TRANSGLOBE ENERGY CORPORATION

ANNUAL INFORMATION FORM

Year Ended December 31, 2021

Dated March 17, 2022

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SCHEDULE "A"	Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor
SCHEDULE "B"	Report of Management and Directors on Oil and Gas Disclosure
SCHEDULE "C"	Charter of Audit Committee

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
bbls/d	barrels per day
bopd	barrels of oil per day
Mbopd	thousand barrels of oil per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet

Other

boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
MMboe	million barrels of oil equivalent
km^2	square kilometres
m^3	cubic metres
$M	thousands of dollars
$MM	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

We have adopted the standard of 6 Mcf: 1 bbl when converting natural gas to oil and 1 bbl: 6 Mcf when converting oil to natural gas. **Disclosure provided herein in respect of boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value**.

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	0.28174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls oil	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMBtu	0.950

CURRENCY AND EXCHANGE RATES

All dollar amounts in this AIF, unless otherwise indicated, are stated in United States dollars ("**US$**"). TransGlobe Energy Corporation ("**TransGlobe**" or the "**Company**") uses the U.S. dollar as reporting currency for its consolidated financial statements. The exchange rates for the average of the indicative rates during the period and the end of period for the U.S. dollar in terms of Canadian dollars as reported by the Bank of Canada were as follows for each of the years ended December 31, 2021, 2020 and 2019.

	2021	2020	2019
End of Period	C$1.27	C$1.27	C$1.30
Period Average	C$1.25	C$1.34	C$1.33

FORWARD-LOOKING STATEMENTS

This AIF may include certain statements deemed to be "forward-looking statements" or "future-oriented financial information" within the meaning of applicable Canadian and United States securities laws (collectively, "**forward-looking information**"). These statements relate to future events or the Company's future performance. All statements other than statements of historical fact are forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "seek", "may", "will", "should", "expect", "plan", "anticipate", "continue", "believe", "estimate", "predict", "project", "potential", "targeting", "intend", "could", "might", "continue", "should" or the negative of these terms or other comparable terminology. These statements are only predictions. In addition, this AIF may contain forward-looking information attributed to third-party industry sources. 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 information. The Company believes the expectations reflected in such forward-looking information are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking information included in this AIF should not be unduly relied upon.

Undue reliance should not be placed on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur and may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Forward-looking statements in this AIF include, but are not limited to, statements with respect to:

- the performance characteristics of the Company's oil and natural gas properties;
- oil and gas production levels;
- the quantity of oil and gas reserves;
- capital expenditure programs;
- supply and demand for oil and gas, and commodity prices;
- drilling plans;
- expectations regarding the Company's ability to raise capital and to continually add to reserves though acquisitions, exploration and development;
- the Company's ability to manage its exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates;
- the budget for the exploration program;
- future development costs;
- TransGlobe's expectations that its development activities will be economic;
- future reserves growth and the success of its exploration program;
- the continuation of the Company's marketing of its own Egypt entitlement oil on a go-forward basis and the resulting reduced credit risk;
- the satisfaction of work commitments in Egypt;
- estimated timing of development of undeveloped reserves;
- future abandonment and reclamation costs;
- anticipated average production for 2022;
- expected exploration and development spending and the funding thereof;
- treatment under governmental regulatory regimes and tax laws;
- realization of the anticipated benefits of acquisitions and dispositions;
- the expected benefits to be derived by the Company from the Merged Concession;
- that the Company does not anticipate that environmental protection requirements will have a significant effect on its capital expenditures, earnings or competitive position;
- tax horizon;
- the Company's hedging activities and the anticipated benefits to be derived therefrom;
- that there is a low risk of the Company becoming liable for decommissioning liabilities in Egypt;
- TransGlobe's anticipated abandonment and reclamation costs in Canada;
- adverse technical factors associated with exploration, development, production, transportation or marketing of crude oil reserves; and
- changes or disruptions in the political or fiscal regimes in the Company's areas of activity.

Statements relating to "reserves" or "resources" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions that some or all of the resources and reserves described can be profitably produced in the future.

This document also includes forward-looking information in regarding the payment of dividends, including the timing and amount thereof, and the Company's intention to declare and pay dividends in the future. Future dividend payments, if any, and the level thereof is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time will be dependent upon, among other things, free cash flow, share buybacks, financial requirements for the Company's operations and the execution of its strategy, ongoing production maintenance, growth through acquisitions, fluctuations in working capital and the timing and amount of capital expenditures, payment irregularity in Egypt, debt service requirements, general economic conditions and other factors beyond the Company's control. Further, the ability of the Company to pay dividends will be subject to applicable laws (including the satisfaction of the liquidity and solvency tests contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness.

Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking information contained in this AIF is expressly qualified by this cautionary statement.

Although the forward-looking information contained in this AIF is based upon assumptions which management of the Company believes to be reasonable, the Company cannot assure investors that actual results will be consistent with such forward-looking information. With respect to forward-looking information contained in this AIF, the Company has made assumptions regarding: current commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and gas; the impact (and duration thereof) that the COVID-19 pandemic will have on: (i) the demand for crude oil and natural gas, (ii) the supply chain, including the Company's ability to obtain the equipment and services it requires, and (iii) the Company's ability to produce, transport and/or sell its crude oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; future operating costs; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; and other matters.

Actual operational and financial results may differ materially from TransGlobe's expectations contained in the forward-looking information as a result of various risk factors, many of which are beyond the control of the Company. These risk factors include, but are not limited to:

- unforeseen changes in the rate of production from the Company's oil and gas fields;
- changes or disruptions in the political or fiscal regimes in the Company's areas of activity;
- continued volatility in market prices for crude oil and natural gas;
- actions taken by OPEC with respect to the supply of oil;
- potential disruption of the Company's operations as a result of the COVID-19 pandemic through potential loss of manpower and labour pools resulting from quarantines in the Company's operating areas, risk of the financial capacity of the Company's contract counterparties and potentially their ability to perform contractual obligations;
- exposure to third party credit risk due to the receivables due from EGPC;
- general economic conditions in Canada, the United States, Egypt and globally, including as a result of demand and supply effects resulting from the COVID-19 pandemic;
- general economic stability of the Company’s financial lenders and creditors;
- payment of crude oil and natural gas marketing contracts and both associated and non-associated financial hedging instruments;
- adverse technical factors associated with exploration, development, production, transportation or marketing of the Company's crude oil and natural gas reserves;
- changes in Egyptian or Canadian tax, energy or other laws or regulations;
- geopolitical risks associated with the Company's operations in Egypt;
- capital expenditure programs, including changes in capital expenditures;
- delays in production starting up due to an industry shortage of skilled manpower, equipment or materials;
- the cost of inflation;
- the performance characteristics of the Company's oil and gas properties and the Company's success at acquisition, exploitation and development of reserves;
- failure to achieve production targets on timelines anticipated or at all;
- changes or fluctuations in production levels;
- the quantity of oil and gas reserves;
- supply and demand for oil and gas, and commodity prices;
- the Company's ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- changes to treatment under governmental regulatory regimes and tax laws;
- failure to realize the anticipated benefits of acquisitions and dispositions;
- industry conditions, including fluctuations in the price of oil and natural gas;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in commodity prices, foreign exchange rates or interest rates;
- risks inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- unanticipated operating events which can reduce production or cause production to be shut-in or delayed;
- failure to obtain industry partner and other third-party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisitions of reserves, undeveloped land and skilled personnel;
- incorrect assessments of the value of acquisitions;
- competition from other producers;
- lack of availability of qualified personnel;
- credit risks;
- the potential for reserves evaluators' estimates and assumptions to be inaccurate;
- the need to obtain required approvals from regulatory authorities;
- TransGlobe’s development activities will not be economic;
- that environmental protection requirements will have a significant effect on the Company’s capital expenditures, earnings or competitive position;
- the Company becoming liable for decommissioning liabilities in Egypt; and
- other factors considered under "*Risk Factors*" in this AIF.

Forward-looking information contained herein concerning the oil and natural gas industry in the countries in which TransGlobe operates and the Company's general expectations concerning this industry are based on estimates prepared by management of the Company using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

The Company has included the above summary of assumptions and risks related to forward-looking information provided in this AIF in order to provide Shareholders with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes. The Company believes that the expectations reflected in the forward-looking information contained in this AIF are reasonable, but no assurance can be given that these expectations will prove to be correct, and investors should not attribute undue certainty to, or place undue reliance on, such forward-looking information. Such forward-looking information speaks only as of the date of this AIF. If circumstances or management's beliefs, expectations or opinions should change, the Company does not intend, and does not assume any obligation, to update such forward-looking information, except as required by applicable Canadian and United States securities laws. Please consult the Company's SEDAR profile at www.sedar.com and the Company's profile on the Electronic Data Gathering and Retrieval System of the U.S. Securities and Exchange Commission ("**EDGAR**") at www.sec.gov for further, more detailed information concerning these matters.

This AIF also contains financial outlook within the meaning of applicable securities laws, including but not limited to: the Company's estimated exploration and development spending budget, including the estimated allocations between Egypt and Canada. The financial outlook has been prepared by TransGlobe's management to provide an outlook of the Company's activities and results. The financial outlook has been prepared based on a number of assumptions including those set forth below in this AIF, the assumptions discussed above and assumptions with respect to the costs and expenditures to be incurred by the Company, capital equipment and operating costs, foreign exchange rates, taxation rates for the Company, general and administrative expenses and the prices to be paid for the Company's production. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the financial outlook or assurance that such operating results will be achieved and, accordingly, the complete financial effects of all of those costs, expenditures, prices and operating results are not objectively determinable. The actual results of operations of the Company and the resulting financial results will likely vary from the amounts set forth in the analysis presented in this AIF, and such variation may be material. The Company and its management believe that the financial outlook has been prepared on a reasonable basis as of January 27, 2022, reflecting the best estimates and judgments, and represent, to the best of management's knowledge and opinion, TransGlobe's expected expenditures and results of operations. However, because this information is highly subjective and subject to numerous risks including the risks discussed above, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, TransGlobe undertakes no obligation to update such financial outlook and forward-looking statements and information, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

NON-GAAP AND OTHER FINANCIAL MEASURES

This AIF uses various “non-GAAP financial measures”, “non-GAAP ratios” and “supplementary financial measures” (as such terms are defined in NI 52-112), which are described in further detail below. Such measures are not standardized financial measures under IFRS and might not be comparable to similar financial measures disclosed by other issuers where similar terminology is used. Such financial measures should not be considered as alternatives to, or more meaningful than measures determined in accordance with IFRS. These measures facilitate management’s comparisons to the Company’s historical operating results in assessing its results and strategic and operational decision-making and may be used by financial analysts and others in the oil and natural gas industry to evaluate the Company’s performance. Further, management believes that such financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Company’s principal business activities.

Non-GAAP Financial Measures

In this AIF, netback and capital expenditures for the year-ended December 31, 2021 have been disclosed, which are non-GAAP financial measures. See the 2021 MD&A at page 15 for the composition of such measures, an explanation of how such measures provide useful information to a reader and the additional purposes for which management uses such measures, and a reconciliation of such measure to the most directly comparable IFRS measure disclosed in the Company’s financial statements, which information is incorporated by reference herein.

Non-GAAP Ratios

In this AIF, netback per boe/bbl for the year-ended December 31, 2021 has been disclosed, which is a non-GAAP ratio. TransGlobe calculates netback per boe/bbl as netback divided by average daily sales volumes. Netback per boe/bbl uses netback, which is a non-GAAP financial measure. See the 2021 MD&A at page 15 for the composition of such non-GAAP ratio and an explanation of how such measure provides useful to a reader that the additional purposes for which management uses such measure, which information is incorporated by reference herein.

Supplementary Financial Measures

"**Average realized sales price**" is comprised of total petroleum and natural gas sales, as determined in accordance with IFRS, divided by the Company's average daily production volumes.

"Production and operating expenses per boe" is comprised of production and operating expenses, as determined in accordance with IFRS, divided by the Company's average daily sales volumes.

"Royalties and current taxes per boe" is comprised of royalties and current taxes, as determined in accordance with IFRS, divided by the Company's average daily sales volumes.

"Royalties and taxes per boe" is comprised of royalties and current taxes, as determined in accordance with IFRS, divided by the Company's average daily sales volumes.

"Selling costs per boe" is comprised of selling costs, as determined in accordance with IFRS, divided by the Company's average daily sales volumes.

CERTAIN DEFINITIONS

In this AIF, the following words and phrases have the following meanings, unless the context otherwise requires:

"**1P**" means proved reserves;

"**2021 MD&A**" means the Company's management's discussion and analysis for the year ended December 31, 2021, and dated March 17, 2022;

"**2P**" means proved plus probable reserves;

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

"**AER**" means the Alberta Energy Regulator;

"**AIF**" means this Annual Information Form and the appendices attached hereto;

"**AIM**" means the Alternative Investment Market of the London Stock Exchange;

"**Arta**" means the Arta field in the West Gharib concession in the Egyptian Eastern Desert;

"**ATB**" means ATB Financial;

"**Board**" or "**Board of Directors**" means the Board of Directors of the Company;

"**Brent**" means the reference price paid in U.S. dollars for a barrel of light sweet crude oil produced from the Brent field in the UK sector of the North Sea;

"**Business Day**" means a day, other than a Saturday or Sunday, or a statutory holiday, on which major Canadian chartered banks are open for business in Calgary, Alberta;

"**C$**" means Canadian dollars;

"**Cardium**" means the Cardium formation that spans a large area from southwest Alberta to northeast British Columbia, with the producing area concentrated along the eastern slopes of the Rocky Mountains to the northwest of Calgary;

"**CHR&G**" means the Compensation Human Resources & Governance Committee;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook maintained by The Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;

"**Common Shares**" means the common shares of the Company;

"**Dry Hole**" or "**Dry Well**" or "**Non-Productive Well**" means a well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well;

"**EDGAR**" means the Electronic Data Gathering and Retrieval System of the U.S. Securities and Exchange Commission;

"**EGPC**" means the Egyptian General Petroleum Corporation;

"**Egypt**" means the Arab Republic of Egypt;

"**Exploratory Well**" means a well drilled either in search of a new, as-yet undiscovered oil or natural gas reservoir or to greatly extend the known limits of a previously discovered reservoir;

"**GLJ**" means GLJ Ltd, independent petroleum consultants;

"**GLJ Report**" means the report of GLJ dated February 22, 2022 evaluating the crude oil, natural gas and NGL reserves of the Company as at December 31, 2021;

"**Gross**" or "**gross**" means:

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

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

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

"**Harmattan**" means the Harmattan area of west central Alberta, Canada;

"**HSE**" has the meaning ascribed thereto under "*General Development of the Business – 2020*";

"**IFRS**" means International Financial Reporting Standards as issued by the International Accounting Standards Board;

"**Merged Concession**" or "**PetroBakr Concession**" means the modernized concession that merged the West Bakr, West Gharib and NW Gharib concessions;

"**Merged Concession agreement**" means the agreement with EGPC for the Merged Concession signed by the Ministry of Petroleum at an official signing ceremony on January 19, 2022;

"**Nasdaq**" means the Nasdaq Capital Market;

"**Net**" or "**net**" means:

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

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

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

"**NGLs**" means natural gas liquids;

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

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

"**NI 52-112**" means National Instrument 52-112 – *Non-GAAP and Other Financial Measures Disclosure*;

"**NW Gharib**" means the North West Gharib Concession area in Egypt;

"**NW Sitra**" means the North West Sitra Concession area in Egypt;

"**OPEC**" means the Organization of Petroleum Exporting Countries;

"**OPEC+**" has the meaning ascribed thereto under "*General Development of the Business – 2020*";

"**PSC**" means production sharing concession;

"**RBL**" means revolving reserves-based lending facility;

"**RHSES Committee**" means the Reserves, Health, Safety, Environment & Social Responsibility Committee;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval of the Canadian Securities Administrators;

"**S Ghazalat**" means the South Ghazalat Concession area in Egypt;

"**Shareholders**" means the holders of Common Shares of the Company;

"**South Alamein**" means the South Alamein Concession area in Egypt;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5th Supp.), as amended, including the regulations promulgated thereunder, each as amended from time to time;

"**TPI**" means TransGlobe Petroleum International Inc.;

"**TransGlobe**" or the "**Company**" means TransGlobe Energy Corporation, a corporation organized and registered under the laws of Alberta, Canada, and as the context requires, its subsidiary companies;

"**TSX**" means the Toronto Stock Exchange;

"**U.S.**" means the United States of America;

"**West Bakr**" means the West Bakr Concession area in Egypt;

"**West Gharib**" means the West Gharib Concession area in Egypt;

"**Yemen**" means the Republic of Yemen; and

"**Yusr**" means the Yusr reservoirs in the West Bakr concession in the Egyptian Eastern Desert.

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

General

TransGlobe was incorporated on August 6, 1968 and was organized under variations of the name "Dusty Mac" as a mineral exploration and extraction venture under *The Company Act* (British Columbia). In 1992, the Company entered the oil and gas exploration and development industry in the United States and later in Yemen, Canada and Egypt, ceasing operations as a mining company. The Company changed its name to TransGlobe Energy Corporation on April 2, 1996 and on June 9, 2004, the Company continued from the Province of British Columbia to the Province of Alberta pursuant to the ABCA. The Company's U.S. oil and gas properties were sold in 2000 to fund opportunities in Yemen and the Company's previous Canadian oil and gas assets and operations were divested in early 2008 to assist with the funding of opportunities in Egypt and Yemen. In 2015, the Company relinquished and divested all of its interests in Yemen. In 2016, the Company re-entered Canada with the acquisition of production and working interests in certain assets in west central Alberta

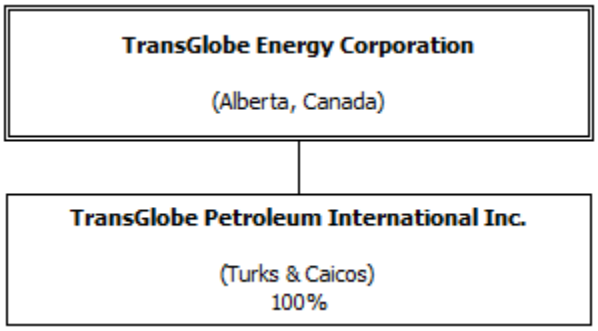
TransGlobe and its subsidiaries are engaged in oil and natural gas exploration, development and production, and the acquisition of oil and natural gas properties in Egypt and Alberta, Canada. The Company currently employs 55 full-time employees and 6 full-time consultants.

The Common Shares have been listed on the TSX under the symbol "TGL" since November 7, 1997 and on the Nasdaq under the symbol "TGA" since January 18, 2008. Prior to listing on the Nasdaq, the Company had its U.S. listing on the American Stock Exchange since 2003. The Common Shares have been listed on the AIM under the symbol "TGL" since June 29, 2018.

The Company's principal office is located at 900, 444 - 5th Avenue S.W., Calgary, Alberta, T2P 2T8. The Company's registered office is located at 2400, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

Intercorporate Relationships

The following organization chart and table present the name and jurisdiction of incorporation of the Company's material subsidiaries as at the date of this document. The chart and table do not include all of the subsidiaries of TransGlobe. The assets and revenues of excluded subsidiaries did not individually exceed 10%, and in aggregate exceed 20%, of the total consolidated assets or total consolidated revenues of TransGlobe as at the date of this document.



