ANNUAL INFORMATION FORM

For the year ended December 31, 2022

February 23, 2023

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Glossary of Terms

Unless the context otherwise requires, in this Annual Information Form the following terms and abbreviations have the meanings set forth below. **Additional terms relating to oil and natural gas reserves, resources and operations have the meanings set forth under "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information*" in this Annual Information Form and under "*Note to Reader Regarding Disclosure of Contingent Resources Information*" in Appendix A. All references to "Annual Information Form" include this Annual Information Form of the Corporation dated February 23, 2023, for the year ended December 31, 2022 and all appendices hereto.**

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended

"**Board**" means the board of directors of the Corporation

"**Bruin Acquisition**" means the acquisition by Enerplus USA of all of the equity interests of Bruin E&P HoldCo, LLC, a Delaware limited liability company, completed on March 10, 2021. See "*General Development of the Business – Developments in the Past Three Years*"

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

"**Common Shares**" means the common shares in the capital of the Corporation

"**Corporation**" means Enerplus Corporation, a corporation existing under the ABCA, and, where the context requires, its subsidiaries, taken as a whole

"**Credit Facilities**" means, collectively, the SLL Credit Facilities and the Senior Unsecured Notes. See "*Material Contracts and Documents Affecting the Rights of Securityholders*"

"**CSA Notice 51-324**" means Canadian Securities Administrators Staff Notice 51-324 (Revised) – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*, issued by the Canadian securities regulatory authorities

"Dunn County Acquisition" means the acquisition by Enerplus USA of certain assets in the Willison Basin from Hess Bakken Investments II, LLC, completed on April 30, 2021. See "*General Development of the Business – Developments in the Past Three Years*"

"**Enerplus**" means the Corporation and, where the context requires, its subsidiaries, taken as a whole

"**Enerplus USA**" means Enerplus Resources (USA) Corporation, a corporation organized under the laws of Delaware and a wholly-owned subsidiary of the Corporation

"**EOR**" mean enhanced oil recovery, as described in more detail under "*Business of the Corporation – Description of Properties*"

"**ESG**" means environmental, social and governance

"**ESG Policy**" means the Corporation's Environmental, Social and Governance Policy

"**Financial Statements**" means the audited consolidated financial statements of the Corporation as at December 31, 2022 and 2021 and for each of the years in the three-year period ended December 31, 2022

"**GHG**" means greenhouse gas

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

"**H&S Policy**" means the Corporation's Health & Safety Policy

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent petroleum consultants

"**McDaniel Reports**" means, collectively, the independent engineering evaluations of certain of the Corporation's crude oil, natural gas liquids and natural gas reserves in North Dakota and Colorado, and the Corporation's contingent resources associated with its North Dakota properties, prepared by McDaniel effective December 31, 2022 utilizing the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2023

"**MD&A**" means management's discussion and analysis for the year ended December 31, 2022

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

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*, adopted by the Canadian securities regulatory authorities

"**NSAI**" means Netherland, Sewell & Associates, Inc., independent petroleum consultants

"**NSAI Report**" means the independent engineering evaluation of the Corporation's shale gas reserves and contingent resources in the Marcellus properties prepared by NSAI effective December 31, 2022, utilizing the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2023

"**NYMEX**" means the New York Mercantile Exchange, a U.S.-based commodities futures market

"**NYSE**" means the New York Stock Exchange

"**Scope 1 Emissions**" means all direct GHG emissions

"**Scope 2 Emissions**" means indirect GHG emissions from consumption of purchased electricity, heat, or steam

"**SEC**" means the United States Securities and Exchange Commission

"**Senior Unsecured Notes**" means, as at December 31, 2022, the US$203.2 million principal amount of outstanding senior unsecured notes issued by Enerplus. See "*Description of Capital Structure – Senior Unsecured Notes*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*"

"**SLL Credit Facilities**" means, collectively and as at December 31, 2022, the Corporation's US$900 million senior, unsecured, covenant-based sustainability-linked revolving credit facility and the Corporation's US$365 million senior, unsecured, covenant-based sustainability-linked revolving credit facility, each held with a syndicate of financial institutions. See "*Description of Capital Structure – SLL Credit Facilities*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*"

"**Sproule**" means Sproule Associates Limited, independent petroleum consultants

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

"**TCFD**" means the Task Force on Climate-related Financial Disclosures

"**Term Facility**" means a US$400 million senior, unsecured, covenant-based term credit facility with a syndicate of financial institutions initially set to mature on March 10, 2024, which was most recently converted into the US$365 million SLL Credit Facility. See "*Description of Capital Structure – SLL Credit Facilities*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*"

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

"**U.S. GAAP**" means generally accepted accounting principles in the United States

"**USMCA**" means United States-Mexico-Canada Agreement

"**WTI**" means West Texas Intermediate crude oil that serves as the benchmark crude oil for NYMEX crude oil contracts delivered at Cushing, Oklahoma

Abbreviations, Conversions and Currency

In this Annual Information Form, the following abbreviations have the meanings set forth below:

API	American Petroleum Institute gravity, a measure of how heavy or light a petroleum liquid is compared to water
bbls	barrels, with each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/day	barrels per day
Bcf	one billion cubic feet
BOE(1)	barrels of oil equivalent
BOE/day(1)	barrels of oil equivalent per day
Mbbls	one thousand barrels
MBOE(1)	one thousand barrels of oil equivalent
Mcf	one thousand cubic feet
Mcf/day	one thousand cubic feet per day
MMBOE(1)	one million barrels of oil equivalent
MMbtu	one million British Thermal Units
MMcf	one million cubic feet
NGLs	natural gas liquids
NPV	net present value of future net revenue, discounted at 10%

Note:
(1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs. For further information, see "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information – Barrels of Oil Equivalent*".

In this Annual Information Form, unless otherwise indicated, all dollar amounts are in U.S. dollars and all references to "**$**" and "**US$**" are to U.S. dollars. References to "**CDN$**" are to Canadian dollars. On December 30, 2022, the exchange rate for one Canadian dollar, expressed in U.S. dollars and based upon the closing rate from Bloomberg, was $0.74. The average exchange rate in 2022 for one Canadian dollar, expressed in U.S. dollars and based upon the average closing rate from Bloomberg, was $0.77.

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.471

Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information

DISCLOSURE OF RESERVES AND PRODUCTION INFORMATION

Except for the information presented in Appendix B and as otherwise noted below, all oil and gas information presented in this Annual Information Form has been prepared and is presented in accordance with the Canadian disclosure standards set forth in NI 51-101 (the "**Canadian Standards**").

The oil and gas reserves information of the Corporation contained in Appendix B, effective as at December 31, 2022, is prepared and presented in accordance with the provisions of the Financial Accounting Standards Board's ASC Topic 932 Extractive Activities – Oil and Gas ("**ASC 932**"), which generally utilize definitions and estimations of proved reserves that are consistent with Rule 4-10 of Regulation S-X promulgated by the SEC (together with the ASC 932, the "**U.S. Rules**"), but does not necessarily include all of the disclosure required by the SEC disclosure requirements set forth in Subpart 1200 of Regulation S-K (the "**U.S. Standards**"). Concurrently with the evaluation of the Corporation's reserves under Canadian Standards, McDaniel and NSAI prepared and reviewed estimates of the Corporation's reserves under the U.S. Standards. The practice of preparing production and reserves data under NI 51-101 differs from the U.S. Rules. The significant differences between the two reporting requirements are described under *"Notice to U.S. Readers*", below.

The oil and gas reserves and operational information of the Corporation contained in this Annual Information Form contains the information required to be included in the Statement of Reserves Data and Other Oil and Gas Information pursuant to Canadian Standards. Readers should also refer to the Report on Reserves Data and Contingent Resources Data by McDaniel and NSAI attached as Appendix C and the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix D. The effective date for the Statement of Reserves Data and Contingent Resources and Other Oil and Gas Information contained in this Annual Information Form is December 31, 2022 and the preparation dates for such information are February 2, 2023 for the McDaniel Reports and February 7, 2023 for the NSAI Report.

For information regarding contingent resources of the Corporation and its presentation in accordance with Canadian Standards, see Appendix A.

In this Annual Information Form, all oil and natural gas production volumes are presented on a "net" basis, as described under " - *Interests in Reserves, Contingent Resources, Production, Wells and Properties*" below, unless expressly indicated that it is being presented on a "gross" basis in accordance with Canadian Standards.

In this Annual Information Form, all oil and natural gas information includes tight oil and shale gas, respectively, unless expressly indicated that it is being presented on a separate basis. The Corporation's actual oil and natural gas reserves and future production may be greater than or less than the estimates provided in this Annual Information Form. The estimated future net revenue from the production of such oil and natural gas reserves does not necessarily represent the fair market value of such reserves. See "*Oil and Natural Gas Reserves – Summary of Reserves*" and Appendix B, as applicable, for additional information.

NOTICE TO U.S. READERS

Except for the information set forth in Appendix B, all data on oil and natural gas reserves contained in this Annual Information Form has generally been prepared and is presented in accordance with Canadian Standards, which are not comparable in all respects to U.S. Standards or other foreign disclosure standards. The primary differences between the two reporting frameworks include:

- Under NI 51-101 and Canadian industry practice, reserves and production are reported using gross volumes, while the U.S. Standards and U.S. industry practice is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments, plus royalty interests. As discussed above, certain oil and gas production volumes in this Annual Information Form are presented on a net basis.

- Under NI 51-101, the Corporation has determined and disclosed estimated future net revenue from its reserves using forecast prices and escalating costs, whereas the U.S. Standards require that reserves estimates be prepared using an unweighted average of the closing prices for the applicable commodity on the first day of each of the twelve months preceding the Corporation's fiscal year-end, with the option of also disclosing reserves estimates based upon future or other prices and constant costs.

- NI 51-101 requires that reserves and other data be reported on a more granular product type bases than required under the U.S. Standards.

- NI 51-101 requires that proved undeveloped reserves be reviewed annually for retention or reclassification if development has not proceeded as previously planned, while the U.S. Standards specify a five-year limit after initial booking for the development of proved undeveloped reserves.

- The SEC prohibits disclosure of oil and gas resources in SEC filings, including contingent resources, whereas Canadian securities regulatory authorities allow disclosure of oil and gas resources. Resources are different than, and should not be construed as, reserves.

As a consequence of the foregoing, except for the reserves information set forth in Appendix B, which has been prepared in accordance with U.S. Rules, the Corporation's reserves estimates and certain production volumes that are presented on a gross basis may not be comparable to those made by companies utilizing U.S. Standards. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see *"Note to Reader Regarding Disclosure of Contingent Resources Information*" in Appendix A.

For certain oil and gas information prepared and presented in accordance with the U.S. Rules, see Appendix B.

BARRELS OF OIL EQUIVALENT

The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs. The conventions BOEs, MBOEs and MMBOEs may be misleading, particularly if used in isolation because the foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

INTERESTS IN RESERVES, CONTINGENT RESOURCES, PRODUCTION, WELLS AND PROPERTIES

Certain of the following definitions and guidelines are contained in the Glossary to NI 51-101 contained in CSA Notice 51-324, which incorporates certain definitions from the COGE Handbook. Readers should consult CSA Notice 51-324 and the COGE Handbook for additional explanation and guidance.

In addition to the terms having defined meanings set forth in CSA Notice 51-324, the terms set forth below have the following meanings when used in this Annual Information Form:

"**gross**" means:

i. in relation to the Corporation's interest in production, reserves or contingent resources, its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation

ii. in relation to wells, the total number of wells in which the Corporation has an interest

iii. in relation to properties, the total area in which the Corporation has an interest

"**net**" means:

i. in relation to the Corporation's interest in production, reserves or contingent resources, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves

ii. in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells

iii. in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation

"**working interest**" means the percentage of undivided interest held by the Corporation in the oil and/or natural gas or mineral lease granted by the mineral owner (Crown or freehold), which interest gives the Corporation the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

RESERVES CATEGORIES AND LEVELS OF CERTAINTY FOR REPORTED RESERVES

In this Annual Information Form, except in Appendix B, the following terms have the meaning assigned thereto in CSA Notice 51-324 and the COGE Handbook:

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: 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 may be divided into proved and probable categories according to the degree of certainty associated with the estimates.

"**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.

"**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.

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

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

DEVELOPMENT AND PRODUCTION STATUS

Each of the reserves categories reported by the Corporation (proved and probable) may be divided into developed and undeveloped categories:

"**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.

- "**developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- "**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**undeveloped reserves**" are those reserves that are 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 or probable) to which they are assigned.

DESCRIPTION OF PRICE AND COST ASSUMPTIONS

"**Forecast prices and costs**" means future prices and costs that are:

i. generally accepted as being a reasonable outlook of the future

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

Presentation of Financial Information

The Corporation presents its financial information in accordance with U.S. GAAP and in U.S. dollars as its reporting currency.

This Annual Information Form references certain financial measures, including "adjusted funds flow", "capital spending" and "free cash flow", which are specified financial measures under National Instrument 52-112. See "Non-GAAP and Other Financial Measures" in the MD&A for additional detail regarding such measures, which section is incorporated by reference in this Annual Information Form.

The Corporation continues to qualify as a foreign private issuer for the purposes of its U.S. securities filings based on the most recent assessment performed as at June 30, 2022. The Corporation is required to reassess this conclusion annually, at the end of the second quarter. See "*Risk Factors – The Corporation could lose its status as a "foreign private issuer" in the United States, which may result in additional compliance costs and restricted access to capital markets*".

Forward-Looking Statements and Information

This Annual Information Form contains certain forward-looking statements and forward-looking information (collectively, "forward-looking information") within the meaning of applicable securities laws which are based on the Corporation's current internal expectations, estimates, projections, assumptions, and beliefs. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plan", "intend", "guidance", "objective", "strategy", "should", "believe" and similar expressions are intended to identify forward-looking information. These statements are not guarantees of future performance, and 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 Corporation 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 Annual Information Form should not be relied upon unduly. Such forward-looking information speaks only as of the date of this Annual Information Form and the Corporation does not undertake any obligation to publicly update or revise any forward-looking information, except as required by applicable laws.

In particular, this Annual Information Form contains forward-looking information pertaining to the following:

- the quantity of, and future net revenues from, the Corporation's reserves and/or contingent resources
- crude oil, NGLs and natural gas production levels
- commodity prices, foreign currency exchange rates and interest rates
- operating expenditures
- current capital spending programs, drilling programs, development plans and other future expenditures, including the planned allocation of capital spending among the Corporation's properties and the sources of funding for such expenditures
- supply and demand for oil, NGLs and natural gas
- the Corporation's business strategy, including its asset and operational focus
- future acquisitions and divestments, and future growth potential
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves and/or resources through acquisitions and development
- schedules for and timing of certain projects and the Corporation's strategy for growth
- the Corporation's future operating and financial results
- the Corporation's tax pools and the time at which the Corporation may incur certain income or other taxes
- treatment of, and compliance by the Corporation with, governmental and other regulatory regimes and tax, environmental and other laws

- the Corporation’s ESG strategy, including specific targets relating to GHG emissions and freshwater use reductions, as well as climate change-related initiatives

- estimates of the Corporation’s future abandonment and reclamation obligations

- future dividends that may be paid by the Corporation

- future repurchases of Common Shares by the Corporation

The forward-looking information contained in this Annual Information Form reflects several material factors and expectations and assumptions made by the Corporation including, without limitation: stability, or no further deterioration, in the global economic and market environment, including related to the Ukraine and Russian conflict or from the COVID pandemic, variations thereof, and/or future pandemics, epidemics, or other world-wide health crises; the Corporation's current commodity price and other cost assumptions will generally be accurate; the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures, repurchase shares, pay dividends and other requirements or strategic initiatives, as needed; the Corporation's conduct and results of operations will be consistent with its expectations; the Corporation and its industry partners will have the ability to develop the Corporation's crude oil and natural gas properties in the manner currently contemplated; a lack of infrastructure, government regulations or export bans do not result in the Corporation or a third party curtailing its production and/or receiving reductions to its realized prices; 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 Corporation's reserves and resources volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; and there will be sufficient availability of services and labour to conduct the Corporation's operations as planned.

For the purposes of the disclosure under the “Environmental, Social and Governance” sub-heading within this Annual Information Form, the term “material” is not used for, does not have, and is not intended to have, the same meaning as such term is assigned under the applicable securities laws, including, but not limited to, with respect to financial materiality, materiality to investors or creditors, enterprise value, or other indications of financial impact, and is used solely to reflect the Corporation’s identification of those ESG areas that the Corporation has determined within its judgement present significant ESG risks or opportunities to its operations.

The Corporation's current 2023 capital spending budget of between $500 to $550 million contained in this Annual Information Form assumes: a WTI price of $80 per barrel, a Bakken crude oil price differential of $0.75 per barrel above WTI, a NYMEX natural gas price of $3.50 per Mcf, a Marcellus natural gas price differential of $0.75 per Mcf below NYMEX and a foreign exchange rate of CDN/USD 0.75.

The Corporation believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable at this time, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The Corporation's actual results could differ materially from those anticipated in this forward-looking information as a result of both known and unknown risks, including the risk factors set forth under "*Risk Factors*" in this Annual Information Form and risks relating to:

- ongoing volatility in market prices for crude oil, NGLs and natural gas, including changes in supply or demand for those products, and the Corporation's realized prices

- actions by governmental or regulatory authorities, including as a result of economic sanctions, a global pandemic or mandated production curtailments, potential export bans initiated by governments or different interpretations of applicable laws, treaties or administrative positions, as well as changes in income tax laws or changes in royalty regimes and incentive programs relating to the oil and gas industry

- changes in general economic, market (including credit market) and business conditions in North America and worldwide, including risks of recession, inflation, interest rate increases and foreign exchange fluctuations

- changes in political environments (e.g., geopolitical and technopolitical) and public opinion

- unanticipated operating results, including changes or fluctuations in crude oil, NGLs and natural gas production levels

- incorrect assessments of the value of acquisitions or divestments, or the failure to complete divestments

- failure to realize anticipated benefits of recently completed or future acquisitions

- changes in foreign currency exchange rates, including Canadian currency compared to U.S., and its impact on the Corporation’s operations and financial condition
- changes in interest rates
- the ability of the Corporation to achieve specific targets that are part of its ESG strategy, including those relating to Scope 1 and Scope 2 GHG emissions intensity, methane emissions intensity and freshwater use reductions, as well as other climate change-related initiatives
- changes in development plans by the Corporation or third-party operators
- the ability of the Corporation to comply with debt covenants under the Credit Facilities
- the ability of the Corporation to access required capital
- changes in capital and other expenditure requirements and debt service requirements
- liabilities and unexpected events inherent in oil and gas operations, including geological, technical, drilling and processing risks, as well as unforeseen title defects or litigation
- actions of and reliance on industry partners
- uncertainties associated with estimating reserves and resources
- competition for, among other things, capital, acquisitions of reserves and resources, undeveloped lands, access to services, third party processing capacity and skilled personnel
- constraints on, or the unavailability of, adequate infrastructure, including pipeline and other transportation capacity, to deliver the Corporation's production to market, whether in the control of the Corporation or not
- the Corporation's success at the acquisition, exploitation and development of reserves and resources
- changes in tax, environmental, regulatory, or other legislation applicable to the Corporation, including those which are climate change-related, and the Corporation's ability to comply with current and future environmental legislation and regulations and other laws and regulations, including those impacting financial institutions, that could limit commodity market liquidity and/or impact the Corporation's production and operations

Many of these risk factors and other specific risks and uncertainties are discussed in further detail throughout this Annual Information Form and in the Corporation's MD&A, which are available on the internet under the Corporation's SEDAR profile at www.sedar.com, the Corporation's EDGAR profile at www.sec.gov as part of the annual report on Form 40-F filed with the SEC (together with this Annual Information Form), and on the Corporation's website at www.enerplus.com. Readers are also referred to the risk factors described in this Annual Information Form under "*Risk Factors*" and in other documents the Corporation files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the Corporation or electronically on the internet on the Corporation's SEDAR profile at www.sedar.com, on the Corporation's EDGAR profile at www.sec.gov and on the Corporation's website at www.enerplus.com.

Corporate Structure

ENERPLUS CORPORATION

The Corporation was incorporated on August 12, 2010 under the ABCA for the purposes of participating in a plan of arrangement under the ABCA, pursuant to which the business of Enerplus Resources Fund, as the Corporation's predecessor, was transitioned to the Corporation on January 1, 2011. Prior to this transaction, the business of the Corporation was carried on by Enerplus Resources Fund and its subsidiaries as an income trust since 1986.

Effective May 11, 2012, the Corporation amended and restated its Articles in connection with the implementation of a stock dividend program. See "*Description of Capital Structure – Common Shares*" and "*Dividends – Stock Dividend Program*".

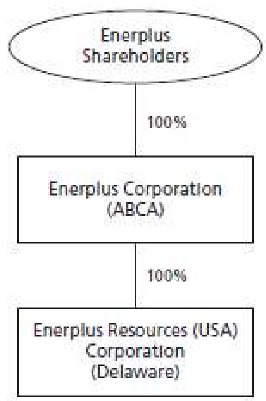
The Corporation's head offices are located at The Dome Tower, 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1, which is also its registered office, and at The US Bank Tower, 2200, 950 - 17th Street, Denver, Colorado, 80202-2805. The Common Shares are currently traded on the TSX and the NYSE under the symbol "ERF".

MATERIAL SUBSIDIARIES

As of December 31, 2022, Enerplus USA was the only material subsidiary of Enerplus Corporation. All of the issued and outstanding securities of Enerplus USA are owned by the Corporation.

ORGANIZATIONAL STRUCTURE

The simplified organizational structure of Enerplus Corporation and its material subsidiary as of December 31, 2022 is set forth below.



General Development of the Business

DEVELOPMENTS IN THE PAST THREE YEARS

Developments in 2020

In early 2020, the Corporation's focus was on maintaining a strong balance sheet and returning cash to shareholders through its monthly dividend and share repurchases. With the onset of the COVID pandemic in March of 2020, there was a sudden global economic downturn creating significant challenges for the energy industry and reduced global demand for crude oil and natural gas. In response to the decline in crude oil demand and historically low prices, Enerplus suspended its operated drilling and completions activity in North Dakota, and temporarily curtailed production from certain wells across its crude oil and natural gas liquids properties during the second quarter of 2020 to preserve cash flow. As commodity prices improved, Enerplus brought the majority of the curtailed production back online by early July 2020 and resumed limited completion activity during the fourth quarter under a lower capital spending program. The Corporation continued its monthly dividend through 2020; however, the Corporation did not renew its normal course issuer bid in order to preserve capital and maintain its balance sheet strength.

Developments in 2021

ACQUISITIONS & ASSET SALES

On March 10, 2021, the Corporation completed the Bruin Acquisition for approximately $465 million, before purchase price adjustments of $45 million, resulting in the final purchase price of approximately $420 million. The Bruin Acquisition included approximately 24,000 BOE/day of gross production (72% tight oil, 14% NGLs and 14% natural gas) at the time of closing and was financed with the Term Facility and equity financing completed on February 3, 2021.

On April 30, 2021, the Corporation completed the Dunn County Acquisition involving certain crude oil and natural gas assets comprised of 78,700 net acres in the Williston Basin for total cash consideration of $312 million, before purchase price adjustments and transaction costs of $5.2 million, resulting in the final purchase price of $306.8 million. The Dunn County Acquisition included approximately 6,000 BOE/day of gross production (76% tight oil, 10% NGLs, and 14% natural gas) at the time of closing and was financed with cash on hand and by borrowing on the $900 million SLL Credit Facility.

On November 2, 2021, the Corporation completed the sale of its Sleeping Giant (Montana) and Russian Creek (North Dakota) interests in the Williston Basin for total cash consideration of $115 million, before purchase price adjustments and transaction costs of $7.2 million, resulting in the final purchase price of $107.8 million. Under this transaction, the Corporation was eligible to receive up to an additional $5 million contingent upon where WTI settled for each of 2022 and 2023. In January 2023, the Corporation received a $2.5 million contingent payment as WTI averaged over $65 per barrel in 2022; the second payment will be received if WTI averages over $60 per barrel in 2023. The divested assets included approximately 3,000 BOE/day of gross production (76% tight oil, 1% NGLs and 23% natural gas).

For a description of the Corporation's Bakken interests, see "*Business of the Corporation – Description of Properties – Crude Oil Properties*".

FINANCINGS

Equity Financing

On February 3, 2021, Enerplus completed a CDN$132 million equity offering with a total of 33,062,500 Common Shares issued. Net proceeds from the offering were used to finance the Bruin Acquisition and to fund increased capital expenditures on the acquired properties and other expenses in connection with the Bruin Acquisition.

Credit Facilities

Upon closing of the Bruin Acquisition on March 10, 2021, Enerplus entered into a three-year senior unsecured $400 million Term Facility, which was set to mature on March 10, 2024. The Term Facility loan included financial and other covenants consistent with the $900 million SLL Credit Facility. See " – *Developments in 2022 – Financing*" below.

On April 29, 2021 Enerplus increased and extended its senior, unsecured bank credit facility to $900 million with a maturity date of October 31, 2025. As part of the extension of the SLL Credit Facility, the Corporation transitioned the facility to a sustainability-linked credit facility.

See "*Description of Capital Structure*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*".

SHAREHOLDER RETURNS – DIVIDEND & SHARE REPURCHASES

On May 6, 2021, the Corporation announced an increase in the amount of its dividend, as well as a change in the frequency of its dividend payment from monthly to quarterly, effective with its June 2021 dividend payment. The Corporation also increased its dividend for September and December 2021, which resulted in an increase of 37%, on an annualized basis, during 2021.

The Corporation renewed its normal course issuer bid on August 16, 2021 to purchase up to 10% of the public float (within the meaning under the TSX rules) during a 12-month period. During 2021, Enerplus repurchased an aggregate of approximately 12.9 million Common Shares for aggregate proceeds of approximately $123.2 million.

