

There are currently no Restricted Voting Shares outstanding.

Preferred Shares

The Preferred Shares are issuable in series having such rights, restrictions, privileges, conditions and designations as the Board may from time to time determine.

The Preferred Shares shall be entitled to preference over the Common Shares (and any other shares of the Company ranking junior to the Preferred Shares) with respect to payment of dividends and distribution of assets in the event of liquidation, dissolution or winding up of the Company, whether voluntary or involuntary, to the extent fixed in the case of each respective series, and may also be given such other preferences over the Common Shares (and any other shares of the Company ranking junior to the Preferred Shares) as may be fixed in the case of each such series.

There are currently no Preferred Shares outstanding.

Senior Secured Credit Agreement

On October 6, 2016, Journey entered into a private placement with AIMCo for the issuance of 30,000 units at a price of $1,000 per unit for aggregate proceeds of $30 million. Each unit is comprised of: i) one promissory note with a par value of $1,000 which bears interest at the rate of 7.65% per annum payable semi-annually; and ii) 165 Common Share purchase warrants. The Promissory Notes (2016) mature on October 31, 2021 and all or a portion of the principal amount outstanding thereunder may be repaid by Journey without penalty after two years from the date of issuance. Journey issued 4.95 million warrants in connection with this promissory note private placement, with each warrant entitling the holder to purchase one Common Share at a price per share of $2.75 until their expiry on October 7, 2019. On March 2, 2017, AIMCo exercised all of their warrants and gross proceeds of $13.6 million were received by Journey.

On January 31, 2018, Journey entered into a second promissory note private placement with AIMCo for the issuance of 22,000 units at a price of $1,000 per unit for aggregate proceeds of $22 million. Each unit is comprised of: i) one promissory note with a par value of $1,000 which bears interest at the rate of 7.65% per annum payable semi-annually; and ii) 105 Common Share purchase warrants. The Promissory Notes (2018) mature on September 30, 2022 and all or a portion of the principal amount outstanding thereunder may be repaid by Journey without penalty after two years from the date of issuance. Journey issued 2.31 million warrants in connection with this promissory note private placement, with each warrant entitling the holder to purchase one Common Share at a price per share of $2.51 until their expiry on June 1, 2021.

On September 30, 2019 all outstanding promissory notes were restructured into a single, second lien, term debt comprised of two tranches. The Promissory Notes (2016) had an aggregate principal amount of $30 million and a maturity date of October 31, 2021. These notes were restructured into a second lien tranche with a principal amount of $22 million with $8 million being repaid by Journey at closing. The maturity of this tranche was extended from October 31, 2021 to October 31, 2023 and the interest rate was changed to 11.5% per annum from 7.65% per annum. 1,137,331 share purchase warrants were issued at an exercise price of $3.15 per warrant in consideration for the change in terms. The Promissory Notes (2018) had a principal amount of $22 million and an interest rate of 7.65% per annum

with a maturity of September 30, 2022. To assist Journey with ensuring they had sufficient funds to close the Enerplus acquisition, AIMCo deferred that maturity of this tranche of term debt by six months to March 31, 2023.

On October 30, 2020, Journey secured a $38 million of term debt from AIMCo to fund the settlement of the $75 million credit facility with its syndicate of first-lien lenders. The $38 million of term debt was provided in three tranches. The first is for $15 million; bears interest at 11.5% per annum; and matures on June 30, 2021. The maturity of this first tranche was originally December 31, 2021 to coincide with the disposition of Journey's Countess, Alberta assets. The agreement for the sale of assets was terminated on March 1, 2021 and AIMCo extended the maturity of the first tranche to June 30, 2021. Journey repaid all of this tranche in 2021. The second tranche is for $10 million and was repaid in in October of 2021. The third tranche of new debt is for a principal amount of $13 million; matures on October 31, 2025; and bears interest of 9.0% in year one, 9.85% in year two and 12.95% for years three and four.