TransGlobe's Canadian properties are owned by TransGlobe Energy Corporation and the Company's interest in the concessions in Egypt are held by TPI and its subsidiaries. The following table sets out the name and jurisdiction of incorporation of the subsidiaries beneficially owned, controlled or directed, directly or indirectly, by TPI. Unless otherwise indicated, the Company owns, directly or indirectly, 100% of the voting securities of all the subsidiaries below.

Name of TPI Subsidiary	Purpose	Jurisdiction of	Ownership
TransGlobe West Gharib Inc.	Owns part of TransGlobe's interest in the West Gharib concession in Egypt.	Turks & Caicos Islands, B.W.I.	100%
TransGlobe West Bakr Inc.	Owns TransGlobe's interest in the West Bakr concession in Egypt.	Turks & Caicos Islands, B.W.I.	100%
TG NW Gharib Inc.	Owns TransGlobe's interest in the NW Gharib concession in Egypt.	Turks & Caicos Islands, B.W.I.	100%
TG S Ghazalat Inc.	Owns TransGlobe's interest in the S Ghazalat concession in Egypt.	Turks & Caicos Islands, B.W.I.	100%

Unless the context otherwise requires, reference in this AIF to "TransGlobe" or the "Company" includes the Company and its direct and indirect wholly-owned subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a description of the general developments of the business of TransGlobe over the last three financial years and to the date of this Annual Information Form.

2019

TransGlobe's 2019 drilling program included drilling six development wells in Egypt (five in West Bakr and one in NW Gharib) and two exploration wells (one in West Bakr and one in NW Gharib). Facilities were also installed at S Ghazalat 6X. In Canada, the Company successfully drilled three one-mile horizontal development oil wells and one two-mile outpost appraisal well on lands acquired in 2018, located south of the Harmattan area and north of the Lochend area, which the Company refers to as South Harmattan.

TransGlobe produced an average of 16,041 boe/d in 2019. Egypt average production was 13,713 bbls/d, including heavy crude oil production of 12,840 bbls/d and light & medium crude oil production of 873 bbls/d. In Canada average production was 2,328 boe/d including 814 bbls/d of light & medium crude oil, 582 bbls/d of natural gas liquids and 5,594 Mcf/d of conventional natural gas.

2P reserves at year-end 2019 were up 4% from 2018 primarily due to 2P reserves replacement of 135% (excluding economic factors) against 5.8 MMboe of production. Production outperformed forecasts, primarily at West Bakr, which led to positive 2P technical revisions of 4.4 MMboe.

In 2019, the Company relinquished the South Alamein and NW Sitra concessions and received approval for the S Ghazalat development lease from EGPC and the Ministry of Petroleum, with first oil produced at the end of December 2019.

Throughout 2019, the Company engaged in constructive negotiations with EGPC to amend, extend and consolidate the Company's Eastern Desert concession agreements.

TransGlobe paid two dividends in 2019 of $0.035 per Common Share.

2020

In early 2020, the Company reduced its capital program (before capitalized G&A) from $37.1 million to $7.1 million and suspended its dividend in order to preserve cash. These decisions were made in response to global reactions to the initial spread of COVID-19 and the related economic fallout which created significant volatility, uncertainty, and turmoil in the oil and gas industry. Oil demand significantly deteriorated in 2020 as a result of the pandemic and corresponding preventative measures taken globally to mitigate the spread of the virus. In addition to this, in Q1-2020 the OPEC and other oil producing nations ("OPEC+") were initially unable to reach an agreement on production levels for crude oil, at which point Saudi Arabia and Russia initiated efforts to aggressively increase production. These events in early 2020 compounded the impact of a material decline in oil demand and the supply increase from OPEC+ members attempting to capture market share at the onset of the pandemic. The Board determined that it would evaluate its decision on future dividend payments on a semi-annual basis going forward. See "*Dividend Policy*" and "*Risk Factors*".

TransGlobe's reduced capital program in 2020 focused only on those investments that were critical to Health, Safety and the Environment ("HSE") and value preservation during the low commodity price environment. TransGlobe drilled one Yusr development well in Egypt at West Bakr (HW-2A) and performed four recompletions. In Canada, the Company drilled one 2-mile horizontal Cardium oil well in the South Harmattan area. The Company stimulated and equipped this well for production in early 2021.

TransGlobe produced an average of 13,425 boe/d in 2020. Egypt average production was 11,147 bbls/d, including heavy crude oil production of 10,271 bbls/d and light & medium crude oil production of 876 bbls/d. In Canada average production was 2,278 boe/d including 711 bbls/d of light & medium crude oil, 785 bbls/d of natural gas liquids and 4,686 Mcf/d of conventional natural gas.

2P reserves at year-end 2020 were down by 14% from 2019 primarily due to 5.7 MMboe of negative economic factors due to depressed commodity prices and 4.9 MMboe of production, partially offset by 2.3 MMboe of positive technical revisions and 1.9 MMboe of extensions and improved recovery.

In December 2020, TransGlobe announced that it reached an agreement with EGPC for its Merged Concession agreement. The Merged Concession has a new 15-year development term and a 5-year extension option. The modernized financial concession terms are expected to promote increased investment and the implementation of new technology in TransGlobe's mature fields. The effectiveness of the Merged Concession agreement was subject to a customary Egyptian Parliamentary ratification and the satisfaction of other closing conditions. See *General Development of the Business – 2021* and *General Development of the Business – 2022.*

On December 31, 2020, TransGlobe's Common Shares were transferred from The Nasdaq Global Select Market to The Nasdaq Capital Market.

2021

In anticipation of the approval of the Merged Concession and its associated February 1, 2020 effective date along with commodity price improvements, the Company moved forward to re-start investment in Egypt and Canada in 2021. In Egypt, the 2021 development program focused on the Eastern Desert and included: seven development wells in West Bakr, one Red Bed appraisal well in NW Gharib, six recompletions in West Bakr, and development/maintenance projects in the Eastern Desert. In the Western Desert, the Company drilled an oil exploration well at South Ghazalat. The well was suspended pending further evaluation of options to improve productivity on the lower Bahariya reservoir, and to assess the commercial potential of the gas-bearing upper Bahariya reservoir. A recompletion of SGZ-6X well to the lower Bahariya reservoir and expansion of the South Ghazalat early production facility was also completed.

The 2021 capital program in Canada consisted of drilling three (three net) horizontal wells and completing one (one net) standing well, all targeting the Cardium light oil resource at Harmattan, and additional maintenance/development capital. The 2-mile horizontal well drilled in South Harmattan in 2020 was completed and brought on production.

TransGlobe produced an average of 12,854 boe/d in 2021. In Egypt, average production was 10,578 bbls/d, including heavy crude oil production of 9,528 bbls/d and light & medium crude oil production of 1,050 bbls/d. In Canada average production was 2,276 boe/d including 758 bbls/d of light & medium crude oil, 740 bbls/d of natural gas liquids and 4,667 Mcf/d of conventional natural gas.

2P reserves at year-end 2021 were up by 18% from 2020 primarily due to the successful drilling program in Canada at South Harmattan and the term extension resulting from the Merged Concession in Egypt.

In December 2021, TransGlobe announced that the Merged Concession was ratified by Egypt's Parliament and signed into law by President El-Sisi Which merged the Company's three producing Eastern Desert concessions into one agreement, extended the primary term of the merged agreement and amended its fiscal terms.

2022

In January 2022, TransGlobe announced that it had paid the initial modernization payment of $15.0 million and signature bonus of $1.0 million as a precondition to the official signing of the Merged Concession by all parties. The Merged Concession agreement was fully executed at an official signing ceremony with the Ministry of Petroleum on January 19, 2022. See "*Material Contracts".*

The Company made the second modernization payment of $10.0 million on February 1, 2022.

On March 16, 2022, the Board declared a dividend of $0.10 per Common Share, which will be paid in cash on May 12, 2022 to shareholders of record on April 29, 2022. The ex-dividend date is April 28, 2022. See "*Dividend Policy*" and "*Risk Factors*".

Significant Acquisitions

TransGlobe did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS AND PRINCIPAL PROPERTIES

General

TransGlobe is engaged in the exploration, development and production of crude oil and natural gas in Egypt and Canada. The Company also regularly reviews potential acquisitions and new international exploration blocks to supplement its exploration and development activities.

TransGlobe has had operations in Egypt during the past 17 years. The Company also operated in Canada from 1999 to 2008, and made a re-entry into Canada in December 2016. As at December 31, 2021, the Company has interest in four PSCs in Egypt: West Gharib, West Bakr, NW Gharib, and S Ghazalat. In Canada, the Company owns production and working interests in certain facilities in the Cardium light oil and Mannville liquids-rich gas assets in the Harmattan area of west central Alberta.

A significant portion of the Company's operations occur outside of Canada and therefore are subject to political and regulatory risk in those other jurisdictions. See "*Risk Factors*".

Impact of the COVID-19 Pandemic

In March 2020 the World Health Organization declared the outbreak of COVID-19 a global pandemic. The breadth and depth of the impact of the COVID-19 pandemic on the global economy, including commodity and financial markets, has continued to evolve with significant disruptive effects throughout Canada and the World, while also contributing to increased market volatility and changes to the macroeconomic environment. These factors had a resulting impact to TransGlobe and its operations and financial results in 2021.

The extent of the impact, if any, of the COVID-19 pandemic on the Company in the future will depend on developments beyond the Company's control, including actions taken by governments, financial institutions, monetary policy authorities, and public health authorities to contain and respond to public health concerns and general economic conditions as a result of the pandemic. TransGlobe cannot be certain of the potential effects any such actions may have on its business or operating and financial results for the fiscal year ending December 31, 2022.

The Company and its subsidiaries have followed all public health and safety guidelines to mitigate the impact of COVID-19. TransGlobe will continue to actively monitor the situation and may take further actions in the future.

See "*Risk Factors*".

Competitive Conditions

There is considerable competition in the worldwide oil and natural gas industry, including in Egypt and Canada where the Company's assets, activities, and employees are located. Operators more established than the Company, with access to broader technical skills, technology, larger amounts of capital and other resources, and are active in the industry in Egypt and Canada, where the Company has operations. This represents a significant risk for the Company, which must rely on modest resources as compared to some of its competitors. See "*Risk Factors - Competition*".

Environmental Protection

The Company operates under the jurisdiction of a number of regulatory bodies and agencies that set forth numerous prohibitions and requirements with respect to planning and approval processes related to land use, sustainable resource management, waste management, responsibility for the release of presumed hazardous materials, protection of wildlife and the environment, and the health and safety of workers. Legislation provides for restrictions and prohibitions on the transport of dangerous goods and the release or emission of various substances, including substances used and produced in association with certain oil and gas industry operations. The legislation addresses various permits, including for drilling, well completion, installation of surface equipment, air monitoring, surface and ground water monitoring in connection with these activities, waste management and access to remote or environmentally sensitive areas.

Historically, environmental protection requirements have not had a significant financial or operational effect on TransGlobe's capital expenditures, earnings or competitive position. Subject to any changes in current environmental protection legislation, or in the way the legislation is interpreted

in the jurisdictions in which it operates, TransGlobe does not presently anticipate environmental protection requirements will have a significant effect on such matters in 2022. The Company is exposed to potential environmental liability in connection with its business of oil and gas exploration and production. See "*Risk Factors*".

Social or Environmental Policies

The Company's RHSES Committee reviewed and approved fundamental policies pertaining to health, safety, environment and social responsibility which have the potential to impact the Company's activities and strategies. The RHSES Committee reported to the Board on TransGlobe's performance with respect to applicable laws, regulations and Company policies and also in respect to emerging trends, issues and regulations related to health, safety and environment. The RHSES Committee is comprised of a majority of independent directors and continues to report to the Board on TransGlobe's performance with respect to applicable laws, regulations and Company policies and also in respect to emerging trends, issues and regulations related to health, safety and environment.

TransGlobe acknowledges that investors, particularly large institutional investors, are seeking improved disclosure from the companies they invest in on the material risks, opportunities, financial impacts and governance processes related to climate change. TransGlobe is in the early stages of evaluating the impact of climate-change related risks on its business and strategy. In 2020, TransGlobe committed to initiate steps, commensurate with its size and available resources, to better understanding and assessing the materiality of these risks to its business, including the Board's oversight of climate-related risks and opportunities and management's role in assessing and managing climate-related risks and opportunities. In the Company's 2020 Annual Report, TransGlobe provided initial disclosures on its sustainability performance, including as it relates to climate change related risks. TransGlobe will continue to consider further disclosures in the future under existing standards, such as the Global Reporting Initiative Sustainability Reporting Standards, the Sustainability Accounting Standards Board's documentation, and recommendations issued by the Task Force for Climate Related Financial Disclosures. See *"Sustainability Report*" on pages 8 to 12 of the 2021 Annual Report, which is available on the Company's profile on SEDAR. The Company's disclosures are expected to evolve and mature as understanding, data analytics, and modeling of climate-related issues become more widespread. See "*Risk Factors – Climate Change*" for more details of certain climate change related risks that affect, and may in the future affect, TransGlobe's business.

Specialized Skill and Knowledge

TransGlobe employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial, accounting and business skills, which are widely available in the industry. Drawing on significant experience in the oil and gas business, TransGlobe 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; the ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows TransGlobe to effectively identify, evaluate and execute on its business plan.

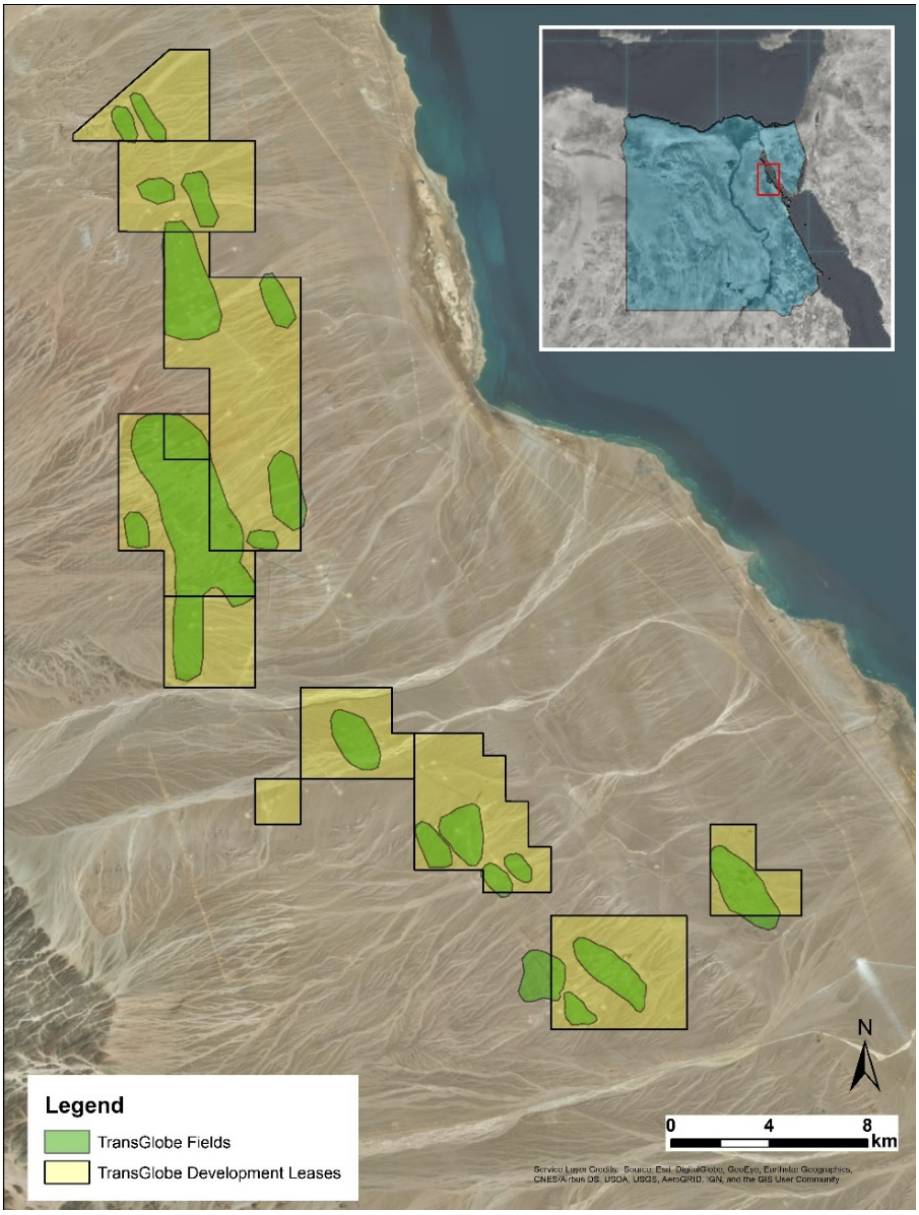
Cyclical and Seasonal Impact of Industry

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to fix netbacks on production volumes. See "*Statement of Reserves Data and other Oil and Gas Information - Other Oil and Gas Information - Forward Contracts*" for our current hedging program.

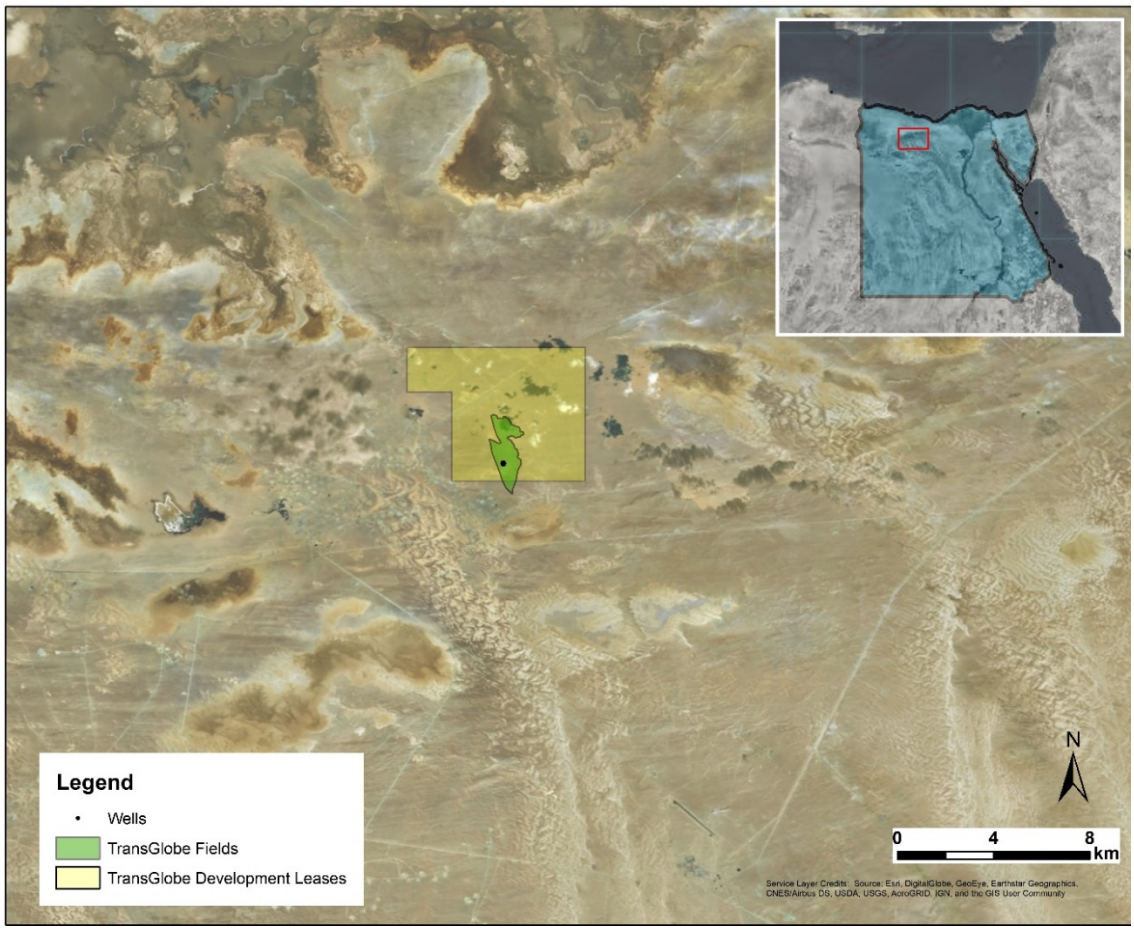
Egypt Business Unit

Summary of International Land Holdings as at December 31, 2021

Eastern Desert, Egypt



Western Desert, Egypt



Summary of Egypt PSC Terms

All of the Company's Egyptian blocks are PSCs between the host government and the contractor. The government takes their share of production based on the terms and conditions of the respective contracts. The contractors' share of all taxes and royalties are paid out of the government's share of production. TransGlobe is the contractor in all of its Egypt PSCs.