Developments in 2022

ASSET SALES

On February 2, 2022, Enerplus announced its plans to initiate a divestment process for its Canadian assets. On October 31, 2022 Enerplus completed the sale of its Ante Creek and Medicine Hat assets, together with broad interests west of the fifth and sixth meridians of Alberta, for total consideration of $104.4 million (CDN$142.2 million), prior to closing adjustments. On December 19, 2022, Enerplus completed the sale of substantially all of its remaining Canadian assets for total consideration of $174.5 million (CDN$238.2 million), prior to closing adjustments. After purchase price adjustments, proceeds from the two divestments were $213.0 million.

Notwithstanding the sale of substantially all of its Canadian assets in 2022, the Corporation continues to maintain a Canadian head office. See "*Business of the Corporation – Summary of Principal Production Locations*" and "*Business of the Corporation – Description of Properties*".

FINANCING

On February 23, 2022 Enerplus converted the Term Facility into a revolving bank credit facility with no other amendments, which was subsequently, on November 3, 2022, converted into the $365 million SLL Credit Facility maturing on October 31, 2025. Also, on November 3, 2022 the $900 million SLL Credit Facility was extended with $50 million maturing on October 31, 2025 and $850 million maturing on October 31, 2026.

See "*Description of Capital Structure*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*".

SHAREHOLDER RETURNS – DIVIDEND & SHARE REPURCHASES

During 2022, the Corporation changed its dividend declaration amount to US dollars (from Canadian dollars) and increased its quarterly dividend by 67% to US$0.055 per share.

In August 2022, the Corporation renewed its normal course issuer bid to purchase up to 10% of the "public float" (within the meaning under the TSX rules) during a 12-month period commencing on August 16, 2022. During 2022, Enerplus repurchased an aggregate of approximately 27.9 million Common Shares at an aggregate cost of approximately $410.9 million. From January 1, 2023 to February 22, 2023, the Corporation repurchased an additional approximately 1.4 million Common Shares for an aggregate cost of approximately $23.7 million.

Business of the Corporation

OVERVIEW

Substantially all of the Corporation's crude oil and natural gas property interests at December 31, 2022 are located in the United States, in North Dakota, Colorado and Pennsylvania. Capital spending on the Corporation's assets in 2022 totaled $432.0 million. Substantially all of the Corporation's Canadian assets were sold during 2022 (see "*General Development of the Business—Developments in the Past Three Years—Developments in 2022—Asset Sales")*.

Capital spending on the Corporation's Williston Basin and Colorado assets totaled $368.0 million during 2022. Capital spending on the Corporation's natural gas interests in northeast Pennsylvania was $57.6 million. Capital spending in Canada totaled approximately $6.1 million.

In 2022, the Corporation spent $17.4 million on abandonment and reclamation activities, $11.9 million of which related to the abandonment of its Tommy Lakes asset in British Columbia with the majority of the remaining $5.5 million spent across various other Canadian properties.

Production volumes for the year ended December 31, 2022 from the Corporation's properties consisted of 61% crude oil and NGLs and 39% natural gas, on a BOE/day basis. The Corporation's major producing properties generally have related field facilities and infrastructure to accommodate its production. The Corporation's 2022 average daily production was 100,326 BOE/day, comprised of: 47,511 bbls/day of tight oil, 2,556 bbls/day of heavy oil, 1,950 bbls/day of light and medium oil (a total of 52,017 bbls/day of crude oil), 9,681 bbls/day of NGLs and 231,770 Mcf/day of natural gas (includes 225,845 Mcf/day of shale gas). Production increased approximately 9% compared to 2021 average daily production of 92,221 BOE/day, comprised of: 42,981 bbls/day of tight oil, 3,302 bbls/day of heavy oil, 2,231 bbls/day of light and medium oil (totaling 48,514 bbls/day of crude oil), 7,823 bbls/day of NGLs and 215,304 Mcf/day of natural gas (includes 207,486 Mcf/day of shale gas). See "*Summary of Principal Production Locations*". The increase in average daily production in 2022 compared to 2021 is largely attributable to strong well performance from Enerplus' Bakken assets, including the full year contribution from its 2021 acquisitions, and higher completions activity in the Marcellus.

The Corporation's 2022 production in the United States was approximately 95**%** of its total production, with the remaining 5**%** from Canada. Approximately 66% of the Corporation's 2022 production was operated by the Corporation, with the remainder operated by industry partners.

At December 31, 2022, the crude oil and natural gas property interests held by the Corporation were estimated to contain total proved plus probable gross reserves of 317.1 MMbbls of tight oil, 56.3 MMbbls of NGLs and 1,365.9 Bcf of shale gas, for a total of 601.1 MMBOE. The Corporation's proved reserves represented approximately 65% of total proved plus probable reserves, with approximately 62% of the Corporation's proved plus probable reserves weighted to crude oil and NGLs. See "*Oil and Natural Gas Reserves*".

Unless otherwise noted: (i) all production, reserves and operational information in this Annual Information Form is presented as at or, where applicable, for the year ended, December 31, 2022, (ii) all production information represents the Corporation's net production from these properties, which is calculated after deduction of royalty interests owned by others and including the Corporation's royalty interests, and (iii) except for disclosure in Appendix B, all references to reserves volumes represent gross reserves using forecast prices and costs. See "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information*".

SUMMARY OF PRINCIPAL PRODUCTION LOCATIONS

For the year ended December 31, 2022, on a BOE basis, approximately 95% of the Corporation's gross production was derived from the United States (64% from North Dakota, 26% from Pennsylvania and 5% from Colorado) and 5% from Canada (4% from Alberta and 1% from Saskatchewan).

The following table describes the average daily gross production from the Corporation's principal producing properties and regions during the year ended December 31, 2022.

2022 Average Daily Gross Production from Principal Properties and Regions(1)

	Products						
	Crude Oil						
Property/Region	**Light and Medium**	**Heavy**	**Tight**	**NGLs**	**Conventional Natural Gas**	**Shale Gas**	**Total, Gross**
	(bbls/day)	(bbls/day)	(bbls/day)	(bbls/day)	(Mcf/day)	(Mcf/day)	**(BOE/day)**
United States							
North Dakota	-	-	58,041	11,583	-	69,335	81,180
Marcellus, Pennsylvania	-	-	-	-	-	211,168	35,195
DJ Basin, Colorado	-	-	996	131	-	881	1,274
Total United States	**-**	**-**	**59,037**	**11,714**	**-**	**281,384**	**117,649**
Canada(2)							
Freda Lake, Saskatchewan	1,945	-	-	-	-	-	1,945
Medicine Hat Glauconitic "C" Unit, Alberta	-	1,464	-	-	213	-	1,500
Giltedge, Alberta	-	1,386	-	-	213	-	1,422
Ante Creek, Alberta	710	-	-	112	837	-	962
Other Canada	25	468	-	216	4,506	195	1,490
Total Canada	**2,680**	**3,318**	**-**	**328**	**5,769**	**195**	**7,319**
Total	**2,680**	**3,318**	**59,037**	**12,042**	**5,769**	**281,579**	**124,968**

(1) The gross production volumes in this table will not match certain of the production volumes presented elsewhere in this Annual Information Form, which are presented on a net basis. See "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information – Disclosure of Reserves and Production Information*" in this Annual Information Form.
(2) During 2022, Enerplus sold substantially all of its Canadian assets. See "*General Development of the Business – Developments in the Past Three Years – Developments in 2022*". For additional information on the Corporation's crude oil and natural gas properties, see "*Description of Properties*".

CAPITAL EXPENDITURES AND COSTS INCURRED

The Corporation invested $432.0 million in its capital spending program during 2022, with 87% directed to crude oil-related projects, approximately 43% higher than its 2021 capital spending program of $302.3 million. Capital spending during 2022 was focused primarily in the Corporation's North Dakota Bakken crude oil property (with investment of $365.2 million). The Corporation's Marcellus non-operated assets received capital investment of $57.6 million during the year. The remaining $9.2 million of capital was spent across the Corporation's other assets, including approximately $6.1 million in Canada.

In the financial year ended December 31, 2022, the Corporation made the following expenditures in the categories noted, as prescribed by NI 51-101:

	Property Acquisition Costs		Exploration Costs	Development Costs
	Proved	**Unproved**		
	(US$ in millions)			
United States	$ 21.3	$ -	$ 1.4	$ 424.5
Canada	1.2	-	0.2	5.9
Total	$ 22.5	$ -	$ 1.6	$ 430.4

For further information regarding the Corporation's properties and its 2022 exploration and development activities, see "*Description of Properties*", below.

Based on a budgeted commodity price of $80 per barrel WTI for crude oil, $3.50 per Mcf NYMEX for natural gas, a Bakken differential of $0.75 per bbl above WTI, a Marcellus differential of $0.75 per Mcf below NYMEX and a foreign exchange rate of CDN/USD 0.75, the Corporation's 2023 exploration and development capital spending is estimated to be between $500 to $550 million.

The Corporation intends to finance its 2023 capital spending program with cash, internally generated cash flow and/or debt. The Corporation will review its 2023 capital investment plans throughout the year in the context of prevailing economic conditions, commodity prices and potential acquisitions and divestments, making adjustments as it deems necessary. See "*Forward-Looking Statements and Information*".

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes the number and type of wells that the Corporation drilled, or participated in the drilling of, for the year ended December 31, 2022, all of which were located in the United States. Wells have been classified in accordance with the definitions of such terms in NI 51-101.

	Development Wells		Exploratory Wells	
Category of Well	**Gross**	**Net**	**Gross**	**Net**
Crude oil wells	103	46.2	-	-
Natural gas wells	81	5.5	-	-
Service wells	-	-	-	-
Dry and abandoned wells	-	-	-	-
Total	184	51.7	-	-

For a description of the Corporation's 2023 development plans and the anticipated sources of funding these plans, see "*Capital Expenditures and Costs Incurred*", above.

OIL AND NATURAL GAS WELLS AND UNPROVED PROPERTIES

The following table summarizes, at December 31, 2022, the Corporation's interests in producing wells and wells which were drilled but not producing, but which may be capable of production in the future (the "**Non-Producing Wells**"), along with the Corporation's interests in unproved properties (as defined in NI 51-101). Although many wells produce both crude oil and natural gas, a well is categorized as a crude oil well or a natural gas well based upon the proportion of crude oil or natural gas production that constitutes the majority of production from that well.

	Producing Wells				Non-Producing Wells				Unproved Properties (acres)	
	Crude Oil		Natural Gas		Crude Oil		Natural Gas			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States										
Colorado	30	14.1	-	-	17	0.9	-	-	23,480	21,528
North Dakota	1,333	774.9	-	-	31	17.7	-	-	5,023	2,081
Pennsylvania	-	-	1,132	111.0	-	-	47	5.7	22,685	5,877
Total	1,363	789.0	1,132	111.0	48	18.6	47	5.7	51,188	29,486

The Corporation expects its rights to explore, develop and exploit on approximately 648 net acres of its unproved properties to expire in the ordinary course prior to December 31, 2023. The Corporation has no material work commitments on its unproved properties and, where the Corporation determines appropriate, it can extend expiring leases by either making the necessary applications to extend or performing the necessary work.

For any properties with no reserves or on unproved lands, the Corporation does not have any unusually significant abandonment and reclamation costs, unusually high expected development costs or operating costs, or 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. Operating expenditures and abandonment and reclamation costs for all properties with no reserves or on unproved lands are included in the Corporation's asset retirement disclosures in the Financial Statements.

DESCRIPTION OF PROPERTIES

Outlined below is a description of the Corporation's crude oil and natural gas properties and assets, all of which are located onshore in the United States.

For additional information on contingent resources associated with certain of the Corporation's crude oil and natural gas properties, including estimated volumes of economic contingent resources, see "*Appendix A – Contingent Resources Information*".

Crude Oil Properties

OVERVIEW

The Corporation's primary crude oil properties are located in the Bakken in North Dakota and the Wattenberg Field in Weld County of the DJ Basin of Colorado. The Corporation spent $376.7 million on its crude oil assets in 2022, including the Canadian waterflood assets which were sold during the year.

The Corporation has approximately 235,600 net acres of land primarily on the Fort Berthold Indian Reservation ("**FBIR**") as well as Williams and Dunn Counties. On a production basis, Enerplus operates approximately 92% of its North Dakota asset. The Corporation's Bakken properties produce a light sweet crude oil (42° API), with some associated natural gas and NGLs, from both the Bakken and Three Forks formations. Production in the Bakken averaged 65,370 BOE/day in 2022, which consisted of 46,706 bbls/day of tight oil, 9,333 bbls/day of NGLs and 55,987 Mcf/day of shale gas. During 2022, the Corporation spent $365.2 million on its operated and non-operated assets in North Dakota, and including the assets acquired pursuant to the Bruin Acquisition and Dunn County Acquisition. This included drilling 45.7 net horizontal wells (38.8 operated and 7.0 non-operated), targeting the Bakken and Three Forks formations (all of which were long lateral wells), with 43.3 net wells brought on-stream (35.5 operated and 7.8 non-operated**).** At the end of 2022, the Corporation had 13.3 net operated drilled uncompleted wells in North Dakota.

The Corporation holds approximately 32,950 net acres (held through leasing and farm-ins) in the DJ Basin of Colorado (northwest Weld County, Wattenberg Field). The Wattenberg Field has been producing since the 1970's and is characterized as having high recoveries and initial production rates, long reserves life and multiple stacked producing horizons. Capital investment in the DJ Basin in 2022 was $2.8 million and focused on completing and bringing 0.3 net operated wells onstream. Average annual production for 2022 was 1,026 BOE/day (78% tight oil). At the end of 2022, the Corporation had no operated drilled uncompleted wells in Colorado.

Overall, the Corporation's crude oil properties produced an average of 72,168 BOE/day in 2022, an increase of 8% from 2021 primarily due to the benefit of the 2021 acquisitions. On a BOE basis, production from crude oil properties represented 72% of the Corporation's 2022 average daily production of 100,326 BOE/day.

Approximately 51.0 MMBOE of gross proved plus probable reserves were added in North Dakota during 2022, including extensions, acquisitions, technical revisions and economic factors. After adjusting for 2022 gross production of 29.6 MMBOE, total gross proved plus probable reserves associated with this property as at December 31, 2022 were 424.7 MMBOE, approximately 5% greater than at December 31, 2021.

The Corporation had 426.8 MMBOE of gross proved plus probable reserves associated with its crude oil assets at December 31, 2022, representing approximately 71% of its total gross proved plus probable reserves.

The Corporation has entered into long-term agreements for the gathering, dehydration, processing, compression and transportation of the Corporation's share of crude oil, natural gas and NGL production from its North Dakota properties. These agreements are intended to provide the Corporation with cost certainty, and access to the U.S. Gulf Coast, where it can further access export crude oil markets. See "*Marketing Arrangements and Forward Contracts*" for further information. The Corporation has also entered into a long-term agreement for gas processing in the DJ Basin under a contract with dedicated lands, but no take or pay, or minimum commitments.

Natural Gas Properties

OVERVIEW

The Corporation's natural gas properties consist entirely of its non-operated Marcellus shale gas interests located in northeastern Pennsylvania, where the Corporation holds an interest in approximately 32,500 net acres. The Corporation's Marcellus shale gas production averaged approximately 169 MMcf/day in 2022, representing approximately 28% of the Corporation's total average daily production of 100,326 BOE/day.

In 2022, $57.6 million was invested in the Corporation's non-operated Marcellus interests. The Corporation participated in the drilling of 5.5 net wells and 6.8 net wells were brought on-stream.

Gross proved plus probable Marcellus shale gas reserves were 1,045.8 Bcf as at December 31, 2022, a decrease of 5.3 Bcf from 2021, and represented approximately 29% of the Corporation's total gross proved plus probable reserves.

The Corporation has entered into long-term agreements for the gathering, dehydration, compression and transportation of the Corporation's share of production from its Marcellus properties. These agreements are intended to provide the Corporation with cost certainty and access to the northeastern United States and broader U.S. natural gas markets through connections with major interstate pipelines. See "*Marketing Arrangements and Forward Contracts*" for further information.

QUARTERLY PRODUCTION HISTORY[1]

The following table sets forth the Corporation's average daily production volumes, on a gross basis, by product type, for each fiscal quarter in 2022 and for the entire year, separately for production in Canada and the United States, and in total.

	Year Ended December 31, 2022				
Country and Product Type	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States					
Light and medium oil (bbls/day)	-	-	-	-	-
Heavy oil (bbls/day)	-	-	-	-	-
Tight oil (bbls/day)	52,617	53,630	66,088	63,618	59,037
Total crude oil (bbls/day)	**52,617**	**53,630**	**66,088**	**63,618**	**59,037**
Natural gas liquids (bbls/day)	10,017	10,340	13,208	13,238	11,714
Total liquids (bbls/day)	**62,634**	**63,970**	**79,296**	**76,856**	**70,751**
Conventional natural gas (Mcf/day)	-	-	-	-	-
Shale gas (Mcf/day)	261,456	269,567	286,227	307,720	281,384
Total United States (BOE/day)	**106,210**	**108,898**	**127,001**	**128,143**	**117,649**
Canada					
Light and medium oil (bbls/day)	2,992	2,913	2,845	1,977	2,680
Heavy oil (bbls/day)	3,803	3,824	3,529	2,130	3,318
Tight oil (bbls/day)	-	-	-	-	-
Total crude oil (bbls/day)	**6,795**	**6,737**	**6,374**	**4,107**	**5,998**
Natural gas liquids (bbls/day)	428	407	386	93	328
Total liquids (bbls/day)	**7,223**	**7,144**	**6,760**	**4,200**	**6,326**
Conventional natural gas (Mcf/day)	7,380	7,310	6,799	1,641	5,769
Shale gas (Mcf/day)	242	215	198	125	195
Total Canada (BOE/day)	**8,493**	**8,398**	**7,926**	**4,494**	**7,319**
Total					
Light and medium oil (bbls/day)	2,992	2,913	2,845	1,977	2,680
Heavy oil (bbls/day)	3,803	3,824	3,529	2,130	3,318
Tight oil (bbls/day)	52,617	53,630	66,088	63,618	59,037
Total crude oil (bbls/day)	**59,412**	**60,367**	**72,462**	**67,725**	**65,035**
Natural gas liquids (bbls/day)	10,445	10,747	13,594	13,331	12,042
Total liquids (bbls/day)	**69,857**	**71,114**	**86,056**	**81,056**	**77,077**
Conventional natural gas (Mcf/day)	7,380	7,310	6,799	1,641	5,769
Shale gas (Mcf/day)	261,698	269,782	286,425	307,845	281,579
Total (BOE/day)	**114,703**	**117,296**	**134,927**	**132,637**	**124,968**

(1) The gross production volumes in this table will not match certain of the production volumes presented elsewhere in this Annual Information Form, which are presented on a net basis. See "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information – Disclosure of Reserves and Production Information*" in this Annual Information Form.

QUARTERLY NETBACK HISTORY

The following tables set forth the Corporation's average netbacks received for each fiscal quarter in 2022 and for the entire year, separately for gross production in Canada and the United States. Netbacks are calculated on the basis of prices received, which are net of transportation costs but before the effects of commodity derivative instruments, less related royalties and production costs. For multiple product wells, production costs are entirely attributed to that well's principal product type. As a result, no production costs are attributed to the Corporation's NGLs production as those costs have been attributed to the applicable wells' principal product type.

	Year Ended December 31, 2022				
Light and Medium Crude Oil (US$ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada *(~2% of total Company production)*					
Sales price[1]	$ 83.56	$ 100.52	$ 81.42	$ 73.90	**$ 85.79**
Transportation	(0.80)	(0.61)	(0.86)	(0.87)	**(0.78)**
Royalties[2]	(23.92)	(30.13)	(24.25)	(18.41)	**(24.67)**
Production costs[3]	(12.51)	(12.68)	(14.41)	(7.41)	**(12.12)**
Netback	$ 46.33	$ 57.10	$ 41.90	$ 47.21	**$ 48.22**

	Year Ended December 31, 2022				
Heavy Oil (US$ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada *(~3% of total Company production)*					
Sales price[1]	$ 74.86	$ 92.74	$ 70.88	$ 54.36	**$ 75.61**
Transportation	(1.74)	(1.88)	(1.92)	(4.11)	**(2.21)**
Royalties[2]	(16.76)	(23.71)	(18.79)	(13.23)	**(18.73)**
Production costs[3]	(15.84)	(19.41)	(22.32)	(18.41)	**(19.02)**
Netback	$ 40.52	$ 47.74	$ 27.85	$ 18.61	**$ 35.65**

	Year Ended December 31, 2022				
Tight Oil (US$ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States *(~47% of total Company production)*					
Sales price[1]	$ 93.86	$ 110.31	$ 94.14	$ 84.48	**$ 95.12**
Transportation	(4.43)	(4.56)	(4.24)	(3.99)	**(4.29)**
Royalties[2]	(25.51)	(30.06)	(26.64)	(22.89)	**(26.15)**
Production costs[3]	(14.71)	(14.36)	(14.83)	(14.88)	**(14.71)**
Netback	$ 49.21	$ 61.33	$ 48.43	$ 42.72	**$ 49.97**

	Year Ended December 31, 2022				
Natural Gas Liquids (US$ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States *(~9% of total Company production)*					
Sales price[1]	$ 38.06	$ 33.56	$ 32.01	$ 22.30	**$ 30.86**
Transportation	(0.39)	(0.38)	(0.39)	(0.41)	**(0.39)**
Royalties[2]	(8.04)	(7.54)	(6.70)	(4.79)	**(6.62)**
Production costs[3]	—	—	—	—	**—**
Netback	$ 29.63	$ 25.64	$ 24.92	$ 17.10	**$ 23.85**
Canada *(<1% of total Company production)*					
Sales price[1]	$ 55.56	$ 68.11	$ 55.24	$ 22.34	**$ 56.99**
Transportation	(2.83)	(2.27)	(2.28)	(6.91)	**(2.78)**
Royalties[2]	(19.39)	(21.70)	(17.29)	13.29	**(17.16)**
Production costs[3]	—	—	—	—	**—**
Netback	$ 33.34	$ 44.14	$ 35.67	$ 28.72	**$ 37.05**

	Year Ended December 31, 2022				
Conventional Natural Gas (US$ per Mcf)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada *(<1% of total Company production)*					
Sales price[1]	$ 3.93	$ 6.13	$ 3.25	$ 4.15	**$ 4.44**
Transportation	(0.39)	(0.39)	(0.37)	(0.78)	**(0.42)**
Royalties[2]	0.13	0.42	0.76	2.60	**0.59**
Production costs[3]	(4.19)	(1.33)	(2.15)	(5.20)	**(2.75)**
Netback	$ (0.52)	$ 4.83	$ 1.49	$ 0.77	**$ 1.86**

	Year Ended December 31, 2022									
Shale Gas (US$ per Mcf)		**First Quarter**		**Second Quarter**		**Third Quarter**		**Fourth Quarter**		**Annual**
United States *(~38% of total Company production)*										
Sales price[1]	$	4.70	$	6.20	$	6.71	$	4.87	$	**5.62**
Transportation		(0.56)		(0.57)		(0.53)		(0.52)		**(0.54)**
Royalties[2]		(1.01)		(1.35)		(1.46)		(1.07)		**(1.22)**
Production costs[3]		(0.08)		(0.09)		(0.05)		(0.08)		**(0.08)**
Netback	$	3.05	$	4.19	$	4.67	$	3.20	$	**3.78**
Canada *(<1% of total Company production)*										
Sales price[1]	$	3.66	$	5.31	$	4.20	$	2.78	$	**4.11**
Transportation		(0.36)		(0.35)		(0.33)		(0.52)		**(0.38)**
Royalties[2]		0.35		0.96		0.50		1.03		**0.67**
Production costs[3]		(0.89)		(1.56)		(1.60)		(1.35)		**(1.33)**
Netback	$	2.76	$	4.36	$	2.77	$	1.94	$	**3.07**

Notes:

(1) Before the effects of commodity derivative instruments.

(2) Includes production taxes.

(3) Production costs are costs incurred to operate and maintain wells and related equipment and facilities, including operating costs of support equipment used in oil and gas activities and other costs of operating and maintaining those wells and related equipment and facilities. Examples of production costs include items such as field staff labour costs, costs of materials, supplies and fuel consumed and supplies utilized in operating the wells and related equipment (such as power (including gains and losses on electricity contracts), chemicals and lease rentals), repairs and maintenance costs, property taxes, insurance costs, costs of workovers, net processing and treating fees, overhead fees, taxes (other than income, capital, withholding or U.S. state production taxes) and other costs.

TAX HORIZON

The Corporation is subject to standard applicable corporate income taxes. Based on existing tax legislation, the Corporation's available tax pools, expected capital spending and forecasted net income, the Corporation expects to pay U.S. cash taxes of approximately 5% to 6% of adjusted funds flow before tax in 2023. The Corporation does not anticipate paying cash taxes in Canada until 2027. These expectations may vary depending on numerous factors, including fluctuations in commodity prices, the Corporation's capital spending, changes in tax laws, and the nature and timing of the Corporation's acquisitions and divestments. As a result, the Corporation emphasizes that it is difficult to give guidance on future taxability as it operates within an industry that constantly changes. See "*Risk Factors – Changes in laws or free trade agreements, including those affecting tax, royalties and other financial and trade matters, including exports, and interpretations of those laws and trade agreements, may adversely affect the Corporation and its securityholders*".

For additional information, see Notes 2 and 14 to the Financial Statements and the information under the heading "Income Taxes" in the Corporation's MD&A, which can be found on its SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

MARKETING ARRANGEMENTS AND FORWARD CONTRACTS

Crude Oil and NGLs

The Corporation’s realized crude oil price averaged $93.63/bbl and $30.70/bbl for its NGLs for the year ended December 31, 2022, excluding transportation costs and the effects of commodity derivative instruments, compared to $65.89/bbl for its crude oil and $29.51/bbl for its NGLs for the year ended December 31, 2021.