In connection with the term debt advances in 2020 Journey issued five million share-purchase warrants to AIMCo. The warrants entitle the holder to purchase one common share of Journey at an exercise price of $0.16 per warrant prior to their expiry date of October 30, 2025. In addition, a commitment fee loan, of $5.35 million is payable to AIMCo on October 30, 2025 and bears interest at rates, which are dependent upon Edmonton mixed sweet reference oil prices. Below $65 per barrel the loan bears no interest. Between $65 and $80 per barrel, the loan bears interest at 5.0% per annum and if oil prices exceed $80 per barrel the loan bears interest at 10.0% per annum.

Throughout 2023 and 2025 there were a series of amendments to the repayment terms and maturity of the Senior Secured First Lien Debt. On March 19, 2025 and concurrently with entering into the new Bank Credit Facilities, the remaining principal of this debt in the amount of $12.4 million, was repaid.

Vendor Take Back Loan

As part of the Enerplus Acquisition that closed October 31, 2022, Journey issued a $45.0 million VTB loan to the vendor. The loan bears interest at 10.0% per annum and repayments of the principal are to occur monthly commencing on December 2, 2022. The monthly principal repayment was determined by reference to the monthly oil price for West Texas Intermediate ("WTI") crude oil for the relevant month. If the monthly WTI price is equal to or in excess of $100 USD per barrel the monthly repayment is $4.0 million plus accrued interest on principal balance. If the monthly WTI price is equal to or in excess of $85 USD per barrel but less than $100 USD per barrel the monthly repayment is $3.0 million plus accrued interest. If the monthly WTI price is equal to or in excess of $70 USD per barrel but less than $85 USD per barrel the monthly repayment is $2.0 million plus accrued interest. If the monthly WTI price is below $70 USD per barrel the monthly repayment is $1.0 plus accrued interest. After taking into account the calculated monthly repayments, if there is any principal balance unpaid as of October 31, 2025 the remaining amount becomes due and payable on that date. The VTB was secured by a specific security interest over only the Medicine Hat assets acquired from Enerplus in the acquisition. When Journey issued the convertible debentures (described below) a portion of the proceeds of that issuance were used to retire the outstanding principal and accrued interest on the VTH loan. On March 21, 2024 the remaining balance of the VTB Loan was repaid.

Convertible Debentures

On March 20, 2024 the Company issued $38.0 million of convertible Debentures. Following is a summary of the material attributes and characteristics of the outstanding debentures. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the indenture which may be viewed under Surge's profile on SEDAR+ at www.sedarplus.com.

The Debentures were issued in $1,000 increments and are direct, subordinated, unsecured obligations of the Corporation, subordinated to any existing and future senior indebtedness of the Corporation and ranking equally with one another and with all other existing and future subordinated unsecured indebtedness of the Corporation to the extent subordinated on the same terms.

The Debentures will mature and be repayable on March 20, 2029 (the "**Maturity Date**") and will accrue interest at the rate of 10.25% per annum payable semi-annually in arrears on March 31 and September 30 of each year (each a "**Interest Payment Date**"), commencing on September 30, 2025 and computed on the basis of a 365-day year. Interest on the Debentures will be payable in lawful money of Canada.

At the holder's option, the Debentures may be converted into Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earlier of (i) the business day immediately preceding the Maturity Date; or (ii) if the Debentures are called for redemption, on the business day immediately preceding the date (the "**Redemption Date**") specified by the Corporation for redemption of the Debentures, in each case, at a conversion price of $5.00 per Common Share, representing a conversion rate of approximately 200 Common Shares per $1,000 principal amount of Offered Debentures, subject to adjustment in accordance with the Indenture. Holders who convert their Debentures will receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to, but excluding, the date of conversion from, and including, the most recent Interest Payment Date. If a holder elects to convert its Debentures in connection with a change of control that occurs prior to the Maturity Date, the holder will be entitled to receive additional Common Shares as a make-whole premium on conversion in certain circumstances (as more fully described in the Indenture).