The PSCs provide for the government to receive a percentage gross royalty on the gross production. The remaining oil production, after deducting the gross royalty, if any, is split between cost sharing oil and production sharing oil. Cost sharing oil is up to a maximum percentage as defined in the specific PSC. Cost oil is assigned to recover approved operating and capital costs spent on the specific project. Unutilized cost sharing oil or excess cost oil (maximum cost recovery less actual cost recovery) is shared between the government and the contractor as defined in the specific PSCs. Each PSC is treated individually in respect of cost recovery and production sharing purposes. The remaining production sharing oil (total production less cost oil) is shared between the government and the contractor as defined in the specific PSCs. None of the Egyptian PSCs contain minimum production or sales requirements, and there are no restrictions with respect to pricing of the Company's sales volumes. Except as otherwise disclosed in this AIF, all crude oil sales are priced at current market rates at the time of sale.

As at December 31, 2021, TransGlobe's PSCs included West Gharib, West Bakr, NW Gharib and S Ghazalat. With the Merged Concession agreement fully executed on January 19, 2022, TransGlobe's PSCs include the Merged Concession and S Ghazalat as at March 17, 2022.

The following tables summarize the Company's international PSC terms for the first tranche(s) of production for each block. All of the contracts have different terms for production levels above the first tranche, which are unique to each contract. The government's share of production increases and the contractor's share of production decreases as the production volumes go to the next production tranche. TransGlobe is the operator of, and has a 100% working interest in, all PSCs.

EASTERN DESERT - GULF OF SUEZ BASIN - EGYPT

The tables below outline the Company's key concession terms.

	As at March 17, 2022	As at December 31, 2021		
Block	**Merged Concession**	**West Gharib**	**West Bakr**	**NW Gharib**
Year acquired	2020	2007	2011	2013
Block Area (acres)	45,067	22,725	11,143	11,199
Expiry date	2035	2024-2026	2025	2036-2037
Extensions				
Exploration	N/A	N/A	N/A	N/A
Development	+ 5 years	+ 5 years	N/A	+ 5 years
Production Tranche (MBopd)	0-25	0-5	0-50	0-5
Max. cost oil	40%	30%	30%	25%
Excess cost oil				
Contractor	15%	30%	0%	5%
Depreciation per quarter				
Operating	100%	100%	100%	100%
Capital	6%	6%	5%	5%
Production Sharing Oil:				
Contractor	30%*	30%	15%	15%
Government	70%*	70%	85%	85%

*Merged Concession profit oil is set on a scale according to average Brent price and production:

Brent Price ($/bbl)	Crude oil produced (MBopd)									
	Less than or equal to 5 MBopd		More than 5 MBopd and less than or equal to 10 MBopd		More than 10 MBopd and less than or equal to 15 MBopd		More than 15 MBopd and less than or equal to 25 MBopd		More than 25 MBopd	
	Government %	Contractor %	Government %	Contractor %	Government %	Contractor %	Government %	Contractor %	Government %	Contractor %
Less than or equal to $40/bbl	67	33	68	32	69	31	70	30	71	29
More than $40/bbl and less than or equal to $60/bbl	68	32	69	31	70	30	71	29	72	28
More than $60/bbl and less than or equal to $80/bbl	70	30	71	29	72	28	74	26	76	24
More than $80/bbl and less than or equal to $100/bbl	72.5	27.5	73	27	74	26	76	24	78	22
More than $100/bbl	75	25	76	24	77	23	78	22	80	20

WESTERN DESERT - WESTERN DESERT BASIN - EGYPT

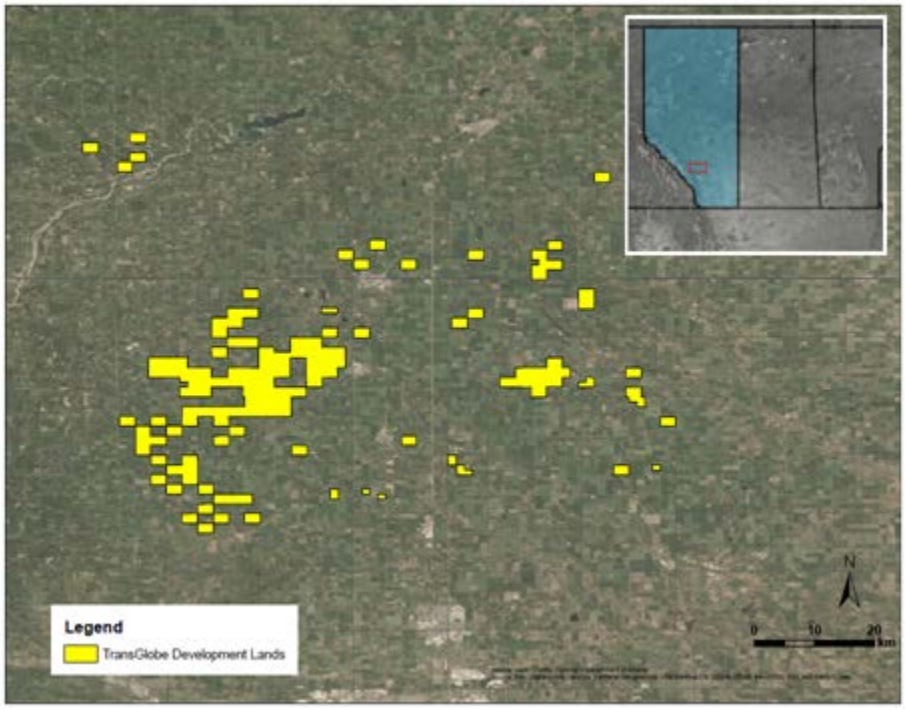
	As at December 31, 2021 and March 17, 2022
Block	**S Ghazalat**
Year acquired	2013
Block Area (acres)	7,340[1]
Expiry date	2039
Extensions	
Exploration	N/A
Development	20 + 5 years
Production Tranche (mbopd)	0-5
Max. cost oil	25%
Excess cost oil	
Contractor	5%
Depreciation per quarter	
Operating	100%
Capital	5%
Production Sharing Oil:	
Contractor	17%
Government	83%

The primary focus of the 2021 Egypt capital program was to maintain Eastern Desert production in anticipation of the approval of the Merged Concession agreement and its February 1, 2020 effective date while working to mature TransGlobe's contingent resource portfolio and continue evaluation of the South Ghazalat concession in the Western Desert. The Company drilled eight development wells and one exploration well in 2021. Seven development wells were drilled at West Bakr (HW-08, K-62, K-64, K-65, K-66, K-68, HE-2) and one well was drilled in North West Gharib (NWG-3B-2).

With improved oil prices and spare capacity available in the South Ghazalat early production facility, the Company accelerated drilling an oil exploration well on the SGZ-7B prospect to the east of SGZ-6X. The well has been suspended pending further evaluation of options to improve productivity on the lower Bahariya reservoir, and to assess the commercial potential of the gas-bearing upper Bahariya reservoir. This well fulfills the Company's commitment to EGPC as part of the South Ghazalat development lease approval in 2019.

Canada Business Unit

Alberta, Canada



The primary focus of the 2021 Canada capital program was developing South Harmattan with the goal of decreasing uncertainty across the northern portion of the South Harmattan property. In 2021, the Company completed the 2-mile horizontal South Harmattan well drilled in the first quarter of 2020. The Company also successfully drilled one 2-mile and two 1-mile horizontal wells in the northern area of the Cardium reservoir extension at South Harmattan, first identified by the 2-20 well in 2019. These three wells were successfully put on production in the fourth quarter of 2021.

2022 Outlook Highlights

- Production is expected to average between 12.4 and 13.4 Mboe/d in 2022 (mid-point of 12.9 Mboe/d);
- Egypt production is expected to average between 10.0 and 10.8 Mbbls/d in 2022 (mid-point of 10.4 Mbbls/d);
- Canada production is expected to average between 2.4 Mboe/d and 2.6 Mboe/d in 2022 (mid-point of 2.5 Mboe/d); and
- Exploration and development spending is budgeted to be $57.7 million (before capitalized G&A) and includes $33.1 million for Egypt and $24.6 million for Canada, to be funded from cash flow and working capital.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The report on reserves data in Form 51-101F2 and the report of management and directors on oil and gas disclosure in Form 51-101F3 are attached as Schedules "A" and "B", respectively, to this AIF, which forms are incorporated herein by reference.

The statement of reserves data and other oil and gas information set forth below is dated February 22, 2022, with the effective date being December 31, 2021.

Disclosure of Reserves Data

All of the Company's reserves herein reported were evaluated by GLJ, an independent reserves evaluator for the year ended December 31, 2021. In 2021, GLJ, independent petroleum engineering consultants based in Calgary, Alberta, were retained by the Company's RHSES Committee to independently evaluate 100% of TransGlobe's reserves as at December 31, 2021.

The reserves data set forth below (the "**Reserves Data**") is based upon the GLJ Report which is dated February 22, 2022 with an effective date of December 31, 2021. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The Company reports in U.S. currency and therefore the reports have been converted to U.S. dollars at the prevailing conversion rate at December 31 of the respective years. See "*Currency and Exchange Rates".* All of the Company's reserves are located in the province of Alberta, Canada and Egypt.

Based on the facts and circumstances existing as at the effective date of the GLJ Report, GLJ evaluated the Company's reserves based on the terms and conditions under the Merged Concession agreement.

The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Company believes is important to the readers of this information.

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

In general, estimates of economically recoverable crude 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 reserves recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies, and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude 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 may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with the Company's properties may vary from the information presented herein and such variations could be material. In addition, there is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material.

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

The information relating to the Company's reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs and anticipated production. See "*Forward-Looking Statements*" and "*Risk Factors*".

Possible reserves are those additional reserves that are less certain to be recovered than probable resources. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

SUMMARY OF OIL AND GAS RESERVES
TOTAL COMPANY
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	Light & Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total	
By Category	**Gross[1] (Mbbls)**	**Net[2] (Mbbls)**	**Gross[1] (Mbbls)**	**Net[2] (Mbbls)**	**Gross[1] (MMcf)**	**Net[2] (MMcf)**	**Gross[1] (Mbbls)**	**Net[2] (Mbbls)**	**Gross[1] (Mboe)**	**Net[2] (Mboe)**
Proved										
Developed Producing	3,029	2,305	12,596	8,798	12,270	10,433	2,222	1,768	19,891	14,609
Developed Non-Producing	409	281	2,560	1,580	569	523	22	18	3,086	1,966
Undeveloped	2,317	1,983	866	569	5,652	5,200	926	818	5,051	4,236
Total Proved	**5,755**	**4,569**	**16,022**	**10,947**	**18,491**	**16,156**	**3,170**	**2,604**	**28,028**	**20,811**
Probable	4,626	3,636	7,193	4,318	18,251	16,791	3,166	2,785	18,027	13,537
Proved+Probable	**10,381**	**8,205**	**23,215**	**15,265**	**36,742**	**32,947**	**6,336**	**5,389**	**46,055**	**34,348**
Possible	2,863	2,056	7,159	4,104	12,809	11,371	2,265	1,893	14,421	9,949
Proved+Probable+ Possible	**13,244**	**10,261**	**30,374**	**19,369**	**49,551**	**44,318**	**8,601**	**7,282**	**60,476**	**44,297**

[1] Gross reserves are the Company's working interest share before the deduction of royalties.

[2] Net reserves are the Company's working interest share after the deduction of royalties. Net reserves in Egypt include the Company's share of future cost recovery and production sharing oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, a portion of the reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices.

SUMMARY OF OIL AND GAS RESERVES
EGYPT
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	Light & Medium Crude Oil		Heavy Crude Oil		Total Bbls	
By Category	**Gross[1] (Mbbls)**	**Net[2] (Mbbls)**	**Gross[1] (Mbbls)**	**Net[2] (Mbbls)**	**Gross[1] (Mbbls)**	**Net[2] (Mbbls)**
Proved						
Developed Producing	1,513	971	12,596	8,798	14,109	9,769
Developed Non-Producing	336	212	2,560	1,580	2,896	1,792
Undeveloped	350	235	866	569	1,216	804
Total Proved	**2,199**	**1,418**	**16,022**	**10,947**	**18,221**	**12,365**
Probable	1,256	763	7,193	4,318	8,449	5,080
Proved+Probable	**3,455**	**2,181**	**23,215**	**15,265**	**26,670**	**17,445**
Possible	987	557	7,159	4,104	8,145	4,661
Proved+Probable+ Possible	**4,442**	**2,738**	**30,374**	**19,369**	**34,815**	**22,106**

[1] Gross reserves are the Company's working interest share before the deduction of royalties.

[2] Net reserves are the Company's working interest share after the deduction of royalties. Net reserves in Egypt include the Company's share of future cost recovery and production sharing oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, a portion of the reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices.

SUMMARY OF OIL AND GAS RESERVES
CANADA
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	Light & Medium Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total Bbls	
By Category	**Gross[1] (Mbbls)**	**Net[2] (Mbbls)**	**Gross[1] (MMcf)**	**Net[2] (MMcf)**	**Gross[1] (Mbbls)**	**Net[2] (Mbbls)**	**Gross[1] (Mboe)**	**Net[2] (Mboe)**
Proved								
Developed Producing	1,516	1,333	12,270	10,433	2,222	1,768	5,782	4,840
Developed Non-Producing	73	69	569	523	22	18	190	174
Undeveloped	1,967	1,748	5,652	5,200	926	818	3,835	3,432
Total Proved	**3,556**	**3,150**	**18,491**	**16,156**	**3,170**	**2,604**	**9,807**	**8,446**
Probable	3,371	2,873	18,251	16,791	3,166	2,785	9,578	8,457
Proved+Probable	**6,927**	**6,023**	**36,742**	**32,947**	**6,336**	**5,389**	**19,385**	**16,903**
Possible	1,876	1,499	12,809	11,371	2,265	1,893	6,276	5,288
Proved+Probable+ Possible	**8,803**	**7,522**	**49,551**	**44,318**	**8,601**	**7,282**	**25,661**	**22,191**

[1] Gross reserves are the Company's working interest share before the deduction of royalties.
[2] Net reserves are the Company's working interest share after the deduction of royalties.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE
TOTAL COMPANY
AS OF DECEMBER 31, 2021
(FORECAST PRICES & COSTS)

The estimated future net revenues presented in the tables below do not represent fair market value. The estimated future net revenues presented below are calculated using the price forecasts and inflation rates set forth below under "*Pricing Assumptions*".

US$	Before Income Tax[1] Discounted at %/yr					After Income Tax[1] Discounted at %/yr					Unit Value Before Tax (discounted at 10%/year)
$MM	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**($/Boe)**
Proved											
Developed Producing	340.8	291.9	257.8	232.5	212.9	340.8	291.9	257.8	232.5	212.9	17.65
Developed Non-Producing	34.1	30.0	26.5	23.7	21.3	34.1	30.0	26.5	23.7	21.3	13.50
Undeveloped	87.4	50.2	30.9	19.9	13.2	82.8	48.6	30.2	19.6	13.1	7.29
Total Proved	**462.3**	**372.2**	**315.2**	**276.1**	**247.4**	**457.7**	**370.5**	**314.6**	**275.8**	**247.3**	**15.15**
Probable	305.0	178.7	119.7	87.5	67.8	258.4	156.9	108.3	81.0	63.9	8.84
Proved+Probable	**767.3**	**550.8**	**435.0**	**363.6**	**315.2**	**716.1**	**527.4**	**422.9**	**356.8**	**311.2**	**12.66**
Possible	269.4	142.2	92.3	67.2	52.4	232.1	127.5	85.0	63.0	49.7	9.28
Proved+Probable+ Possible	**1,036.7**	**693.0**	**527.3**	**430.8**	**367.7**	**948.2**	**654.9**	**507.9**	**419.8**	**360.9**	**11.90**

[1] In Egypt, under the terms of the PSCs, income tax is current and assessed on all production sharing oil; therefore all Egypt future net revenues are after income tax.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE
EGYPT
AS OF DECEMBER 31, 2021
(FORECAST PRICES & COSTS)

US$	Before Income Tax[1] Discounted at %/yr					After Income Tax[1] Discounted at %/yr					Unit Value Before Tax (discounted at 10%/year)
$MM	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**($/Bbl)**
Developed Producing	242.7	215.1	194.2	177.7	164.4	242.7	215.1	194.2	177.7	164.4	19.88
Developed Non-Producing	30.4	27.0	24.1	21.6	19.5	30.4	27.0	24.1	21.6	19.5	13.42
Undeveloped	11.8	10.1	8.7	7.5	6.5	11.8	10.1	8.7	7.5	6.5	10.83
Total Proved	**284.9**	**252.2**	**226.9**	**206.8**	**190.4**	**284.9**	**252.2**	**226.9**	**206.8**	**190.4**	**18.35**
Probable	101.7	78.0	62.2	51.1	43.1	101.7	78.0	62.2	51.1	43.1	12.24
Proved+Probable	**386.6**	**330.2**	**289.1**	**257.9**	**233.6**	**386.6**	**330.2**	**289.1**	**257.9**	**233.6**	**16.57**
Possible	108.1	76.7	57.6	45.2	36.8	108.1	76.7	57.6	45.2	36.8	12.35
Proved+Probable+ Possible	**494.7**	**406.9**	**346.7**	**303.2**	**270.4**	**494.7**	**406.9**	**346.7**	**303.2**	**270.4**	**15.68**

[1] In Egypt, under the terms of the PSCs, income tax is current and assessed on all production sharing oil; therefore all Egypt future net revenues are after income tax.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE
CANADA
AS OF DECEMBER 31, 2021
(FORECAST PRICES & COSTS)

US$	Before Income Tax Discounted at %/yr					After Income Tax Discounted at %/yr					Unit Value Before Tax (discounted at 10%/year)
$MM	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**($/Boe)**
Proved											
Developed Producing	98.1	76.8	63.6	54.8	48.5	98.1	76.8	63.6	54.8	48.5	13.15
Developed Non-Producing	3.7	3.0	2.5	2.1	1.8	3.7	3.0	2.5	2.1	1.8	14.33
Undeveloped	75.6	40.1	22.2	12.4	6.7	71.0	38.4	21.5	12.1	6.6	6.47
Total Proved	**177.4**	**119.9**	**88.3**	**69.3**	**57.0**	**172.8**	**118.3**	**87.7**	**69.0**	**56.9**	**10.46**
Probable	203.3	100.7	57.5	36.4	24.7	156.7	78.9	46.1	29.8	20.7	6.80
Proved+Probable	**380.7**	**220.6**	**145.9**	**105.6**	**81.7**	**329.5**	**197.2**	**133.8**	**98.9**	**77.6**	**8.63**
Possible	161.4	65.5	34.8	22.0	15.6	124.0	50.8	27.4	17.7	12.9	6.57
Proved+Probable+ Possible	**542.0**	**286.1**	**180.6**	**127.7**	**97.2**	**453.5**	**248.0**	**161.2**	**116.6**	**90.5**	**8.14**

TOTAL FUTURE NET REVENUE[1]
(UNDISCOUNTED)
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

Reserves Category	Revenue (US$MM)	Royalties (US$MM)	Operating Costs[2] (US$MM)	Development Costs (US$MM)	Well Abandonment and Reclamation Costs[2] (US$MM)	Future Net Revenue Before Income Taxes[3] (US$MM)	Income Taxes[3] (US$MM)	Future Net Revenue After Income Taxes[3] (US$MM)
Proved Reserves								
Canada	400.9	51.9	114.4	47.3	9.9	177.4	4.6	172.8
Egypt	1,184.9	523.7	364.2	12.1	-	284.9	-	284.9
Total Company	**1,585.8**	**575.6**	**478.6**	**59.4**	**9.9**	**462.3**	**4.6**	**457.7**
Proved+Probable Reserves								
Canada	835.2	106.5	228.4	105.8	13.8	380.7	51.2	329.5
Egypt	1,751.3	813.7	530.1	21.0	-	386.6	-	386.6
Total Company	**2,586.5**	**920.1**	**758.5**	**126.7**	**13.8**	**767.3**	**51.2**	**716.1**
Proved+Probable+Possible Reserves								
Canada	1,141.4	158.1	310.3	115.2	15.8	542.0	88.5	453.5
Egypt	2,310.2	1,114.3	679.0	22.1	-	494.7	-	494.7
Total Company	**3,451.5**	**1,272.4**	**989.3**	**137.3**	**15.8**	**1,036.7**	**88.5**	**948.2**

1 Values are calculated by considering existing tax pools for the Company in the evaluation of the Company's properties and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see the Company's financial statements and management's discussion and analysis for the year ended December 31, 2021.