The Corporation's crude oil is marketed to a diverse portfolio of intermediaries and end users, generally on negotiated contracts ranging from 30 days up to multiple years. The Corporation transports its crude oil production to its buyers by pipeline and/or truck, and may occasionally sell a portion to buyers who may utilize rail transportation (after title is transferred into the buyer's name). In 2022, the Corporation received an average price differential for its U.S. Bakken crude oil of $1.09/bbl above WTI, compared to an average of $2.15/bbl below WTI in 2021. The Corporation has access to firm transportation of 22,550 gross barrels per day on the Dakota Access Pipeline ("**DAPL**"), via its own contracted service and with third party capacity, on which it transports a portion of its North Dakota crude oil production to the U.S. Gulf Coast, where it can further access export crude oil markets.

The Corporation's NGLs associated with its crude oil production volumes are marketed on its behalf by midstream companies in North Dakota and Colorado and prices are linked to the monthly spot markets for NGLs. See "*Risk Factors – Sales Pipelines and Rail Transportation Systems*".

Natural Gas

In marketing its natural gas production, the Corporation strives for a mix of contracts and customers. In 2022, 73% of the Corporation's natural gas production originated from its non-operated Marcellus interest in northeast Pennsylvania. The Corporation delivered approximately 56% of its Marcellus production in 2022 onto the Transco Leidy Pipeline, with most of the remaining volumes delivered onto the Tennessee Gas Pipeline 300 Line in Pennsylvania. A portion was then transported to the Kentucky/Tennessee border. The Corporation has firm sales contracts for up to 47 MMcf/day of natural gas production in the Marcellus for terms of up to approximately eight years with buyers who hold pipeline capacity on these and other pipelines in the region. The Corporation also has firm transportation agreements to transport gas within and out of the region for approximately 65 MMcf/day, with terms ending between 2023 and 2036.

The Corporation’s realized natural gas price averaged $5.51/Mcf in 2022, excluding transportation costs and the effects of commodity derivative instruments, compared to $2.94/Mcf in 2021. In 2022, the Corporation received an average price differential for its U.S. Marcellus shale gas production of $0.72/Mcf below NYMEX compared to an average of $0.81/Mcf below NYMEX in 2021. Approximately 27% of the Corporation's natural gas production was associated natural gas production from its crude oil operations in North Dakota and the DJ Basin. The Corporation does not market these volumes directly, as they are marketed on Enerplus' behalf by midstream companies.

Future Commitments and Forward Contracts

The Corporation may use various types of derivative financial instruments and fixed price physical sales contracts to manage the risk related to fluctuating commodity prices. Absent such hedging activities, all of the crude oil and NGLs and the majority of natural gas production of the Corporation is sold into the open market at prevailing market prices, which exposes the Corporation to the risks associated with commodity price fluctuations and foreign exchange rates. See "*Risk Factors*". Information regarding the Corporation's financial instruments is contained in Note 16 to the Financial Statements and under the heading "*Results of Operations – Price Risk Management*" in the Corporation's MD&A, each of which is available through the internet on the Corporation's website at www.enerplus.com, on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

Oil and Natural Gas Reserves

SUMMARY OF RESERVES

As at December 31, 2022, all of the Corporation's crude oil and natural gas reserves were associated with its properties located in the United States. The Corporation’s reserves have been evaluated in accordance with NI 51-101. Independent reserves evaluations have been conducted on properties comprising 100% of the net present value (discounted at 10%, before tax, using forecast prices and costs) of the Corporation's total proved plus probable reserves.

McDaniel, an independent petroleum consulting firm based in Calgary, Alberta, has evaluated properties which comprise all of the Corporation's reserves associated with the Corporation's properties located in North Dakota and Colorado. McDaniel used the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2023 to prepare its report.

NSAI, independent petroleum consultants based in Dallas, Texas, has evaluated all of the Corporation's reserves associated with the Corporation's properties in Pennsylvania. For consistency in the Corporation's reserves reporting, NSAI used the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2023 to prepare its report.

The following sections and tables summarize, as at December 31, 2022, the Corporation's crude oil, NGLs and natural gas reserves and the estimated net present values of future net revenues associated with such reserves, together with certain information, estimates and assumptions associated with such reserves estimates. The data contained in the tables is a summary of the evaluations and, as a result, the tables may contain slightly different numbers than the evaluations themselves due to rounding. Additionally, the columns and rows in the tables may not add due to rounding. For information relating to the changes in the volumes of the Corporation's reserves from December 31, 2021 to December 31, 2022, see "*Reconciliation of Reserves*" below.

All estimates of future net revenues are stated prior to provision for interest and general and administrative expenses and after deduction of royalties and estimated future capital spending, and are presented both before and after deducting income taxes. For additional information, see "*Business of the Corporation – Tax Horizon*", "*Industry Conditions*" and "*Risk Factors*" in this Annual Information Form.

With respect to pricing information in the following reserves information, the wellhead oil prices were adjusted for quality and transportation based on historical actual prices. The natural gas prices were adjusted, where necessary, based on historical pricing based on heating values and transportation. The NGLs prices were adjusted to reflect historical average prices received.

It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained, and variances could be material. The reserves estimates of the Corporation's crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information*" in conjunction with the following tables and notes.

The following tables set forth the estimated gross and net reserves volumes and net present value of future net revenue attributable to the Corporation's reserves at December 31, 2022, using forecast price and cost cases.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)
As of December 31, 2022

RESERVES CATEGORY	Tight Oil		Natural Gas Liquids		Shale Gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)	(MBOE)
Proved								
Proved Developed Producing	92,788	74,632	18,839	15,172	756,966	607,337	237,789	191,027
Proved Developed Non-Producing	2,925	2,352	413	332	4,131	3,334	4,026	3,240
Proved Undeveloped	84,560	67,699	13,340	10,676	313,106	252,747	150,085	120,500
Total Proved	**180,273**	**144,684**	**32,592**	**26,179**	**1,074,204**	**863,419**	**391,899**	**314,766**
Probable	136,863	109,661	23,743	19,036	291,705	237,802	209,224	168,331
Total Proved Plus Probable	**317,136**	**254,345**	**56,335**	**45,215**	**1,365,908**	**1,101,221**	**601,123**	**483,097**

Summary of Net Present Value of Future Net Revenue
Attributable to Oil and Gas Reserves (Forecast Prices and Costs)
As of December 31, 2022

RESERVES CATEGORY	NET PRESENT VALUE OF FUTURE NET REVENUE DISCOUNTED AT (%/Year) — Before Deducting Income Taxes					After Deducting Income Taxes(1)					Unit Value(2)
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	
	(in US$ millions)										US$/BOE
Proved											
Proved Developed Producing	4,622	3,712	3,126	2,726	2,436	3,724	3,013	2,540	2,213	1,976	$16.37
Proved Developed Non-Producing	103	83	69	58	50	78	63	52	44	38	$21.15
Proved Undeveloped	2,801	2,036	1,545	1,209	968	2,118	1,538	1,163	907	723	$12.82
Total Proved	**7,526**	**5,831**	**4,740**	**3,994**	**3,455**	**5,919**	**4,614**	**3,755**	**3,164**	**2,737**	**$15.06**
Probable	5,407	3,337	2,258	1,631	1,238	4,099	2,511	1,681	1,203	904	$13.41
Total Proved Plus Probable	**12,934**	**9,169**	**6,998**	**5,625**	**4,693**	**10,019**	**7,125**	**5,436**	**4,366**	**3,641**	**$14.49**

Notes:

(1) Income tax calculations are based on the forecast cash flows of reserves volumes only, taking into consideration the forecast capital required to develop the reserves, the estimated abandonment, decommissioning and reclamation costs of the Corporation, and having regard for remaining corporate tax pools at the effective date, applicable deductions and appropriate federal and state tax rates.

(2) Calculated using net present value of future net revenue before deducting income taxes, discounted at 10% per year, and net reserves. The unit values are based on net reserves volumes.

FORECAST PRICES AND COSTS

The forecast price and cost case assumes no legislative or regulatory amendments, and includes the effects of inflation. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2023 (utilized by McDaniel, NSAI and by the Corporation in its internal evaluations for consistency in the Corporation's reserves reporting), and the following inflation and exchange rate assumptions:

Year	CRUDE OIL WTI(1)	NATURAL GAS U.S. Henry Hub Gas Price	Inflation Rate	Exchange Rate
	($US/bbl)	($US/MMbtu)	(%/year)	($US/$Cdn)
2023	80.33	4.74	0.0	0.745
2024	78.50	4.50	2.3	0.765
2025	76.95	4.31	2.0	0.768
2026	77.61	4.40	2.0	0.772
2027	79.16	4.49	2.0	0.775
2028	80.74	4.58	2.0	0.775
2029	82.36	4.67	2.0	0.775
2030	84.00	4.76	2.0	0.775
2031	85.69	4.86	2.0	0.775
2032	87.40	4.95	2.0	0.775
2033	89.15	5.05	2.0	0.775
2034	90.93	5.15	2.0	0.775
2035	92.75	5.26	2.0	0.775
2036	94.61	5.36	2.0	0.775
2037	96.50	5.47	2.0	0.775
Thereafter	(2)	(2)	2.0	0.775

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40° API/0.5% sulphur

(2) Escalation is approximately 2% per year thereafter

In 2022, the Corporation received a weighted average price (before transportation costs and the effects of commodity derivative instruments) of $93.63/bbl for crude oil, $30.70/bbl for natural gas liquids and $5.51/Mcf for natural gas.

UNDISCOUNTED FUTURE NET REVENUE BY RESERVES CATEGORY

The undiscounted total future net revenue by reserves category as of December 31, 2022, using forecast prices and costs, is set forth below (columns or rows may not add due to rounding):

RESERVES CATEGORY	Revenue	Royalties[(1)]	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes[(2)]
				(in US$ millions)				
Proved Reserves	18,495	4,814	4,270	1,553	331	7,526	1,607	5,919
Proved Plus Probable Reserves	31,787	8,411	6,985	3,038	420	12,934	2,915	10,019

Notes:
(1) Royalties include any net profits interests paid
(2) Income tax calculations are based on the forecast cash flows of reserves volumes only, taking into consideration the forecast capital required to develop the reserves, the estimated abandonment, decommissioning and reclamation costs of the Corporation, and having regard for remaining corporate tax pools at the effective date, applicable deductions and appropriate federal and state tax rates.

NET PRESENT VALUE OF FUTURE NET REVENUE BY RESERVES CATEGORY AND PRODUCT TYPE

The net present value of future net revenue before income taxes by reserves category and product type as of December 31, 2022, using forecast prices and costs and discounted at 10% per year, is set forth below:

RESERVES CATEGORY	PRODUCT TYPE		Future Net Revenue Before Income Taxes (Discounted at 10%)	Unit Value[(1)]
			(in US$ thousands)	(US$/bbl; US$/Mcf)
Proved Reserves	Tight Oil[(2)]	$	3,871,047	$ 26.76
	Shale Gas[(3)]		868,900	1.23
	Total	**$**	**4,739,947**	
Proved Plus Probable Reserves	Tight Oil[(2)]	$	6,048,905	$ 23.78
	Shale Gas[(3)]		949,062	1.13
	Total	**$**	**6,997,967**	

Notes:
1) Unit values are calculated using the 10% discounted rate divided by the major product type net reserves for each group.
2) Including net present value of solution gas and other by-products.
3) No by-product oil or NGLs are associated with shale gas.

ESTIMATED PRODUCTION FOR GROSS RESERVES ESTIMATES

The volume of total production for the Corporation estimated for 2023 in preparing the estimates of gross proved reserves and gross probable reserves is set forth below. Actual 2023 production (including from North Dakota and Marcellus properties in the separate tables below) may vary from the estimates provided by McDaniel and NSAI as the Corporation's actual development programs, timing and priorities may differ from the forecast of development by McDaniel and NSAI. Columns may not add due to rounding.

	Gross Proved Reserves			
Product Type	**Estimated 2023 Aggregate Production**		**Estimated 2023 Average Daily Production**	
Crude Oil				
Tight Oil	22,744	Mbbls	62,312	bbls/day
Total Crude Oil	22,744	Mbbls	62,312	bbls/day
Natural Gas Liquids	3,850	Mbbls	10,547	bbls/day
Total Liquids	26,594	Mbbls	72,859	bbls/day
Shale Gas	107,908	MMcf	295,638	Mcf/day
Total	44,578	MBOE	122,132	BOE/day

	Gross Probable Reserves			
Product Type	Estimated 2023 Aggregate Production		Estimated 2023 Average Daily Production	
Crude Oil				
Tight Oil	2,083	Mbbls	5,708	bbls/day
Total Crude Oil	2,083	Mbbls	5,708	bbls/day
Natural Gas Liquids	351	Mbbls	963	bbls/day
Total Liquids	2,435	Mbbls	6,670	bbls/day
Shale Gas	3,583	MMcf	9,817	Mcf/day
Total	3,032	MBOE	8,307	BOE/day

The tables below set forth McDaniel's and NSAI's estimated 2023 production for the Corporation's North Dakota, United States properties, and the Marcellus property, located in Pennsylvania, United States, respectively, as each field is estimated to account for more than 20% of the above estimate of the Corporation's 2023 production.

	Gross Proved Reserves							
	North Dakota				Marcellus			
Product Type	Estimated 2023 Aggregate Production		Estimated 2023 Average Daily Production		Estimated 2023 Aggregate Production		Estimated 2023 Average Daily Production	
Crude Oil								
Tight Oil	22,505	Mbbls	61,659	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	22,505	Mbbls	61,659	bbls/day	-	Mbbls	-	bbls/day
Natural Gas Liquids	3,814	Mbbls	10,448	bbls/day	-	Mbbls	-	bbls/day
Total Liquids	26,319	Mbbls	72,107	bbls/day	-	Mbbls	-	bbls/day
Shale Gas	22,922	MMcf	62,800	Mcf/day	84,743	MMcf	232,172	Mcf/day
Total	30,139	MBOE	82,573	BOE/day	14,124	MBOE	38,695	BOE/day

	Gross Probable Reserves							
	North Dakota				Marcellus			
Product Type	Estimated 2023 Aggregate Production		Estimated 2023 Average Daily Production		Estimated 2023 Aggregate Production		Estimated 2023 Average Daily Production	
Crude Oil								
Tight Oil	2,072	Mbbls	5,676	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	2,072	Mbbls	5,676	bbls/day	-	Mbbls	-	bbls/day
Natural Gas Liquids	350	Mbbls	958	bbls/day	-	Mbbls	-	bbls/day
Total Liquids	2,422	Mbbls	6,634	bbls/day	-	Mbbls	-	bbls/day
Shale Gas	2,102	MMcf	5,760	Mcf/day	1,470	MMcf	4,026	Mcf/day
Total	2,772	MBOE	7,594	BOE/day	245	MBOE	671	BOE/day

FUTURE DEVELOPMENT COSTS

The amount of development costs deducted in the estimation of net present value of future net revenue is set forth below. The Corporation intends to fund its development activities through cash, internally generated cash flow and/or debt. The Corporation does not anticipate that the cost of obtaining the funds required for these development activities will have a material effect on the Corporation's disclosed oil and gas reserves or future net revenue attributable to those reserves. For additional information, see "*Business of the Corporation – Capital Expenditures and Costs Incurred*".

	Proved Reserves		Proved Plus Probable Reserves	
Year	**Undiscounted**	**Discounted at 10%/year**	**Undiscounted**	**Discounted at 10%/year**
		(in US$ millions)		
2023	484	462	485	463
2024	347	304	347	304
2025	472	372	472	372
2026	248	181	316	229
2027	1	1	463	305
2028	0	-	379	227
Remainder	0	-	574	308
Total	1,553	1,320	3,038	2,207

RECONCILIATION OF RESERVES

Overview

The Corporation's total gross proved plus probable reserves at December 31, 2022 were 601.1 MMBOE, a decrease of 2% from year-end 2021. The Corporation's gross proved plus probable crude oil and NGLs reserves were 373.5 MMBOE and represented 62% of total proved plus probable gross reserves, a decrease of 3% from year-end 2021. The Corporation replaced approximately 139% of its 2022 gross production through its exploration and development program, adding 63.3 MMBOE of proved plus probable reserves, including revisions and economic factors. Of the Corporation’s 63.3 MMBOE of proved plus probable additions, including revisions and economic factors, 51.0 MMBOE are attributed to the North Dakota properties and 12.0 MMBOE (71.7 Bcf) to the Marcellus shale gas property.

In 2022, the Corporation sold substantially all of its Canadian assets, which included all Canadian assets that had reserves assigned to them in 2021.

The following tables reconcile the Corporation's gross crude oil and natural gas reserves from December 31, 2021 to December 31, 2022, by country and in total, using forecast prices and costs. Certain columns may not add due to rounding.

UNITED STATES GROSS OIL AND GAS RESERVES

	Light & Medium Oil			Heavy Oil			Tight Oil			Natural Gas Liquids		
UNITED STATES Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2021	-	-	-	-	-	-	178,600	120,746	299,346	33,208	22,102	55,310
Acquisitions	-	-	-	-	-	-	290	72	363	31	7	38
Dispositions	-	-	-	-	-	-	(1,432)	(350)	(1,782)	(158)	(47)	(204)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	19,235	24,216	43,451	3,002	4,016	7,018
Economic Factors	-	-	-	-	-	-	4,963	2,131	7,094	1,005	409	1,414
Technical Revisions	-	-	-	-	-	-	165	(9,951)	(9,786)	(220)	(2,744)	(2,965)
Production	-	-	-	-	-	-	(21,549)	-	(21,549)	(4,276)	-	(4,276)
December 31, 2022	**-**	**-**	**-**	**-**	**-**	**-**	**180,273**	**136,863**	**317,136**	**32,592**	**23,743**	**56,335**

	Conventional Natural Gas			Shale Gas			Total		
UNITED STATES Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2021	-	-	-	1,070,154	297,339	1,367,493	390,168	192,404	582,572
Acquisitions	-	-	-	148	35	183	346	85	431
Dispositions	-	-	-	(1,381)	(413)	(1,794)	(1,820)	(465)	(2,285)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	67,503	69,832	137,336	33,488	39,871	73,358
Economic Factors	-	-	-	5,924	2,280	8,203	6,956	2,919	9,875
Technical Revisions	-	-	-	34,560	(77,368)	(42,808)	5,705	(25,590)	(19,886)
Production	-	-	-	(102,705)	-	(102,705)	(42,942)	-	(42,942)
December 31, 2022	**-**	**-**	**-**	**1,074,204**	**291,704**	**1,365,908**	**391,899**	**209,224**	**601,123**

CANADIAN GROSS OIL AND GAS RESERVES

	Light & Medium Oil			Heavy Oil			Tight Oil			Natural Gas Liquids		
CANADA Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2021	6,245	1,917	8,162	15,612	5,079	20,691	-	-	-	689	222	911
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(5,267)	(1,917)	(7,184)	(14,401)	(5,079)	(19,480)	-	-	-	(570)	(222)	(792)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Production	(978)	-	(978)	(1,211)	-	(1,211)	-	-	-	(120)	-	(120)
December 31, 2022	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

	Conventional Natural Gas			Shale Gas			Total		
CANADA Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2021	15,196	4,481	19,677	345	88	433	25,136	7,980	33,116
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(13,090)	(4,481)	(17,571)	(274)	(88)	(362)	(22,465)	(7,980)	(30,445)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-
Production	(2,106)	-	(2,106)	(71)	-	(71)	(2,671)	-	(2,671)
December 31, 2022	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

TOTAL GROSS OIL AND GAS RESERVES

TOTAL Factors	Light & Medium Oil Proved	Light & Medium Oil Probable	Light & Medium Oil Proved Plus Probable	Heavy Oil Proved	Heavy Oil Probable	Heavy Oil Proved Plus Probable	Tight Oil Proved	Tight Oil Probable	Tight Oil Proved Plus Probable	Natural Gas Liquids Proved	Natural Gas Liquids Probable	Natural Gas Liquids Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2021	6,245	1,917	8,162	15,612	5,079	20,691	178,600	120,746	299,346	33,897	22,324	56,221
Acquisitions	-	-	-	-	-	-	290	72	363	31	7	38
Dispositions	(5,267)	(1,917)	(7,184)	(14,401)	(5,079)	(19,480)	(1,432)	(350)	(1,782)	(728)	(269)	(996)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	19,235	24,216	43,451	3,002	4,016	7,018
Economic Factors	-	-	-	-	-	-	4,963	2,131	7,094	1,005	409	1,414
Technical Revisions	-	-	-	-	-	-	165	(9,951)	(9,786)	(220)	(2,744)	(2,965)
Production	(978)	-	(978)	(1,211)	-	(1,211)	(21,549)	-	(21,549)	(4,395)	-	(4,395)
December 31, 2022	**-**	**-**	**-**	**-**	**-**	**-**	**180,273**	**136,863**	**317,136**	**32,592**	**23,743**	**56,335**

TOTAL Factors	Conventional Natural Gas Proved	Conventional Natural Gas Probable	Conventional Natural Gas Proved Plus Probable	Shale Gas Proved	Shale Gas Probable	Shale Gas Proved Plus Probable	Total Proved	Total Probable	Total Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2021	15,196	4,481	19,677	1,070,500	297,427	1,367,927	415,304	200,384	615,688
Acquisitions	-	-	-	148	35	183	346	85	431
Dispositions	(13,090)	(4,481)	(17,571)	(1,655)	(501)	(2,156)	(24,286)	(8,445)	(32,731)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	67,503	69,832	137,336	33,488	39,871	73,358
Economic Factors	-	-	-	5,924	2,280	8,203	6,956	2,919	9,875
Technical Revisions	-	-	-	34,560	(77,368)	(42,808)	5,705	(25,590)	(19,886)
Production	(2,106)	-	(2,106)	(102,776)	-	(102,776)	(45,613)	-	(45,613)
December 31, 2022	**-**	**-**	**-**	**1,074,204**	**291,704**	**1,365,908**	**391,899**	**209,224**	**601,123**

The following tables reconcile the Corporation's net crude oil and natural gas reserves from December 31, 2021 to December 31, 2022, in total, using forecast prices and costs. Certain columns may not add due to rounding.

UNITED STATES NET OIL AND GAS RESERVES

TOTAL Factors	Light & Medium Oil (NET) Proved	Light & Medium Oil (NET) Probable	Light & Medium Oil (NET) Proved Plus Probable	Heavy Oil (NET) Proved	Heavy Oil (NET) Probable	Heavy Oil (NET) Proved Plus Probable	Tight Oil (NET) Proved	Tight Oil (NET) Probable	Tight Oil (NET) Proved Plus Probable	Natural Gas Liquids (NET) Proved	Natural Gas Liquids (NET) Probable	Natural Gas Liquids (NET) Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2021	**-**	**-**	**-**	**-**	**-**	**-**	**143,365**	**96,717**	**240,082**	**26,669**	**17,706**	**44,375**
Acquisitions	-	-	-	-	-	-	231	57	288	24	6	30
Dispositions	-	-	-	-	-	-	(1,145)	(279)	(1,425)	(126)	(37)	(163)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	15,463	19,410	34,873	2,414	3,225	5,639
Economic Factors	-	-	-	-	-	-	3,998	1,709	5,706	809	328	1,137
Technical Revisions	-	-	-	-	-	-	114	(7,953)	(7,839)	(165)	(2,191)	(2,357)
Production	-	-	-	-	-	-	(17,342)	-	(17,342)	(3,445)	-	(3,445)
December 31, 2022	**-**	**-**	**-**	**-**	**-**	**-**	**144,684**	**109,661**	**254,345**	**26,179**	**19,036**	**45,215**

TOTAL Factors	Conventional Natural Gas (NET) Proved	Conventional Natural Gas (NET) Probable	Conventional Natural Gas (NET) Proved Plus Probable	Shale Gas (NET) Proved	Shale Gas (NET) Probable	Shale Gas (NET) Proved Plus Probable	Total (NET) Proved	Total (NET) Probable	Total (NET) Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2021	**-**	**-**	**-**	**861,611**	**243,965**	**1,105,576**	**313,636**	**155,084**	**468,720**
Acquisitions	-	-	-	143	34	177	278	69	347
Dispositions	-	-	-	(1,105)	(330)	(1,435)	(1,456)	(372)	(1,827)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	54,910	56,228	111,138	27,029	32,007	59,035
Economic Factors	-	-	-	(356)	(524)	(880)	4,748	1,949	6,697
Technical Revisions	-	-	-	30,584	(61,570)	(30,986)	5,046	(20,406)	(15,360)
Production	-	-	-	(82,368)	-	(82,368)	(34,515)	-	(34,515)
December 31, 2022	**-**	**-**	**-**	**863,419**	**237,802**	**1,101,221**	**314,766**	**168,331**	**483,097**

CANADIAN NET OIL AND GAS RESERVES

TOTAL	Light & Medium Oil (NET)			Heavy Oil (NET)			Tight Oil (NET)			Natural Gas Liquids (NET)		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2021	**5,173**	**1,551**	**6,724**	**13,255**	**4,210**	**17,465**	**-**	**-**	**-**	**567**	**196**	**763**
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(4,461)	(1,551)	(6,012)	(12,322)	(4,210)	(16,532)	-	-	-	(479)	(196)	(675)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Production	(712)	-	(712)	(933)	-	(933)	-	-	-	(88)	-	(88)
December 31, 2022	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

TOTAL	Conventional Natural Gas (NET)			Shale Gas (NET)			Total (NET)		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2021	**14,648**	**4,329**	**18,977**	**328**	**84**	**412**	**21,491**	**6,693**	**28,184**
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(12,485)	(4,329)	(16,814)	(263)	(84)	(347)	(19,387)	(6,693)	(26,080)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-
Production	(2,162)	-	(2,162)	(65)	-	(65)	(2,104)	-	(2,104)
December 31, 2022	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

TOTAL NET OIL AND GAS RESERVES

TOTAL	Light & Medium Oil (NET)			Heavy Oil (NET)			Tight Oil (NET)			Natural Gas Liquids (NET)		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2021	**5,173**	**1,551**	**6,724**	**13,255**	**4,210**	**17,465**	**143,365**	**96,717**	**240,082**	**27,236**	**17,902**	**45,139**
Acquisitions	-	-	-	-	-	-	231	57	288	24	6	30
Dispositions	(4,461)	(1,551)	(6,012)	(12,322)	(4,210)	(16,532)	(1,145)	(279)	(1,425)	(605)	(234)	(839)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	15,463	19,410	34,873	2,414	3,225	5,639
Economic Factors	-	-	-	-	-	-	3,998	1,709	5,706	809	328	1,137
Technical Revisions	-	-	-	-	-	0	114	(7,953)	(7,839)	(165)	(2,191)	(2,357)
Production	(712)	-	(712)	(933)	-	(933)	(17,342)	-	(17,342)	(3,534)	-	(3,534)
December 31, 2022	**-**	**-**	**-**	**-**	**-**	**-**	**144,684**	**109,661**	**254,345**	**26,179**	**19,036**	**45,215**

TOTAL	Conventional Natural Gas (NET)			Shale Gas (NET)			Total (NET)		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2021	**14,648**	**4,329**	**18,977**	**861,939**	**244,049**	**1,105,988**	**335,127**	**161,776**	**496,904**
Acquisitions	-	-	-	143	34	177	278	69	347
Dispositions	(12,485)	(4,329)	(16,814)	(1,368)	(414)	(1,782)	(20,843)	(7,064)	(27,907)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	54,910	56,228	111,138	27,029	32,007	59,035
Economic Factors	-	-	-	(356)	(524)	(880)	4,748	1,949	6,697
Technical Revisions	-	-	-	30,584	(61,570)	(30,986)	5,046	(20,406)	(15,360)
Production	(2,162)	-	(2,162)	(82,433)	-	(82,433)	(36,619)	-	(36,619)
December 31, 2022	**-**	**-**	**-**	**863,419**	**237,802**	**1,101,221**	**314,766**	**168,331**	**483,097**

UNDEVELOPED RESERVES

The following tables disclose the volumes of proved undeveloped reserves and probable undeveloped reserves of the Corporation that were first attributed in the years indicated.