The Debentures will not be redeemable by the Corporation prior to March 31, 2027, except in certain limited circumstances following a change of control. On, and after, March 31, 2027 and prior to March 31, 2029, the Debentures may be redeemed by the Corporation, subject to certain restrictions, in whole or in part from time to time, on not more than 60 days', and not less than 30 days', prior written notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption, provided that the Current Market Price on the date on which notice of redemption is given is not less than 125% of the Conversion Price.

Bank Credit Facilities

On March 19, 2025 Journey announced it has entered into a new banking relationship with a Canadian Chartered Bank. Journey has secured a new credit facility with a Canadian Chartered Bank, for up to $55 million consisting of three credit facilities. The first facility is a $12.4 million, two-year amortizing term-loan, the proceeds of which have been used to repay the outstanding balance of the AIMCo term debt. The second facility is a $15 million operating facility to be used for working capital needs on a revolving basis. The third facility is a delayed-draw term facility of a maximum of $27.6 million that will be used as needed to fund Journey's Duvernay development. None of the New Credit Facilities are subject to pre-payment restrictions or penalties. There is a $150 million floating debenture on the Company's assets that secure any amounts outstanding.

MARKET FOR SECURITIES

Trading Price and Volume

The outstanding Common Shares of the Company trade on the TSX under the symbol JOY and on the United States over the counter market (OTCQX) under the symbol JRNGF. The following table sets out the high and low closing prices and average trading volume of Common Shares as reported by the TSX, for the periods indicated.

	$ per Share		
Period	**TSX High Close**	**TSX Low Close**	**TSX Average Daily Trading Volume**
2025			
January	2.19	2.00	92,903
February	2.04	1.65	64,274
March	1.82	1.43	59,657

April	1.83	1.31	98,334
May	1.69	1.34	91,118
June	2.29	1.71	115,988
July	2.46	2.01	527,885
August	3.04	2.36	103,856
September	3.36	2.95	87,533
October	3.88	3.03	137,228
November	4.19	3.79	102,367
December	3.87	3.06	85,498
2026			
January	3.59	3.04	145,877
February	4.18	3.31	162,491
March 1-23	5.78	4.24	361,317

Prior Sales

Set forth below are details of the securities issued by the Company during 2025 and to the date of this AIF in 2026.

Date of Issuance	Type of Securities	Number Issued	Price per Security ($)	Aggregate Funds Received (Paid) ($)
October 8, 2025	Common Shares	374,584	N/A	None. Vesting of employee share awards.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at the date hereof, none of the Company's securities are subject to contractual restrictions on transfer.

DIRECTORS AND OFFICERS

Summary Information

The name, city of residence, and principal occupation during the last five years of each of the current directors and officers of the Company are set forth in the following table.

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director/Officer Since
Alex G. Verge Alberta, Canada	President and Chief Executive Officer and Director	Director and President and Chief Executive Officer of Journey since July 1, 2012.	July 1, 2012[(2)]