2 Please see "*Additional Information Concerning Abandonment and Reclamation Costs*" below.

3 In Egypt, under the terms of the PSCs, income tax is current and assessed on all production sharing oil; therefore all Egypt future net revenues are after income tax. Income taxes payable in Egypt have been recorded as Operating Costs for reporting purposes. In Canada, operating costs are net of processing and other income.

NET PRESENT VALUE OF FUTURE NET REVENUES
BY PRODUCT TYPE
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

Reserves Category	Product Type	Future Net Revenue Before Taxes[3,4] (discounted at 10%/year) (US$MM)	Unit Value Before Tax[3,4] (discounted at 10%/year) ($/Boe)
Total Proved	Light & Medium Crude Oil[1]	96.2	11.73
	Heavy Crude Oil[1]	208.0	19.08
	Conventional Natural Gas[2]	11.0	6.34
Proved+Probable	Light & Medium Crude Oil[1]	154.4	10.31
	Heavy Crude Oil[1]	265.4	17.45
	Conventional Natural Gas[2]	15.1	3.58
Proved+Probable +Possible	Light & Medium Crude Oil[1]	191.1	9.87
	Heavy Crude Oil[1]	316.7	16.16
	Conventional Natural Gas[2]	19.4	3.66

1 Including solution gas and other by-products.

2 Including by-products but excluding solution gas.

3 Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company net reserves.

4 In Egypt, under the terms of the PSCs, income tax is current and assessed on all production sharing oil; therefore all Egypt future net revenues are after income tax.

1. Columns may not add due to rounding.

2. The crude oil, NGLs and conventional natural gas reserves estimates presented in the Reserves Data are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

"**Development costs**" 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, to the extent necessary in developing the reserves;

(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.

"**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 (sometimes referred to as "prospecting" costs) 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 (sometimes referred to as "geological and geophysical costs");

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

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping Exploratory Wells; and

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

Reserves Categories

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

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

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

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(c) **Possible reserves** are those additional reserves that are even less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will be greater than the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5.4 of the COGE Handbook.

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

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

(b) **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.

(c) **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.

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

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

Levels of Certainty for Reported Reserves

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

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

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

(iii) at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A 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 Section 5 of the COGE Handbook.

Pricing Assumptions

Forecast Prices and Costs

The forecast cost and price assumptions assume changes in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

The forecast of prices, inflation and exchange rates utilized in the GLJ Report are provided in the table below and were computed using the average of the forecasts ("IQRE Average Forecast") of GLJ, McDaniel & Associates Consultants Ltd. and Sproule Associates Limited each dated January 1, 2022. The IQRE Average Forecast is dated January 1, 2022. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs.

Year	WTI Cushing Oklahoma (US$Bbl)	Edmonton Par Price 40 API (C$/Bbl)	Brent Reference Price (US$/Bbl)	AECO Gas Price (C$/MMBtu)	Ethane (C$/Bbl)	Propane (C$/Bbl)	Butane (C$/Bbl)	Pentane (C$/Bbl)	Inflation Rates % Year	Exchange Rate (C$/US$)
Forecast										
2022	72.83	86.82	75.33	3.56	11.48	43.39	57.49	91.85	—	0.80
2023	68.78	80.73	71.46	3.20	10.33	35.92	50.17	85.53	2.30	0.80
2024	66.76	78.01	69.62	3.05	9.81	34.62	48.53	82.98	2.00	0.80
2025	68.09	79.57	71.01	3.10	10.01	35.31	49.50	84.63	2.00	0.80
2026	69.45	81.16	72.44	3.17	10.22	36.02	50.49	86.33	2.00	0.80
2027	70.84	82.78	73.88	3.23	10.42	36.74	51.50	88.05	2.00	0.80
2028	72.26	84.44	75.36	3.30	10.64	37.47	52.53	89.82	2.00	0.80
2029	73.70	86.13	76.87	3.36	10.86	38.22	53.58	91.61	2.00	0.80
2030	75.18	87.85	78.40	3.43	11.08	38.99	54.65	93.44	2.00	0.80
2031	76.68	89.60	79.97	3.50	11.31	39.77	55.74	95.32	2.00	0.80
Thereafter	Escalate oil, gas and product prices at 2.0% per year thereafter								+2.0%/year	+0%/year

[1] Inflation rates for forecasting expenditure prices and costs.

The weighted average historical price in US$ realized by the Company in Egypt, for the year ended December 31, 2021 for crude oil was $62.92/bbl.

The weighted average historical price in US$ realized by the Company in Canada, for the year ended December 31, 2021 for crude oil and natural gas liquids was $65.87/bbl and $32.16/bbl, respectively, and for conventional natural gas was $2.93/Mcf.

RECONCILIATION OF GROSS RESERVES
BY PRODUCT TYPE
TOTAL COMPANY
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	LIGHT & MEDIUM CRUDE OIL			HEAVY CRUDE OIL		
FACTORS	**Gross Proved (MBbl)**	**Gross Probable (MBbl)**	**Gross Proved Plus Probable (MBbl)**	**Gross Proved (MBbl)**	**Gross Probable (MBbl)**	**Gross Proved Plus Probable (MBbl)**
December 31, 2020	4,766	3,875	8,641	12,284	9,063	21,347
Discoveries	-	-	-	-	-	-
Extensions and improved recovery	683	1,190	1,873	1,359	980	2,339
Technical Revisions	905	(478)	427	5,607	(3,269)	2,338
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	59	39	98	249	419	668
Production	(658)	-	(658)	(3,478)	-	(3,478)
December 31, 2021	**5,756**	**4,626**	**10,382**	**16,021**	**7,193**	**23,215**

	CONVENTIONAL NATURAL GAS			NATURAL GAS LIQUIDS		
FACTORS	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (MBbl)**	**Gross Probable (MBbl)**	**Gross Proved Plus Probable (MBbl)**
December 31, 2020	16,471	9,005	25,476	2,995	1,637	4,632
Discoveries	-	-	-	-	-	-
Extensions and improved recovery	1,916	8,968	10,884	358	1,677	2,035
Technical Revisions	1,056	(2,344)	(1,288)	(49)	(625)	(674)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	759	2,622	3,381	138	477	615
Production	(1,712)	-	(1,712)	(272)	-	(272)
December 31, 2021	**18,490**	**18,251**	**36,741**	**3,170**	**3,166**	**6,336**

RECONCILIATION OF GROSS RESERVES
BY PRODUCT TYPE
EGYPT
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	LIGHT & MEDIUM CRUDE OIL			HEAVY CRUDE OIL		
FACTORS	**Gross Proved (MBbl)**	**Gross Probable (MBbl)**	**Gross Proved Plus Probable (MBbl)**	**Gross Proved (MBbl)**	**Gross Probable (MBbl)**	**Gross Proved Plus Probable (MBbl)**
December 31, 2020	1,362	1,488	2,850	12,284	9,063	21,347
Discoveries	-	-	-	-	-	-
Extensions and improved recovery[1]	3	47	50	1,359	980	2,339
Technical Revisions[2]	1,188	(299)	888	5,607	(3,269)	2,338
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors[3]	30	20	50	249	419	668
Production	(383)	-	(383)	(3,478)	-	(3,478)
December 31, 2021	**2,200**	**1,256**	**3,455**	**16,021**	**7,193**	**23,215**

[1] For reporting under NI 51-101, reserves additions under "Extensions and Improved Recovery" include Infill Drilling, Improved Recovery and Extensions.
[2] Technical Revisions are primarily the result of production performance changes to existing wells.
[3] Attributed to pricing changes between year end 2020 and year end 2021.

RECONCILIATION OF GROSS RESERVES
BY PRODUCT TYPE
CANADA
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	LIGHT & MEDIUM CRUDE OIL			CONVENTIONAL NATURAL GAS		
FACTORS	**Gross Proved (MBbl)**	**Gross Probable (MBbl)**	**Gross Proved Plus Probable (MBbl)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**
December 31, 2020	3,404	2,387	5,791	16,471	9,005	25,476
Discoveries	-	-	-	-	-	-
Extensions and improved recovery[1]	679	1,144	1,823	1,916	8,968	10,884
Technical Revisions[2]	(282)	(178)	(461)	1,056	(2,344)	(1,288)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors[3]	30	18	48	759	2,622	3,381
Production	(275)	-	(275)	(1,712)	-	(1,712)
December 31, 2021	**3,556**	**3,371**	**6,926**	**18,490**	**18,251**	**36,741**

[1] For reporting under NI 51-101, reserves additions under "Extensions and Improved Recovery" include Infill Drilling, Improved Recovery and Extensions.
[2] Technical Revisions are primarily the result of production performance changes to existing wells.
[3] Attributed to pricing changes between year end 2020 and year end 2021.

	NATURAL GAS LIQUIDS		
FACTORS	**Gross Proved (MBbl)**	**Gross Probable (MBbl)**	**Gross Proved Plus Probable (MBbl)**
December 31, 2020	2,995	1,637	4,632
Discoveries	-	-	-
Extensions and improved recovery[1]	358	1,677	2,035
Technical Revisions[2]	(49)	(625)	(674)
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors[3]	138	477	615
Production	(272)	-	(272)
December 31, 2021	**3,170**	**3,166**	**6,336**

[1] For reporting under NI 51-101, reserves additions under "Extensions and Improved Recovery" include Infill Drilling, Improved Recovery and Extensions.
[2] Technical Revisions are primarily the result of production performance changes to existing wells.
[3] Attributed to pricing changes between year end 2020 and year end 2021.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under the COGE Handbook. In general, undeveloped reserves are planned to be developed over the next two years.

In some cases, it will take longer than two years to develop these 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*" herein.

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to the Company in the most recent three financial years.

Proved Undeveloped Reserves

Year	Light & Medium Crude Oil (MBbl)		Heavy Crude Oil (MBbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2019	327	1,901	383	1,296	920	4,689	162	822
2020	—	2,027	899	1,791	—	5,109	—	929
2021	336	2,317	200	866	946	5,652	177	926

[1] In 2019, proved undeveloped reserves were assigned to Egypt's West Bakr development program and Canada's Cardium development program.
[2] In 2020, proved undeveloped reserves were assigned to Egypt's West Bakr development program.
[3] In 2021, proved undeveloped reserves were assigned to Egypt's West Bakr development program and Canada's Cardium Development program.

A total of 5.7 Bcf of conventional natural gas, 2.3 MMbbl of light crude oil and medium crude oil, 1.8 MMbbl of heavy crude oil and 0.9 MMbbl of NGLs were assigned in the GLJ Report under forecast prices and costs as gross proved undeveloped reserves as at December 31, 2021, representing approximately 18% of total proved reserves, together with $59.3 million of associated undiscounted future capital expenditures. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by offset well data.

The Company plans to develop five percent of its proved undeveloped reserves over the next two years. These reserves are attributed to the Company's Harmattan property in Canada and PetroBakr Concession in Egypt. The remaining proved undeveloped reserves will be developed between 2022 and 2024 deferred due to the land retention requirements in Harmattan in Canada and higher-priority opportunities in Egypt. Although TransGlobe expects the development of the proved undeveloped reserves attributed to the Company's assets to be consistent with that set out above, current industry conditions and other uncertainties as discussed under "*Risk Factors*" and "*Canadian Industry Conditions*" herein could result in development of such proved undeveloped reserves on a different schedule than set out above.

Probable Undeveloped Reserves

Year	Light & Medium Crude Oil (MBbl)		Heavy Crude Oil (MBbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2019	510	2,610	150	2,301	1,447	14,587	255	2,255
2020	—	2,069	498	2,378	—	4,949	—	900
2021	1,032	2,977	780	1,242	2,909	13,815	544	2,382

[1] In 2019, probable undeveloped reserves were assigned to Egypt's West Bakr development program and Canada's Cardium development program.
[2] In 2020, probable undeveloped reserves were assigned to Egypt's West Bakr development program.
[3] In 2021, probable undeveloped reserves were assigned to Egypt's West Bakr development program and Canada's Cardium development program.

A total of 13.8 Bcf of conventional natural gas, 3.0 MMbbl of light crude oil and medium crude oil, 1.2 MMbbl of heavy crude oil and 2.4 MMbbl of NGLs were assigned in the GLJ Report under forecast prices and costs as gross probable undeveloped reserves as at December 31, 2021, representing approximately 49% of total probable reserves, together with $126.7 million of associated undiscounted future capital expenditures. The probable undeveloped reserves are generally associated with infill/development drilling locations supported by offset well data.

The Company's probable undeveloped reserves are attributed to Harmattan in Canada and the PetroBakr Concession in Egypt. The Company's probable undeveloped reserves are scheduled to be developed over the next seven years scheduled to maximize the processing capacity at the Company's Harmattan 12-18-031-02W5M battery and the Company's Harmattan 09-05-031-02W5M compressor station in Canada and higher-priority opportunities in Egypt. Approximately ten per cent of the Company's probable undeveloped reserves will be developed over the next two years. Although TransGlobe expects the development of the probable undeveloped reserves attributed to the Company's assets to be consistent with that set out above, current industry conditions and other uncertainties as discussed under "*Risk Factors*" and "*Canadian Industry Conditions*" herein could result in development of such probable undeveloped reserves on a different schedule than set out above.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; (viii) unexpected or unusually high abandonment and reclamation costs; (ix) unusually high development costs; (x) unusually high operating costs; (xi) contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations; (xii) ratification by the Egyptian Parliament of the Merged Concession on December 21, 2021; (xiii) imminent execution of the Merged Concession agreement by the agreement parties; and (ix) other government levies imposed over the life of the reserves. Although every reasonable effort is made to ensure that reserves estimates are accurate, reserves estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserves estimates can arise from changes in year-end prices, commodity prices, reservoir performance, governmental restrictions, economic conditions, geologic conditions or production. These revisions can be either positive or negative. See "*Risk Factors*".

Changes in future commodity prices relative to the forecasts described above under "*Pricing Assumptions*" could have a negative impact on the reserves associated with the Company's assets, and in particular on the development of undeveloped reserves, unless future development costs are adjusted in parallel. The Company's assets include a significant amount of proved and probable undeveloped reserves. At the forecast prices and costs used in the GLJ Report, these development activities are expected to be economic. However, should oil and natural gas prices decrease materially, these activities may need to be deferred to ensuing years to remain economic or may not be pursued at all. Other than the foregoing and the factors disclosed or described herein, the Company does not anticipate any other significant economic factors or other significant uncertainties which may affect any particular components of the reserves data in respect of the Company's assets.

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to: (i) proved reserves (in total) estimated using forecast prices and costs; and (ii) proved plus probable reserves (in total) estimated using forecast prices and costs.

Future Development Costs

FUTURE DEVELOPMENT COSTS
TOTAL COMPANY
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	Forecast Prices and Costs	
Year	**Proved Reserves (US$MM)**	**Proved Plus Probable Reserves (US$MM)**
2022	6.5	16.0
2023	5.9	14.1
2024	17.8	28.9
2025	16.5	16.5
2026	12.7	12.7
Remaining	-	38.5
Total Undiscounted	**59.4**	**126.7**
Discounted @ 10%	**45.0**	**90.6**

To fund its capital program, including future development costs, the Company will consider various financing alternatives, including retention of funds from operations, debt financing and issuance of additional Common Shares and other securities. The Company will evaluate the appropriate financing alternatives closely and make use of such options dependent on the given investment situation and the capital markets. If cash flows are other than projected, capital expenditure levels may be adjusted. In addition, depending on a number of factors including commodity prices, industry conditions and the Company's financial and operating results, funds from credit facilities and equity financings may not be available on terms acceptable to the Company, which could also result in adjustments to the capital program as required. There can be no guarantee that funds will be available or that the Company will be able to allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to reserves.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Company does not anticipate that interest or other funding costs would make further development of the Company's assets uneconomic. See "*Significant Factors or Uncertainties Affecting Reserves Data*".

FUTURE DEVELOPMENT COSTS
EGYPT
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	Forecast Prices and Costs	
Year	Proved Reserves (US$MM)	Proved Plus Probable Reserves (US$MM)
2022	6.5	13.1
2023	2.9	5.2
2024	2.7	2.7
2025	-	-
2026	-	-
Remaining	-	-
Total Undiscounted	**12.1**	**21.0**
Discounted @ 10%	**10.9**	**19.3**

FUTURE DEVELOPMENT COSTS
CANADA
AS OF DECEMBER 31, 2021
(FORECAST PRICES AND COSTS)

	Forecast Prices and Costs	
Year	**Proved Reserves (US$MM)**	**Proved Plus Probable Reserves (US$MM)**
2022	-	2.9
2023	3.0	8.9
2024	15.1	26.3
2025	16.5	16.5
2026	12.7	12.7
Remaining	-	38.5
Total Undiscounted	**47.3**	**105.8**
Discounted @ 10%	**34.1**	**71.3**

Other Oil and Gas Information

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company has a working interest as at December 31, 2021. All of the Company's wells are located onshore.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Egypt	100.0	99.7	129.0	128.8	-	-	-	-
Canada	63.0	60.4	21.0	14.7	60.0	56.1	16.0	10.3
Total	**163.0**	**160.1**	**150.0**	**143.5**	**60.0**	**56.1**	**16.0**	**10.3**

[1] Non-producing wells include wells which are capable of producing, but which are currently not producing, and are re-evaluated with respect to future commodity prices, proximity to facility infrastructure, design of future exploration and development programs, and access to capital.