Proved Undeveloped Reserves

Year[(1)]	Crude Oil Tight	NGLs	Shale Gas	Total
	(Mbbls)	(Mbbls)	(MMcf)	(MBOE)
2020	9,896	1,397	65,091	22,141
2021	28,182	4,784	108,948	51,124
2022	17,736	2,790	56,814	29,995

Note:
(1) First attributed volumes include additions during the year and do not include revisions to previous undeveloped reserves.

Probable Undeveloped Reserves

Year[(1)]	Crude Oil Tight	NGLs	Shale Gas	Total
	(Mbbls)	(Mbbls)	(MMcf)	(MBOE)
2020	6,174	687	38,195	13,227
2021	12,641	2,106	38,135	21,103
2022	23,846	3,953	68,264	39,176

Note:
(1) First attributed volumes include additions during the year and do not include revisions to previous undeveloped reserves.

The Corporation attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information, and the optimization of existing fields. The Corporation considers each of its undeveloped locations to be projects that have larger capital expenditures and, consistent with the COGE Handbook, has generally assigned development of or the commencement of significant capital expenditures on proved undeveloped locations to occur within three years (five years for resource plays) and within five years (ten years for resource plays) for probable undeveloped reserves. The Corporation has in recent years continually developed its undeveloped reserves in the United States. The Corporation intends to fund the development of its undeveloped reserves as of December 31, 2022 with cash, internally generated cash flow and/or debt. These expenditures are expected to extend the continual development of undeveloped reserves beyond two years.

In the Fort Berthold property, the Corporation has been active for the last several years in drilling and developing these undeveloped reserves, converting the associated volumes to producing reserves. The Corporation has, in the past, maintained the gross proved plus probable undeveloped location well count year over year and added undeveloped locations to replace those that were drilled in the preceding year. With the acquisition of additional properties in North Dakota and improved commodity price forecasts, the Corporation expects to increase its activity in its North Dakota properties and has increased the gross proved plus probable undeveloped location count from 423 locations in 2021 to 494 locations as of December 31, 2022. The conversion of the proved undeveloped locations to producing reserves is scheduled to occur continuously over the next four years and the development of the remaining probable undeveloped locations is scheduled to occur within eight years.

In 2022, the Corporation continued to participate in the development of its non-operated undeveloped reserves in the Marcellus property, converting 6.2 net proved plus probable locations to developed reserves. These converted locations were replaced with additions of 7.7 net proved plus probable undeveloped locations as of December 31, 2022. Development timing for both proved undeveloped and proved plus probable undeveloped locations is determined by the scheduling prepared by the operators of the property. In this case, development of the proved undeveloped locations is scheduled to take place over four years and the development of the probable undeveloped locations is scheduled to take place over the next five years.

SIGNIFICANT FACTORS OR UNCERTAINTIES

Changes in future commodity prices relative to the forecasts described above under "*Forecast Prices and Costs*" could have a negative impact on the Corporation's reserves and, in particular, on the development of undeveloped reserves, unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above, the Corporation does not anticipate any other significant economic factors or other significant uncertainties which may affect any particular components of its reserves data.

In connection with its operations, the Corporation will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The Corporation budgets for and recognizes as a liability in its Financial Statements the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. There are no significant abandonment and reclamation costs associated with its reserves properties or properties with no attributed reserves, and the Corporation does not anticipate its abandonment and reclamation liabilities to negatively impact its reserves data or its ability to develop these reserves at this time. Abandonment and reclamation costs associated with surface leases, wells, undeveloped locations, facilities and pipelines for the Corporation's properties with assigned reserves in the United States have been reflected in reserves estimates.

For further information, see "*Risk Factors – The Corporation's actual reserves and resources will vary from its reserves and resources estimates, and those variations could be material*" and "*– Court rulings and regulatory regimes on the liability surrounding abandonment and reclamation obligations of oil and gas companies may adversely affect the Corporation".*

PROVED AND PROBABLE RESERVES NOT ON PRODUCTION

The Corporation has approximately 4.8 MMBOE (4.5 MMBOE in its crude oil properties and 0.3 MMBOE (1.8 Bcf) in its natural gas properties) of proved plus probable reserves which are capable of production but which, as of December 31, 2022, were not on production. These reserves have generally been non-producing for periods ranging from a few months to four years. The majority of these volumes are associated with operated wells in North Dakota (21 wells) and Pennsylvania (2 wells) that are shut-in due to pump failures or in need of a workover. All of these non-producing assets have been scheduled to recommence production by 2023.

Supplemental Operational Information

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

The Corporation has adopted the H&S Policy and the ESG Policy to articulate Enerplus' commitment to health and safety, stakeholder engagement, environmental and regulatory compliance and governance practices. These policies are high-level statements of intent that guide Enerplus' decision-making and are consistent with its values and demonstrate its goal of producing safe and socially responsible energy. The Board and the President & Chief Executive Officer are ultimately accountable for ensuring compliance with both policies. The Corporation's management and its corporate sustainability department are responsible for ensuring they are communicated and integrated across the Corporation. All employees and contractors of the Corporation are required to comply with the policies. As part of the corporate performance scorecard system, ESG targets are factored into the bonus structure applied to all executives and employees. Tying ESG performance to compensation is important to Enerplus for alignment of the Corporation's goals. The Board has oversight for all of the Corporation's ESG activities.

Enerplus has five material ESG focus areas in scope, with accountability for each area assigned to a committee of the Board. The Board's Reserves, Safety and Social Responsibility ("**RS&SR**") Committee has responsibility for four of the five areas, including emissions and water management, health and safety and community engagement. Oversight of the final focus area – culture – resides with the Board's Compensation and Human Resources Committee. In conjunction with the current focus areas, in its assessment Enerplus is identifying both emerging and maintaining focus areas and is continuing to integrate them into the Corporation's broader ESG strategy and management activities. The following are emerging material focus areas which have the potential to become material for Enerplus in the future: supply chain and digital technology, including cybersecurity risks. In addition, Enerplus has identified areas of previous focus which are now considered to be "maintaining" areas of focus as a result of a thorough understanding and development of good processes around them; these include board constitution and culture, as well as environmental risk management and spills and releases.

The Corporation strives to develop and operate its oil and natural gas assets in a socially responsible manner and places a high priority on protecting the health and safety of its employees, contractors and the public in the communities in which it operates, as well as preserving the quality of the environment. The Corporation also encourages active and open collaboration with its stakeholders. The Corporation has established processes and programs designed to evaluate and manage health, safety, environmental and regulatory risks, and strives for ongoing improvement in its corporate sustainability and ESG performance.

The H&S Policy discusses the Corporation's commitment to protect the health and safety of all persons and communities involved in, or affected by, its business activities. Specifically, the H&S Policy specifies the Corporation will:

- Ensure its culture of accountability is applied to personal safety and the safety of others
- Proactively identify and mitigate life critical safety risks in its operations through a focus on leading indicators and incident investigations
- Set annual safety targets focused on continuous improvement and monitor performance throughout the year with the Board, leadership, employees and contractors
- Provide safety training and expect all workers to identify, report and act on all hazards
- Create and maintain an environment that supports and requires a Stop Work culture
- Partner with like-minded contractors to incorporate industry best practices into operational standards and processes to keep people safe while delivering operational excellence

The ESG Policy reiterates the Corporation's commitment to environmental, social and governance issues and states that the Corporation will:

- Invest in innovative solutions to reduce GHG and methane emissions
- Increase the efficiency of energy consumption to reduce emissions intensity
- Improve water and land use practices
- Limit the waste generated
- Prevent and manage releases
- Monitor environmental performance and provide transparent disclosure
- Continuously improve environmental management system and provide resources and training to improve its capability to meet and exceed environmental commitments
- Proactively comply with all applicable rules and regulations
- Invest in building and sustaining positive relationships with each of its stakeholders
- Continuously monitor culture via multiple qualitative tools and a quantitative survey system
- Engage with community stakeholders to understand their needs and concerns and promote economic and social development in its operating areas
- Support the Board's engagement and oversight of the development and execution of its ESG approach

The Corporation's commitment to building meaningful and transparent relationships with its stakeholders is embedded in the ESG Policy. In addition, it expresses the Corporation's commitment to engaging with stakeholders to promote economic and social development for the people and communities in its operating areas. Finally, the Corporation's commitment to the responsible development of resources and regulatory compliance is published in its ESG Report and Data Tables. Enerplus prepares its ESG reporting and disclosure information in accordance with the Sustainability Accounting Standards Board (SASB), the Global Reporting Initiatives (GRI) disclosure frameworks and the TCFD recommended disclosure guidelines. In addition, it also uses the International Petroleum Industry Environmental Conservation Association's (IPIECA) Oil and gas industry guidance on voluntary sustainability reporting and, in 2022, the Corporation updated its external disclosure to include American Exploration & Production Council (AXPC) reporting. The ESG reports prepared discuss and summarize the Corporation's environmental, safety, social responsibility and governance performance, along with its targets and goals, and can be found at www.enerplus.com.

The Corporation's anticipated risk management activities and ESG strategy will require climate change-related risks to be integrated into its long-range planning process, but we cannot predict what form this will ultimately take given the long-time horizons and evolving expectations. See "*Risk Factors—The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including but not limited to those which are climate change-related, as well as public opposition and activism—Climate change-related risks*".

Health and Safety

The Corporation's total combined (employee/contractor) recordable injury frequency rate 2022 was 0.60 per 200,000 worker hours, an increase from the rate of 0.55 recorded in 2021. The Corporation had an employee recordable injury frequency rate of 0.23 per 200,000 worker hours in 2022, in-line with 0.22 per 200,000 worker hours in 2021. The Corporation's total contractor recordable injury frequency was 0.73 per 200,000 worker hours in 2022, an increase from 0.66 injuries per 200,000 worker hours in 2021. The Corporation recorded one lost-time injury in 2022, compared to zero in 2021. As an ESG focus area, the Corporation has established a lost time injury frequency ("**LTIF**″) reduction target of 25%, on average, from 2020 to 2023, relative to 2019, for its employees and contractors and since 2020, has achieved a three-year average reduction in LTIF of 80%.

Health and safety risks influence workplace practices, operating costs and the establishment of health and safety standards. In addition to integrating targets into its ESG focus areas, the Corporation continues to maintain its health and safety management system, which is designed to:

- Increase emphasis on safety awareness and promote continuous improvement and safety excellence
- Provide staff with the training and resources needed to complete work safely
- Incorporate hazard assessment and risk management as an integral part of everyday business
- Monitor performance to ensure that its operations comply with all legal obligations and its internally-imposed standards

The Corporation's health and safety management system is reviewed annually for continuous improvement opportunities. The Corporation continues to develop and implement prevention measures and safety management program improvements to support its focus and commitment for an injury-free workplace.

Environment

The Corporation's operations are subject to applicable laws and regulations relating to the environment. See "*Industry Conditions – Environmental Regulation*". The Corporation is committed to meeting its responsibilities to protect the environment through a variety of programs and actively monitors its operations for compliance with all relevant and applicable environmental regulations and industry best practices. Currently, the Corporation engages in the following:

- Capital expenditures related to site abandonment and reclamation activities for the Corporation's Canadian and United States properties in 2022 totaled approximately $17.4 million, including $11.9 million on its Tommy Lakes asset, $4.8 million across other Canadian assets and the remainder on U.S. assets. The Corporation received 33 reclamation certificates from regulatory agencies in 2022 by returning sites to their previous equivalent land capability.

- Government regulators conducted 98 inspections of the Corporation's field operations in the United States and Canada in 2022, a decrease compared to the prior year's 153 government regulator inspections. The percentage of non-compliant inspections received by the Corporation in 2022 increased to 19%, compared to 8% received in 2021. The majority of non-compliant inspections were related to Canadian assets which were sold during 2022.

- The Corporation conducts an internal site inspection program at its U.S. and Canadian locations to proactively assess environmental, regulatory and general housekeeping items. Findings from the internal site inspection program and any action items are recorded in the Corporation's internal reporting platforms in order to measure compliance and ensure potential issues are addressed.

- In 2022, the Corporation completed a total of 1,540 fugitive emissions surveys for its production pad facilities to detect losses from leaks and vents and has repaired all identified leaks. The repairs were carried out directly by the Corporation as part of its normal operations.
- Enerplus uses water in the development of its assets. The Corporation is exploring opportunities to reduce, reuse and recycle freshwater in its North Dakota completions operations, introducing technology to treat water in real-time on location.

The Corporation is required to submit a report under the Canadian federal Greenhouse Gas Reporting Program ("**GHGRP**") for any facility that emitted more than 10,000 tonnes of carbon dioxide equivalent ("**CO_2e**") during 2021; one facility report was submitted in June 2022.

The Corporation is subject to the reporting requirement under the U.S. Environmental Protection Agency (the "**U.S. EPA**") Clean Air Act and the Mandatory Reporting of Greenhouse Gases Rule. The latest of these reports was submitted to the U.S. EPA on March 31, 2022 for the 2021 operational year. For more information on the environmental regulation applicable to the Corporation, see "*Industry Conditions – Environmental Regulation*".

In 2021, Scope 1 Emissions of CO_2e were 941,897 tonnes. The Corporation expects its 2022 Scope 1 Emissions (expected to be available in the second quarter of 2023) to be lower than 2021 by more than 10%. Enerplus believes it is compliant with all relevant gas capture regulatory requirements. As a part of its ESG strategy, Enerplus' has set GHG emissions intensity reduction goals, based on Scope 1 Emissions and Scope 2 Emissions, as defined by the GHGRP. In 2022, the Corporation revised its methane emissions intensity reduction targets to a reduction of 30% by 2025, and 50% by 2030, based on a 2021 baseline. It also revised its 2030 target of a 35% reduction in Scope 1 Emissions and Scope 2 Emissions, relative to 2021 levels (set in June of 2022) due to updates to the baseline, which now reflect its 2021 acquisitions. Based on preliminary estimates, Enerplus expects its total Scope 1 and Scope 2 Emissions intensity in 2022, measured on a gross metric tonne of CO_2e per gross wellhead BOE basis, to be reduced by approximately 16%, and its methane emissions intensity to be reduced by over 10%, both relative to a 2021 baseline; positive contributions toward achieving the Corporation's 2025 and 2030 targets. The Corporation believes achieving progress toward its emissions reduction targets is possible, for example, through the installation of vapour recovery units on all new pads and retrofits on old pads where possible, as well as the replacement of intermittent and high-bleed pneumatic devices. The Corporation spent approximately $4.5 million on this work in 2022.

In addition to the quantitative GHG emissions targets established, Enerplus continued to capture and leverage ideas being generated by employees that focused on reducing its GHG emissions in order to continue to meet its ongoing environmental obligations and achieve progress toward its ESG goals. To facilitate this, the Corporation is committed to, and has budgeted a portion of its capital expenditures to ideas that get approved as active projects. In 2021, Enerplus established an internal, executive-led working committee that meets bi-weekly and reviews task force driven assessments. This working committee also reviews the status of funded, active projects. In addition, the Board's RS&SR Committee regularly reviews health, safety, environmental and regulatory updates and risks. At present, the Corporation believes it is, and expects to continue to be, in compliance with all material applicable environmental laws and regulations.

Overall, the Corporation strives to operate in a socially responsible manner and believes its health, safety and environmental initiatives and performance confirm its ongoing commitment to environmental stewardship and the health and safety of its employees, contractors and the general public in the communities in which it operates. Annually, the Corporation identifies material ESG focus areas to support this commitment and sets forth strategic goals and targets. The Corporation believes that by monitoring various lagging and leading metrics, identifying areas for improvement, and implementing strategies, processes and procedures in those material focus areas, the Corporation will continue to improve its corporate sustainability and ESG performance. For more information on the Corporation's ESG initiatives visit www.enerplus.com.

INSURANCE

The Corporation carries insurance coverage to protect its assets at the standards typical within the oil and natural gas industry. Insurance levels are determined and acquired by the Corporation after considering the perceived risk of loss and appropriate coverage, together with the overall cost. The Corporation currently purchases insurance to protect against a number of risks including, but not limited to, third party liability, property damage, business interruption, pollution and well control. In addition, liability coverage is carried for the directors and officers of the Corporation.

The Corporation commissions periodic third-party loss prevention audits to identify and evaluate the risk exposures associated with production equipment, process operations, utility supply systems and natural hazards. The purpose of the loss prevention audits is to generate detailed loss prevention reports with risk-based recommendations for improving the overall safety and performance of the Corporation's facilities, mitigating the potential exposure to financial loss associated with property damage and production loss, and ensuring the adequacy of its relevant insurance coverage.

PERSONNEL

As at December 31, 2022, the Corporation employed a total of 379 persons, including full-time benefit employees and payroll consultants, 152 of whom were in Canada and 227 of whom were in the United States.

Description of Capital Structure

The authorized capital of the Corporation consists of an unlimited number of Common Shares, and a number of preferred shares issuable in series ("**Preferred Shares**"), which are limited to an amount equal to not more than one-quarter of the number of issued and outstanding Common Shares at the time of the issuance of any such Preferred Shares. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares. Copies of the Corporation's Articles, By-law No. 1 and By-law No. 2 were filed on January 2, 2013, June 16, 2014, and May 6, 2016, respectively, on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

COMMON SHARES

Holders of Common Shares are entitled to receive notice of and to attend all meetings of shareholders of the Corporation and to one vote at such meetings for each Common Share held. The holders of the Common Shares are, at the discretion of the Corporation's board of directors and subject to applicable legal restrictions and subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Corporation, entitled to receive any dividends declared by the Corporation on the Common Shares and to share in the remaining property of the Corporation upon liquidation, dissolution or winding-up.

The Articles contain provisions facilitating payment of dividends on Common Shares through issuance of Common Shares in circumstances where the board of directors declares, and a shareholder of the Corporation validly elects to receive, the payment of dividends, in whole or in part, in the form of Common Shares. See "*Dividends – Stock Dividend Program*".

PREFERRED SHARES

There are no Preferred Shares outstanding as of the date of this Annual Information Form. Preferred Shares may be issued from time to time in one or more series with such rights, restrictions, privileges, conditions and designations attached thereto as shall be fixed from time to time by the Corporation's board of directors. Subject to the provisions of the ABCA, the Preferred Shares of each series shall rank in parity with the Preferred Shares of every other series. The Preferred Shares shall be entitled to preference over the Common Shares and any other shares of the Corporation ranking junior to the said Preferred Shares with respect to payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, to the extent fixed in the case of each respective series, and may also be given such other preferences over the Common Shares and any other shares of the Corporation ranking junior to the said Preferred Shares as may be fixed in the case of each such series.

SENIOR UNSECURED NOTES

Enerplus has issued Senior Unsecured Notes, of which $203.2 million principal amounts were outstanding at December 31, 2022. Certain terms of the Senior Unsecured Notes are summarized below:

Issue Date	Original Principal	Remaining Principal	Coupon Rate	Interest Payment Dates	Maturity Date	Term
September 3, 2014	US$200 million	US$84 million	3.79 %	March 3 and September 3	September 3, 2026	Remaining principal payments required in four equal annual installments beginning September 3, 2023
May 15, 2012	US$355 million	US$119.2 million	4.40 %	May 15 and November 15	May 15, 2024	Remaining principal payments required in two equal annual installments beginning May 15, 2023

For additional information see "*Material Contracts and Documents Affecting the Rights of Securityholders*". See also Note 8 to the Financial Statements.

SLL CREDIT FACILITIES

As at December 31, 2022, the Corporation had $56.3 million drawn on its $900 million SLL Credit Facility, and was undrawn on its $365 million SLL Credit Facility. The $365 million SLL Credit Facility matures on October 31, 2025; $50 million and $850 million of the $900 million SLL Credit Facility mature on October 31, 2025 and October 31, 2026, respectively. The SLL Credit Facilities incorporate ESG-linked incentive pricing terms which reduce or increase the borrowing costs by up to 5 basis points as Enerplus' sustainability performance targets ("SPT") are exceeded or missed. The SPTs are based on

ESG goals focused on Scope 1 and Scope 2 GHG emissions intensity, freshwater usage and LTIF reductions, relative to the applicable 2019 and 2021 baseline data.

For a description of the SLL Credit Facilities, see disclosure under the heading “Liquidity and Capital Resources” in the MD&A and Note 8 to the Corporation's Financial Statements, which are incorporated by reference into this Annual Information Form. See also "*Material Contracts and Documents Affecting the Rights of Securityholders*".

Dividends

DIVIDEND POLICY AND HISTORY

The Corporation's board of directors is responsible for determining the dividend policy of the Corporation. The dividend policy must comply with the requirements of the ABCA, including satisfying the solvency test applicable to ABCA corporations. The Corporation currently has established a dividend policy of paying quarterly dividends to holders of Common Shares. The dividend payment dates are on or about the 15th day each March, June, September and December and the dividend record dates are on or about the last business day of the calendar month preceding the dividend payment date. **However, any decision to pay dividends on the Common Shares will be made by the Corporation's board of directors on the basis of the relevant conditions existing at such future time, and there can be no guarantee that the Corporation will maintain its current dividend policy. Dividend amounts likely will vary, and there can be no assurance as to the level of dividends that will be paid or that any dividends will be paid at all.** See "*Risk Factors – Dividends and other payments on the Corporation's Common Shares are variable*. Cash dividends are declared in US dollars, however, may be paid in Canadian dollars for shareholders who have elected to receive such. These payments are converted to Canadian dollars based upon the exchange rate closer to the dividend payment date. As such, certain shareholders are subject to foreign exchange rate risk on such payments.

The Corporation declared a monthly dividend of CDN$0.01 per share in 2020. In 2021, the Corporation declared and paid a monthly divided of CDN$0.01 per share in January through May. In May of 2021, the Corporation announced a transition to a quarterly dividend of CDN$0.033 per share starting with its June dividend. The dividend was increased to CDN$0.038 per share for the dividend declared in August of 2021 and further increased to CDN$0.041 per share for the dividend declared in November of 2021.

During 2022, the Corporation began declaring dividends in U.S. dollars and declared the following quarterly dividends:

- Q1 2022 – US$0.033 per share, paid on March 15
- Q2 2022 – US$0.043 per share, paid on June 15
- Q3 2022 – US$0.050 per share, paid on September 15
- Q4 2022 – US$0.055 per share, paid on December 15

On February 23, 2023, Enerplus declared its first quarter 2023 dividend of US$0.055 per share, payable on March 15, 2023.

For certain tax information relating to the dividends paid on the Common Shares for Canadian and U.S. federal income tax purposes, please refer to the Corporation's website at www.enerplus.com.

Shareholders are advised to consult their tax advisors regarding questions relating to the tax treatment of dividends paid by the Corporation. For additional information on potential risks associated with the taxation of dividends paid by the Corporation, see "*Risk Factors*".

STOCK DIVIDEND PROGRAM

Effective May 11, 2012, the Corporation implemented a stock dividend program pursuant to which shareholders of the Corporation were able to elect to receive dividends in the form of Common Shares, instead of receiving a cash dividend, issued at a deemed price of 95% of the five-day weighted average trading price of the Common Shares on the TSX immediately prior to the applicable dividend payment date. Effective with the April 2014 dividend, the Corporation elected to eliminate the 5% discount applied to determine the number of Common Shares issued pursuant to the stock dividend program. Effective September 19, 2014, the board of directors of the Corporation suspended the stock dividend program to eliminate the dilution associated with the issuance of Common Shares through the program.

Industry Conditions

OVERVIEW

The Corporation, and the oil and natural gas industry generally, are subject to extensive controls and regulation governing operations (including land tenure, exploration, development, production, refining, transportation, marketing, remediation, abandonment and reclamation) imposed by legislation enacted by various levels of government. The Corporation and the oil and natural gas industry are also subject to agreements among the various federal and state governments with respect to pricing and taxation of oil and natural gas. Although it is not expected any of these controls, regulations or agreements will affect the Corporation's operations in a manner materially different than they would affect other oil and gas producers in similar operating areas, the controls, regulations and agreements should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record, and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the Corporation's participation in the oil and gas industry that are applicable to the Corporation's operations.