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director/Officer Since
Craig H. Hansen[(1)(3)]	Chair of the Board and Director	Independent businessman. Previously the President of Zargon Oil and Gas Ltd. and its subsidiaries from 1993 through 2020.	August 6, 2019
Thomas J. Mullane[(1)(3)(4)(6)] Alberta, Canada	Director	Independent businessman. Prior thereto was the President, CEO and board member of Freehold Royalties Ltd. since May of 2013.	August 9, 2021
Reginald (Steve) Smith[(1)(3)(4)(5)] Alberta, Canada	Director	Mr. Smith is currently a Director of Southern Energy Corp., Karve Energy Inc. and Jasper Brewing Inc. He was previously the Chief Financial Officer and a Director of Broadview Energy Inc. and before that a portfolio manager with Norrep Capital Management Ltd.	August 9, 2021
Scott Treadwell[(1)(4)(5)(6)] Alberta, Canada	Director	President of SixRing Inc. Prior thereto was an independent corporate consultant from March to September 2022 and Chief Operating Officer of Phyto Organix Foods from August 2021 to March 2022. Prior thereto, Vice President, Capital Markets & Strategy at Calfrac Well Services Ltd since 2017.	June 1, 2022
Jenna Kaye[(1)(5)(6)] Alberta, Canada	Director	CEO and Founder of Odyssey Trust Company; Co-Founder and Director of Axis Connects Corp.; Co-Founder and Chair of Tetra Trust; Principal at Icebook Investments Corp.	July 28, 2022
Gerald N. Gilewicz Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Journey since September 4, 2012.	September 4, 2012
Brett Boklaschuk Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Journey since May 12, 2015; previously served as the Manager of Business Development at Journey from November 2012.	May 12, 2015
Guido DeCiancio Alberta, Canada	Vice President, Land	Vice President, Land at Journey since April 1, 2022; prior thereto Manager of Land and Business Development since March 24, 2014	April 1, 2022
Aaron Bell Alberta, Canada	Vice President, Engineering	Vice President, Engineering at Journey since April 1, 2022; prior thereto Manager of Engineering since August 27, 2012.	April 1, 2022
Richard Tracy Alberta, Canada	Vice President, Operations	Vice President, Operations at Journey since April 1, 2022; prior thereto Manager of Operations since November 1, 2018; prior thereto, engineer since 2011.	April 1, 2022
Ryan Yates Alberta, Canada	Vice President, Business Development	Vice President, Operations at Journey since April 1, 2023; prior thereto Manager of Business Development since March 17, 2017.	April 1, 2023

Notes:

(1) Independent director.

(2) Mr. Verge was also a director of Sword Energy Inc., the predecessor to Journey.

(3) Member of the Reserves Committee. Mr. Mullane is the Chair of the Reserves Committee.

(4) Member of the Audit Committee. Mr. Smith is the Chair of the Audit Committee.
(5) Member of the Governance & Compensation Committee. Mr. Treadwell is the Chair of the Governance & Compensation Committee.
(6) Member of the Environmental and Social Committee. Ms. Kaye is the Chair of the Environmental, Social and Sustainability Committee.

All of the Company's directors' terms of office will expire at the earliest of their resignation, the close of the next annual meeting of Shareholders called for the election of directors, or on such other date as they may be removed according to the ABCA. Each director will devote the amount of time as is required to fulfill his obligations to the Company. The Company's officers are appointed by and serve at the discretion of the Board of Directors.

Directors and Officers – Biographies

The following are brief profiles of the directors and officers of the Company, including a description of each individual's principal occupation within the past five years.

Alex G. Verge – President and Chief Executive Officer and Director

Mr. Verge serves as the President and CEO of Journey. Mr. Verge has more than 40 years of experience in the oil and gas industry and has served as director and Chief Executive Officer and President of NuVista Energy Ltd. from July 2003 to November 2010 and served as a Vice President of Engineering of Bonavista Energy Company and Bonavista Energy Trust (formerly Bonavista Petroleum Ltd.) from January 1998 to June 2003. Prior to joining Bonavista Petroleum Ltd., he worked in the business development group at Poco Petroleums Ltd. and held various engineering positions at Rising Resources, Shell Canada Resources Limited, and Gulf Canada Resources Inc. Mr. Verge is a Member of the Association of Professional Engineers, Geologists & Geophysicists of Alberta. Mr. Verge received a Bachelor of Science degree in Chemical Engineering from the University of Toronto and a Masters of Engineering degree in Chemical and Petroleum Engineering from the University of Calgary.