Properties with No Attributed Reserves

The following table sets out the Company's developed and undeveloped land holdings as at December 31, 2021.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Egypt	25,035	25,035	-	-	25,035	25,035
Canada	10,290	8,549	32,492	29,347	42,782	37,896
Total	**35,325**	**33,584**	**32,492**	**29,347**	**67,817**	**62,931**

Commitments

Pursuant to the approved S Ghazalat development lease, the Company was committed to drilling one exploration well during the initial four year period of the 20 year development lease. The Company issued a production guarantee in the amount of $1.0 million which was met when the commitment well (SGZ-7B) was drilled.

Development of properties with no attributable reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" and "*Canadian Industry Conditions*" herein. In addition, the Company expects that funding of development operations on such properties will be evaluated in the context of the Company's total capital requirements having regard to rates of return, the likelihood of success and risked return versus cost of capital, and availability and reliability of methods of hydrocarbon delivery.

Development of the Company's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" herein. In addition, we expect that funding of development operations on such properties will be evaluated in the context of our total capital requirements having regard to rates of return, the likelihood of success and risked return versus cost of capital, and availability and reliability of methods of hydrocarbon delivery.

Forward Contracts

In conjunction with the Company's RBL facility with ATB, renewed effective June 4, 2021, the Company is required to enter into hedging arrangements based on its debt utilization. If utilization is below 50%, TransGlobe is required to hedge 25% of its annual forecasted average daily Canadian production of oil and natural gas volumes (net of royalties); utilization of between 50%-69% requires a hedge of 50%; and utilization of 70% and above requires a hedge of 60%.

Subject to the Company's Hedging Policy, TransGlobe uses hedging arrangements from time to time as part of its risk management strategy to manage commodity price fluctuations and stabilize cash flows for future exploration and development programs. The hedging program is actively monitored and adjusted as deemed necessary to protect the cash flows from the risk of commodity price exposure.

The nature of TransGlobe's operations exposes it to fluctuations in commodity prices, interest rates and foreign currency exchange rates. TransGlobe monitors and, when appropriate, uses derivative financial instruments to manage its exposure to these fluctuations. All transactions of this nature entered into by TransGlobe are related to an underlying financial position or to future crude oil and natural gas production. TransGlobe does not use derivative financial instruments for speculative purposes. TransGlobe has elected not to designate any of its derivative financial instruments as accounting hedges and thus accounts for changes in fair value in net earnings at each reporting period. TransGlobe has not obtained collateral or other security to support its financial derivatives as management reviews the creditworthiness of its counterparties prior to entering into derivative contracts. The derivative financial instruments are initiated within the guidelines of the Company's Hedging Policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions.

Refer to the annual Consolidated Financial Statements for our commitments under all hedging agreements as at December 31, 2021.

Additional Information Concerning Abandonment and Reclamation Costs

In Egypt, estimated future abandonment and reclamations costs related to properties evaluated have not been taken into account by GLJ. Under model concession agreements, the Merged Concession agreement and the Fuel Material Law, liabilities in respect of decommissioning movable and immovable assets (other than wells) passes to the Egyptian Government through the transfer of ownership from the contractor to the government under the cost recovery process. While the current risk to the Company of becoming liable for decommissioning liabilities in Egypt is low, future changes to legislation could result in decommissioning liabilities in Egypt. Any increase in Egyptian decommissioning liabilities could adversely affect the Company's financial condition.

In relation to petroleum wells, under good oilfield practices, the contractor is responsible for decommissioning non-producing wells under a decommissioning plan approved by EGPC during the life of the concession agreement. If EGPC agrees that a producing well is not economic, then the contractor will be responsible for decommissioning the well under an EGPC approved decommissioning plan. EGPC, at its own discretion, may not require a well to be decommissioned if it wants to preserve the ability to use the well for other purposes. As EGPC has discretion on decommissioning wells, there is a risk that the Company could incur well decommissioning costs. In accordance with the respective concession agreements, expenses approved by EGPC are recoverable through the cost recovery mechanism. Therefore the future abandonment and reclamation costs have been assessed a zero value.

In connection with the Company's Canadian operations, the Company will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The expected total reserve well abandonment and reclamation costs, net of estimated salvage value, included in the GLJ Report for the 126.8 net wells under the proved reserves category is $9.9 million undiscounted, of which a total of $0.1 million is estimated to be incurred through 2022. These estimates include costs for all wells with reserves assigned.

Tax Horizon

In 2021, the Company did not pay any income taxes in Canada and does not anticipate any taxes payable in the near future. In Egypt, the Company's income tax liabilities are paid out of the government's share of production. As such, all current income tax liabilities in Egypt are settled immediately as they become due.

Capital Expenditures

The following table summarizes the capital expenditures (including capitalized general and administrative expenses) related to the Company's activities for the year ended December 31, 2021:

	Egypt	Canada	Total
(US$MM)			
Exploration costs	2.1	-	2.1
Development costs	12.4	12.2	24.6
Corporate and other	0.1	-	0.1
Capital expenditures[1]	**14.6**	**12.2**	**26.8**

[1] Non-GAAP financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies. Refer to "*Non-GAAP and Other Financial Measures*" contained within this AIF.

The Company did not incur any capital expenditures related to the acquisition of proved or unproved properties in the year ended December 31, 2021.

Exploration and Development Activities

The following tables set forth the gross and net exploratory and development wells which the Company drilled in Egypt and Canada during the year ended December 31, 2021:

Egypt	**Gross**			**Net**		
	Exploration	**Development**	**Total**	**Exploration**	**Development**	**Total**
Crude Oil	1.0	8.0	9.0	1.0	8.0	9.0
Total	**1.0**	**8.0**	**9.0**	**1.0**	**8.0**	**9.0**

Canada	**Gross**			**Net**		
	Exploration	**Development**	**Total**	**Exploration**	**Development**	**Total**
Crude Oil	-	3.0	3.0	-	3.0	3.0
Total	**-**	**3.0**	**3.0**	**-**	**3.0**	**3.0**

[1] The Company did not complete any gas wells, service wells, stratigraphic test wells or dry holes in the year ended December 31, 2021.

Development activities in 2021 were focused on the West Gharib, West Bakr and NW Gharib concessions in Egypt, and the Harmattan area in Canada. Exploration activities in 2021 were focused on the S Ghazalat concession in Egypt.

Production Estimates

The following table sets out the volume of the Company's daily production (working interest before royalties) estimated for the year ending December 31, 2022 by GLJ which is reflected in the estimate of future net revenue (Forecast Price Case) disclosed in the prior reserves summary tables.

	Egypt		**Canada**			**Total**
	Light & Medium Crude Oil	**Heavy Crude Oil**	**Light & Medium Crude Oil**	**Conventional Natural Gas**	**Natural Gas Liquids**	**Company**
	Gross (Bbls/d)	**Gross (Bbls/d)**	**Gross (Bbls/d)**	**Gross (Mcf/d)**	**Gross (Bbls/d)**	**Gross (Boe/d)**
Proved Developed Producing	781	8,578	646	4,637	832	11,609
Proved Developed Non-Producing	-	446	11	181	7	494
Proved Undeveloped	-	547	-	-	-	547
Total Proved	781	9,571	657	4,818	839	12,651
Total Probable	70	1,194	141	113	20	1,444
Total Proved Plus Probable	**852**	**10,765**	**798**	**4,931**	**859**	**14,096**

The following tables set out the volume of the Company's daily production (working interest before royalties) estimated for the year ending December 31, 2022 for the Company's fields that account for 20% or more of the of the estimated production by country disclosed above.

	Egypt							
	S Ghazalat	K-Field	Arta	H-Field	Other fields		Total	
	Light & Medium Crude Oil	Heavy Crude Oil	Heavy Crude Oil	Heavy Crude Oil	Light & Medium Crude Oil	Heavy Crude Oil	Light & Medium Crude Oil	Heavy Crude Oil
	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Bbls/d)
Proved Developed Producing	220	3,125	2,003	1,757	561	1,692	781	8,578
Proved Developed Non-Producing	-	237	-	133	-	75	-	446
Proved Undeveloped	-	398	149	0	-	0	-	547
Total Proved	220	3,761	2,152	1,891	561	1,768	781	9,571
Total Probable	-	880	86	126	70	102	70	1,194
Total Proved Plus Probable	**220**	**4,641**	**2,238**	**2,016**	**632**	**1,870**	**852**	**10,765**

	Canada			
	Harmattan			Total
	Light & Medium Crude Oil	Conventional Natural Gas	Natural Gas Liquids	Canada
	Gross (Bbls/d)	Gross (Mcf/d)	Gross (Bbls/d)	Gross (Boe/d)
Proved Developed Producing	646	4,637	832	2,251
Proved Developed Non-Producing	11	181	7	48
Proved Undeveloped	-	-	-	-
Total Proved	657	4,818	839	2,299
Total Probable	141	113	20	180
Total Proved Plus Probable	**798**	**4,931**	**859**	**2,479**

Production History

The following table summarizes certain information in respect of sales volumes, product prices received, royalties paid, operating expenses and resulting netbacks made by the Company (and its subsidiaries) for the periods indicated:

	2021			
	Quarter Ended			
	Mar. 31	Jun. 30	Sep. 30	Dec. 31
Average Daily Production Volumes[9]				
Egypt[1]				
Heavy Crude Oil (Bbls/d)	9,419	9,736	10,014	8,942
Light & Medium Crude Oil (Bbls/d)	819	992	1,261	1,123
Canada[2]				
Light & Medium Crude Oil (Bbls/d)	564	687	601	1,176
Conventional Natural Gas (Boe/d)	710	805	789	806
Natural Gas Liquids (Bbls/d)	709	857	677	716
Consolidated (Boe/d)	***12,221***	***13,077***	***13,342***	***12,763***
Average Daily Sales Volumes[9]				
Egypt				
Heavy Crude Oil (Bbls/d)	7,091	12,881	11,369	8,942
Light & Medium Crude Oil (Bbls/d)	617	1,312	1,432	1,123
Canada				
Light & Medium Crude Oil (Bbls/d)	564	687	601	1,176
Conventional Natural Gas (Boe/d)	710	805	789	806
Natural Gas Liquids (Bbls/d)	709	857	677	716
Consolidated (Boe/d)	***9,691***	***16,542***	***14,868***	***12,763***
Average Realized Sales Prices[9]				
Egypt[1]				
Heavy Crude Oil (US$/Bbl)	53.31	60.27	64.73	71.50
Light & Medium Crude Oil (US$/Bbl)	53.31	60.27	64.73	71.50
Canada				
Light & Medium Crude Oil (US$/Bbl)	52.66	63.05	65.43	65.87
Conventional Natural Gas (US$/Mcf)	2.46	2.59	2.71	2.93
Natural Gas Liquids (US$/Bbl)	26.42	27.03	35.40	32.16
Consolidated (US$/Boe)	**48.47**	**56.48**	**60.85**	**66.95**
Royalties and Current Taxes[9]				
Egypt[1]				
Heavy Crude Oil (US$/Bbl)	40.58	29.77	38.95	42.92
Light & Medium Crude Oil (US$/Bbl)	40.58	29.77	38.95	42.92
Canada				
Light & Medium Crude Oil (US$/Bbl)	4.15	7.38	6.02	6.42
Conventional Natural Gas (US$/Mcf)	0.69	1.23	1.00	1.07
Natural Gas Liquids (US$/Bbl)	4.15	7.38	6.02	6.42
Consolidated (US$/Bbl)	**33.11**	**26.59**	**34.37**	**35.21**
Production and Operating Expenses[9]				
Egypt[1]				
Heavy Crude Oil (US$/Bbl)	11.43	13.87	12.64	14.74
Light & Medium Crude Oil (US$/Bbl)	11.43	13.87	12.64	14.74
Canada[4,5,6]				
Light & Medium Crude Oil (US$/Bbl)	8.52	8.43	9.78	7.53
Conventional Natural Gas (US$/Mcf)	1.42	1.41	1.63	1.26
Natural Gas Liquids (US$/Bbl)	8.52	8.43	9.78	7.53
Consolidated (US$/Bbl)	**10.83**	**13.10**	**12.24**	**13.22**
Selling Costs[9]				
Egypt[1]				
Heavy Crude Oil (US$/Bbl)	0.05	1.29	1.03	0.05
Light & Medium Crude Oil (US$/Bbl)	0.05	1.29	1.03	0.05
Canada				
Light & Medium Crude Oil (US$/Bbl)	—	—	—	—
Conventional Natural Gas (US$/Mcf)	—	—	—	—
Natural Gas Liquids (US$/Bbl)	—	—	—	—
Consolidated (US$/Bbl)	**0.05**	**1.29**	**1.03**	**0.05**
Netback[10]				
Egypt[1]				
Heavy Crude Oil (US$/Bbl)	1.25	15.34	11.31	13.77
Light & Medium Crude Oil (US$/Bbl)	1.25	15.34	11.31	13.77
Canada[7, 8]				
Light & Medium Crude Oil (US$/Bbl)	17.03	17.80	21.02	36.03
Conventional Natural Gas (US$/Mcf)	2.84	2.97	3.50	6.01
Natural Gas Liquids (US$/Bbl)	17.03	17.80	21.02	36.03
Consolidated (US$/Bbl)	**4.49**	**15.68**	**12.66**	**18.47**

[1] All production from West Gharib, West Bakr, NW Gharib is sold as a blended crude oil. Royalties and taxes are calculated on a concession basis without distinction between Heavy Crude Oil and Light & Medium Crude Oil.

[2] Includes minor royalty volumes received but does not deduct royalty volumes paid.

[3] The Company directly markets its share of entitlement oil from the West Gharib, West Bakr and NW Gharib concessions. Reported sales volumes fluctuate quarter to quarter depending on the timing of liftings. Under-lifted entitlement oil is held and booked as inventory. At year-end 2021, the Company's entitlement inventory was nil.

[4] Includes solution gas and by-products.

[5] Operating costs have been allocated to each product type based on proportionate revenue splits and other reasonable methods of allocation.

[6] Operating costs include all costs related to the operation of wells, facilities and gathering systems, transportation and NGLs processing.

[7] Includes NGLs.

[8] Average prices received, royalties, operating costs and netbacks have not been provided separately for NGLs as they have been included with the amounts stated above for conventional natural gas, as conventional natural gas is the primary revenue stream.

[9] Supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies. Refer to "*Non-GAAP and Other Financial Measures*" contained within this AIF.

[10] Non-GAAP ratio that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies. Refer to "*Non-GAAP and Other Financial Measures*" contained within this AIF.

The following table indicates the Company's average daily volumes from its important fields for the year ended December 31, 2021:

	Heavy Crude Oil	Light & Medium Crude Oil	Conventional Natural Gas	Natural Gas Liquids	Total
	(Bbls/d)	(Bbls/d)	(Mcf/d)	(Bbls/d)	(Boe/d)
Egypt					
West Gharib	2,349	570	-	-	2,919
West Bakr	6,703	-	-	-	6,703
NW Gharib	476	-	-	-	476
S Ghazalat	-	480	-	-	480
Canada	-	758	4,667	740	2,276
Total	**7,180**	**1,238**	**4,667**	**740**	**12,854**

DIVIDEND POLICY

On March 16, 2022, the Board amended the Company's dividend policy. TransGlobe's dividend policy is to return capital to shareholders through dividend payments targeting a minimum of 75% of free cash flow. For these purposes, free cash flow is defined as net cash generated by operating activities less capital expenditures and debt repayments, calculated on an annual basis. The assessment to pay a dividend will be done semi-annually. The declaration and payment of future dividends is subject to the sole discretion of the Board and may vary dependent upon a number of factors, including: commodity price volatility and outlook, production levels, share buyback programs, working capital management, compliance with any restrictions on the payment of dividends contained in any agreements and/or legislation that the Company is subject to, foreign exchange movements, operating costs, capital expenditures, royalties, and taxes. Dependent upon the foregoing and other factors deemed relevant by the Board and management of the Company to the declaration and payment of dividends, the Company may change its dividend policy at any time. The Board will evaluate its decision on future dividend payments on a semi-annual basis going forward. Dividends are not guaranteed. Any reduction of dividends may have an adverse effect on the market price of the Company's Common Shares. See "*Risk Factors*".

During the year ended December 31, 2019 the Company paid the following dividends on its Common Shares.

Ex-dividend date	Record date	Payment date	Per share amount
March 28, 2019	March 29, 2019	April 18, 2019	$0.035
August 30, 2019	August 31, 2019	September 13, 2019	$0.035

There were no dividends paid in the years ended December 31, 2020 and December 31, 2021.

Subsequent to year end, the Board approved a dividend payment to shareholders of $0.10 per Common Share, payable on May 12, 2022 to shareholders of record on April 29, 2022. The ex-dividend date is April 28, 2022.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

TransGlobe is authorized to issue an unlimited number of Common Shares without nominal or par value. As at March 17, 2022 there were 72,774,830 Common Shares issued and outstanding.

Each Common Share entitles its holder to: (i) vote at any meeting of Shareholders of the Company; (ii) to receive any dividend declared by the Company; and (iii) to receive the remaining property of the Company upon dissolution.

The Company's articles have been filed in accordance with NI 51-102 and are available on the Company's SEDAR profile at www.sedar.com and the Company's EDGAR profile at www.sec.gov.

MARKET FOR SECURITIES

TransGlobe's Common Shares trade on the TSX and the AIM under the symbol TGL and on the Nasdaq under the symbol TGA.