The Corporation owns oil and natural gas properties and related assets in the United States (North Dakota, Pennsylvania and Colorado). The Corporation's oil and natural gas operations are regulated by a wide range of administrative agencies under statutory provisions of the states, where such operations are conducted, by certain agencies of the federal government for operations on U.S. federal leases and, in some cases, by local agencies. These provisions regulate matters such as the exploration for and production of crude oil and natural gas, including rules related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. The Corporation's operations are also subject to various conservation laws and regulations in respect of matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit or limit the venting or flaring of natural gas and associated liquids, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

The Corporation is required under Canada's Extractive Sector Transparency Measures Act ("**ESTMA**") to disclose certain payments made to governments of all levels, including Indigenous groups in Canada and Indian Reservations in the United States. In addition, the Corporation will be required to furnish an annual report, or an alternative report complying with Canada's ESTMA, to the SEC beginning in 2024 disclosing any payment made during the prior fiscal year by the Corporation to the U.S. government or a foreign government for the purpose of the commercial development of oil, natural gas, or minerals. These and other disclosure regulations could require us to incur significant costs, require us to disclose competitively sensitive commercial information, or cause us to violate non-disclosure laws or agreements, including those of the Indigenous groups in Canada and Native American tribes within the United States.

PRICING AND MARKETING OF CRUDE OIL AND NATURAL GAS

Producers of crude oil negotiate sales contracts directly with crude oil purchasers. Most agreements are linked to continental or global oil prices, which are set by daily, weekly and monthly physical and financial transactions for crude oil around the world. Those prices are primarily based on overall fundamentals of supply and demand. Specific prices depend, in part, on crude oil quality, prices of competing fuels, distance to markets, access to downstream transportation, the value of refined products, the supply/demand balance and other contractual terms. In the United States, the Federal Energy Regulatory Commission ("**FERC**") regulates rates, terms and conditions of service for interstate transportation of crude oil, which affect the marketing of crude oil, as well as revenues producers receive for sales of crude oil. Intrastate crude oil transportation service is also subject to regulation by some state regulatory agencies. In addition, exports of crude oil and natural gas liquids from the United States require a license from the Bureau of Industry and Security of the U.S. Department of Commerce, with certain export transactions generally approved and other transactions considered on a case-by-case basis to determine whether they are in the national interest.

Producers of natural gas are free to negotiate prices and other terms with purchasers, provided export contracts meet certain criteria. In relation to U.S. exports, this would include restrictions on export licenses imposed by the United States Department of Energy. The prices depend, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to the market, access to downstream transportation, length of contract term, seasonal factors, weather conditions, the value of refined products, the supply/demand balance and other contractual terms. In the United States, the FERC regulates rates, terms and conditions of service for interstate transportation of natural gas, which affect the marketing of natural gas, as well as revenues producers receive for sales of natural gas. Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies.

Internationally, prices for crude oil and natural gas fluctuate in response to changes in the supply and demand for crude oil and natural gas, general market uncertainty and a variety of other factors beyond the Corporation's control. Crude oil and natural gas prices continued to be volatile during 2022 in response to a variety of factors including, among others, supply and demand impacts due to the ongoing Ukraine and Russian conflict, lingering concerns over crude oil demand due to COVID, concerns over the potential impact of a global recession, as well as ongoing decisions by the Organization of Petroleum Exporting Countries ("**OPEC**") and non-OPEC members to manage production levels to achieve balance in crude oil supply and demand. See "*Risk Factors – Oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Corporation's business, results of operations or cash flows and financial condition*". In addition, crude oil and natural gas producers in some areas of North America currently receive discounted prices for their production relative to certain continental and/or international benchmark prices due to the lack of adequate egress which would allow crude oil and natural gas production to be transported and sold to national and, in some cases, international markets. See "*Risk Factors – The inability to access land, inadequately developed infrastructure, and the impact of special interest groups on either, may result in a decline in the Corporation's ability to market its oil and natural gas production*".

Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (i) to defraud using any device, scheme or artifice; (ii) to make any untrue statement of material fact or omit a material fact; or (iii) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission ("**CFTC**") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act ("**CEA**"). With regard to the use of certain transmission or transportation facilities and the Corporation's physical purchases and sales of natural gas, crude oil, or other energy commodities and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess or seek civil penalties of up to $1,496,035 per violation, per day, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Failure to comply with the federal laws and regulations governing our operations and business activities can result in the imposition of administrative, civil and criminal remedies.

ROYALTIES AND INCENTIVES

In addition to federal regulations, each U.S. state has legislation and regulations which govern oil and gas holdings and land tenure, royalties, production rates, environmental protection and other matters. In all U.S. jurisdictions, producers of oil and natural gas are typically required to make annual rental payments in respect of federal, state and freehold leases until production begins. Upon commencement of production, royalties and production taxes are paid in respect of oil and natural gas produced from federal, state and freehold lands. Producers on U.S. Indian leases are required to make annual rental payments regardless of well production, in addition to other fixed fees for land improvement, on a per well basis. The applicable royalty and production tax regime is a significant factor in the profitability of oil and natural gas production.

Royalties or similar payments payable on production from lands other than federal and state lands in the United States are determined by negotiations between the freehold mineral owner and the lessee. Federal, U.S. Indian, and state royalties and production taxes in the United States are determined by government regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties or net profits or net carried interests.

From time to time, the federal and state governments in the United States have established incentive programs which have included royalty rate or production tax reductions (including for specific wells), royalty holidays, and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. If applicable, oil and natural gas royalty holidays, reductions and tax credits would effectively reduce the amount of royalties paid by oil and gas producers to the applicable governmental entities. However, in other instances, such royalties may be increased. For example, in November 2021, the U.S. Department of the Interior ("DOI") released a report with several recommendations on how to revise federal oil and gas leasing and permitting practices, including by adjusting royalty and bonding rates, prioritizing leasing in areas with known resource potential, and avoiding leasing that conflicts with recreation, wildlife habitat, conservation, and historical and cultural resources. The Inflation Reduction Act of 2022 ("IRA"), signed into law on August 16, 2022, responded to one of the report's recommendations and increased onshore royalty rates to 16⅔%. Several of the report's other recommendations, however, will require further Congressional action and Enerplus cannot predict the extent to which the recommendations may be implemented now or in the future, but restrictions on federal oil and gas activities have the potential to result in increased costs and adversely impact the Corporation's operations.

LAND TENURE

Crude oil and natural gas located in the United States is predominantly owned by private owners. The U.S. Department of the Interior – Bureau of Land Management ("**BLM**"), and the state in which the minerals are located also may hold ownership to such rights. These owners, from governmental bodies to private individuals, grant rights to explore for and produce oil and gas pursuant to leases, licenses and permits for varying periods and on conditions including requirements to perform specific work or make payments. As to those rights held by private owners, all terms and conditions may be negotiated. For those rights held by governmental agencies, typically the terms and conditions of the oil and gas lease have been predetermined by each governing or regulatory body. Substantially all of the leaseholds currently owned by the Corporation in the U.S. have been granted through private individuals.
The Corporation's operations in North Dakota that are located on the Fort Berthold Indian Reservation ("**FBIR**") involve allottee lands, which are lands that are administered by the Bureau of Indian Affairs ("**BIA**") but owned by individual tribal members. As such, these operations are governed by both state and federal regulations. U.S. federal departments such as the BIA, the BLM, and the U.S. EPA enforce the federal regulations. Federal U.S. regulations may differ significantly from regulations generally applicable to non-federally regulated lands and, as a consequence, may result in the slowing, or halting of, the Corporation's developments on the FBIR.

A lease generally may be continued after the initial term provided certain minimum levels of exploration or production have been achieved and all lease rentals have been timely paid, subject to certain exceptions. To develop minerals, including oil and natural gas, it is necessary for the mineral estate owner to have access to the surface estate. Under common law, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each jurisdiction has developed and adopted its own statutes that operators must follow both prior to and following drilling, including notification requirements and the obligation to provide compensation for lost land use and surface damage. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

ENVIRONMENTAL REGULATION

The Corporation is subject to the applicable municipal, tribal, state and federal environmental laws and regulations in its operating areas in the U.S. These requirements provide for environmental protection and impose restrictions and prohibitions regarding disturbances and releases, or emissions of various regulated substances produced or utilized in association with oil and gas industry operations. With respect to a property designated as a contaminated site, environmental laws may impose remediation obligations upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused release of the substance, and any past or present owner, tenant, or other person in possession of the site. In addition, legislation requires that well, pipeline and facility sites are abandoned and restored to the satisfaction of the applicable authorities. Compliance with these requirements can involve significant expenditures. A breach of such requirements may result in the imposition of material fines and penalties, the suspension or revocation of necessary licenses and authorizations, civil liability for pollution and natural resource damage, or the issuance of clean-up orders. See "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to* environmental *costs, claims and liabilities, including those which are climate change-related, as well as public opposition and activism*".

In the United States, oil and gas operations are regulated at the federal, tribal, state and local levels of government. At the federal level, well planning and permitting is primarily regulated by the BLM and the BIA for operations on public and tribal lands under the *Federal Land Policy and Management Act* and the U.S. EPA for operations under the *National Environmental Policy Act*. Environmental conservation and cultural and natural resources protection at the federal and state level are administered by numerous agencies under multiple statutes, codes, and regulations.

Planning, permitting and compliance related to environmental media protection and contaminants at the federal level are administered by the U.S. EPA, or by analogous state agencies whose programs have been granted primacy by the U.S. EPA. The U.S. EPA governs federal legislation, as amended from time to time, including the *Clean Air Act*, the *Clean Water Act*, the *Resource Conservation and Recovery Act* (other than oil and gas exploration and production exempt wastes), the *Comprehensive Environmental Response, Compensation and Liability Act*, the *Oil Pollution Act*, the *Emergency Planning and Community Right-to-Know Act* and the *Safe Drinking Water Act* and Federal Executive Orders.

The Corporation's U.S. operations are subject to various regulations, including those relating to well permits, linear facilities, hydraulic fracturing, underground injection, emissions limitations and setbacks (buffers) for environmental and public health protection, which are imposed by several state agencies regulating oil and gas activities. In addition to the agencies which directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, water quality, aquatic biology, wildlife, land use, transportation, noise, spills and incidents, cumulative impacts, and impacts on disproportionately impacted communities.

Additional regulations affecting the Corporation's U.S. operations include: (i) the Federal Implementation Plan for Oil and Natural Gas Well Production Facilities, FBIR (Mandan, Hidatsa, and Arikara Nations) (the "**MHA Nation**"), in North Dakota

and (ii) the Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. These regulations provide emission control requirements for the Corporation's U.S. assets, as well as increased monitoring, recordkeeping, reporting and regulatory oversight. In May 2020, the Office of the Solicitor of the DOI issued an opinion (the "Missouri River Opinion") finding that the State of North Dakota, not the MHA Nation, was the legal owner of the minerals underlying the Missouri River. The MHA Nation filed actions in two federal courts seeking to overturn the May 2020 decision. In March 2021, the DOI withdrew the Missouri River Opinion and, only recently, on February 4, 2022, the DOI issued a new opinion on the matter, stating that the minerals beneath the Missouri River riverbed located on the FBIR belong to the MHA Nation and not the state of North Dakota. However, the state of North Dakota asserts that this decision is incorrect and is currently seeking to overturn a ruling that it not be allowed to intervene in litigation regarding the MHA Nation's claims to mineral-related revenues. The Corporation cannot predict what effect this may ultimately have on its operations.
Hydraulic fracturing is typically regulated by state oil and natural gas commissions, though federal agencies have asserted regulatory authority over certain aspects of the hydraulic fracturing process. For more information, see "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including but not limited to those which are climate change-related, as well as public opposition and activism*". All U.S. states in which the Corporation operates have regulations on hydraulic fracturing disclosure. The Corporation utilizes the internet-based chemical registry FracFocus for posting of the required disclosure information. In the United States, FracFocus is operated by the Ground Water Protection Council, a group of state water officials, and the Interstate Oil and Gas Compact Commission, an association of oil and gas producing states. The online registry was created in response, at least in part, to concerns from landowners about the chemical content of fracturing fluids that were being injected into oil and gas wells on their land as well as adjacent properties. FracFocus is widely accepted among the oil and gas industry and the Corporation utilizes the registry in all of its operational areas.

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants, the costs of which could be significant. The need to obtain permits has the potential to delay the development of our oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, BLM and certain state regulators have imposed restrictions on the flaring of natural gas, with the BLM also seeking to determine the sufficiency of an operator's methane waste minimization plan.

The need for an operator to flare gas primarily stems from the fact that the rate of oil and gas development in North Dakota currently outpaces the construction of gas gathering and processing infrastructure. This situation is the result of various factors, including delays in obtaining right of way approvals, which is particularly cumbersome with respect to operations taking place on FBIR due to the application of additional regulatory requirements. The Corporation is working diligently with its midstream partner and the regulators to expand gas gathering capacity and increase gas capture rates. One measure being taken is the installation of NGL processing skids which are being used to extract NGLs from gas that would have otherwise been flared. See "*Risk Factors - Higher than expected declines or curtailments in the Corporation's production due to infrastructure constraints, third party operational business practices or failures, or government regulation could have an adverse effect on results of operations or cash flows and financial condition*". The North Dakota Industrial Commission ("**NDIC**") has issued orders and pursued other regulatory initiatives to implement legally enforceable "gas capture percentage goals" targeting the capture of natural gas produced in the state. As of November 1, 2020, the enforceable gas capture percentage goal is 91%. Failure of an operator to comply with the applicable goal at maximum efficiency rate may result in the imposition of monetary penalties and restrictions on production from subject wells. As of December 31, 2022, the Corporation was continuing to capture approximately 91% of its natural gas production in North Dakota. While it was satisfying the applicable gas capture percentage goals as of December 31, 2022, there is no assurance that Enerplus will remain in compliance in the future, or that such future satisfaction of such goals will not have a material adverse effect on its business and results of operations.

The NDIC has adopted conditioning standards aimed at improving the safety of crude oil when transported. The regulation focuses on ensuring that produced crude oil is sufficiently conditioned at the well site to remove volatility characteristics that might pose unreasonable transportation hazards, regardless of the mode of transportation utilized**.** The Corporation has been in compliance with the NDIC conditioning standards requirements.

Other states have adopted similar or more stringent regulations for environmental protection. For example, Colorado has adopted sweeping changes to the states oil and gas law, including, among other matters, requiring the Colorado Oil and Gas Conservation Commission ("**COGCC**") to prioritize public health and environmental concerns in its decisions, instructing the COGCC to adopt rules to minimize emissions of methane and other air contaminants, and delegating considerable new authority to local governments to regulate surface impacts. In keeping with SB 19-181, the COGCC in November 2020 adopted revisions to several regulations to increase protections for public health, safety, welfare, wildlife, and environmental resources. Most significantly, these revisions establish more stringent setbacks (2,000 feet instead of the previously required 500 feet) on new oil and gas development and eliminate routine flaring and venting of natural gas at new or existing wells across the state, each subject to only limited exceptions. Some local communities have adopted, or are considering adopting, additional restrictions for oil and gas activities, such as requiring greater setbacks. Additionally, on December 17, 2021, the Colorado Air Quality Control Commission adopted regulations aimed at curbing methane emissions from oil and gas operations to include setting methane emission limits per 1,000 barrels of oil equivalent produced, more frequent inspections, and limits on emissions during maintenance.

Implementation of more stringent environmental regulations on the Corporation's U.S. operations could affect the Corporation's capital and operating expenditures and plans. The Corporation endeavours to reduce the potential of these impacts to U.S. operations in many ways, including through participation and membership in trade organizations such as the American Exploration and Production Council, North Dakota Petroleum Council, Independent Petroleum Association of America, Western Energy Alliance and the Colorado Oil and Gas Association. In addition, the Corporation participates directly in legislative hearings, rulemaking processes, meetings with state officials and local stakeholder groups, and provides both written and verbal comments on proposed legislation and regulations. As in Canada, the Corporation's U.S. operations endeavour to carry out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice.

British Columbia

In British Columbia, all oil and gas operations are overseen by the British Columbia Oil and Gas Commission ("**BCOGC**"), primarily through the Oil and Gas Activities Act. The BCOGC also oversees compliance with a variety of environmentally related statutes, including the Forest Act, Heritage Conservation Act, Land Act, Environmental Management Act and the Water Sustainability Act. The Corporation has one property in British Columbia which is subject to regulatory oversight by the BCOGC. The abandonment of this property began in 2019 and the majority of work is expected to be completed by 2023. After completion of the abandonment, there will be ongoing work on reclamation and remediation through to and beyond 2024. All work is being completed in compliance with the governing statutory regime.

Alberta

In Alberta, the Alberta Energy Regulator ("**AER**") is the single regulator of oil and gas development in Alberta and oversees all aspects of the regulatory process, including related to exploration, construction and development, abandonment, reclamation, and remediation activities. The AER oversees compliance with the Oil and Gas Conservation Act, Public Lands Act, Mines and Minerals Act, Water Act and the Environmental Protection and Enhancement Act by oil and gas operators. The AER operates in conjunction with Alberta Environment and Parks to ensure the province's environmental, social and economic targets are met. Alberta Environment and Parks is also responsible for climate change-related regulations such as the Alberta Technology Innovation and Emissions Reduction program. The Corporation is abandoning a property in 2023 and expects the program to last several years.

Climate change-related legislation

Globally, the shift to a low-carbon economy continues to shape ESG practices and business strategy, in particular with respect to climate change-related actions. Climate change-related legislation at the state and federal levels has the potential to significantly affect the oil and gas industry regulatory environment and impose significant operational and/or financial obligations on companies.

In addition, globally, the TCFD has been working to help identify information needed by investors, lenders and credit and insurance underwriters to appropriately assess and price climate change-related risks and opportunities. Although not legislated in North America, the TCFD has developed voluntary disclosure under a singular, accessible framework specific to climate change-related actions and provides the fundamental framework upon which the Securities and Exchange Commission's ("**SEC**") proposed rule on climate-related disclosures released in March 2022 is based upon. Four core recommendations have been presented which would apply to organizations across all sectors and jurisdictions. The four core areas of recommendation relate to governance, strategy, risk management and metrics and targets. An additional eleven detailed recommended disclosures have been made, along with the call for the reporting of decision-useful information in mainstream filings. Enerplus continues to recognize the TCFD recommended guidelines and is working toward integrating fit for purpose disclosure from the guidelines into its ESG strategy. The TCFD Aligned Reporting Table in connection with Enerplus' 2022 ESG Report is available at www.enerplus.com.

The United States was part of the United Nations Framework Convention on Climate Change ("**UNFCCC**") meeting in Paris in 2015. A binding commitment, (the "**Paris Agreement**"), was signed by all panel countries that set a target of no more than a two-degree Celsius warming of the earth based on GHG levels in the atmosphere. This commitment to limit warming may increase state and federal GHG regulatory rigour as country-level emissions will be reviewed periodically in subsequent meetings to assess alignment with the targets agreed upon. The agreement also called for countries to submit non-binding, individually determined emissions reduction targets every five years after 2020. Following President Biden's executive order in January 2021, the United States rejoined the Paris Agreement and, in April 2021, established a goal of reducing economy wide net GHG emissions 50-52% below 2005 levels by 2030. Additionally, at the 26th Conference of the Parties to the UN

Framework Convention on Climate Change ("**COP26**") in Glasgow in November 2021, the United States and the European Union jointly announced the launch of a Global Methane Pledge, which is an initiative committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including "all feasible reductions" in the energy sector. At COP27 in Sharm El-Sheik in November 2022, countries reiterated the agreements from COP26 and were called upon to accelerate efforts toward the phase out of inefficient fossil fuel subsidies. The United States also announced in conjunction with the European Union and other partner countries that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity gas. Although no firm commitment or timeline to phase out or phase down all fossil fuels was made at COP27, there can be no guarantees that countries will not seek to implement such a phase out in the future.

Additionally, the U.S. EPA continues to enforce GHG emissions regulations pursuant to the Clean Air Act that establish a reporting program for CO_2, methane and other GHG emissions. It has also established a permitting program for certain large GHG emissions sources. There has been considerable uncertainty surrounding regulation of methane emissions in the United States, as the U.S. EPA under former President Obama's Administration published final regulations under the Clean Air Act establishing new source performance standards ("**NSPS**") for reduction of methane from certain new, modified or reconstructed oil and gas facility sources in 2016, but since that time the U.S. EPA under former President Trump's Administration has undertaken several measures to delay or restrict implementation of those standards, including publishing in September 2020 final rule policy and technical amendments to the NSPS, for stationary sources of air emissions. The policy amendments, effective September 14, 2020, notably removed the transmission and storage sector from the regulated source category and rescinded methane and volatile organic compound ("**VOC**") requirements for the remaining sources that were established by former President Obama's Administration, whereas the technical amendments, effective November 16, 2020, included changes to fugitive emissions monitoring and repair schedules for gathering and boosting compressor stations and low-production wells, recordkeeping and reporting requirements, and more. However, subsequently, the U.S. Congress approved, and President Biden signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. Additionally, in November 2021, EPA issued a proposed rule that, if finalized, would establish OOOO(b) new source and OOOO(c) first-time existing source standards of performance for methane and VOC emissions for oil and gas facilities. Operators of affected facilities will have to comply with specific standards of performance, which include leak detection using optical gas imaging and subsequent repair requirements, and reduction of emissions by 95% through capture and control systems. In November 2022, EPA released a supplemental methane proposal. Among other items, the proposal sets forth specific revisions strengthening the first nationwide emissions guidelines for states to limit methane emissions from existing oil and gas facilities. The proposal also revises requirements for fugitive emissions monitoring and repair, as well as equipment leaks and the frequency of monitoring surveys, establishes a "super-emitter" response program to timely mitigate emissions events, and provides additional options for the use of advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions. The EPA's proposed rule would prohibit flaring at new sources (OOOO(b)) and later prohibit flaring at existing sources (OOOO(c)), except in certain limited circumstances. The proposal is currently subject to public comment and is expected to be finalized in 2023. Relatedly, the BLM has proposed new regulations to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal leased land. The proposed rule would require payment of royalties on subject flared volumes and potential curtailment of production when flared volumes exceed certain rates. It is likely that both rules will be subject to legal challenges, though we cannot predict how this may affect implementation. To the extent finalized as proposed, these rules could increase our operating costs, limit our operations in certain areas, or otherwise adversely impact our business. Finally, the IRA imposes a fee on the emissions of methane from certain sources in the oil and natural gas sector. Beginning in 2024, the methane emissions charge will begin at $900 per metric ton of leaked methane, rising to $1,200 in 2025, and $1,500 in 2026 and thereafter. Calculation of the fee is based on certain thresholds established in the IRA. On a state level, some states have enacted laws concerning GHG emissions, including increased stringency of emissions standards or the imposition of regulatory markets that require certain limits on GHG emissions.

The Corporation has not experienced a material adverse effect from requirements to comply with applicable environmental laws and regulations and is committed to meeting its responsibilities to protect the environment wherever it operates or holds working interests. The Corporation anticipates that this compliance may result in increased costs of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. See "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including those which are climate change-related, as well as public opposition and activism*" and "*Risk Factors – Government policy and/or regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations, including production targets, and result in increased operating and capital costs*".

WORKER SAFETY

The Corporation's operations must be carried out in accordance with safe work procedures, rules and policies contained in applicable safety legislation. Such legislation requires that every employer ensures the health and safety of all persons at any of its work sites and all workers engaged in the work of that employer. The legislation, which provides for incident reporting procedures, also requires every employer to ensure all of its employees are aware of their duties and responsibilities under the applicable legislation. Penalties under applicable occupational health and safety legislation include significant fines and incarceration. The Corporation is currently in compliance with applicable safety legislation.

Risk Factors

The following risk factors, together with other information contained in this Annual Information Form and other filings, including the Corporation's MD&A, and its Financial Statements and related notes, should be carefully considered before investing in the Corporation. Each of these risks may negatively affect the trading price of the Common Shares, the number of Common Shares that may be repurchased by the Corporation, or the amount of dividends that may, from time to time and at the discretion of the Corporation's board of directors, be declared and paid by the Corporation to its shareholders.

Please note, all references to "natural gas" in this section refer to both natural gas and shale gas.

Crude oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Corporation's business, results of operations, or cash flows and financial condition.

The Corporation's results of operations and financial condition are dependent on the prices it receives for the oil and natural gas it produces and sells. Oil and natural gas prices have fluctuated widely during recent years and may continue to be volatile in the future. These price fluctuations have been and could occur in response to a variety of factors beyond the Corporation's control, including:

- global energy supply and demand, production, and regulatory policies, including sanctions that may be placed on countries that supply energy to the global market
- actions taken by OPEC+ or non-OPEC+ members to set, maintain, or alter production levels
- the ability to export, considering government or political actions or orders, regulations, taxation, and market demand, crude oil and liquefied natural gas and NGLs from North America
- geopolitical uncertainty, including for example, the impact of the Ukraine and Russia conflict and European energy instability; the risk of international hostile actions, as well as actions in the United States or Canada that could disrupt trade or other relations
- sustained pandemics or epidemics, including the continuing effect of the COVID, pandemic, which may disrupt economies, whether local or global, and may impact supply, demand or commodity prices for crude oil, NGLs or natural gas
- global and domestic economic conditions, as well as currency fluctuations and inflation
- the level of consumer demand, including demand for different qualities and types of crude oil, NGLs and natural gas
- the production and storage levels of global natural gas and crude oil, and the supply and price of imported or exported crude oil and liquefied natural gas
- supply chain challenges and disruptions
- weather conditions
- the proximity of reserves and resources to, and capacity of, gathering and transportation facilities, and the availability of storage, refining, processing and fractionation capacity
- the impact of world-wide energy conservation and decarbonization efforts, GHG reduction measures, the price and availability of alternative fuels and the impact of regulatory initiatives associated therewith
- existing and proposed changes to government regulations and policy decisions, including moratoriums with respect thereto

Oil and natural gas producers in North America may receive lower prices for some of their production due to regional constraints impacting their ability to transport and sell production in more favourably priced markets. Additionally, limited natural gas and NGLs processing capacity or other infrastructure constraints may result in producers not realizing the full price for their production. The inability to resolve such constraints may result in ongoing volatility in commodity prices and in reduced commodity prices received by oil and natural gas producers, such as the Corporation.