Craig H. Hansen – Chair of the Board and Director

Mr. Hansen is currently an independent businessman. Mr. Hansen was previously President and Chief Executive of Zargon Oil and Gas Ltd. and its predecessor, Zargon Energy Trust, from 1993 through 2020. Mr. Hansen obtained a B.Sc. (Hons.) in Chemical Engineering from the University of Alberta in 1978 and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Hansen has over 40 years of Canadian energy industry experience encompassing technical, management and corporate matters. From 2005-2020, Mr. Hansen served five two-year terms on the Board of the Canadian Petroleum Association of Petroleum Producers (CAPP), and in 2020 received the Chairman's award for career contributions. Prior to founding Zargon Oil & Gas Ltd. Mr. Hansen was employed with Dome Petroleum Ltd. and NRG Engineering Ltd. Mr. Hansen is president of C.H. Hansen Engineering Ltd., a consulting company, which provides financial, investment and technical services related to the Canadian energy industry.

Thomas J. Mullane – Director

Mr. Mullane is currently an independent businessman. Mr. Mullane was previously President and Chief Executive Officer of Freehold Royalties Ltd. and has over 25 years of industry experience. Mr. Mullane graduated from the University of Alberta with a Bachelor of Science (Chemical Engineering) degree and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Mullane holds the ICD.D designation from the Institute of Corporate Directors.

Reginald (Steve) Smith – Director

Mr. Smith is a CPA, CA and is currently a Director of Southern Energy Corp., Karve Energy Inc. and Jasper Brewing Inc. Most recently, Mr. Smith was the Director and CFO of Broadview Energy Ltd. He started his career in the oil

and gas industry in finance with management and executive roles at numerous companies including Canadian Pioneer Petroleum Ltd., Poco Petroleums Ltd., Renaissance Energy, and Pan East Petroleum Corp. Mr. Smith has spent 12 years as an executive in the oil and gas industry and 20 years in the buy-side and sell-side of the investment industry as the Chief Financial Officer and Portfolio Manager with Norrep Capital Management Ltd. and Vice President and Director - Institutional Research at FirstEnergy Capital.

Scott Treadwell – Director

Mr. Treadwell is currently the President of SixRing Inc. and has over 20 years of experience in the Oil and Gas Industry. From 2021 until 2022, Mr. Treadwell was the Chief Operating Officer at Phyto Organix Foods Inc. Prior thereto, from 2017 to 2021 Mr. Treadwell served as Vice President, Capital Markets and Strategy for Calfrac Well Services Ltd. Prior to joining Calfrac, Mr. Treadwell was an equity research analyst providing coverage of Canadian oilfield service companies for TD Securities and Macquarie Capital Markets Canada from 2010 until 2017. Prior to that, Mr. Treadwell held various operational, business development and financial roles at Precision Energy Services, Weatherford Canada, Talisman Energy and the National Energy Board. In addition, Mr. Treadwell served as an officer for 9 years in the Royal Canadian Navy. Mr. Treadwell is a member of the Association of Professional Engineers and Geoscientists of Alberta (P.Eng) and holds a Bachelors Degree in Chemical and Materials Engineering from the Royal Military College of Canada and a Masters of Business Administration (Finance) from the Haskayne School of Business at the University of Calgary.

Jenna Kaye – Director

Jenna Kaye is the CEO and Founder of Odyssey Trust Company. She is the first female founder of a Federally Regulated Financial Institution. Jenna is also a Principal of Icebook Investments Corp, a family office with over $20 million of capital invested in early-stage companies across a wide variety of industries (fertility, life sciences, real estate, energy, retail), a Founder and Director of Axis Connects Corp., a diversity and inclusion non-profit organization, and Corporate Diversity Consultants, a consulting firm for public issuers providing governance, recruiting and pipeline building solutions to increase diverse representation at the board and c-suite levels. She is a regular participant at Creative Destruction Labs (Calgary, Paris, Toronto) and Endless Frontier Labs (NYU) mentoring sessions. Jenna has a passion for deregulated finance and cryptocurrency and is the Co-Founder and Director of Tetra Trust Company, Canada's first regulated crypto custodian, backed by Coinbase (NASDAQ: COIN). Ms. Kaye has an MBA/LLB from Dalhousie University and practice law at a national law firm.