Common Shares

The following table sets out the monthly high and low closing prices and the total monthly trading volumes for the Common Shares on the Nasdaq for the indicated periods:

(U.S. dollars, except volumes)	Price Range		
	High ($/share)	Low ($/share)	Volume
2021			
January	1.18	0.91	10,061,976
February	1.58	1.10	11,222,773
March	1.81	1.46	9,103,484
April	1.65	1.45	4,081,867
May	1.79	1.49	5,116,396
June	2.16	1.78	10,188,731
July	2.00	1.59	4,929,024
August	1.82	1.55	3,904,885
September	2.19	1.78	5,000,985
October	3.19	2.28	17,897,590
November	3.39	2.49	17,819,413
December	3.10	2.55	9,916,428
2022			
January	3.35	2.76	14,557,550
February	3.90	2.76	11,575,811
March (1 to 16)	4.09	3.32	12,157,614

The following table sets out the monthly high and low closing prices and the total monthly trading volumes for the Common Shares on the TSX for the indicated periods:

(Canadian dollars, except volumes)	Price Range		
	High (C$/share)	Low (C$/share)	Volume
2021			
January	1.49	1.16	2,004,570
February	1.95	1.40	1,973,236
March	2.27	1.82	2,265,631
April	2.02	1.82	965,696
May	2.14	1.82	1,387,650
June	2.63	2.15	1,762,352
July	2.42	2.00	1,025,545
August	2.30	1.96	686,851
September	2.77	2.26	862,581
October	3.94	2.86	1,836,063
November	4.26	3.12	1,988,572
December	3.94	3.30	1,000,351
2022			
January	4.19	3.53	1,006,255
February	4.94	4.01	852,970
March (1 to 16)	5.25	4.26	758,166

The following table sets out the monthly high and low closing prices and the total monthly trading volumes for the Common Shares on the AIM for the indicated periods:

(British pound sterling, except volumes)	Price Range		
	High (£/share)	Low (£/share)	Volume
2021			
January	0.90	0.75	260,814
February	1.03	0.79	166,884
March	1.25	1.03	75,634
April	1.24	1.11	28,747
May	1.23	1.11	47,168
June	1.48	1.24	60,335
July	1.44	1.20	55,671
August	1.26	1.15	54,780
September	1.58	1.26	124,597
October	2.23	1.63	98,314
November	2.55	1.89	135,241
December	2.25	1.98	57,120
2022			
January	2.42	2.04	80,515
February	2.70	0.02	38,093
March (1 to 16)	3.14	2.52	47,853

PRIOR SALES

The following table summarizes the issuance of stock options, which are convertible into Common Shares, during the year ended December 31, 2021:

Date of Issuance	Number of Stock Options	Weighted Average Exercise Price per Stock Option
March 19, 2021	402,115	C$2.16

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

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

DIRECTORS AND OFFICERS

The name and place of residence of each director and officer, the offices held by each in the Company, the principal occupation of each director and officer, the period served as director or officer and the aggregate number of securities of the Company owned by such individuals as at March 17, 2022 is set as below:

Name and Place of Residence	Position Held	Year Became Director or Officer	Principal Occupation and Positions for the Past Five Years
David B. Cook Texas, U.S.	Chairman of the Board and Director	2014	Mr. Cook is a corporate director. Mr. Cook was the Chief Executive Officer of Noreco (Norwegian Energy Company) until November, 2021. Prior thereto, he held the position of Chief Executive Officer of INEOS DeNoS, located in London, UK having taken that role following the sale of DONG Oil and Gas (part of the DONG Energy group, now Orsted) to INEOS on September 29, 2017, where he was also CEO. He has more than 25 years' experience in the energy business having held senior positions at INEOS, DONG, the Abu Dhabi National Energy Company PJSC ("TAQA"), BP, TNK-BP and Amoco including serving as Executive Officer and Head of Oil and Gas at TAQA and prior to joining TAQA, as Vice President for BP Russia.
Randy C. Neely [2] London, England	President, Chief Executive Officer and Director	2012	Mr. Neely was appointed President and Chief Executive Officer of the Company in January 2019 and to the Board of Directors in May 2018. He was previously appointed as President in January 2018 and Vice President, Finance and Chief Financial Officer in May 2012. Mr. Neely has 25 years of experience in executive and financial roles, including Chief Financial Officer of Zodiac Exploration, Pearl (Blackpearl) Exploration & Production and Trident Exploration. Prior to working directly in the oil and gas industry, Mr. Neely spent three and a half years in investment banking with TD Securities and eight years with KPMG LLP.
Jennifer Ann Kaufield Alberta, Canada[3]	Director	2022	Ms. Kaufield was appointed to the Board on January 1, 2022. Ms. Kaufield is an independent businesswoman with over 30 years of experience in private and public corporations both domestic and international. Ms. Kaufield was previously Chief Financial Officer of Titanium Corporation Inc.
Ross G. Clarkson [5] British Columbia, Canada	Director	1995	Mr. Clarkson is a corporate director. Mr. Clarkson was appointed to the Board in October of 1995 and served as President and Chief Executive Officer until January 2018. Mr. Clarkson continued to serve as Chief Executive Officer until January 2018. He has more than 40 years of oil and gas exploration, management and executive experience.
Edward LaFehr [3][5] Alberta, Canada	Director	2019	Mr. LaFehr is the Chief Executive Officer of Baytex Energy Corp., a mid-sized oil and gas company based in Calgary. Mr. LaFehr has 35 years of experience in the oil and gas industry working with Amoco, BP, Talisman and Abu Dhabi National Energy Company PJSC (TAQA), holding senior positions in North American, Europe and the Middle East regions. Prior to joining Baytex, he was President of TAQA's North American oil and gas business based in Calgary and subsequently Chief Operating Officer for TAQA, globally. Prior to this, he served as Senior Vice President for Talisman Energy in Calgary. From 2009 to 2011 Mr. LaFehr was Managing Director of Pharaonic Petroleum Company in Cairo, Egypt. In this capacity he served on BP Egypt's executive team and represented BP's interests on the Board of Directors of Pharaonic and ENI's Petrobel JV companies with the Egyptian Government.
Tim Marchant [4][5] Alberta, Canada	Director	2020	Dr. Marchant has 40 years of oil and gas industry experience in Canada and international locations, with extensive experience in exploration, foreign growth strategies, sustainability and international operations. Currently, he is the Adjunct Professor of Strategy and Energy Geopolitics at the Haskayne School of Business, University of Calgary where he teaches energy, corporate social responsibility and sustainability strategies; he also lectures on board environment, social and governance strategies for the Institute of Corporate Directors Education Program. Dr. Marchant is former Chair of the Board of Directors of Valeura Energy Inc. and continues as a member of the Governance & Compensation Committee (since 2015). Prior to his international assignments, he spent 17 years with Amoco Canada.
Steven Sinclair [3][4] Alberta, Canada	Director	2017	Mr. Sinclair is a corporate director who has over 30 years of financial and operating experience retiring from his position of Senior Vice President and Chief Financial Officer of ARC Resources Ltd. in 2014. Mr. Sinclair is also a director and audit committee chair of a Calgary headquartered private oil and gas company.
Edward D. Ok [2] London, England	Vice-President, Finance, Chief Financial Officer and Corporate Secretary	2018	Mr. Ok has served as the Corporate Secretary of the Company since June 2020 and Vice President, Finance and Chief Financial Officer since January 2018. He has been with the Company since 2012 in senior financial roles. Prior to joining TransGlobe, Mr. Ok was at Zodiac Exploration. Mr. Ok is a Chartered Accountant with over 10 years of industry experience.
Geoff Probert [2] London, England	Vice President, and Chief Operating Officer	2019	Mr. Probert has served as the Vice President and Chief Operating Officer of the Company since January 1, 2020 and joined the Company as Vice President on May 18, 2019. Prior to joining TransGlobe, Mr. Probert served in senior management and executive roles at Echo Energy Plc, Aminex Plc and Petroceltic International Plc.

[1] TransGlobe's directors shall hold office until the next annual general meeting of the Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.
[2] Member of the Company's Disclosure & Compliance Committee.
[3] Member of the Company's Audit Committee
[4] Member of the Compensation, Human Resources and Governance Committee.
[5] Member of the Company's Reserves, Health, Safety, Environment & Social Responsibility Committee.
[6] As at March 17, 2022, the directors and officers of TransGlobe, as a group, beneficially owned or controlled or directed, directly or indirectly, 2,755,334 Common Shares or approximately 3.79% of the issued and outstanding Common Shares.

Cease Trade Orders

No current director or executive officer of the Company has, within the last ten years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including the Company) that:

(i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade order or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or

(ii) was subject to an order that resulted, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade order or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

Bankruptcies

No current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Company) that, while such 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 for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, 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 securityholder.

Penalties or Sanctions

No current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has been subject to: (i) 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 (ii) 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

Directors and officers of the Company may, from time to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA, 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 with the Company to 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. See "*Risk Factors*".

INTERESTS OF EXPERTS

Names of Experts

Other than as described below, there is no person or corporation who is named as having prepared or certified a statement, report or valuation described and included in the filing, or referred to in a filing, made under NI 51-102 by the Company during, or relating to the Company's most recently completed financial year whose profession or business gives authority to the report, valuation, statement or opinion made by the person, or Company, other than GLJ, the Company's independent engineering evaluator, and BDO Canada LLP, the Company's independent auditor.

Interests of Experts

There were no registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of one of its associates or affiliates: (i) held by GLJ or by the "designated professionals" (as defined in Form 51-102F2 to NI 51-102) of GLJ, when GLJ prepared the report, valuation, statement or opinion referred to herein as having been prepared by GLJ; (ii) received by GLJ or by the "designated professionals" of GLJ, after the time specified above; or (iii) to be received by GLJ or by the "designated professionals" of GLJ; except in each case for the ownership of Common Shares, which in respect of GLJ and GLJ's "designated professionals", as a group, has at all relevant times represented less than 1% of the outstanding Common Shares. In addition, neither GLJ, nor any director, officer or employee of GLJ, is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or of any associate or affiliate of the Company.

BDO Canada LLP, the Company's auditors are independent of the Company within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules and standards of the Public Company Accounting Oversight Board and the securities laws and regulations administered by the U.S. Securities and Exchange Commission.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Except as described below, there are no legal proceedings material to the Company to which the Company is or was a party to, or in respect of which any of its properties are or were the subject of, during the 2021 financial year, nor are there any such proceedings known to be contemplated. In addition, there were no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the 2021 financial year, no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and no settlement agreements entered into by the Company before a court relating to securities legislation or with a securities regulatory authority during the 2021 financial year.

On March 31, 2015, TG Holdings Yemen, Inc. ("TG Holdings"), a wholly-owned subsidiary of TransGlobe, relinquished its 13.8% interest in a concession in western Yemen known as "Block 32". In 2018, the Ministry of Oil and Minerals of the Republic of Yemen ("MOM") raised claims against the contractor parties, including TG Holdings in the International Court of Arbitration of the International Chamber of Commerce. The claims variously related to accounting practices, environmental and asset integrity/retirement claims, claims related to payment of customs duties and penalties, claims related to amounts allegedly owing to third parties for employment and facilities usage claims, and claims related to the handover of the concession. A decision was rendered by the arbitral tribunal with an effective date of March 31, 2021. The final award determined that the contractor parties, including TG Holdings, are entitled to their share of production sharing oil that was lifted by MOM in the amount of $5.0 million. The award also determined that the contractor parties, including TG Holdings, were jointly and severally liable for certain costs in the amount of $6.5 million.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own or control or direct, directly or indirectly or a combination of both, more than 10% of the Company's Common Shares, or their associates and affiliates, had any material interest, direct or indirect, in any transaction with the Company within the three most recently completed financial years or during the current financial year that has materially affected or would reasonably be expected to materially affect the Company.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Odyssey Trust Company of Canada at its principal offices in Calgary, Alberta, Toronto, Ontario and Vancouver, British Columbia.

MATERIAL CONTRACTS

Other than discussed herein, there are no material contracts, other than the contracts entered into in the ordinary course of business, that are material to the Company and that were entered into within the most recently completed financial year, or before the most recently completed financial year but are still in effect.

On May 16, 2017, TransGlobe announced it had entered into a credit agreement for an RBL with ATB Financial (as they are now). Pursuant to the original credit agreement, the RBL commitment was up to a maximum of C$30 million. The amount available to be drawn on the RBL is dependent upon the borrowing base, which is determined with reference to the Company's proved oil and gas reserves in Canada, as evaluated in the most recent annual reserves report(s) and delivered pursuant to the credit agreement – as amended on May 11, 2018, July 11, 2019, June 30, 2020, and June 4, 2021). As of the original closing date, the borrowing base was set at C$30 million – most recently, the borrowing base was set at C$22.5 million on June 4, 2021. TransGlobe initially used the funds available under the RBL to repay the previously existing C$15 million vendor takeback loan, which had an interest rate of 10% per annum. Additional funds were allocated as necessary to carry out the Company's capital expenditure program in Canada. The credit agreement, and all amendments thereto, are available on the Company's profile on SEDAR at www.sedar.com.

In December 2021, TransGlobe announced that the Merged Concession had been ratified by Egypt's Parliament and signed into law by President El-Sisi. The Merged Concession agreement was subsequently executed at an official signing ceremony with the Egyptian Ministry of Petroleum on January 19, 2022. The Merged Concession has a new 15-year development term and a 5-year extension option. The modernized financial concession terms are expected to promote increased investment and the implementation of new technology in these mature fields. See *General Development of the Business – 2021* and *General Development of the Business – 2022.* The Company has paid the initial modernization payment of $15 million and signature bonus of $1 million as a precondition to the official execution of the Merged Concession agreement. The equalization payment compensates EGPC for the improved fiscal terms on the underlying base forecasted production. The Company will be required to pay an additional $10 million modernization payment on February 1 for each of the next five years beginning on February 1, 2022 until February 1, 2026. The Company paid the modernization payment of $10 million on February 1, 2022. In addition, the Company has agreed to minimum financial work commitments of $50 million over each five-year period for the 15 years of the primary term (total $150 million). Amounts spent beginning on the Merged Concession agreement effective date of February 1, 2020 will be included against the capital commitment. All investments which exceed the five-year minimum $50 million threshold will carry forward to offset against subsequent five-year commitments. See *Summary of Egypt PSC Terms*. A copy of the Merged Concession agreement will be filed on the Company's profile on SEDAR at www.sedar.com promptly following receipt of Egyptian Parliamentary ratification.

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

The audit committee of the Company (the "**Audit Committee**") is currently comprised of Steven Sinclair (Chair), Jennifer Kaufield, and Edward LaFehr. The following chart sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Steven Sinclair Alberta, Canada	Yes	Yes	Mr. Sinclair is a corporate director. Mr. Sinclair previously served as Senior Vice President and Chief Financial Officer of ARC Resources Ltd until his retirement in 2014 and is currently a director and audit committee chair of a Calgary headquartered private oil and gas Company. Mr. Sinclair has over 30 years of financial and operating experience. Mr. Sinclair received his Bachelor of Commerce degree from the University of Calgary in 1978 and his Chartered Accountant's designation in 1981.
Jennifer Ann Kaufield Alberta, Canada	Yes	Yes	Ms. Kaufield was appointed to the Board on January 1, 2022. Ms. Kaufield is an independent businesswoman with over 30 years of experience in private and public corporations both domestic and international. Ms. Kaufield was previously Chief Financial Officer of Titanium Corporation Inc. Ms. Kaufield received her Bachelor of Administration, Accounting from St. Francis Xavier University and Chartered Accountant (CA) and Chartered Professional Accountant (CPA) designations.
Edward LaFehr Alberta, Canada	Yes	Yes	Mr. LaFehr is President and CEO of Baytex Energy Corporation. Mr. LaFehr has over 35 years experience in the oil and gas industry working with Amoco, BP, Talisman Energy Inc. and Abu Dhabi National Energy Company ("TAQA"), holding senior positions in North American, Europe and the Middle East regions. Prior to joining Baytex, Mr. LaFehr President of TAQA's North American oil and gas business based in Calgary and subsequently COO for TAQA, globally. Mr. LaFehr holds Masters degrees in geophysics and mineral economics from Stanford University and the Colorado School of Mines respectively.

Pre-Approval of Policies and Procedures

It is within the mandate of the Company's Audit Committee to approve all audit and non-audit related fees. The Audit Committee is informed routinely as to the non-audit services to be provided by the auditor pursuant to this pre-approval process. The auditors also present the estimate for the annual audit related services to the Audit Committee for approval prior to undertaking the annual audit of the financial statements.

The Audit Committee's pre-approval procedure is to approve all non-audit services to be performed by the Company's auditors in advance of the engagement of the Company's auditors to perform such services. The pre-approval process involves management presenting the Audit Committee with a description of any proposed non-audit services. The Audit Committee considers the appropriateness of such services and whether the provision of those services would impact the auditor's independence, including the magnitude of the potential fees. Once the committee has satisfied itself of its concerns, if any, it then votes either in favor of or against contracting the Company's auditors to perform the proposed non-audit services.

Audit Committee Charter

The full text of the Company's audit committee charter is included in Schedule "C" to this AIF.

Principal Accountant Fees and Services

The aggregate fees for professional services billed to TransGlobe by BDO Canada LLP and by the Company's former auditor Deloitte LLP during the fiscal years ended December 31, 2021 and December 31, 2020 were as follows:

(U.S. dollars)	Fiscal Year Ended December 31, 2021	Fiscal Year Ended December 31, 2020
Audit Fees		
BDO Canada LLP	318,251	80,154
Deloitte LLP	-	177,945
Audit Related Fees	-	-
Tax Fees		
BDO Canada LLP	8,548	-
Deloitte LLP	-	23,556
TOTAL		
BDO Canada LLP	**326,799**	**80,154**
Deloitte LLP	**-**	**201,501**

The nature of the services provided by BDO Canada LLP and Deloitte LLP under each of the categories indicated in the table is described below.

Audit Fees

Audit fees were for professional services rendered by BDO Canada LLP and Deloitte LLP for the audit of the Company's annual financial statements, as well as for the review of the Company's interim quarterly financial statements.

Audit Related Fees

Audit related fees were for professional services rendered by BDO Canada LLP and Deloitte LLP for assurance services that are reasonably related to the performance of the audit of the Company's annual financial statements (not included in audit fees).

Tax Fees

Tax fees were for tax compliance, including the review of tax returns, tax advice and tax planning and advisory services relating to common forms of domestic and international taxation (i.e. income tax, capital tax, goods and services tax and payroll tax).

All Other Fees

During the fiscal years ended December 31, 2021 and 2020, no other fees were incurred other than those described above.

CANADIAN INDUSTRY CONDITIONS

Companies operating in the Canadian oil and gas industry are 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 as well as with respect to the pricing and taxation of petroleum 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 Western Canadian oil and gas industry. 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.

The Company's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of the Company's upstream oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells and construction of related infrastructure; (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, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct 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.

The discussion below outlines 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 some of the Company's assets are located. While these matters do not affect the Company'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

Oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In the first quarter of 2022, oil prices have risen to the highest levels since 2014 due to tight supply and a resurgence in demand. The OPEC forecasts robust growth in world oil demand in 2022, despite newly emerging COVID-19 variants, expected interest rate increases in major economies and other uncertainties with respect to the world economy.

Natural Gas

Negotiations between buyers and sellers determine the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale.

Natural Gas Liquids

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

Exports from Canada

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the Canadian Energy Regulator Act (the "**CERA**"). Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Company does not directly enter into contracts to export its production outside of Canada.

Transportation Constraints and Market Access

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

Producers negotiate with pipeline operators to transport their products to market on a firm or interruptible basis depending on the specific pipeline and the specific substance. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers and the price received.

Pipelines

The Enbridge Inc. ("**Enbridge**") Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, came into service in October 2021. The Line 3 Replacement faced significant permitting difficulties in the United States resulting in the two-year delay. The pipeline provides an incremental 370,000 bbls/day of export capacity from Western Canada into the United States.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2022. The pipeline is expected to be in-service in the third quarter of 2023, an extension from Trans Mountain's December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. On December 15, 2021, Enbridge moved to transfer the Attorney General's lawsuit from Michigan State Court to United States Federal Court.

Marine Tankers

The *Oil Tanker Moratorium Act*, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Natural Gas and LNG

Natural gas prices in Western Canada have 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 prices received in other North American markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation ("**TC Energy**") received federal approval to expand the NOVA Gas Transmission Ltd. pipeline system ("**NGTL System**") and the expanded NGTL System is expected to be fully operational by April 2022.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. 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 (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of December 2021, construction of the CGL Pipeline is approximately 60% complete.

In addition to LNG Canada and the CGL Pipeline projects, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive financial investment decision.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could impact Western Canada's oil and gas industry at large, including the Company's business.

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

Land Tenure

Mineral Rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (collectively, "**leases**") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

All of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a disposition. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences; British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop oil and natural gas reserves.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the Indian Act (Canada). 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 through *An Act to Amend the Indian Oil and Gas Act*,. The Company does not have operations on Indian reserve lands.

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. Similar rules apply to facility and pipeline operators.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL 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, though certain provincial taxes and other charges on production or revenues may be payable.

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

Occasionally, the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

In addition, from time-to-time, including during COVID-19 pandemic, the federal government creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the oil and gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic such as the various short-term loan programs and the Canada Emergency Wage Subsidy, for example, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, Innovation, Science and Economic Development Canada and, in some cases, the Canada Revenue Agency.

Alberta

Crown royalties

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.

In 2016, the Government of Alberta adopted a modernized Crown royalty framework (the "**Modernized Framework**") that applies to all conventional oil (i.e., not oil sands) and natural gas wells drilled after December 31, 2016 that produce Crown-owned resources. The previous royalty framework (the "**Old Framework**") will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026, following which time they will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta), came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

Royalties on production from wells subject to the Modernized Framework are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's average drilling and completion costs, determined annually by the Alberta Energy Regulator (the "**AER**"), and incorporates information specific to each well such as vertical depth and lateral length.