Future declines in crude oil and/or natural gas prices, or an extended low commodity price environment, may have a material adverse effect on the Corporation's operations and cash flows, financial condition, borrowing ability, levels of reserves and resources, and the level of capital spending available for the development of the Corporation's crude oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to proceed with as part of the Corporation's exploration or development plans or projects if commodity prices are low, thereby impacting the Corporation's production volumes. Low prices may also impact the Corporation's desire to market its production when market conditions are less satisfactory for the Corporation. Alternatively, due to regulatory or contractual obligations, the Corporation may be required to produce from or develop certain properties to fulfill its obligations despite unsatisfactory market conditions for marketing of any production therefrom, increasing the risk of financial losses. Furthermore, the Corporation may be subject to the decisions of third-party operators who, independently and using different economic parameters than the Corporation, may decide to curtail or shut-in jointly owned production.

Risks relating to the impact of the Ukraine and Russia conflict.

The existing conflict between Ukraine and Russia and the international response has, and may continue to have, potential wide-ranging consequences for global market volatility and economic conditions, including affecting crude oil and natural gas prices. Certain countries including Canada, the United States, Australia and certain European countries have imposed strict financial and trade sanctions against Russia, which may have continued far-reaching effects on the global economy, energy and commodity prices and food security and crop nutrient supply and prices. The short-, medium- and long-term implications of the conflict in Ukraine are difficult to predict with any degree of certainty at this time. Depending on the extent, duration, and severity of the conflict, it may have the effect of heightening many of the other risks described in this Annual Information Form and the MD&A, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; crude oil and natural gas prices; inflationary pressures, interest rates and costs of capital; and supply chains and cost-effective and timely transportation.

An increase in capital or operating costs could have a material adverse effect on results of operations or cash flows and financial condition.

Higher capital or operating costs associated with the Corporation's operations will directly impact its capital efficiencies and/or decrease the amount of the Corporation's cash flow and/or free cash flow. Capital costs of completions, specifically the costs of steel, proppant, pumper services, and operating costs such as electricity, chemicals, supplies, processing charges, energy services and labour costs, are a few of the Corporation's costs that are susceptible to material fluctuation. Although the Corporation has a portion of its current capital and operating costs protected with existing agreements, changing regulatory conditions, such as potential new or revised regulations in the U.S. requiring certain raw materials, such as steel, for use on certain projects to be sourced from the U.S., or that goods and/or services be procured from specific vendors or classes of vendors on certain projects, other supply chain challenges, disruptions and adverse effects of inflation and rising interest rates, may result in higher than expected supply costs for the Corporation. Additionally, the Corporation has certain service contracts tied to inflationary measure benchmarks (such as the Consumer Price Index and WTI crude oil price), which could increase its operating costs should the benchmarks rise significantly.

The Corporation may be unable to compete successfully with other organizations in the oil and natural gas industry or obtain required supplies and services to compete.

The oil and natural gas industry is highly competitive. The Corporation competes for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled/qualified labour, access to drilling rigs, service rigs and other equipment and materials such as sand and other proppant, hydraulic fracturing pumping equipment and related skilled personnel, access to processing facilities, pipeline and refining capacity, as well as many other services, and in many other respects, with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of these organizations not only explore for, develop and produce oil and natural gas, but also conduct refining operations and market oil and other products on a world-wide basis. As a result of these complementary activities, some of the Corporation's competitors may have greater opportunities and more diverse resources to draw upon. Also, organizations that have complementary activities or are integrated may have access to, or be able to access, services or supply chain options the Corporation is not able to access, thereby limiting its ability to compete and potentially directly impacting its operational and financial results.

Service providers, including those the Corporation relies on, are also in a highly competitive environment that is impacted by worker availability, commodity prices and global supply inventories. Where worker availability is impacted by shortages, due to location or pandemic related issues, for example, some may choose or be required to streamline or discontinue their business, further reducing the supply of vendors and potentially increasing the competition for service/supplies, and thereby the costs to producers.

In addition, the Corporation may be at a competitive disadvantage to other industry participants able to minimize taxes under more favourable tax jurisdictions and/or regulatory environments, or which have access to a lower cost of capital.

Increasing attention to ESG and sustainability matters may impact the Corporation's business.

Companies across all industries are facing increasing scrutiny from stakeholders related to their ESG and sustainability practices. These standards are evolving, and if the Corporation fails to comply with these standards or are perceived to have not responded appropriately to these standards, regardless of whether there is a legal requirement to do so, the Corporation may suffer from reputational damage and the business, financial condition, and/or stock price could be materially and adversely affected. Increasing attention to climate change and sustainability, increasing societal expectations on companies to address climate change-related targets, and potential consumer use of substitutes to fossil-fuel energy commodities may result in increased costs, reduced demand for hydrocarbon products, reduced profits, increased investigations and litigation, and negative impacts on the Corporation's share price and access to capital markets. Increasing attention to climate change-related and sustainability targets and expected actions, for example, may result in demand shifts for hydrocarbon products and additional governmental investigations and private litigation against the Corporation.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and shareholders. Such ratings are used by some investors to inform their investment and voting decisions. Additionally, certain investors use these scores to benchmark companies against their peers, and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company’s sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of the Corporation’s shares from consideration by certain investment funds, engagement by investors seeking to improve such scores and a negative perception of the Corporation's operations by certain investors. Additionally, to the extent ESG matters negatively impact the Corporation’s reputation, it may not be able to compete as effectively to recruit or retain employees, which may adversely affect its operations.

The Corporation also makes certain disclosures regarding sustainability, publishing an ESG report that provides updates on its performance related to certain ESG topics and sets certain ESG goals. Many of its disclosures are necessarily based on estimates and assumptions that are inherently difficult to assess. Moreover, Enerplus may not be able to adequately identify ESG-related risks and opportunities and, further, may not be able to meet ESG targets in the manner, or on such a timeline as initially contemplated, including as a result of unforeseen costs or technical difficulties associated with achieving such results. While the Corporation may elect to seek out various additional voluntary ESG targets now or in the future, such targets are aspirational. Notwithstanding this, Enerplus may receive pressure from investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals, but it cannot guarantee it will be able to implement such goals because of potential costs or technical or operational obstacles.

Additionally, public statements with respect to emissions reduction goals, environmental targets, or, more broadly, ESG-related goals, are becoming increasingly subject to heightened scrutiny from public and governmental authorities with respect to the risk of potential “greenwashing,” i.e., misleading information or false claims overstating potential ESG benefits. For example, in March 2021, the SEC established the Climate and ESG Task Force in the Division of Enforcement to identify and address potential ESG-related misconduct, including greenwashing. The Canadian securities regulators (the “**CSA**”) have been monitoring issuers’ disclosures relating to various ESG-related matters and have published a public guidance stating their concerns with certain practices involving unsupported claims that may constitute greenwashing. Certain non-governmental organizations and other private actors have filed lawsuits under various securities and consumer protection laws alleging that certain ESG-statements, to include emission reduction goals or standards used, were misleading, false, or otherwise deceptive. As a result, the Corporation may face increased litigation risks which could, in turn, lead to further negative sentiment and diversion of investments. Enerplus could also face increasing costs to comply with increased regulatory focus and scrutiny.

Government policy and/or regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations, including production targets, and result in increased operating and capital costs.

The oil and gas industry operates under federal, state and municipal legislation and regulation governing such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income, gathering, transportation and exportation of crude oil, natural gas and other products, and other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, the imposition of specific drilling obligations, the imposition of production curtailments, control over the development and abandonment of fields (including restrictions on production), restrictions on the combustion of natural gas and possibly expropriation or cancellation of contract rights. See "*Industry Conditions*". To the extent the Corporation fails to comply with applicable government regulations or regulatory approvals, the Corporation may be subject to compliance and enforcement actions that are either remedial, which are intended to fix the non-compliance and any related impacts, or punitive, which are intended to deter future non-compliance. Such actions include penalties, fines or fees, notices of non-compliance, warnings, orders, administrative sanctions, and prosecution. In addition, obstructive tactics which could prevent certain measures from being voted upon in the United States legislature, or any government action resulting in a prolonged government shutdown, may impact the Corporation as a result of its inability to obtain regulatory and other approvals.

Government regulations may be changed from time to time in response to economic, political, or socioeconomic conditions. The Corporation's entry into new jurisdictions and its adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. U.S. federal and state governments continue to scrutinize emissions, as well as the usage and disposal of chemicals and water used in fracturing procedures in the oil and gas industry; certain states have called for bans on oil and gas drilling using hydraulic fracturing. More activity by the Corporation on Indian lands in the United States may increase compliance obligations under tribal or local rules. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations, or the modification of existing regulations affecting the crude oil and natural gas industry could negatively impact the development of oil and gas properties and assets, reduce demand for, or restrict the supply of, crude oil and natural gas production, or impose increased costs on oil and gas companies, any of which could have a material adverse impact on the Corporation. Additionally, various levels of Canadian and U.S. governments are considering, or have implemented, legislation to reduce emissions of GHGs, including volatile organic compounds. See "*Industry Conditions – Environmental Regulation*" for a description of these initiatives. Because the Corporation's operations emit various types of GHGs, such new legislation or regulations could increase the costs related to operating and maintaining the Corporation's facilities, and could require it to install new emission controls on its facilities, acquire allowances for its GHG emissions, shut-in production, pay taxes, fees and other penalties related to its GHG emissions, and administer and manage a GHG emissions program. Currently, the Corporation is not able to estimate such increased costs; however, they could be material. Any of the foregoing could have adverse effects on the Corporation's business, financial position, results of operations and prospects.

Changes in laws or free trade agreements, including those affecting tax, royalties and other financial and trade matters, including exports, and interpretations of those laws and trade agreements, may adversely affect the Corporation and its securityholders.

Tax laws, including those that may affect the taxation of the Corporation, or other laws or government incentive programs relating to the oil and gas industry generally, may be changed, or interpreted in a manner that adversely affects the Corporation and its securityholders. Canadian, U.S. and foreign tax authorities having jurisdiction over the Corporation (whether as a result of the Corporation's operations or its financing structures), may change or interpret applicable tax laws, treaties or administrative positions in a manner which is detrimental to the Corporation or its securityholders. Tax authorities may disagree with how the Corporation calculates its income for tax purposes. The Corporation may be subject to additional taxation (direct or indirect, including carbon tax, goods and services tax, prop0oed share buyback taxes or sales tax), levies or royalty payments imposed by government and tribal authorities with jurisdiction over its properties. The Corporation has income and other tax filings that are subject to audit and potential reassessment which may impact the Corporation's tax liability. The Corporation believes appropriate provisions for current and deferred income taxes have been made in its Financial Statements; however, it is difficult to predict the outcome of audit findings by tax authorities. These findings may increase the amount of its tax liabilities and be detrimental to the Corporation. In addition, the USMCA came into force on July 1, 2020, which negotiated certain changes to NAFTA that impacts merchandise commerce activities after it came into effect. This could lead to the imposition of additional duties and tariffs, or other changes that could negatively impact the Corporation’s business.

The loss of members of the Corporation’s management or other key personnel could impact its business.

The Corporation's business and prospects for future success, including the successful implementation of strategies and/or handling of issues integral to its future success, depend to a significant extent upon the continued service and performance of the management team and key personnel. Shareholders are entirely dependent on the management and key personnel of the Corporation with respect to the exploration for and development of additional reserves and resources, the acquisition of oil and natural gas properties and assets, and the management and administration of all matters relating to the Corporation and its properties and assets, including hiring competent personnel. The loss of any member of the Corporation's management team or other key personnel, and its inability to attract, motivate and retain substitute key personnel with comparable experience and skills, could materially and adversely affect the business, financial condition and results of operations.

The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including but not limited to those which are climate change-related, as well as public opposition and activism.

GENERAL

The oil and natural gas industry elicits concerns about climate change-related issues, as well as general public opposition to the industry. As a result, industry participants may be subject to increased public activism and, in particular, activist activity that may result in increased costs, delays or damage to facilities or operations. This may also result in negative impacts to industry supply chains, obstructing the availability of procured materials. In addition, extensive environmental regulation pursuant to local, federal and state laws and regulations in the United States, may result in legislative and regulatory changes that could have an adverse effect on the Corporation, including its ability to meet its production targets. Existing and future laws and regulations may also impose additional costs on companies operating in the oil and gas industry, or significant liabilities for failure to comply with the requirements.

Concerns over climate change-related actions and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general. Any defaults by the Corporation under the applicable legislation could result in the imposition of fines or the issuance of "clean up" orders. As the form of such legislation and regulations continues to evolve, specific financial and operational outcomes are not clearly identifiable.

Generally, the business of exploration, development and production of oil and natural gas wells and facilities is subject to the risks and hazards associated with such operations. These include, but are not limited to, blowouts, fire, explosion, environmental releases (including sour gas), induced seismicity, and other safety hazards, which could result in significant damage to the Corporation’s property, personal injury, loss of life, and liability to regulators or third parties. In addition, general public and government opposition toward the oil and gas industry, including the shift to global decarbonization, could reduce demand for oil and gas and therefore, adversely affect market prices for production, as well as the financial and operating results of the Corporation.

The Corporation is not fully insured against all environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damage) is not available on economically reasonable terms. Accordingly, the Corporation's properties may be subject to liability due to hazards that cannot be insured against or that have not been insured against due to prohibitive premium costs or for other reasons.

Any site reclamation or abandonment costs incurred in the ordinary course, in a specific period, will be funded out of cash flows and, therefore, will reduce the amounts that may be available for development of projects and resources, debt repayments, or as available cash for share repurchases and/or dividends to shareholders. Enerplus has estimated the present value of its future asset retirement obligations to be $114.7 million at December 31, 2022 (see its Financial Statements) the majority of which are expected to be incurred between 2023 and 2034 for Canada, and 2037 and 2052 for the United States.

The Corporation does not establish a separate reclamation fund for the purpose of funding its estimated future environmental and reclamation obligations; therefore, it cannot assure investors that it will be able to satisfy its future environmental and reclamation obligations. Further, the availability in some jurisdictions of monies collected via levies on oil and gas producers, in order to cover remediation and/or reclamation costs incurred by the Corporation on behalf of insolvent or defunct partners, may be reduced or eliminated as such funds become depleted. Should the Corporation be unable to fully fund the cost of remedying an environmental claim, the Corporation might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

CLIMATE CHANGE-RELATED RISKS

As noted, public support for climate change-related action has grown in recent years, as has the receptivity to employing new technologies to address the same. Governments in the United States, Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. At the international level, the United Nations-sponsored Paris Agreement requires nations to submit non-binding, individually determined emissions reduction targets every five years after 2020. Following President Biden’s executive order in January 2021, the United States rejoined the Paris Agreement and, in April 2021, established a goal of reducing economy wide net GHG emissions 50-52% below 2005 levels by 2030. Additionally, at COP26 in Glasgow in November 2021, the United States and the European Union jointly announced the launch of a Global Methane Pledge, which is an initiative committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including "all feasible reductions" in the energy sector. At COP27 in Sharm El-Sheik in November 2022, countries reiterated the agreements from COP26 and were called upon to accelerate efforts toward the phase out of inefficient fossil fuel subsidies. The United States also announced, in conjunction with the European Union and other partner countries, that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity gas. Although no firm commitment or timeline to phase out or phase down all fossil fuels was made at COP27, there can be no guarantees that countries will not seek to implement such a phase out in the future. The impact of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States’ commitments under the Paris Agreement, COP26, COP27, or other international conventions cannot be predicted at this time, and it is unclear what additional initiatives may be adopted or implemented that may have a negative impact on the Corporation’s financial condition.

The major climate change-related risks are generally grouped into two categories: physical risks and transition risks. Physical risks are those that a change in climate itself could have on a business (e.g., as a result of a fire or flooding). Transition risks are broader and generally describe those risks related to the consequences of a global transition to reduced carbon. Specifically, transition risks encompass risks of regulatory and policy changes, as well as reputational concerns.

Physical Risks

Climate change may result in various physical risks, such as the increased frequency or intensity of extreme weather events (including but not limited to flooding, drought, winter storms, and wildfire) or changes in meteorological and hydrological patterns, which could adversely impact us or our contractors’ operations. Such physical risks may result in damage to our facilities or infrastructure we rely on to transport our products or otherwise adversely impact our operations, such as if facilities are subject to water use curtailments in response to drought, or demand for our products, such as to the extent warmer winters reduce the demand for energy for heating purposes. Such physical risks may also impact our suppliers, which may adversely affect our operations. Extreme weather conditions can interfere with our operations and increase our costs, and damage resulting from extreme weather may not be fully insured. However, the Corporation does not believe that its current operations expose it to physical risks in a manner which materially differs from those facing other North American onshore oil and gas producers.

Transition Risks - Regulatory and Policy

The global push to meet net zero emissions targets by 2050 increases the risk of potentially burdensome regulatory and/or policy changes from governments, some of which could have a direct, negative impact on the Corporation should they impede access or negatively impact our relationship with our stakeholders, service providers, lenders, insurers and the investment community. In addition, as a result of these regulations and policies, the Corporation could also be unable to obtain value for, or from, its oil and gas assets and reserves.

More specific concerns of the fossil fuels industry relate to GHG emissions, including methane, as well as water and land use. More stringent legislation or regulations in the United States, relative to other jurisdictions, including requirements to significantly reduce GHG emissions, water consumption, or setback requirements for facilities and wells, could result in increased costs and competitive disadvantages. For example, following the Trump Administration's revision of certain emissions regulations to rescind certain requirements established in 2016, the U.S. Congress approved, and President Biden signed into law a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. Additionally, in November 2021, EPA issued a proposed rule that, if finalized, would establish new source and first-time existing source standards of performance for methane and volatile organic compound emissions for oil and gas facilities. Operators of affected facilities will have to comply with specific standards of performance, which include leak detection using optical gas imaging and subsequent repair requirements, and reduction of emissions by 95% through capture and control systems. In November 2022, EPA released a supplemental methane proposal which, among other items, set forth revisions strengthening the first nationwide emissions guidelines for states to limit methane emissions from existing oil and gas facilities. The proposal also revises requirements for fugitive emissions monitoring and repair, as well as equipment leaks, and the frequency of monitoring surveys and establishes a "super-emitter" response program to timely mitigate emissions events. The proposal is currently subject to public comment and is expected to be finalized in 2023; however, it is likely that it, alongside the November 2021 proposed rule, will be subject to legal challenges. President Biden has also made climate change a focus of his administration. In August 2022, the IRA passed into law. The IRA imposes a fee on the emissions of methane from certain sources in the oil and natural gas sector. Beginning in 2024, the methane emissions charge will begin at $900 per metric tonne of leaked methane, rising to $1,200 in 2025, and $1,500 in 2026 and thereafter. President Biden and has also issued various executive orders calling for substantial climate change-related action, including, among other things, the increased use of zero-emissions vehicles by the United States federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate change-related risks across agencies and economic sectors. Failure to comply with such regulations and laws could result in significant penalties being imposed. In addition, a potential increase in capital spending, operating expenses, abandonment and reclamation obligations, or the loss of operating licenses, any of which may not be recoverable in the marketplace, could also result in operations or growth projects becoming less profitable, uneconomic, or result in the Corporation's inability to continue the development of its properties. See "*Industry Conditions – Environmental Regulation – Climate change-related legislation*".

There is also a risk that financial institutions will adopt, or be pressured, or required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector; both the Bank of Canada and the Federal Reserve of the United States have joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate change-related risks in the financial sector. Additionally, at COP26, the Glasgow Financial Alliance for Net Zero ("**GFANZ**") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net-zero emissions by 2050. The impact of these initiatives could require the adoption of new technologies, which could require a significant investment in capital and resources or result in additional costs if climate change-related targets are not achieved, therefore negatively impacting the Corporation's results and economics. The CSA and the SEC have separately released proposed rules that would establish a framework for the reporting of climate risks, targets, and metrics. Although the final form and substance of this rule and its requirements are not yet known, and the ultimate impact on the Corporation is uncertain, the proposed rule, if finalized, may result in increased compliance costs and increased costs of and restrictions on access to capital.

At COP26 many countries announced further expanded global climate goals and targets. Given the commitments made by Canada and the U.S., the Corporation may be subject to significant changes in government policy, resulting in reduced investment if it does not comply, or unplanned spending, which could impact its operations and financial condition. In addition, should policies put in place result in permanent, significant reductions in the demand for fossil fuels, commodity prices could be negatively impacted and result in asset impairment charges, or stranded assets. Although these policies could materially impact the Corporation, it is not possible for the Corporation to quantify or estimate such impact due to the current lack of clarity around policy changes and requirements currently, as well as the timing of the same.

For a more detailed discussion on regulatory risks for the Corporation, please see "*Supplemental Operational Information*" and "*Industry Conditions – Environmental Regulation*".

Transition Risks – Reputational

The Corporation continues to develop its 2023 climate strategy, delivering a phased approach for key components during 2021 and 2022. This strategy will address climate change-related risks and opportunities for the Corporation. Examples of progress achieved in 2022 towards the goal include the implementation of solutions to improve emissions forecasting and integrating emissions into long-range planning. In addition, these initiatives have led to the initial development of a power strategy which, at this early stage incorporates electrification of certain facilities, the goal of which will be to further reduce emissions and improve the emission efficiencies of existing power sources when grid power is not available**.** Enerplus is participating in an electrification project in North Dakota in 2023 and approximately $10 million of the Corporation's 2023 capital spending budget has been allocated to this initiative. The Corporation's objective is to be a responsible operator—in the eyes of its shareholders, employees, contractors, regulators, lenders, communities and the general public, and this includes being responsive to climate change-related issues. However, despite its best intentions, activities undertaken directly by the Corporation or its employees in operating its business, or by others in industry, could adversely affect the Corporation's reputation. For example, there has been an increase in activist activity in the United States, including threats of culpability, and legal action against other oil and gas producers, as well as public opposition to fossil fuels and the oil and gas industry in which the Corporation operates due to negative public perceptions related to pipeline operator incidents, unpopular expansions or new projects, none of which are necessarily controlled by the Corporation but have the potential to impact the Corporation given the industry-linked association. A number of parties have sought to bring suit against certain oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. See "*— The inability to access land, inadequately developed infrastructure, and the impact of special interest groups on either, may result in a decline in the Corporation's ability to market its oil and natural gas production*".

If the reputation of the Corporation, or the oil and gas industry in general, is diminished, it could result in: the loss of employees, or revenue; delays in regulatory approvals; increased operating, capital, financing, insurance and regulatory costs; reduced shareholder confidence and negative stock price movement; negative relationships with Indian Reservations and Indigenous groups; or a loss of public support in general.

GHG Emissions and Targets

Among other sustainability goals, the Corporation has established a 2030 GHG emissions intensity reduction target of 35% for Scope 1 Emissions and Scope 2 Emissions (based on a 2021 baseline year). The Corporation's ability to lower GHG emissions on both an absolute basis and in respect of its 2030 emissions intensity reduction target is subject to numerous risks and uncertainties, and the Corporation's actions taken to implement these objectives may also expose it to certain additional and/or heightened financial and operational risks. A reduction in GHG emissions intensity relies on, among other things, the Corporation's ability to implement and improve energy efficiency at all facilities, future development and growth opportunities, development and deployment of new technologies and a focus on a reduction in flaring. In the event that the Corporation is unable to implement these strategies and technologies as planned without negatively impacting its expected operations or business plans, or in the event that such strategies or technologies do not perform as expected, the Corporation may be unable to meet its GHG emissions intensity reduction targets or goals on the current timelines, or at all. Moreover, given the evolving nature of GHG emissions accounting methodologies and climate science, we cannot guarantee that factors outside of the Corporation's control could give rise to the need to restate or revise its emissions intensity reduction goals, cause them to be missed altogether, or limit the impact of success of achieving Enerplus' goals.

While the Corporation may create and publish voluntary disclosures regarding ESG matters from time to time, certain statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. Additionally, while we have announced, and may in the future announce, various targets in an attempt to improve our ESG profile, we cannot guarantee that we will be able to meet any such targets or that such targets or offerings will have the intended results on our ESG profile, including, but not limited to, as a result of unforeseen costs, consequences, or technical difficulties associated with such targets.

In addition, achieving the Corporation's GHG emissions intensity reductions target and goals could require significant capital expenditures and resources, with the potential that the costs required to achieve such target and goals materially differ from the Corporation's original estimates and expectations, which differences may be material. In addition, while the intent is to improve efficiency and reduce flaring, the shift in resources and focus towards GHG emissions reduction could have a negative impact on the Corporation's operating results. The overall final cost of investing in and implementing a GHG emissions intensity reduction strategy and technologies in furtherance of such strategy, and the resultant change in the deployment of the Corporation's resources and focus, could have a material adverse effect on the Corporation’s business, financial condition and results of operations. While we may receive pressure from certain investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals or policies, we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

RISKS RELATING TO FRACTURING

The Corporation utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated fluids, and other technologies in connection with its drilling and completion activities. There has been public concern over the hydraulic fracturing process. Most of these concerns have raised questions regarding the fluids and the volume of fluid used in the fracturing process, their effect on freshwater aquifers, the use of water in connection with completion operations, the ability of such water to be recycled, and induced seismicity associated with fracturing. U.S. federal and state governments may review aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in certain of the jurisdictions in which the Corporation operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. However, governmental authorities in jurisdictions where the Corporation does not currently operate have either implemented or considered temporary moratoriums on hydraulic fracturing until further studies can be completed. In particular, President Biden issued an executive order suspending new leasing activities, but not operations under existing leases, for oil and gas exploration and production on non-Indian federal lands pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices that take into consideration potential climate and other impacts associated with oil and gas activities on such lands and waters. Although the federal court for the Western District of Louisiana issued a preliminary injunction against the leasing pause in June 2021 and a permanent injunction in August 2022, in response to the executive order, the federal government and a coalition of environmental organizations are appealing this decision and the Department of Interior has issued a report recommending various changes to the federal leasing program, though many such changes would require Congressional action. The Corporation's operations in most jurisdictions require permits from one or more governmental agencies in order to perform drilling and completion activities and conduct other regulated activities. In the United States, such permits are typically issued by state agencies, but U.S. federal and local governmental permits may also be required. In addition, some of the Corporation's drilling and completion activities in the United States may take place on U.S. federal land or Native American lands, requiring leases and other approvals from the U.S. federal government or Native American tribes to conduct such drilling and completion activities. Under certain circumstances, U.S. federal agencies may refuse to approve new leases for hydrocarbon exploration and development on federal lands, and may refuse to grant or delay approvals required for development of existing leases. To the extent that the Corporation's operations in certain areas of the United States are restricted, delayed for varying lengths of time or cancelled, such developments may have a material adverse effect on the Corporation's results of operations and financial condition. President Biden may pursue additional executive orders, new legislation and regulatory initiatives to further implement his regulatory agenda. Additionally, certain environmental and other groups have suggested that additional federal, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process. Claims have been made that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity, particularly where operators are in proximity to pre-existing faults. See "*Industry Conditions – Royalties and Incentives*".