Gerald N. Gilewicz – Chief Financial Officer

Mr. Gilewicz has served as the Chief Financial Officer of Journey since September of 2012. Mr. Gilewicz served as Chief Financial Officer and Vice President of Finance at Vero Energy Inc. from November 2005 to August 2012. Previous to that, Mr. Gilewicz served as Vice President of Finance and Chief Financial Officer of Devlan Exploration Inc. from September 1999 to November 2005. Prior to that, Mr. Gilewicz was a Senior Manager at Deloitte LLP. Mr. Gilewicz is a Chartered Professional Accountant and received his Bachelor of Commerce degree from the University of Saskatchewan.

Brett Boklaschuk – Vice President, Exploration

Since March 2015, Mr. Boklaschuk has served as Vice President, Exploration at Journey. Prior to that, he served as Manager, Business Development and as a Senior Geologist at Journey. In addition, Mr. Boklaschuk has served as a Senior Geologist, Montney at NuVista Energy from 2008 to 2012. Mr. Boklaschuk also served in progressive senior technical roles at Venturion Natural Resources, Cork Exploration, Burlington Resources and Canadian Hunter Exploration. Mr. Boklaschuk received his Bachelor of Science degree from the University of Saskatchewan. He has a

P.Geol from the Alberta Association of Engineers and Geoscientists of Alberta and is a member of Canadian Energy Geoscience Association.

Richard Tracy – Vice President, Operations

Mr. Tracy serves as Vice President, Operations at Journey. Mr. Tracy has held progressive roles in the Operations group at Journey Energy and its predecessor Sword Energy since joining in 2011. Prior to Journey, Mr. Tracy worked in production and operations for various companies including Lonepine Resources, Connacher Oil and Gas, and Enerplus Resources. He has over 18 years of industry experience in production and operations engineering. He received a Bachelor of Science in Chemical Engineering from University of Calgary in 2005 and holds a P.Eng designation with the Association of Professional Engineers and Geoscientists of Alberta.

Aaron P. Bell – Vice President, Engineering

Mr. Bell joined the Journey team in September 2012 as Manager, Engineering. Mr. Bell serves as Vice President, Engineering at Journey. Prior to Journey, he held progressive roles in public companies including ConocoPhillips Canada, Bonavista Energy and most recently Angle Energy. Mr. Bell has over 25 years of industry experience in exploitation and reservoir engineering. He received a Bachelor of Science in Petroleum Engineering from University of Alberta in 2000 and holds a P.Eng designation with the Association of Professional Engineers and Geoscientists of Alberta.

Guido De Ciancio - Vice President, Land

Mr. DeCiancio serves as Vice President, Land at Journey. He previously served as Manager, Business Development & Land. Prior to Journey, he held roles in public & private companies including, Petrovera Resources, Surge Energy Inc., and at Harvest Operations Corp. as Manager of Negotiations. Mr. De Ciancio's career has primarily been to lead strategy and focus on public and private opportunities in the marketplace that has led to over $500MM in negotiated asset transactions throughout his 24-year career. He received a Bachelor of Arts in Economics from University of Calgary in 1997 and is a member of the Canadian Association of Petroleum Landmen.

Ryan Yates - Vice President, Business Development

Mr. Yates serves as Vice President, Business Development at Journey. He previously served as Manager, Business Development. Prior to Journey, he held roles in public and private companies including SW Resources, ProspEx Resources, Burlington Resources and Poco Petroleums in both production operations and exploitation roles. He also held the role of Associate Director, Engineering at Scotia Waterous, assisting on over $11B of acquisition and divestiture transactions. He received a Bachelor of Engineering from the Univeristy of Saskatchewan in 1997 and is a member of the Association of Professional Engineers of Alberta.

Committees of the Board of Directors

The Company currently has an Audit Committee, a Reserves Committee and a Governance & Compensation Committee.