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

Under the Old Framework, royalty rates for conventional oil production can be as high as 40% and royalty rates for natural gas production can be as high as 36%. Similar to the Modernized Framework, these rates vary based on the nature of the resource and market prices. The natural gas royalty formula also provides for a reduction based on the measured depth of the well, as well as the acid gas content of the produced gas.

In addition to royalties, producers of oil and natural gas from Crown lands in Alberta are also required to pay annual rentals to the Government of Alberta.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner.

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

Regulatory Authorities and Environmental Regulation

General

The Canadian oil and gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. 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 such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and greenhouse gas ("**GHG**") emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and 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 CERA and the *Impact Assessment Act* (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency (the "**Agency**") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75km of new rights 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, but this matter remains before the courts.

Alberta

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 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. The Company routinely conducts hydraulic fracturing in its drilling and completion programs. 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 oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in Subsurface Order Nos. 2, 6, and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**") The Company does not have operations in the Seismic Protocol Regions and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

Liability Management

The AER administers the Liability Management Framework (the "**AB LM Framework**") and the Liability Management Rating Program (the "**AB LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AM LM Framework. This change was effected under key new AER directives in 2021. Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effective, including the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LF Program**"), and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under the AB LM Framework and the AB LLMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the AB LM Framework and the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and the AB OWL Program fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LF Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

The Supreme Court of Canada'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 licence transfer when any such 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 the *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes came into force in June 2020.

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

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

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

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

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. In 2018, for example, the AER announced a voluntary area-based closure ("**ABC**") program. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The Company is not participating in the voluntary ABC program.

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 Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. On April 22, 2016, 197 countries, 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. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In 2016, Canada 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 in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

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 regulatory fuel charge (enabled by the *Fuel Charge Regulations*) both of which impose a price on CO2e emissions. This 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 reaches 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, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Starting April 1, 2022, the minimum price permissible under the GGPPA is $50/tonne of CO2e. In addition, on March 5, 2021, the federal government introduced for comment the *Greenhouse Gas Offset Credit System Regulations* (Canada) (the "**Federal Offset Credit Regulations**"). The proposed Federal Offset Credit Regulations are intended to establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS. The final Federal Offset Credit Regulations are currently targeted for publication in mid-2022.

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 a number of 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 federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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.

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced the $750 million Emissions Reduction Fund ("ERF"), intended to help the oil and gas sectors to reduce the production of methane and other GHG emissions. Funds disbursed through the ERF will primarily take the form of repayable contributions to onshore and offshore oil and gas firms. Of the $750 million in funding, $675 million was allocated to the Onshore Deployment Program, while $75 million was dedicated to the Offshore Deployment Program and the Offshore RD&D (research, development and demonstration) Program. Natural Resources Canada expects that all funding for onshore projects will be allocated by March 2022, while funding for offshore projects will be allocated by March 2023.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act in Parliament* (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 Act is required every five years from the date the Act came into force.

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS 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. The federal government has indicated that urgent steps are necessary to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

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 70 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 April 1, 2022, the carbon tax payable in Alberta will increase from $40 to $50 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 A*lberta's Technology Innovation and Emissions Reduction* ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces 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 1% 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.

On September 1, 2020, the Government of Alberta announced $750 million in spending from the TIER fund to support projects that help industries reduce their carbon emissions. Such projects include CCUS, energy efficiency, and increased methane management initiatives. An additional $176 million in spending from the TIER fund was announced for similar GHG reduction projects on November 1, 2021.

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 the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. 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 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.

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

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. Going forward, the Blueberry 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.

On October 7, 2021, the Government of British Columbia and the BRFN reached an initial agreement in response to the Blueberry Decision in which the parties agreed to negotiate a land management process for BRFN territory, and certain previously authorized forestry and oil and gas projects were put on hold pending further negotiation. Currently, the Government of British Columbia and the BRFN are in the midst of negotiations to finalize a new regime for assessment, authorization and management of industrial activities on BRFN territory in a manner consistent with the Blueberry Decision. The long-term impacts and risks of the Blueberry Decision on the Canadian oil and gas industry remain uncertain.

RISK FACTORS

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.

Input Costs for Materials and Services

Historically, the Company's capital and operating costs have risen during periods of increasing commodity prices. These cost increases result from a variety of factors beyond the Company's control. Increased levels of drilling activity in the petroleum industry in recent periods has led to increased costs of certain drilling equipment, materials and supplies. Such costs may rise faster than increases in the Company's revenue, thereby negatively affecting its profitability, cash flow and ability to complete development activities as scheduled and on budget.

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.

Inflation and Cost Management

The Company's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows.

The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and cash flows.

Project Risks

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

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- 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.

Egypt Government Credit Risk

The Company is and may in the future be exposed to third party credit risk through its contractual arrangements with the Government of Egypt. Significant changes in the crude oil industry, including fluctuations in the commodity prices and economic conditions, environmental regulations, government policy, royalty rates and other geopolitical factors, could adversely affect the Company's ability to realize the full value of its accounts receivable from the Government of Egypt. Historically, the Company has had a significant account receivables outstanding from the Government of Egypt. While the Government of Egypt has made regular payments on these amounts owing, the timing of these payments has historically been longer than normal industry standard. The receivable balance due from the Egyptian Government has been reduced to a manageable level as a result of the Company's direct marketing initiative and continued payments from the Egyptian Government. However, there remains a balance due from the Egyptian Government, and there can be no assurance that future payments will occur on a more-timely basis or occur at all. In the event the Government of Egypt fails to meet its obligation, such failures could materially adversely affect the Company's financial and operational results.

Changing Investor Sentiment

A number of factors, including the effects of the use of hydrocarbons on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Company. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Company, or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities even if the Company's operating results, underlying asset values or prospects have not changed.

Risks Relating to Reserves Estimates

There are numerous uncertainties inherent in estimating reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- 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. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates 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 are often 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 and 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 the Company's oil and natural gas reserves will vary from the estimates contained in the reserves evaluation, and such variations could be material. The reserves 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 therefore does not reflect changes in the Company's reserves since that date.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Company 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 or 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 ensure 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, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect 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, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Company may explore for and produce sour gas in certain areas. An unintentional leak of sour 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 geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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 and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Risk Factors – Insurance*". In either event, the Company could incur significant costs.

Global Political Uncertainty

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

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

A change in federal, provincial or municipal governments in Canada 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 in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Company's activities. See "*Canadian Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Canadian Industry Conditions – Transportation Constraints and Market Access*".

Russian Ukrainian 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 is likely to have wide-ranging consequences on the peace and stability of the region and the world economy.

In addition, certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. As part of the sanctions package, the German government paused the certification process for the 1,200 km Nord Stream 2 natural gas pipeline that was built to carry natural gas from Russia to Germany. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

Prices, Markets and Marketing

Oil and natural gas prices may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and conflicts in the Middle East. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. 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 and the value of the Company's reserves. The Company 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 Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Company may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

As a result of global economic and political conditions and the domestic lending landscape, the Company may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable 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 the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. 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. Alternatively, any available financing may be highly dilutive to existing Shareholders. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors:

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

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

Foreign Jurisdiction Risk

The majority of the Company's current production is located in Egypt. As such, and in addition to the specific political risks mentioned above, the Company is subject to political, economic, and other uncertainties, including, but not limited to, expropriation of property without fair compensation, changes in energy policies or the personnel administering them, a change in oil or natural gas pricing policy, the actions of national labour unions, nationalization, currency fluctuations and devaluations, renegotiation or nullification of existing concessions and contracts, exchange controls and royalty and tax increases and retroactive tax claims, investment restrictions, import and export regulations and other risks arising out of foreign governmental sovereignty over the areas in which the Company's operations are conducted, as well as risks of loss due to civil strife, acts of war,

terrorist activities and insurrections, economic sanctions, the imposition of specific drilling obligations and the development and abandonment of fields.

The Egyptian government could adopt new policies that might result in substantially hostile attitudes towards foreign investments such as the Company's. In an extreme case, government actions could result in forced renegotiation of the Company's existing contracts, termination of contract rights and expropriation of its assets (including crude oil inventory) or resource nationalization. Loss of property (damage to, or destruction of, the Company's wells, production facilities or other operating assets) and/or interruption of its business plans (including lack of availability of drilling rigs, oilfield equipment or services if third party providers decide to exit the region or inability of the Company's service equipment providers to deliver necessary items for the Company to continue operations) as a direct or indirect result of political protests, demonstrations or civil unrest in Egypt could have a material adverse impact on the Company's results of operations and financial condition. In addition, the Company cannot provide assurance that future political developments in Egypt, including changes in government, changes in laws or regulations, export restrictions or further civil unrest or other disturbances, would not have an adverse impact on ongoing operations, the Company's ability to comply with its current contractual obligations, the Company's ability to lift and sell its crude oil inventory to third parties, or on the terms or enforceability of its production sharing and concession agreements or other contracts with governmental entities.

The Company's operations may also be adversely affected by laws and policies of Canada and Egypt affecting foreign trade, taxation and investment. In the event of a dispute arising in connection with the Company's operations in Egypt, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdictions of the courts of Canada or enforcing Canadian judgments in such other jurisdictions. The Company may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, the Company's exploration, development and production activities in Egypt could be substantially affected by factors beyond the Company's control, any of which could have a material adverse effect on the Company.

If the Company's operations are disrupted and/or the economic integrity of its projects are threatened for unexpected reasons, its business may be harmed. These unexpected events may be due to technical difficulties, operational difficulties which impact the production, transport or sale of the Company's products, security risks related to terrorist activities and insurrections, difficult geographic and weather conditions, unforeseen business reasons or otherwise. Prolonged problems may threaten the commercial viability of its operations.

Share Price Volatility and Liquidity

The trading price of the securities of 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. 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 oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. Similarly, the market price of the Common Shares of the Company 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 of the Company will trade cannot be accurately predicted.

Management of Growth

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company 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 and assets 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 the resources 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 market conditions 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.

Operating Risks

The Company delivers crude oil through gathering, processing pipeline systems and export cargo terminals that the Company does not own or control. The amount of crude oil that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing pipeline systems and scheduling of export cargos (in Egypt). The lack of availability of capacity in any of the gathering, processing pipeline systems and export cargo terminals, and in particular the export cargo terminals in Egypt, could result in the Company's inability to realize the full economic potential of its production, sales or in a reduction of the price offered for the Company's production.

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, spills and 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. If any of these types of events were to occur, they could result in failure to discover hydrocarbons and if discovered delay in or loss of production, environmental damage, injury to persons or loss of life. They could also result in significant delays to drilling programmes, a partial or total shutdown of operations, significant damage to equipment owned or used by the Company and personal injury, wrongful death or other claims related to loss being brought against the Company. These events could result in the Company being required to take corrective measures, incurring significant civil liability claims, significant fines or penalties as well as criminal sanctions potentially being enforced against the Company and/or its

officers. The Company may also be required to curtail or cease operations on the occurrence of such events. Any of the above could have a material adverse effect on the Company's business, prospects, financial condition or results of operations.

Whilst the Company intends to implement certain policies and procedures to identify and mitigate such hazards, develop appropriate work plans and approvals for high-risk activities and prevent accidents from occurring, these procedures may not be sufficiently robust or appropriately followed by the Company's staff or third-party contractors to prevent accidents. 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 drilling and production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The oil and gas industry in Egypt is not as efficient or developed as the oil and gas industry in North America. As a result, the Company's exploration and development activities may take longer to complete and may be more expensive than similar operations in North America. The availability of technical expertise, specific equipment and supplies may be more limited than in North America. The Company expects that such factors will subject its operations to economic and operating risks that may not be experienced in North American operations.

Climate Change

Chronic Climate Change Risks

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact. As discussed below, the Company faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as 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 Company'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 Company's profitability and a reduction in the value of its assets .

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 Company, for alleged personal injury, property damage, or other potential liabilities. While the Company is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Company, impact its operations and have an adverse 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 Company's management to dedicate significant time and resources to these climate change-related concerns, may adversely affect the Company's operations, the demand for and price of the Company's securities and may negatively impact the Company's cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 – *Disclosure of Climate Related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If the Company is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Canadian Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*"

Physical risks

Based on the Company's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Company's ability to access 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.

COVID-19 and Its Effect on the Global Economy

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, liquids and natural gas. Since 2020, oil prices have largely recovered from their historic lows, but price support from future demand remains uncertain as countries experience varying degrees of virus outbreak and newly emerging virus variants following efforts to re-open local economies and international borders. Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on the Company's operational results and financial condition. Low prices for oil, liquids and natural gas will reduce the Company's funds from operations, and impact the Company's level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness, and temporary closures of the Company's facilities.

The extent to which the Company's operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond its control such as the duration and scope of the pandemic; additional actions taken by business and government in response to the pandemic, and the speed and effectiveness of responses to combat the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified herein, the extent of which is not yet known.

Adverse General Economic, Business and Industry Conditions

The demand for energy, including crude oil, NGLs and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession or other adverse economic or political development in the United States, Europe or Asia, there could be a significant adverse effect on global financial markets and commodity prices. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as the recent COVID-19 (coronavirus), may adversely affect the Company by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGL and natural gas, (ii) impairing its supply chain (for example, by limiting the manufacturing of materials or the supply of services used in the Company operations), and (iii) affecting the health of its workforce, rendering employees unable to work or travel. These and other factors disclosed elsewhere in this Annual Information Form that affect the demand for crude oil, NGLs and natural gas and the Company's business and industry would ultimately have an adverse impact on the Company's results of operations and cash flow.

Competition

The petroleum industry is competitive in all of its phases. The Company competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. 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 Company. The Company'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, and reliability of delivery and storage.

Dividends

The amount of future cash dividends paid by the Company, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Company, the Company may change its dividend policy at any time. Dividends are not guaranteed. Any reduction of dividends may have an adverse effect on the market price of the Company's Common Shares. See "*Dividend Policy*".

The market value of the Common Shares may deteriorate if cash dividends continue to be suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Company to finance capital expenditures or property acquisitions using funds from operations.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the ability of the Company to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired.

Forward-looking Information

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*" of this Annual Information Form.

Hedging Risks

From time to time, the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company 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 it to the risk of financial loss in certain circumstances, including instances in which:

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

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

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blowouts, leaks of sour 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, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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

Information Technology Systems and Cybersecurity

The Company is 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 Company depends on various information technology systems to estimate reserve quantities, process and record financial data, manage the Company's land base, manage financial resources, analyze seismic information, administer contracts with operators and lessees and communicate with employees and third-party partners.

Further, the Company is subject to a variety of information technology and system risks as a part of its operations including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to business activities or the Company's competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information, or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

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 can restrict the social media access of its employees and retains and maintains the ability to retrieve social media content. Despite the Company's efforts, there are 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.

The Company maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments and training and education programs for its employees. Despite the Company'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 Company applies technical and process controls in line with industry-accepted standards to protect its 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 the Company's performance and earnings, as well as its reputation, and any damages sustained may not be adequately covered by the Company'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 Company's business, financial condition and results of operations.

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 and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Canadian Industry Conditions – Regulatory Authorities and Environmental Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in 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 compliance requirements 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 Company's business, financial condition, results of operations and prospects.

Income Taxes

The Company files 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. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Company. 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.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

Egypt Political Risks

Beyond the risks inherent in the petroleum industry, the Company is subject to additional political risks resulting from doing business in Egypt. Since 2011, there has been significant civil unrest and widespread protests and demonstrations throughout the Middle East, including Egypt. Abdel Fattah el-Sisi was elected President of Egypt in 2014 following several years of widespread protests, demonstrations and civil unrest. Since this time, political and economic stability has returned to the country leading to a positive impact in business confidence.

Egypt’s CPI inflation increased slightly from the previous year to approximately 5.9% at the end of 2021, which is on the low end of the Central Bank of Egypt’s target range. Inflation in Egypt remains relatively volatile which could lead to significant economic impacts over which the Company does not have control, including but not limited to, living costs, operational costs, transportation costs, employment levels, borrowing/lending rates and currency valuation. The Company cannot predict the impact of inflation on oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows by decreasing the Company's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Reputational Risk

The Company's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Company or as a result of any negative sentiment toward, or in respect of, the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain 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 Company'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 Company has no control. Similarly, the Company's reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by the Company's operations. In addition, if the Company develops a reputation of having an unsafe work site, it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and hydrocarbon companies may impact the Company'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 Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities.

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 systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of hydrocarbons and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flow by decreasing the Company's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Reliance on Key Personnel

The operations and management of the Company require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Company's business plans which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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

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, U.S. securities laws and under the AIM Rules for Companies, 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.

Third Party Credit Risk

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

Debt Facility Arrangements

The Company's lenders use the Company's reserves, commodity prices, applicable discount rate and other factors to determine periodically the Company's borrowing base. Any increase in commodity prices could reduce the Company's borrowing base credit facilities, reducing the funds available to the Company under its credit facilities. This could result in the requirement to repay a portion, or all, of the Company's indebtedness.

If the Company's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under 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 its credit facilities, the lenders under such credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

From time to time, the Company may enter into transactions to acquire assets or shares of other entities. 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 similar size. Depending on future exploration and development plans, the Company 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 the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Litigation

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries (including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes). The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and could have a material adverse effect on the Company's 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 affect on the Company's financial condition.

Decommissioning Costs

In Canada, liabilities in respect of the decommissioning of its wells, fields and related infrastructure are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and require the Company to make provisions for and/or underwrite the liabilities relating to such decommissioning. It is difficult to accurately forecast the costs that the Company would incur in satisfying any decommissioning obligations. When such decommissioning liabilities crystallize, the Company would be liable either on its own or jointly and severally liable for them with any other former or current partners in the field. In the event that it is jointly and severally liable with other partners and such partners default on their obligations, the Company would remain liable and its decommissioning liabilities could be magnified significantly through such default. Any significant increase in the actual or estimated decommissioning costs that the Company incurs may adversely affect its financial condition.

In Egypt, under model concession agreements and the Fuel Material Law, liabilities in respect of decommissioning movable and immovable assets (other than wells) passes to the Egyptian Government through the transfer of ownership from the contractor to the government under the cost recovery process. While the current risk to the Company of becoming liable for decommissioning liabilities in Egypt is low, future changes to legislation could result in decommissioning liabilities in Egypt. Any increase in Egyptian decommissioning liabilities could adversely affect the Company's financial condition.

In relation to petroleum wells, the contractor is responsible for decommissioning non-producing wells under a decommissioning plan approved by EGPC. If EGPC agrees that a producing well is not economic, then the contractor will be responsible for decommissioning the well under an EGPC approved decommissioning plan. EGPC, at its own discretion, may not require a well to be decommissioned if it wants to preserve the ability to use the well for other purposes. As EGPC has discretion on decommissioning wells, there is a risk that the Company could incur well decommissioning costs. In accordance with the respective concession agreements, expenses approved by EGPC are recoverable through the cost recovery mechanism.

Relinquishment Obligations

The Company is subject to relinquishment obligations under its title documents which oblige the Company to relinquish certain proportions of its concession lease and licence areas and thereby reduce the Company’s acreage. Additionally, the Company may be unable to drill all of its prospects or satisfy its minimum work commitments prior to relinquishment and may be unable to meet its obligations under the title documents. Failure to meet such obligations could result in concessions, leases and licences being suspended, revoked or terminated which could have a material adverse effect on the Company's business.