It is anticipated that U.S. federal and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While the Corporation is unable to predict the impact of any potential regulations upon its business, the implementation of new laws, regulations or permitting requirements with respect to water usage or disposal, or hydraulic fracturing generally, could increase the Corporation's costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact the Corporation's production and prospects, any of which may have a material adverse effect on the Corporation's business, financial condition and results of operations.

The Corporation may not realize the anticipated benefits of its acquisitions, divestments, or other corporate transactions.

From time to time, the Corporation may acquire additional oil and natural gas properties and related assets or may acquire other corporate entities. Achieving the anticipated benefits of such acquisitions will depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining and/or integrating the acquired assets, properties and business into the Corporation's business. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of current or future acquisitions. The risk factors set forth in this Annual Information Form relating to the oil and natural gas business and the operations, reserves and resources of the Corporation apply equally in respect of any future properties, assets or business that the Corporation may acquire. The Corporation generally conducts certain due diligence in connection with acquisitions, but there can be no assurance that the Corporation will identify all of the potential risks and liabilities related to the assets, properties or business that it acquires.

When acquiring assets, the Corporation is subject to inherent risks associated with predicting the future performance of those assets. The Corporation makes certain estimates and assumptions respecting the prospectivity and characteristics of the assets it acquires, which may not be realized over time. As such, assets acquired may not possess the value the Corporation attributed to them, which could adversely impact the Corporation's cash flows. To the extent that the Corporation makes acquisitions with higher growth potential, the higher risks often associated with such potential may result in increased chances that actual results may vary from the Corporation's initial estimates. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods, approaches and assumptions than those of the Corporation's engineers, and these initial assessments may differ significantly from the Corporation's subsequent assessments.

Furthermore, potential investors should be aware that certain acquisitions, and in particular those that are higher risk/higher growth assets and the development of those acquired assets, may require more capital than anticipated from the Corporation, and the Corporation may not receive cash flow from operations from these acquisitions for several years, or may receive cash flow in an amount less than anticipated.

The Corporation may also from time to time seek to divest of properties and assets. These divestments may consist of non-core properties or assets, or may consist of assets or properties that are being monetized to fund debt repayment, alternative projects, or development by the Corporation. There can be no assurance that the Corporation will be successful in such divestments, or realize the amount of desired proceeds from such divestments, or that such divestments will be viewed positively by the financial markets, and such divestments may negatively affect the Corporation's results of operations or the trading price of the Common Shares. In addition, although divestments typically transfer future obligations to the buyer, the Corporation may not be exempt from certain obligations in the future, including for example, abandonment and reclamation obligations, which may have an adverse effect on the Corporation’s operations and financial condition.

The Corporation may also from time to time undertake other corporate actions or transactions which the directors and management of the Corporation believe are in the best interests of the Corporation. Any of the acquisitions, dispositions or other corporate actions may require the dedication of substantial management effort, time and capital and other resources, which may divert management's focus, capital and other resources from other strategic opportunities and operational matters during the process. Although certain substantial acquisitions, business combinations or other corporate transactions, such as a potential re-domicile of the Corporation to another jurisdiction or a share consolidation, for example, could also be subject to approval by a certain majority of the Corporation’s shareholders, the Corporation may not achieve the intended or anticipated favourable results of such actions and may result in adverse consequences to certain or all of the Corporation’s stakeholders, including its shareholders.

Changes in U.S. administration may affect trade between countries.

There is uncertainty regarding U.S. support for existing treaty and trade relationships with other countries, as evidenced by President Biden's executive order on January 20, 2021 revoking the permit for the Keystone XL Pipeline. Implementation by the U.S. government of new legislative or regulatory policies could impose additional costs on the Corporation, decrease demand for the Corporation's products, or otherwise negatively impact the Corporation, which may have a material adverse effect on the Corporation's business, financial condition and operations. In addition, this uncertainty may adversely impact (a) the ability or willingness of Canadian companies to transact business with companies such as the Corporation; (b) the Corporation's profitability; (c) regulation affecting the U.S. and Canada; (d) global stock markets (including the TSX and NYSE); and (e) general global economic conditions. All of these factors are outside of the Corporation’s control, but may nonetheless lead the Corporation to adjust its strategy in order to compete effectively in global markets.

The inability to access land or use existing infrastructure, or adequately develop infrastructure, including as a result of the impact of special interest groups, may result in a decline in the Corporation's ability to operate and market its oil and natural gas production.

The Corporation's business depends in part upon the ability to access its lands to operate, as well as the availability, proximity, and capacity of oil and natural gas gathering systems, pipelines and/or rail transportation systems and processing facilities to provide access to markets for its production. U.S. federal and state regulation of crude oil and natural gas production and processing and transportation could adversely affect the Corporation's ability to produce and market crude oil, natural gas and NGLs. Special interest groups and/or social instability could prevent access to leased land or continue its opposition to infrastructure development, at either the regulatory or judicial level, including the ongoing matters with respect to DAPL, resulting in operational delays, or even cancellation of construction of the required infrastructure or the shutdown of already operating infrastructure projects, any of which frustrate the Corporation’s ability to operate, produce and market its products. In addition, the assets of the Corporation are concentrated in regions with varying levels of government regulations, or under tribal or local rules that could result in the imposition of a limit or ban on shipping of commodities by truck, pipeline or rail.

OIL AND NATURAL GAS GATHERING SYSTEMS

Development of new resource plays generally results in a sharp increase in the volume of oil and natural gas being produced in the area, which could exceed government-regulated gas capture requirements, or the existing capacity of the various gathering system infrastructure. The Corporation relies on the timely construction of adequate gathering systems that allow its crude oil and natural gas production to be transported from the wellhead to existing and/or new sales infrastructure systems, such as pipelines or rail terminals.

The pace at which producer or midstream companies can construct adequate gathering infrastructure to capture the natural gas associated with the development of crude oil and NGLs properties may have an impact on the Corporation's ability to increase crude oil production in its producing regions. Additionally, as exploration and drilling in these regions increases, the amount of natural gas being produced by the Corporation and others could exceed the capacity of the various gathering pipelines available in those areas. If these constraints remain unresolved, the Corporation's ability to transport its production to sales pipelines in these regions may be impaired and could adversely impact the Corporation's production volumes or realized prices in these areas. In the United States, the distinction between federally unregulated natural gas gathering facilities and FERC-regulated natural gas transmission pipelines under the Natural Gas Act ("**NGA**") has been the subject of extensive litigation and may be determined by the FERC on a case-by-case basis. Consequently, the classification and regulation of gathering facilities that transport the Corporation's product could change based on future determinations by the FERC, the courts or the United States Congress. If these gas gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates paid for service on the affected facilities.

SALES PIPELINES AND RAIL TRANSPORTATION SYSTEMS

Oil and natural gas producers in certain regions of North America may receive significantly discounted prices relative to benchmark prices for their production due to constraints on the ability to transport and sell such production to domestic and international markets. While oil and gas transportation infrastructure generally expands capacity to meet market needs, there can be differences in timing in the growth of such capacity. Should inadequate infrastructure exist, even from time to time, Enerplus could be subject to volume curtailments and low regional commodity prices at various times. Unfavourable economic conditions or financing terms, as well as significant delays in the regulatory approval process, may defer or prevent the completion of certain pipeline projects, gathering systems or railway projects that are planned for such areas. There may also be operational or economic reasons, including but not limited to maintenance activities, for curtailing transportation capacity. In addition, there could be legal or regulatory challenges by third parties on existing sales pipelines, which could impact a pipeline's ability to provide services to shippers. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all the production from a given region, causing added expense and/or volume curtailments for all shippers. To the extent that the transportation capacity becomes insufficient in areas where the Corporation operates, the Corporation may have to defer the development of, curtail production from or shut-in wells awaiting a pipeline connection or other available transportation capacity, and/or sell its production at lower prices than it would otherwise realize, or it had projected to realize. This would adversely affect the Corporation's results of, and cash flow from, operations.

A portion of the Corporation's production from the Williston Basin is delivered either directly or indirectly for transport to DAPL. Although the Corporation's products may be delivered for transport to other pipelines, a shutdown of DAPL or any other significant pipeline providing transportation services from the Williston Basin may adversely impact the Corporation's ability to obtain sufficient capacity on those pipelines at an effective cost. In 2016, several Sioux tribes filed a lawsuit in the United States District Court for the District of Columbia ("**District Court**") challenging authorizations issued by the United States Army Corps of Engineers ("**USACE**") to DAPL for operations near the Missouri River. In July 2020, the District Court vacated the USACE's grant of an easement to DAPL and issued an order requiring DAPL to be shut down and emptied of oil by August 5, 2020, pending an Environmental Impact Statement ("**EIS**") for the pipeline. However, this order was stayed by the Court of Appeals for the District of Columbia in early August, pending the outcome of the appeals process. On January 26, 2021, the Court of Appeals for the District of Columbia affirmed the vacatur of the easement and the requirement to prepare an EIS but declined to require the pipeline to shut down while the EIS is prepared. The Court of Appeals implored the USACE to promptly consider if and how it may deal with the vacatur of the easement and left open the possibility for the USACE to order the pipeline shut in for lack of an easement. USACE has formerly stated that it considers the presence of the pipeline without an easement to constitute an encroachment on federal land, but USACE has not pursued an enforcement action with regards to this alleged encroachment. In June of 2021, the District Court rejected a request to enjoin the operation of the pipeline due to the lack of an easement and DAPL continues to operate pending the outcome of the EIS process, which is ongoing. In September 2021, DAPL requested the United States Supreme Court ("**SCOTUS**") hear an appeal on the lower court's decision to require the EIS and on the vacatur of the USACE permit. On February 22, 2022 SCOTUS denied certiorari, declining to hear the appeal. The Corporation is unable to determine the outcome or the impact on DAPL in the future. However, any future ruling or regulatory decision that restricts the availability of pipeline capacity in the Williston Basin may have a material adverse effect on the Corporation.

The Corporation has the ability to transport its crude oil production by a diverse mix of pipeline, trucking and, if necessary, rail (after title is transferred to the buyer's name), all of which are subject to various risks of cost escalation and/or new costs. In certain regions the Corporation is currently dependent upon only one means of transportation. With respect to rail transportation, there may be future incremental costs associated with transporting, and risks that access to rail transport may be constrained, depending upon changes made to existing rail transport regulations. More stringent government regulations concerning the usage of certain types of tank cars that transport crude oil and NGLs by rail in the United States have been enacted, and this could increase the cost of utilizing rail to transport crude oil and/or NGLs. In addition, crude oil and natural gas volumes being shipped by pipelines are required to meet certain quality specifications, which vary by pipeline. Should crude oil, natural gas or NGLs quality specifications fail to be met by a producer that is shipping volumes on a pipeline, the pipeline could shut down or curtail volumes of other producers shipping on that pipeline. Any shutdown, curtailment, reversal of pipeline flow, or a change in the commodity being transported on pipelines shipping volumes of the Corporation’s production may impact the Corporation’s ability to reach its intended market, or deliver fully on its obligations.

ACCESS TO PROCESSING FACILITIES

NGLs production requires processing at fractionation facilities to separate the liquids stream into individual saleable products. The Corporation and the industry rely on the addition of adequate fractionation capacity to ensure the timely and economic processing of NGLs and the continued production of crude oil and natural gas associated with those liquids. Limited natural gas processing capacity in certain regions may result in producers not realizing the full price for NGLs associated with their natural gas production.

Crude oil and natural gas production requires processing at certain facilities in order to be transported on regional pipeline systems. The Corporation and the industry rely on the addition of adequate natural gas and other processing capacity to ensure the timely and economic processing of natural gas production, and the continued production of crude oil and NGLs, as well as any associated natural gas production. Limited natural gas processing capacity in certain regions may result in producers not being able to sell some or all of their natural gas production, lead to curtailment of crude oil production, or result in not realizing the full value of their natural gas production.

A failure to resolve any of the constraints described above may result in the Corporation failing to comply with certain environmental regulations, shutting-in production, or receiving continued reduced commodity prices.

The third parties on whom the Corporation relies for gathering, transportation, and processing services are subject to complex federal, state, other laws that could adversely affect the Corporation’s operations.

The operations of the third parties on whom the Corporation relies for gathering, transportation and processing services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that the Corporation pays for services. Similarly, a failure to comply with such laws and regulations by the third parties could have a material adverse effect on the Corporation’s business and results of operations, which could have an adverse impact on the Corporation’s cash flows and financial condition.

Higher than expected declines or curtailments in the Corporation’s production due to infrastructure constraints, third party operational business practices or failures, supply chain shortages, or government regulation could have an adverse effect on results of operations, or cash flows and financial condition.

Should production for the industry, or specifically for any of the Corporation’s products, be hampered by limited pipeline availability or capacity, government policy and regulations, or third-party business practices, or supply chain shortages, regional commodity prices may become volatile. In some cases, alternate shipping methods, such as rail for crude oil, may be used and could result in higher costs and lower netbacks. In addition, the continuing production from a property, and to some extent the marketing of that production, is dependent upon the abilities of the operators of the Corporation's properties. A significant portion of the Corporation's production is from properties operated by third parties. This results in significant reliance on third party operators in both the operation, which may include decisions to curtail production or obtain adequate goods and services, and the ability to develop such properties as planned.

Operating agreements governing properties not operated by the Corporation typically require the operator to conduct operations in a “good and workmanlike" manner. These operating agreements generally exempt the operator from liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except for liabilities that may result from the operator’s gross negligence or wilful misconduct. To the extent a third-party operator fails to perform its duties properly, faces capital or liquidity constraints or becomes insolvent, the Corporation's results of operations may be negatively impacted.

The timing and amount of capital required to be spent by the Corporation may also differ from the Corporation's expectations and planning, and may impact the ability of and/or cost to the Corporation to finance such expenditures, as well as adversely affect other parts of the Corporation's business and operations.

As a result of the foregoing, the Corporation may be required to curtail or shut-in production, which could damage a reservoir and potentially prevent the Corporation from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. In addition, lower levels of production could result in a material reduction to the Corporation's cash flow, or may result in the Corporation incurring additional operating and capital costs for the well(s) to achieve prior production levels.

The Corporation may require additional financing to maintain and/or expand its assets and operations.

In the normal course of making capital investments to maintain and/or expand the Corporation's oil, NGLs and natural gas reserves and resources, additional Common Shares or other securities of the Corporation may be issued, which may result in a decline in production per share and reserves and/or resources per share. Additionally, from time to time the Corporation may issue Common Shares or other securities from treasury to reduce debt, complete acquisitions, and maintain a more optimal capital structure. The Corporation may also divest of existing properties or assets as a means of financing alternative projects or developments. To the extent that external sources of capital, including the availability of debt financing from banks or other creditors or the issuance of additional Common Shares or other securities, become limited, unavailable or available on less favourable terms, the Corporation's ability to make the necessary capital investments to: (i) retain leases, (ii) carry out its operations, and/or (iii) maintain and/or expand its oil, NGLs and natural gas reserves and resources could be adversely affected. To the extent that the Corporation is required to use additional cash flow to finance capital expenditures or property acquisitions, or to pay debt service charges or to reduce debt, the level of cash that may be available for the Corporation to pay cash dividends to its shareholders may be reduced.

The Corporation's scope of activities and participation in the capital markets may attract increased criticism, shareholder activism and costly litigation.

The Corporation's business activities, both geographically and with a focus on exploration and development of unconventional reservoirs, may draw increased attention from shareholder activists who oppose the strategy of the Corporation, including its operation of the business, its plans for development and its capital allocation decisions, which could have an adverse effect on market value. In addition, such activists could become shareholders with significant influence or control, specifically to meet activist objectives. The Corporation's ongoing participation in the Canadian and U.S. capital markets may expose the Corporation to greater risk of class action lawsuits related to, among other things, securities law matters (including with regard to alleged deficiencies in the Corporation's public disclosure or allegedly inadequate governance), title, contractual and environmental matters (including those that are climate change-related). In addition, the Corporation may, from time to time, be subject to material disputes, mediation, arbitration and litigation involving counterparties and other stakeholders the Corporation interacts with, directly or indirectly, in the ordinary course of conducting its business.

Changes in market-based factors and investor strategies may adversely affect the trading price of the Common Shares and/or the Corporation's stock exchange listings.

The market price of the Common Shares is primarily a function of the value of the properties owned by the Corporation, as well as the ability to grow or sustain production levels, cash flow and returns to shareholders, including dividends paid. The market price of the Common Shares is also sensitive to a variety of market-based factors, including, but not limited to, an increase in passive investing (through vehicles such as exchange traded funds) and options trading, high frequency trading, the inclusion or removal of the Common Shares from one or more stock market indexes or exchange traded funds, interest rates, and the comparability of the Corporation's performance to other growth or yield-oriented exploration and production companies. Additionally, the Common Shares may, from time to time, not meet the investment criteria or characteristics of a particular institutional or other investor, including institutional investors who are not willing or able to hold securities of oil and gas companies for reasons unrelated to financial or operational performance. Any changes in market-based factors or investor strategies, including ESG, or responsible investing criteria/rankings (for example, ESG, social impact or environmental scores), the implementation of new financial market regulations and fossil fuel divestment initiatives undertaken by governments, pension funds and/or other institutional investors, may adversely affect the trading price of the Common Shares, and/or their inclusion in the portfolios of investment managers. In addition, should the trading price of the Common Shares fall below stock exchange listing thresholds, the exchanges will review the appropriateness of the Common Shares for continued listing on such exchanges.

The Corporation may be unable to add or develop additional reserves or resources.

The Corporation adds to its oil and natural gas reserves primarily through acquisitions and ongoing development of its existing reserves and resources, together with certain exploration activities. As a result, the level of the Corporation's future oil and natural gas reserves is highly dependent on its success in developing and exploiting its reserves and resources base and acquiring additional reserves and/or resources through purchases or exploration. Exploitation, exploration and development risks arise for the Corporation and, as a result, may affect the value of the Common Shares and dividends to shareholders due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. Additionally, if capital from external sources is not available or is not available on commercially advantageous terms, the Corporation's ability to make the necessary capital investments to maintain, develop or expand its oil and natural gas reserves and resources will be impaired. Even if the necessary capital is available, the Corporation cannot assure that it will be successful in acquiring additional reserves or resources on terms that meet its investment objectives. Without these additions, the Corporation's reserves will deplete and, as a consequence, either its production or the average life of its reserves will decline.

The Corporation, the use of digital technology, or its information assets and/or critical infrastructure may be subject to technopolitical or cyber security risks which could lead to financial losses or reputational issues.

The Corporation is subject to a variety of information technology and system risks as part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Technologies are often employed to assist, augment, automate or provide autonomous intelligence, which results in reduced reliance on human intervention and/or decision-making. Information technology ("**IT**") and cyber risks, including cyberattacks, data breaches, cyber extortion and similar compromises, are significant risks due to the Corporation's reliance on the internet to conduct day-to-day business activities, its technological infrastructure**,** and its use of third-party service providers. Additionally, use of personal devices by employees, vendors or other third parties can create further avenues for potential cyber-related incidents, as the Corporation has limited control over the use and safety of these devices. The adoption of emerging technologies, such as cloud computing, artificial intelligence and robotics, call for continued focus and investment to manage risks effectively. Although the Corporation actively manages its exposure to these risks, it may not be able to fully prevent events resulting in business interruptions, service disruptions, financial loss, theft of intellectual property and confidential information, litigation, enhanced regulatory attention and penalties, as well as reputational damage which would have an adverse effect and, therefore, may increase the Corporation's risk of financial or reputational loss; any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all.

IT and cyber risks have increased since the beginning of the COVID pandemic and the Russia and Ukraine conflict, with cybercriminals taking advantage of remote working environments to increase malicious activities, creating more threats for cyberattacks. These include phishing emails, malware-embedded mobile apps that purport to track COVID infection rates, and targeting of vulnerabilities in remote access platforms. Although the Corporation has security measures and controls in place that are designed to mitigate these risks, the growing use of the digital space could increase technopolitical risks (example, by monitoring/intercepting phones and communications, or surveilling/locating persons of interest) further increasing the risk of a breach of its security measures, which could result in a loss of material and confidential information and/or have a negative impact on its reputation, result in a breach of privacy laws, and/or disrupt business activities. In addition, third party operators on whom we depend and the operations of our customers and business partners are also subject to such risks

The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief.

Declines or continued volatility in crude oil and natural gas prices may result in a significant reduction in earnings or cash flow, which could lead the Corporation to increase amounts drawn under the SLL Credit Facilities in order to carry out its operations and fulfill its obligations. Significant reductions to cash flow, significant increases in drawn amounts under the SLL Credit Facilities, or significant reductions to proved reserves may result in the Corporation breaching its debt covenants under the Credit Facilities. If a breach occurs, there is a risk that the Corporation may not be able to negotiate covenant relief with one or more of its lenders under the Credit Facilities. Failure to comply with debt covenants, or negotiate relief, may result in the Corporation's indebtedness under the Credit Facilities becoming immediately due and payable, which may have a material adverse effect on the Corporation's operations and financial condition.

The Corporation's Credit Facilities and any replacement credit facility may not provide sufficient liquidity.

Although the Corporation believes that its existing Credit Facilities are sufficient, there can be no assurance that the current amount will continue to be available or will be adequate for the financial obligations of the Corporation, or that additional funds can be obtained as required or on terms which are economically advantageous to the Corporation. The amounts available under the SLL Credit Facilities may not be sufficient for future operations, or the Corporation may not be able to renew either or both of the SLL Credit Facilities, or obtain additional financing on attractive economic terms, if at all. Each of the SLL Credit Facilities is generally available on a three- to four-year term, extendable each year with a bullet payment required at the end of the period if the facility is not renewed. The Corporation renewed both of the SLL Credit Facilities in 2022, incorporating ESG-linked incentive pricing terms, and if the SPTs are not met, may result in higher future borrowing costs. The $365 million SLL Credit Facility currently expires on October 31, 2025; $50 million and $850 million of the $900 million SLL Credit Facility expire on October 31, 2025 and October 31, 2026, respectively. There can be no assurance that such a renewal will be available on favourable terms or that all of the current lenders under the facility will participate or renew at their current commitment levels. If this occurs, the Corporation may need to obtain alternate financing. Any failure of a member of the lending syndicate to fund its obligations under either of the SLL Credit Facilities or to renew its commitment in respect of any SLL Credit Facility, or failure by the Corporation to obtain replacement financing or financing on favourable terms, may have a material adverse effect on the Corporation's business and operations. In addition, dividends to shareholders may be eliminated, as repayment of debt under the Credit Facilities has priority over dividend payments by the Corporation to its shareholders. See "*General Developments of the Business" and* "*Description of Capital Structure".*

The Corporation's operations are subject to certain risks and liabilities inherent in the oil and natural gas business, some of which may not be covered by insurance.

The Corporation's business and operations, including the drilling of oil and natural gas wells and the production and transportation of oil and natural gas, are subject to certain risks inherent in the oil and natural gas business. These risks and hazards include encountering unexpected formations or pressures, blow-outs, pipeline breaks, rail transportation incidents, fires, power interruptions and severe weather conditions. The Corporation's operations may also subject it to the risk of vandalism or terrorist threats, including eco-terrorism and cyber-attacks. The foregoing hazards could result in personal injury, loss of life, reduced production volumes or environmental and other damage to the Corporation's property and the property of others. The Corporation cannot fully protect against all these risks, nor are all these risks insurable. The Corporation may become liable for damages arising from events against which it cannot insure, or against which it may elect not to insure because of high premium costs, or other reasons. While the Corporation has both safety and environmental policies in place to protect its operators and employees, and to meet regulatory requirements in areas where they operate, any costs incurred to repair, damage, or pay liabilities would adversely affect the Corporation's financial position, including the amount of funds that may be available for development programs, debt repayments, or dividend payments to shareholders.

The Corporation's portfolio of investment projects may expose it to increased operational and financial risks.

The Corporation's unconventional oil and gas operations (such as the development of and production from shale formations) involve certain additional risks and uncertainties. The drilling and completion of wells and operations on these unconventional assets present certain challenges that differ from conventional oil and gas operations. Wells on these properties generally must be drilled deeper than in many other areas, which makes the wells more expensive to drill and complete. To reduce costs, wells may be drilled as part of a multi-well pad which may increase the risk of being unable to drill and complete any of the wells on the pad if problems occur. In addition, because of the depth and length of these unconventional wells, they also may be more susceptible to mechanical problems associated with drilling and completion, such as casing collapse and lost equipment in the wellbore. In addition, the fracturing activities required to be undertaken on these unconventional assets may be more extensive and complicated than fracturing the geological formations in the Corporation's other areas of operation and require greater volumes of water than conventional wells. The management of water and the treatment of produced water from these wells may be more costly than the management of produced water from other geologic formations. In addition, to the extent the Corporation acquires properties or assets with a higher exploration risk profile, the risk associated with such acquisitions and the future development of those assets is more uncertain.

Lower crude oil and natural gas prices and higher costs increase the risk of write-downs of the Corporation's crude oil and natural gas properties and deferred tax assets.

Under U.S. GAAP, the net capitalized cost of oil and gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer's fiscal quarter and annual fiscal periods. The amount by which the net capitalized costs exceed the discounted value will be charged to net income.