Share Ownership by Directors and Officers

As a group and as at the date of this AIF, the Company's officers and directors beneficially own or exercise control or direction over, directly or indirectly, 7,695,226 Common Shares, representing approximately 11.4% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

Except as noted below, to the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons) is, as of the date of this AIF, or was within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including the Company), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Mr. Hansen was previously the President and director of Zargon Oil & Gas Ltd. ("**Zargon**"). Zargon was issued a cease trade order dated November 19, 2020, issued by the Alberta Securities Commission and the Ontario Securities Commission due to Zargon's failure to file interim unaudited financial statements, interim management's discussion and analysis, and certification of interim filings for the interim period ended September 30, 2020.

Bankruptcies

Except for one executive officer that, within the past ten years, voluntarily entered into an arrangement with a creditor (which was not part of any bankruptcy proceeding) with respect to the repayment of certain non-material outstanding amounts, and except as set out below, to the knowledge of the Company no director or executive officer of the Company (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (a) is, as of the date of this AIF, or has been within the ten years before the date of this AIF, a director or executive officer of any company (including the Company) 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 (b) has, within the ten years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

Mr. Hansen was previously the President and director of Zargon Oil & Gas Ltd. and its subsidiaries ("Zargon") who announced on January 29, 2021 that it had completed certain transactions contemplated by a Bankruptcy and Insolvency Act (Canada) proposal (the "Proposal") filed by Zargon, Zargon Oil & Gas Partnership ("Zargon Partnership") and Zargon U.S. Holdings Ltd. ("Zargon US"). The Proposal provides for, among other things, the compromise and settlement of claims of creditors of Zargon, Zargon Partnership and Zargon US and a reorganization of the share capital of Zargon under the Business Corporations Act (Alberta) (the "Reorganization"). The Proposal was approved by the creditors on December 4, 2020. The Court issued an order approving the Proposal and the Reorganization on January 6, 2021.

Mr. Treadwell was previously an officer of Calfrac Well Services Ltd., who on December 18, 2020 filed Articles of Arrangement implementing a plan of arrangement under Section 192 of the *Canada Business Corporations Act*. The plan of arrangement gave effect to a recapitalization transaction including a proposal to the unsecured note holders.

Penalties or Sanctions

To the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) 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.

Conflicts of Interest

Certain officers and directors of the Company are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Company. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

The Board has adopted a written mandate and terms of reference for the Audit Committee, which sets out the Audit Committee's responsibility for (among other things) reviewing the Company's financial statements and the Company's public disclosure documents containing financial information and reporting on such review to the Board, ensuring the Company's compliance with legal and regulatory requirements, overseeing qualifications, engagement, compensation, performance and independence of the Company's external auditors, and reviewing, evaluating and approving the internal control and risk management systems that are implemented and maintained by management. A copy of the Audit Committee mandate is attached to this AIF as Appendix "C".

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee consists of Messrs. Smith (Chair), Mullane and Hansen. Each of the members of the Audit Committee is considered "financially literate" and "independent" within the meaning of NI 52–110.

The Company believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by the Company to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and provisions; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Company's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

For a summary of the education and experience of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee, see "*Directors and Officers*".

Pre-Approval Policies and Procedures for the Engagement of Non–Audit Services

The Audit Committee must pre-approve all non-audit services to be provided to the Company by its external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Audit Service Fees

The following table summarizes the fees paid by the Company to its auditors, KPMG LLP for external audit and other services during the period indicated.

Year	Audit Fees [1]	Audit -Related Fees [2]	Tax Fees	All Other Fees [3]
	($)	($)	($)	($)
2025	218,280	49,500	-	-
2024	229,500	48,150	-	-

Notes:

(1) Represents the aggregate fees for services related to the audit of the annual financial statements.

(2) Includes aggregate fees billed for assurance and related services related to the review of the Company's quarterly financial statements.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings Journey is or was a party to, or that any of its property is or was the subject of, during Journey's most recent financial year, nor are any such legal proceedings known to Journey to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of Journey.