Trading Currencies

The Common Shares trading on the AIM are denominated in British Pounds whereas the Common Shares trading on the TSX are in Canadian dollars and on the Nasdaq in United States dollars. Fluctuations in the exchange rate between the currencies, including the pound sterling, will affect the value of the Common Shares and any dividends the Company may declare in the future, denominated in the local currency of investors outside of Canada.

Risk to title due to assignment restrictions

Recent models of the Egyptian concession agreement in Egypt include restrictive wording that require the government's consent for any direct or "indirect" assignment of rights under the concession, which could be interpreted to include acquiring the voting or equity shares of the contractor party to an Egyptian concession. The government's position on the matter is neither clear nor unified, raising ambiguity and the risk that an executed assignment offshore could be revisited by the government and EGPC. If so revisited, this could result in the contractor being required to obtain the government's consent to deeds of assignment, liability for assignment bonuses and/or the government seeking termination for breach of the concession agreement. There are no reported cases of a concession being terminated on such grounds. The Company considers the continued communication, correspondences and dealings subsequent to the completion of the Company's acquisition as limiting the probability that such risks

will materialize. To date, EGPC has recognized and dealt with the Company as though no such approval was required or, if required, was deemed to have been given by EGPC at the time of the transaction.

No Pre-Emptive Rights

The Company is not required under Canadian law to offer new Common Shares to existing Shareholders on a pre-emptive basis as is required of companies incorporated under the UK *Companies Act 2006*. As such, it may not be possible for existing Shareholders to participate in future share issues, which may dilute an existing Shareholder's interest in the Company. However, there are various protections afforded to Shareholders as a result of Canadian securities laws. Additionally, the Company and the Board have undertaken to Canaccord Genuity Limited, its UK Nominated Advisor, that for as long as the Common Shares remain quoted on AIM, the Company will obtain approval by special resolution for issuance of Common Shares in certain circumstances. Shareholders not participating in future offerings may be diluted. The Company may in the future issue options and/or warrants to subscribe for new Common Shares, including (without limitation) to certain advisers, employees, directors, senior management and consultants. The exercise of such warrants and/or options would result in dilution of the shareholdings of other investors.

Actions or Enforcement Judgements

The Company is continued under the laws of the Province of Alberta, Canada, and as the date of this AIF the majority of the Company's directors are residents of Canada and all of its officers are residents of the United Kingdom. Consequently, it may be difficult for investors from outside of Canada, to effect service of process upon the Company or upon those directors or officers, or to realize judgments of non-Canadian courts. Furthermore, it may be difficult for non-Canadian investors to enforce judgments of non-Canadian courts based on civil liability provisions of the non-Canadian securities laws in a Canadian court against the Company or any of the Company's Canadian resident directors. There is substantial doubt whether an original lawsuit could be brought successfully in Canada against any of such persons or the Company predicated solely upon such non-Canadian civil liabilities.

Cash Transfer Restrictions

The Company currently conducts the majority of its operations through its foreign subsidiaries and foreign branches. Therefore, the Company could be dependent on the cash flows of these subsidiaries to meet its obligations. The ability of its subsidiaries to make payments to the Company may be constrained by, among other things: the level of taxation, particularly corporate profits and withholding taxes, in the jurisdictions in which it operates; the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated; and contractual restrictions with third parties. For example, certain governments have imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by a country's central bank. These central banks may require prior authorization and may or may not grant such authorization for the Company's foreign subsidiaries to transfer funds to it and there may be a tax imposed with respect to the expatriation of the proceeds from the Company's foreign subsidiaries.

Title to Assets

Although title reviews may be conducted in Canada 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. Due in part to the nature of property rights development historically in Canada as well as the common practice of splitting legal and beneficial title, public registries are not determinative of actual rights held by parties. Further, the fragmented nature of oil and gas rights, which may be held by the government or private individuals and companies, and may be split among a great number of different granting documents, means that despite best efforts of parties, latent defects may not be immediately discoverable. As such, the actual interest of the Company in properties may accordingly vary from the Company's records. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Company's title to the oil and natural gas properties the Company controls in Canada that could impair the Company's activities on them and result in a reduction of the revenue received by the Company.

AIM

AIM is a market designed primarily for emerging or smaller growing companies which carry a higher than normal financial risk and tend to experience lower levels of liquidity than larger companies. Accordingly, AIM may not provide the liquidity normally associated with the Official List of the UK Listing Authority (the "**Official List**") or some other stock exchanges. The Common Shares may therefore be difficult to sell compared to the shares of companies listed on the Official List and the share price may be subject to greater fluctuations than might otherwise be the case. An investment in shares traded on AIM carries a higher risk than those listed on the Official List.

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which the Company has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic. See "*Canadian Industry Conditions – Royalties and Incentives*".

Regulatory

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. 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. See "*Canadian Industry Conditions – Regulatory Authorities and Environmental Regulation*".

In order to conduct oil and natural gas operations, the Company 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 Company 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 Company's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting, acquisition or disposition activity. See "*Canadian Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*".

Non-Governmental Organizations and Eco-Terrorism Risks

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

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct our operations, development or exploratory activities in any of the jurisdictions in which the Company 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 Company's progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. Although there are no Indigenous and treaty rights claims on lands where the Company 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 Company's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, a recent 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 Company 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 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 "*Canadian Industry Conditions – Indigenous Rights*"

Hydraulic Fracturing

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

Water is an essential component of the Company's drilling and hydraulic fracturing processes. Limitations or restrictions on the Company's ability to secure 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. If the Company is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on its financial condition, results of operations, and cash flows.

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

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Company or by commercial disposal well vendors that the Company may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Company or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Company or its vendors to shut down or

curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Company's business, financial condition, and results of operations.

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau and Red Deer. Since 2015, the AER has introduced seismic protocols for hydraulic fracturing operators in the Seismic Protocol Regions initially in response to significant induced seismic activity in the Duvernay formation in Fox Creek in February 2015. The Company does not have operations in Fox Creek, Red Deer and Brazeau 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 which vary among the three regions. The reporting requirements include 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, depending on the magnitude of an earthquake. Orders imposed by the AER in response to seismic events remain in effect as long as the AER deems them necessary. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, leading to continued monitoring by the AER. The AER may extend seismic protocols to other areas of the province if necessary.

See "*Canadian Industry Conditions – Regulatory Authorities and Environmental Regulation – General - Alberta*".

Conflicts of Interest

Certain directors or officers of the Company may also be directors or officers of other oil and natural gas companies 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 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 with the Company to 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. See "*Directors and Officers – Conflicts of Interest*".

No Takeover Code Protection

The Company is not subject to the provisions of the UK City Code on Takeovers and Mergers and it is emphasized that, although the Common Shares are trading on AIM, the Company will not be subject to takeover regulation in the UK. However, Canadian laws applicable to the Company provide for early warning disclosure requirements and for takeover bid rules for bids made to security holders in various jurisdictions in Canada.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and options to purchase securities, if applicable, is contained in the Company's Information Circular for the most recent annual meeting of Shareholders that involved the election of directors. Additional financial information is provided for in the Company's financial statements and the management's discussion and analysis for the year ended December 31, 2021. These documents, along with other documents affecting the rights of securityholders and other information relating to the Company, may be found on SEDAR at www.sedar.com and in the Company's Annual Report on Form 40-F for the fiscal year ended December 31, 2021, filed on EDGAR at www.sec.gov.

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

Report on Reserves Data

To the Board of Directors of TransGlobe Energy Corporation (the **"Company"**):

1. We have evaluated the Company's reserves data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income tax, 10% discount rate - M$US)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	Dec. 31, 2021	Canada	-	145,861	-	145,861
GLJ Ltd.	Dec. 31, 2021	Egypt	-	289,107	-	289,107
		TOTAL	-	434,967	-	434,967

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 judgements 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 22, 2022.

"Originally Signed By"

Patrick A. Olenick, P. Eng.
Vice President

SCHEDULE "B"

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

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

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule A of this Annual Information Form.

The Reserves Committee of the Board of Directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

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

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

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and

(c) the content and filing of this report.

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

DATED as of this 17th day of March, 2022.

Per:

(Signed) Randy C. Neely

Randy Neely

President, Chief Executive Officer and Director

Per:

(Signed) Edward LaFehr

Edward LaFehr

Director and Chair of the Reserves, Health, Safety, Environment and Social Responsibility Committee

Per:

(Signed) Geoff Probert

Geoff Probert

Vice-President, Chief Operating Officer

Per:

(Signed) David C. Cook

David Cook

Director and Chairman of the Board

SCHEDULE "C"

CHARTER OF AUDIT COMMITTEE

Our Audit Committee Charter outlines the specific roles and duties of the Committee's members.

GENERAL FUNCTIONS, AUTHORITY AND ROLE

The Audit Committee is a committee of the Board of Directors appointed to assist the Board in monitoring (1) the integrity of the financial statements of the Company, (2) compliance by the Company with legal and regulatory requirements related to financial reporting, (3) qualifications, independence and performance of the Company's independent auditors, (4) performance of the Company's accounting, internal controls and financial reporting process and monitoring business risks.

The Audit Committee has the power to conduct or authorize investigations into any matters within its scope of responsibilities, with full access to all books, records, facilities and personnel of the Company, its auditors and its legal advisors. In connection with such investigations or otherwise in the course of fulfilling its responsibilities under this charter, the Audit Committee has the authority to independently retain special legal, accounting, or other consultants to advise it, and may request any officer or employee of the Company, its independent legal counsel or independent auditor to attend a meeting of the Audit Committee or to meet with any members of, or consultants to, the Audit Committee. In its capacity as a committee of the Board of Directors, the Audit Committee has the power to determine the amount of Company funds that are appropriate for payment of (1) compensation to the Company's independent auditor engaged for the purpose of preparing audit reports and performing other audit and non-audit services, (2) independent counsel and other advisers as it determines necessary to carry out its duties and (3) ordinary administrative expenses as it determines necessary to carry out its duties. The Audit Committee also has the power to create specific sub-committees with all of the investigative powers described above.

The Board of Directors and Audit Committee, as representatives of the Company's shareholders, have the ultimate authority and responsibility to retain and evaluate the independent auditor, to nominate annually the independent auditor to be proposed for shareholder approval and to determine appropriate compensation for the independent auditor. In the course of fulfilling its specific responsibilities hereunder, the Audit Committee must maintain free and open communication between the Company's independent auditors, Board of Directors and Company management. The responsibilities of a member of the Audit Committee are in addition to such member's duties as a member of the Board of Directors.

While the Audit Committee has the responsibilities and powers set forth in this charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements are complete, accurate, and in accordance with generally accepted accounting principles. This is the responsibility of management. Nor is it the duty of the Audit Committee to conduct investigations, to resolve disagreements, if any, between management and the independent auditor (other than disagreements regarding financial reporting), or to assure compliance with laws and regulations or the Company's own policies.

MEMBERSHIP

The membership of the Audit Committee will be as follows:

- The Committee will consist of a minimum of three members of the Board of Directors, appointed annually, each of whom is affirmatively confirmed by the Board of Directors as having satisfied the independence standards specified in all applicable rules of the Canadian provincial securities commissions, the U.S. Securities and Exchange Commission (the "SEC") and the regulator of the Alternative Investment Market of the London Stock Exchange ("**AIM**"), any securities exchange on which the Company's shares are traded, with such affirmation disclosed in the Company's Management Proxy Circular.

- The Committee will also consist of all members that meet the definition of "Financially Literate" as defined in National Instrument 52-110 Part 1(1.5) and are able to read and understand fundamental financial statements, including the Company's balance sheet, income statement and cash flow statement. The Committee shall have at least one member that qualifies as a financial expert as defined by the SEC.

- The Committee will not have participated in the preparation of the financial statements of the Company or its subsidiaries at any time during the past three years.

- The Board will elect, by a majority vote, one member as chairperson of the Audit Committee.

- A member of the Audit Committee may not, other than in his or her capacity as a member of the Audit Committee, the Board of Directors, or any other Board committee, accept any consulting, advisory, or other compensatory fee from the Company, and may not be an affiliated person of the Company or any subsidiary thereof.

RESPONSIBILITIES

The responsibilities of the Audit Committee shall be as follows:

Frequency of Meetings

- Meet on at least a quarterly basis, either in person or by telephone.

- Meet with the independent auditor on at least a quarterly basis, either in person or by telephone.

Reporting Responsibilities

- Provide to the Board of Directors proper Committee minutes.

- Report Committee actions to the Board of Directors with such recommendations as the Committee may deem appropriate.

Charter Review

- Annually review and reassess the adequacy of this Charter and recommend any proposed changes to the Board of Directors for approval.

Advice of Counsel

- The Committee shall receive and review any reports from counsel to the Company concerning evidence of any material violation of law by the Company.

Whistleblower Mechanisms

- Adopt and review annually a mechanism through which employees and others can directly and anonymously contact the Audit Committee with concerns about accounting, internal accounting controls and auditing matters. The mechanism must include procedures for receiving, responding to, and keeping of records of, any such expressions of concern.

Independent Auditor

- Recommend to the Board the annual nomination of the independent auditor to be proposed for shareholder approval.

- Approve the compensation of the independent auditor and evaluate the performance of the independent auditor.

- Establish policies and procedures for the engagement of the independent auditor to provide non-audit services. The Audit Committee's pre-approval procedure is to approve all non-audit services to be performed by the Company's auditors in advance of the engagement of the Company's auditors to perform such services. The pre-approval process involves management presenting the Audit Committee with a description of any proposed non-audit services. The Audit Committee considers the appropriateness of such services and whether the provision of those services would impact the auditor's independence, including the magnitude of the potential fees. Once the committee has satisfied itself of its concerns, if any, it then votes either in favor of or against contracting the Company's auditors to perform the proposed non-audit services.

- Ensure that the independent auditor is not engaged for any activities not allowed by any of the Canadian provincial securities commissions, the SEC, the AIM regulator or any securities exchange on which the Company's shares are traded.

- Ensure that the independent auditor is not engaged for any of the following nine types of non-audit services contemporaneous with the audit:

  - Bookkeeping or other services related to accounting records or financial statements of the Company;
  - Financial information systems design and implementation;
  - Appraisal or valuation services, fairness opinions, or contributions-in-kind reports;
  - Actuarial services;
  - Internal audit outsourcing services;
  - Any management or human resources function;
  - Broker, dealer, investment advisor, or investment banking services;
  - Legal services; and
  - Expert services related to the auditing service.

- Ensure that the independent auditor is compliant with the SEC, any security exchange on which the Company's shares are traded and the Institute of Chartered Accountants of Alberta (Rules of Professional Conduct) regarding Audit Partner Rotation requirements.

Hiring Practices

- Ensure that no officer or senior employee who is, or in the past full year has been, affiliated with or employed by a present or former auditor of the Company or an affiliate, is hired by the Company until at least one full year after the end of either the affiliation or the auditing relationship.

Independence Test

- Take reasonable steps to confirm the independence of the independent auditor, which shall include:

  - ensuring receipt from the independent auditor of a formal written statement delineating all relationships between the independent auditor and the Company, consistent with the Independence Standards Board Standard No. 1 and related Canadian regulatory body standards;
  - considering and discussing with the independent auditor any relationships or services, including non-audit services, that may impact the objectivity and independence of the independent auditor; and
  - as necessary, taking, or recommending that the Board of Directors take, appropriate action to oversee the independence of the independent auditor.

Audit Committee Meetings

- Only members of the Audit Committee have the right to attend the Audit Committee meetings. However, the CFO, internal auditors and external auditors will be invited to meetings of the Audit Committee on a regular basis and other non-members may be invited to attend all or part of any meeting as and when appropriate. The Audit Committee may request the presence of the independent auditor at any Audit Committee meeting.

- At the request of the independent auditor, convene a meeting of the Audit Committee to consider matters the auditor believes should be brought to the attention of the directors or shareholders.

- Keep minutes of its meetings and report to the Board for approval of any actions taken or recommendations made.

Restrictions

- Ensure no restrictions are placed by management on the scope of the auditors' review and examination of the Company's accounts.

- Ensure that no Officer or Director attempts to fraudulently influence, coerce, manipulate or mislead any accountant engaged in auditing of the Company's financial statements.

AUDIT AND REVIEW PROCESS AND RESULTS

Scope

- Consider, in consultation with the independent auditor, the audit scope and plan of the independent auditor.

Review Process and Results

- Consider and review with the independent auditor the matters required to be discussed by Statement on Auditing Standards No. 61, as the same may be modified or supplemented from time to time.

- Review and discuss with management and the independent auditor at the completion of the annual examination:

  - the Company's audited financial statements and related notes;
  - the Company's MD&A and news releases related to financial results;
  - the independent auditor's audit of the financial statements and its report thereon;
  - any significant changes required in the independent auditor's audit plan;
  - any non-GAAP related financial information;
  - any serious difficulties or disputes with management encountered during the course of the audit; and
  - other matters related to the conduct of the audit, which are to be communicated to the Audit Committee under generally accepted auditing standards.

- Review and discuss with management and the independent auditor annual and interim financial statements (including related notes and MD&A) at the completion of any review engagement or other examination and prior to public disclosure, and resolve to recommend approval of said documents to the Board of Directors.

- Review and discuss with management and the independent auditor the adequacy of the Company's internal control over financial reporting that management and the Board of Directors have established and the effectiveness of those systems, including, but not limited to, review and discussion of (1) management's report on its assessment of the effectiveness of internal control over financial reporting as of the end of each fiscal year and the independent auditor's report on management's assessment and the effectiveness of internal control over financial reporting, (2) inquiry of management and the independent auditor about significant financial risks, exposures, deficiencies or material weaknesses identified and the steps management has taken to minimize such risks, exposures, deficiencies and material weaknesses to the Company and (3) any changes in internal control over financial reporting that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting and are required to be disclosed, as well as any other changes in internal control over financial reporting that were considered for disclosure in the Company's periodic filings with the SEC.

- Meet separately with the independent auditor, management and the Chief Financial Officer as necessary or appropriate to discuss any matters that the Audit Committee or any of these groups believe should be discussed privately with the Audit Committee.

- Review and discuss with management and the independent auditor the accounting policies which may be viewed as critical, including all alternative treatments for financial information within generally accepted accounting principles that have been discussed with management, and review and discuss any significant changes in the accounting policies of the Company and industry accounting and regulatory financial reporting proposals that may have a significant impact on the Company's financial reports.

- Review with management and the independent auditor the effect of regulatory and accounting initiatives as well as off-balance sheet structures, if any, on the Company's financial statements.

- Review with management and the independent auditor any correspondence with regulators or governmental agencies and any employee complaints or published reports which raise material issues regarding the Company's financial statements or accounting policies.

- Review with the Company's General Counsel legal matters that may have a material impact on the financial statements, the Company's financial compliance policies and any material reports or inquiries received from regulators or governmental agencies related to financial matters.

SECURITIES REGULATORY FILINGS

- Review, prior to filing with regulatory bodies, annual and periodic filings with the Canadian provincial securities commissions, the SEC and the AIM regulator and other published documents containing the Company's financial statements.

RISK ASSESSMENT

- Meet semi-annually with the Officers' Risk Committee to discuss the Company's risk assessment and risk management. One meeting will be an in-depth review of the corporate risk assessment and emerging risks.

- Review the Company's policies with respect to risk assessment and risk management including, without limitation, environmental risk, insurance coverage and the risk of fraud. The Committee also shall discuss the Company's major risk exposures and the steps management has taken to monitor and control them.

AMENDMENTS TO AUDIT COMMITTEE CHARTER

- Annually review this Charter and propose amendments to be ratified by a simple majority of the Board of Directors.