There are no: (a) penalties or sanctions imposed against Journey by a court relating to securities legislation or by a securities regulatory authority since Journey's inception; (b) other penalties or sanctions imposed by a court or regulatory body against Journey that would likely be considered important to a reasonable investor in making an investment decision; and (c) settlement agreements Journey entered into before a court relating to securities legislation or with a securities regulatory authority since Journey's inception.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as otherwise set out herein, there is no material interest, direct or indirect, of any: (a) director or executive officer of Journey; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Journey's voting securities; or (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction within three years before the date of this AIF that has materially affected or is reasonably expected to materially affect Journey.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, material contracts that the Company has entered into within the last financial year, or before the last financial year which are still in effect, are the following:

1. Bank Credit Facilities (March 19, 2025).

Copies of the foregoing may be viewed on the SEDARPLUS website at www.sedarplus.ca.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 - *Continuous Disclosure Obligations* by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator and KPMG LLP, our current external auditors. As at the date hereof, none of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of Journey or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. The Corporation's independent auditors are KPMG LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated March 11, 2026 in respect of the Corporation's consolidated financial statements as at December 31, 2025 and 2024 and for the years then ended. KPMG LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct with Guidance of the Chartered Professional Accountants of Alberta.

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

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on the SEDAR website at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, if applicable, will be contained in the Company's management proxy circular which is expected to be dated in April 2026 relating to the annual general meeting of Shareholders to be held on May 27, 2026. Additional financial information is provided in the financial statements and management's discussion and analysis of the Company for the year ended December 31, 2025, which are accessible on the SEDAR website at www.sedar.com.

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

To the board of directors of Journey Energy Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2025. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2025, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $000s)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves (County or Foreign Geographic Area)**	**Audited**	**Evaluated**	**Reviewed**	**Total**
GLJ Ltd.	December 31, 2025	Canada	–	971,981	–	971,981

6. In our opinion, the reserves data 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 reports.

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

Executed as to our report referred to above:

GLJ Ltd.
Calgary, Alberta, Canada,
February 27, 2026

"Original Signed By"

Ryan Campbell, P. Eng.
Manager, Engineering

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

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

An independent qualified reserves evaluator has audited, evaluated and reviewed and reported on Journey's reserves data. The reports of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Journey has:

- reviewed Journey's procedures for providing information to the independent qualified reserves evaluator;
- 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
- reviewed the reserves data and resources data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed Journey'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

- the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- the content and filing of this report.

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

(signed) "*Alex G. Verge*"
Alex G. Verge
President and Chief Executive Officer

(signed) "*Thomas Mullane*"
Thomas Mullane
Director, and Chair of the Reserves Committee

(signed) "*Aaron Bell*"
Aaron Bell
Vice President, Engineering

(signed) "*Craig Hansen*"
Craig Hansen
Director and member of the Reserves Committee

March 24, 2026

APPENDIX "C"
AUDIT COMMITTEE MANDATE

JOURNEY ENERGY INC.
MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Journey Energy Inc. ("**Journey**" or the "**Company**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Journey and related matters;

2. To provide better communication between directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Journey or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 — Audit Committees unless the Board determines that the exemption contained in NI 52 110 is available and determines to rely thereon.

2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" (as defined in NI 52 110) unless the Board determines that an exemption under NI 52 110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52 110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Journey's internal control systems:

   - identifying, monitoring and mitigating business risks; and

   - ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of Journey and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Journey's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Company to determine the auditors' independence;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   - review and pre approve any non-audit services to be provided to Journey or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Journey) their assessment of the internal controls of Journey, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Journey and its subsidiaries.

7. Review risk management policies and procedures of Journey (e.g. hedging, litigation and insurance).

8. Establish a procedure for:

   - the receipt, retention and treatment of complaints received by Journey regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of Journey of concerns regarding questionable accounting or auditing matters.

9. Maintain and administer the Company's "whistleblower" policy.

10. Review and approve Journey's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Journey.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Company. The Committee will also have the authority to investigate any financial activity of Journey. All employees of Journey are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Journey without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Company as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Company.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies

on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chair of the Board by the Committee Chair.