Under U.S. GAAP, the net deferred tax assets of a corporation are limited to the estimate of future taxable income resulting from existing properties. The Corporation estimates future taxable income based on before-tax future net revenue from proved plus probable reserves, undiscounted, using forecast prices, and adjusted for other significant items affecting taxable income. The amount by which the gross deferred tax assets exceed the estimate of future taxable income will be charged to net income. A previously recorded valuation allowance can be reversed if the estimate of future taxable income increases.

When commodity prices are low or declining, there remains a risk for additional write-downs under U.S. GAAP. There is also risk for future impairment when the fair value of acquired assets is significantly higher than the calculated value of the assets using 12-month trailing commodity prices, as required for under U.S. GAAP. While these write-downs would not affect cash flow, the charge to earnings may be viewed unfavourably in the market. Additional write-downs may lead to the Corporation breaching its covenants under the Credit Facilities, and the Corporation may not be able to negotiate any covenant relief. See "*Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief".*

If the Corporation expands beyond its current areas of operations or expands the scope of operations beyond oil and natural gas production, the Corporation may face new challenges and risks. If the Corporation is unsuccessful in managing these challenges and risks, its results of operations and financial condition could be adversely affected.

The Corporation may acquire oil and natural gas properties and assets outside the geographic areas in which it has historically conducted its business and operations. The expansion of the Corporation's activities into new locations may present challenges and risks that the Corporation has not faced in the past, including operational and additional regulatory matters. In addition, the Corporation's activities could expand beyond oil and natural gas production and development, and the Corporation could acquire other energy related assets. Expansion of the Corporation's activities into new business areas may present challenges and risks that it has not faced in the past, including dealing with additional regulatory matters. If the Corporation does not manage these challenges and risks successfully, its results of operations and financial condition could be adversely affected.

The Corporation's actual reserves and resources will vary from its reserves and resources estimates, and those variations could be material.

The value of the Common Shares depends upon, among other things, the reserves and resources attributable to the Corporation's properties. The actual reserves and resources contained in the Corporation's properties will vary from the estimates summarized in this Annual Information Form, and those variations could be material. Estimates of reserves and resources are by necessity projections, and thus are inherently uncertain. The process of estimating reserves or resources requires interpretations and judgments on the part of petroleum engineers, resulting in imprecise determinations, particularly with respect to new discoveries. Different engineers may make different estimates of reserves or resources quantities and revenues attributable thereto based on the same data. The reserves and resources information contained in this Annual Information Form is only an estimate. A number of factors are considered, and a number of assumptions are made when estimating reserves and resources, such as, among others described in this Annual Information Form:

- historical production in the area compared with production rates from similar producing areas
- future commodity prices, production and development costs, royalties and planned capital spending
- initial production rates and production decline rates
- ultimate recovery of reserves and resources and the success of future exploitation activities
- marketability of production
- the effects of government regulation and other government royalties or levies, such as environmental costs, that may be imposed over the producing life of reserves and resources

Reserves and resources estimates are based on the relevant factors, assumptions and prices on the date the evaluations were prepared. Many of these factors are subject to change and are beyond the Corporation's control. If these factors, assumptions and prices prove to be inaccurate, the Corporation's actual reserves and resources could vary materially from its estimates. Additionally, all such estimates are, to some degree, uncertain, and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable quantities of oil and natural gas, the classification of such reserves and resources based on risk of recovery and associated contingencies, and the estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric or probabilistic calculations and upon analogy to similar types of reserves or resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves or resources based upon production history may result in variations or revisions in the estimated reserves or resources, and any such variations or revisions could be material.

Reserves and resources estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil, natural gas and NGLs prices and operating costs. Market price fluctuations of commodity prices may render uneconomic the recovery of certain categories of petroleum or natural gas. Moreover, short-term factors may impair the economic viability of certain reserves or resources in any particular period. With commodity prices remaining volatile, there is a risk for write-downs under U.S. GAAP. See "*Risk Factors – Lower crude oil and natural gas prices and higher costs increase the risk of write-downs of the Corporation's crude oil and natural gas properties and deferred tax assets*". Write-downs may lead to the Corporation breaching its covenants under the Credit Facilities, and the Corporation may not be able to negotiate any covenant relief. See "*Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief*".

Delays in payment for business operations, including the risk of default by counterparties to contracts, could adversely affect the Corporation.

In addition to the potential delays in payment by purchasers of oil and natural gas to the Corporation or to the operators of the Corporation's properties (and the delays of those operators in remitting payment to the Corporation), payments between any of these parties or any counterparties to contracts (including the Corporation's risk management, marketing, purchase and sale agreements, supplier and service contract counterparties) may also be delayed, or result in default due to, among other things:

- substantial or extended declines in oil, NGLs and natural gas prices
- capital or liquidity constraints experienced by such parties, including restrictions imposed by lenders
- accounting delays or adjustments for prior periods
- shortages of, or delays in, obtaining qualified personnel or equipment, including drilling rigs and completions services
- delays in the sale or delivery of products, or delays in the connection of wells to a gathering system
- adverse weather conditions, such as freezing temperatures, storms, flooding and premature thawing
- blow-outs or other accidents
- title defects
- recovery by the operator of expenses incurred in the operation of the properties, or the establishment by the operator of reserve funds for these expenses

Any of these delays could reduce the amount of the Corporation's cash flow and the payment of dividends to its shareholders in a given period. Any of these delays could also expose the Corporation to additional third-party credit risks.

The Corporation could lose its status as a "foreign private issuer" in the United States, which may result in additional compliance costs and restricted access to capital markets.

The Corporation is required to assess its "foreign private issuer" ("**FPI**") status under U.S. securities laws on an annual basis at the end of its second quarter. While the Corporation currently qualifies as an FPI, it could lose its FPI status in the future. If the Corporation were to lose its status as an FPI it would be required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country. In addition, if the Corporation loses its FPI status, it would be required to report as a U.S. domestic issuer and be subject to other U.S. securities laws applicable to U.S. domestic issuers. The regulatory and compliance costs to the Corporation under U.S. securities laws as a U.S. domestic issuer may be significantly greater than the costs the Corporation incurs as a foreign private issuer. For example, as a U.S. domestic issuer, the Corporation would be required to file periodic reports and registration statements with the SEC on U.S. domestic issuer forms, which are more detailed and extensive in certain respects than the forms available to the Corporation as a foreign private issuer. The Corporation would also be required to report its oil and gas reserves and production information in accordance with applicable U.S. disclosure requirements. Such conversion and modifications would involve additional costs and may restrict the Corporation's access to capital markets for a period of time until it has satisfied SEC reporting requirements. In addition, the Corporation may lose its ability to rely upon exemptions from certain corporate governance requirements on U.S. stock exchanges that are available to FPIs, which could also increase its costs.

The Corporation's risk management activities, as well as ongoing regulatory changes affecting financial institutions, could expose it to losses.

The Corporation may use financial derivative instruments and other hedging mechanisms to limit a portion of the adverse effects resulting from volatility in natural gas and oil commodity prices. To the extent the Corporation hedges its commodity price, interest rate and foreign exchange exposure, it may forego the benefits it would otherwise experience. In addition, the Corporation's commodity price, interest rate and foreign exchange hedging activities, as well as changing bank regulations that may limit liquidity in the commodity markets, could expose it to losses. These losses could occur under various circumstances, including if the other party to the Corporation's hedge does not perform its obligations under the hedge agreement. The Corporation has entered and may in the future enter into hedging arrangements to settle future payments under its equity-based long term incentive programs, which could result in the Corporation suffering losses to the extent the hedged costs of such arrangements exceed the actual costs that would otherwise be payable at the time of settlement.

Fluctuations in foreign currency exchange rates could adversely affect the Corporation's business.

Effective January 1, 2023, the Corporation changed its functional currency to U.S. dollars. However, transactions of some of the Corporation's entities will continue to be affected by the exchange rate between the U.S. and Canadian dollar, as certain entities of the Corporation will continue to incur Canadian denominated payments including but not limited to, for example, general and administrative expenses and Canadian dollar cash dividend payments. The Corporation may from time to time use derivative instruments to manage a portion of its foreign exchange risk, as described in Note 16 to the Corporation's Financial Statements.

Court rulings and regulatory regimes on the liability surrounding abandonment and reclamation obligations of oil and gas companies may adversely affect the Corporation.

In the U.S., oversight of reclamation and remediation activities, including those that relate to orphan wells, is administered through the respective state oil and gas agencies. The levies in the U.S. are based on production and operators are required to maintain reclamation bonds for the wells and/or fields in which they operate.

Generally, the current oil and gas asset abandonment, reclamation and remediation ("A&R") liability regime in Alberta limits each party's liability to its proportionate ownership of an asset. In the case where one joint owner of an oil and gas asset becomes insolvent and is unable to fund the required A&R activities associated with such asset, the solvent counterparties can recover the insolvent party's share of the remediation costs from the Orphan Well Association (the "OWA"). The OWA administers orphaned assets and is funded through a levy imposed on licensees, including the Corporation, based on their proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta.

The Corporation is currently subject to regulation by the AER under the Licensee Liability Rating Program and the Large Facility Liability Management Program, which require licensee's to provide the AER with a security deposit if deemed liabilities exceed deemed assets.

On July 30, 2020, the Government of Alberta announced a new and more holistic Liability Management Framework that would replace the current regime. Much of this Framework will be implemented through AER "Directive 088: Licensee Life-cycle Management" which came into force on December 1, 2021 and will replace the AER's current Licensee Liability Rating Program when it is fully implemented. The Liability Management Framework introduces several new programs and assessments relative to the life cycle of the Corporation's energy assets that are regulated by the AER, including the new licensee capability assessment, the Licensee Management Program, the Inventory Reduction Program (including mandatory annual closure spend targets or security requirements associated with inactive wells), security collection requirements and an expanded mandate for the OWA.

British Columbia has a similar liability management regime to the one formerly in place in Alberta and, like Alberta, is in the process of implementing changes to make its regime more robust. Although we do not expect such changes to have a material impact on our abandonment program, Enerplus cannot guarantee the impact on its abandonment plans at this time.

Unforeseen title defects, disputes or litigation may result in a loss of entitlement to production, reserves and resources.

From time to time, the Corporation conducts title reviews in accordance with industry practice prior to purchases of assets. However, if conducted, these reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat the Corporation's title to the purchased assets. If this type of defect were to occur, the Corporation's entitlement to the production and reserves and, if applicable, resources from the purchased assets could be jeopardized. Furthermore, from time to time, the Corporation may have disputes with industry partners as to ownership rights of certain properties or resources, including with respect to the validity of oil and gas leases held by the Corporation or with respect to the calculation or deduction of royalties payable on the Corporation's production. The existence of title defects or the resolution of disputes may have a material adverse effect on the Corporation or its assets and operations. Furthermore, from time to time, the Corporation or its industry partners may owe one another contractual, trust-related or offset obligations which they may default in satisfying and which may adversely affect the validity of an oil and gas lease in which the Corporation has an interest. The existence of title defects, unsatisfied contractual, trust-related or offset obligations, or the resolution of any disputes with industry partners arising from same, may have a material adverse effect on the Corporation or its assets and operations.

Dividends and other payments on the Corporation's Common Shares are variable.

Although the Corporation currently intends to continue to return cash to shareholders with a quarterly dividend payment and/or share repurchases, investor returns may change from time to time due to changes in the amount of the cash dividend paid or shares repurchased. Commencing in February 2022, cash dividends are declared in U.S. dollars and are converted to Canadian dollars and foreign denominated currencies, as applicable, at the spot exchange rate closer to the dividend payment date. Consequently, certain investors are subject to foreign exchange risk. To the extent that the U.S. dollar weakens with respect to their currency, the amount of the dividend may be reduced when converted to shareholders' home currency. In addition, shareholders may be subject to withholding taxes in accordance with tax treaties or domestic tax law changes, as determined by shareholder residency.

The amount of cash available to the Corporation to pay dividends or repurchase shares can vary significantly from period to period for many reasons including, among other things:

- the Corporation's operational and financial performance, including fluctuations in the quantity of the Corporation's oil, NGLs and natural gas production and the sales price that the Corporation realizes for such production (after hedging contract receipts and payments)
- fluctuations in the costs to produce oil, NGLs and natural gas, including royalty burdens, and costs to administer and manage the Corporation and its subsidiaries
- the amount of cash required or retained for debt service or repayment
- amounts required to fund capital spending and working capital requirements
- access to equity markets
- foreign currency exchange rates and interest rates
- the risk factors set forth in this Annual Information Form

The decision whether to pay dividends and the amount of any such dividend is subject to the discretion of the board of directors of the Corporation, which regularly evaluates the Corporation's dividend policy, and the solvency test requirements of the ABCA. In addition, the level of dividends per Common Share will be affected by the number of outstanding Common Shares and other securities that may be entitled to receive cash dividends or other payments. Dividends may be increased, reduced or suspended entirely depending on the Corporation's operations and the performance of its assets. The market value of the Common Shares may deteriorate if the Corporation is unable to meet dividend expectations in the future, and that deterioration may be material.

In addition, to the extent the Corporation uses internally-generated cash flow to repurchase shares, or finance acquisitions, development costs and other significant capital expenditures, the amount of cash available to pay dividends to the Corporation's shareholders may be reduced. To the extent that external sources of capital, including debt or the issuance of additional Common Shares or other securities of the Corporation, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain, develop or expand its oil and gas reserves and resources and to invest in assets may be impaired. To the extent that the Corporation is required to use cash flow to finance capital spending, property acquisitions or asset acquisitions, as the case may be, the level of the Corporation's cash dividend payments to its shareholders may be reduced or even eliminated.

The board of directors of the Corporation has the discretion to determine the extent to which the Corporation's cash flow will be allocated to the payment of debt service charges as well as the repayment of outstanding debt. The payments of interest and principal with respect to the Corporation's third-party indebtedness, including the Credit Facilities, rank ahead of dividend payments that may be made by the Corporation to its shareholders. An increase in the amount of funds used to pay debt service charges or reduce debt will reduce the amount of cash that may be available for the Corporation to pay dividends or repurchase shares from its shareholders. In addition, variations in interest rates and scheduled principal repayments, if and as required under the terms of the Credit Facilities, could result in significant changes in the amount required to be applied to debt service. Certain covenants in agreements with lenders may also limit payments of dividends.

Conflicts of interest may arise between the Corporation and its directors and officers.

Circumstances may arise where directors and officers of the Corporation are directors or officers of other companies involved in the oil and gas industry which are in competition to the interests of the Corporation. Directors are required to abstain from voting on matters when they are in conflict. Employees, including officers, are not permitted to partake in activities that do not support the best interests of the Corporation. Where employee conflicts exist, they are to be provided in writing to the People & Culture Department, which discloses all conflicts to General Counsel. See "*Directors and Officers – Conflicts of Interest*" and the Corporation's Code of Business Conduct at www.enerplus.com.

The ability of shareholders or investors outside of Canada to enforce civil remedies may be limited.

The Corporation is formed under the laws of Alberta, Canada, and its principal place of business is in Canada. Most of the directors and officers of the Corporation are residents of Canada and some of the experts who provide services to the Corporation (such as its auditors and some of its independent reserves engineers) are residents of Canada, and a portion of their assets and the Corporation's assets are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "**Foreign Jurisdiction**") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgments of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including U.S. federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against the Corporation or any of its directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments by U.S. courts for liability based solely upon the U.S. federal securities laws or the securities laws of any state within the United States.

Market for Securities

The Common Shares are listed and posted for trading on the TSX and the NYSE under the trading symbol "ERF".

The following table sets forth certain trading information for the Common Shares on the TSX and the NYSE for 2022.

	TSX Trading			NYSE Trading		
Month	**High (CDN$)**	**Low (CDN$)**	**Volume**	**High (US$)**	**Low (US$)**	**Volume**
January	15.36	12.96	32,041,767	12.26	10.21	10,624,156
February	16.23	14.28	30,624,056	12.81	11.23	9,980,680
March	18.74	14.62	49,503,220	14.59	11.42	15,919,222
April	17.64	14.79	27,706,882	14.07	11.58	10,203,939
May	19.62	14.68	35,132,510	15.50	11.25	12,245,294
June	23.29	16.20	46,930,330	18.58	12.46	14,164,542
July	18.09	14.48	23,339,014	14.11	11.00	10,472,246
August	21.43	15.48	24,243,590	16.48	12.04	10,115,813
September	21.30	17.02	23,820,340	16.19	12.39	11,327,292
October	24.11	20.12	20,566,435	17.80	14.73	10,081,414
November	25.72	22.95	23,191,292	19.23	16.76	10,351,183
December	25.41	21.90	18,104,534	18.92	16.00	8,580,183

Directors and Officers

DIRECTORS OF THE CORPORATION

The directors of the Corporation are elected by the shareholders of the Corporation at each annual meeting of shareholders. All directors serve until the next annual meeting or until a successor is elected or appointed or until the director is removed at a meeting of shareholders. The name, municipality of residence, year of appointment as a director of the Corporation and principal occupation for the past five years for each current director of the Corporation are set forth below.

Name and Residence	Director Since	Principal Occupation for Past Five Years
Hilary A. Foulkes(1)(7) Calgary, Alberta, Canada	February 2014	Corporate director and Senior Advisor to Tudor Pickering Holt & Co. Canada.
Sherri A. Brillon(2)(4) Calgary, Alberta, Canada	October 2022	Corporate director. Prior thereto, Executive Vice-President and Chief Financial Officer of Encana Corporation from 2009 to 2019.
Judith D. Buie(2)(3)(5)(6) Houston, Texas, United States	January 2020	Corporate director and oil and gas industry advisor.
Karen E. Clarke-Whistler(3)(4)(5) Toronto, Ontario, Canada	December 2018	Corporate director and consultant providing ESG advisory services. Prior thereto, Chief Environment Officer at TD Bank Group until her retirement in 2018.
Ian C. Dundas Calgary, Alberta, Canada	July 2013	President & Chief Executive Officer of Enerplus.
Robert B. Hodgins(3)(4) Calgary, Alberta, Canada	November 2007	Corporate director. Mr. Hodgins held a part-time, non-officer position of Senior Advisor, Investment Banking at Canaccord Genuity Corp. from September 2018 to May 2022.
Mark A. Houser(2)(4)(5) Houston, Texas, United States	March 2022	Corporate director and founder and principal of Symphero Energy Solutions, LLC, an advisory services company in the oil and gas and renewable energy development markets. From 2015 to 2021, he served as Chief Executive Officer of University Lands, which manages the surface and mineral interests of 2.1 million acres of land in West Texas.
Susan M. MacKenzie(4)(5) Calgary, Alberta, Canada	July 2011	Corporate director.
Jeffrey W. Sheets(2)(4) Houston, Texas, United States	December 2017	Corporate director.
Sheldon B. Steeves(2)(5) Calgary, Alberta, Canada	June 2012	Corporate director.

Notes:

1. Chair of the board of directors and ex officio member of all committees of the board of directors.
2. The Audit & Risk Management Committee is currently comprised of Jeffrey W. Sheets as Chair, Sherri A. Brillon, Judith D. Buie, Mark A. Houser and Sheldon B. Steeves.
3. The Corporate Governance & Nominating Committee is currently comprised of Robert B. Hodgins as Chair, Judith D. Buie and Karen E. Clarke-Whistler.
4. The Compensation & Human Resources Committee is currently comprised of Susan M. MacKenzie as Chair, Sherri A. Brillon, Robert B. Hodgins, Karen E. Clarke-Whistler, Mark A. Houser and Jeffrey W. Sheets.
5. The Reserves, Safety & Social Responsibility Committee is currently comprised of Sheldon B. Steeves as Chair, Judith D. Buie, Karen E. Clarke-Whistler, Mark A. Houser and Susan M. MacKenzie.
6. Ms. Buie was a director of Sundance Energy Australia Ltd., and subsequently Sundance Energy Inc. ("Sundance") from February 2019 through April 2021, a US-based oil and gas company, which filed for voluntary Chapter 11 protection in the U.S. Bankruptcy Court for the Southern District of Texas on March 9, 2021. The filing was initiated with the support of Sundance's lenders under a prepackaged plan of reorganization. Sundance emerged on April 23, 2021 from Chapter 11 bankruptcy as a privately held independent E&P based in Denver.
7. Ms. Foulkes was a director of Parallel Energy Trust ("Parallel"), a Canadian-based oil and gas trust, which commenced proceedings in the Court of Queen's Bench of Alberta, under the Companies' Creditors Arrangement Act (Canada) on November 9, 2015. Ms. Foulkes ceased to be a director of Parallel on March 1, 2016. Parallel filed an assignment in bankruptcy and proceedings under the CCAA were terminated in March 2016.

OFFICERS OF THE CORPORATION

The name, municipality of residence, position held and principal occupation for the past five years for each officer of the Corporation are set out below.

Name and Residence	Office	Principal Occupation for Past Five Years
Ian C. Dundas Calgary, Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of the Corporation.
Jodine J. Jenson Labrie Calgary, Alberta, Canada	Senior Vice-President & Chief Financial Officer	Senior Vice-President & Chief Financial Officer of the Corporation.
Wade D. Hutchings Denver, Colorado, United States	Senior Vice-President, Chief Operating Officer	Senior Vice-President & Chief Operating Officer of the Corporation since February 11, 2020. Prior thereto, Senior-Vice President, Exploration & Production at Devon Energy Corporation from 2017 to 2019.
Garth R. Doll Calgary, Alberta, Canada	Vice-President, Marketing	Vice-President, Marketing of the Corporation since February 2019. Prior thereto, Manager, Marketing of the Corporation.
Terry S. Eichinger Calgary, Alberta, Canada	Vice-President, Drilling, Completions & Operations Support	Vice-President, Drilling, Completions & Operations Support since June 2020. Prior thereto, Vice-President, U.S. Operations & Engineering of the Corporation since September 2018. Prior thereto, Senior Manager, U.S. Operations & Engineering of the Corporation.
Nathan D. Fisher Denver, Colorado, United States	Vice-President, United States Business Unit	Vice-President, United States Business Unit of the Corporation since June 2020. Prior thereto, Vice-President, U.S. Development & Geosciences of the Corporation.
Daniel J. Fitzgerald Calgary, Alberta, Canada	Vice-President, Business Development	Vice-President, Business Development of the Corporation.
David A. McCoy Calgary, Alberta, Canada	Vice-President, General Counsel & Corporate Secretary	Vice-President, General Counsel & Corporate Secretary of the Corporation.
Shaina B. Morihira Calgary, Alberta, Canada	Vice-President, Finance	Vice-President, Finance of the Corporation.
Pamela A. Ramotowski Calgary, Alberta, Canada	Vice-President, People & Culture	Vice-President, People & Culture since July 2022. Prior thereto, Vice President, Corporate Services at Steel Reef Infrastructure Corp., a North American based midstream company, from 2021 to 2022. Prior thereto, Vice President, Human Resources at Seven Generations Energy Ltd, a Canadian based E&P company, from 2018 to 2021.

COMMON SHARE OWNERSHIP

As of February 22, 2023, the directors and officers of the Corporation named above beneficially own, or control or exercise direction over, directly or indirectly, an aggregate of 1,010,176 Common Shares, representing approximately 0.47% of the outstanding Common Shares as of that date.

CONFLICTS OF INTEREST

Certain of the directors and officers named above may be directors or officers of issuers or other companies which are in competition with the Corporation, and as such may encounter conflicts of interest in the administration of their duties with respect to the Corporation. In situations where conflicts of interest arise, the Corporation expects the applicable director or officer to declare the conflict and, if a director of the Corporation, abstain from voting in respect of such matters on behalf of the Corporation.

See "*Risk Factors – Conflicts of interest may arise between the Corporation and its directors and officers*".

AUDIT & RISK MANAGEMENT COMMITTEE DISCLOSURE

The disclosure regarding the Corporation's Audit & Risk Management Committee required under National Instrument 52-110 adopted by the Canadian securities regulatory authorities is contained in Appendix E to this Annual Information Form.

Legal Proceedings and Regulatory Actions

The Corporation is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Corporation's favour, the Corporation does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Corporation may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operations or liquidity. Notwithstanding the above, the Corporation is aware of a class action filed in Fort Berthold Tribal Court in November 2017 as Civil Action No. 2017-0505 against the Corporation and fifteen other companies operating on the FBIR (the "**Action**"). The plaintiffs in the Action are members of the Three Affiliated Tribes who own mineral interests on the FBIR and allege that, among other things, the defendant companies have committed trespass and failed to pay royalties properly. They seek judgement against the defendant group for $585 million in damages, $500 million in punitive damages, and disgorgement of the value of oil and gas produced from the plaintiffs' property. The Corporation believes the claim, as against the Corporation, is without merit.

Interest of Management and Others in Material Transactions

To the knowledge of the directors and executive officers of the Corporation, none of the directors or executive officers of the Corporation and no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of the Corporation's securities, nor any associate or affiliate of any of the foregoing, has had any material interest, direct or indirect, in any transaction with the Corporation since January 1, 2020 or in any proposed transaction that has materially affected or is reasonably expected to materially affect the Corporation.

Material Contracts and Documents Affecting the Rights of Securityholders

The Corporation is not a party to any contracts material to its business or operations, other than contracts entered into in the normal course of business.

Copies of the following documents entered in the normal course of business and relating to the Credit Facilities have been filed on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov:

- Amended and Restated Agreement relating to the $365 million SLL Credit Facility (November 15, 2022);
- Amended and Restated Agreement relating to the $900 million SLL Credit Facility (November 15, 2022);
- Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2012 (SEDAR – May 23, 2012; EDGAR – May 24, 2012); and
- Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2014 (SEDAR – October 10, 2014; EDGAR – October 15, 2014).

Copies of the following documents affecting the rights of securityholders have been filed on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov.

- the Articles of Amalgamation (January 2, 2013), and
- By-law No. 1 of the Corporation (June 16, 2014); and By-law No. 2 of the Corporation (May 6, 2016).

Interests of Experts

McDaniel prepared the McDaniel Reports in respect of certain reserves attributable to the Corporation's oil and natural gas properties in the western United States, a summary of which is contained in this Annual Information Form. McDaniel also prepared estimates of contingent resources attributable to the Corporation's North Dakota properties, which are referred to in this Annual Information Form in Appendix A. As of the dates of the McDaniel Reports, the "designated professionals" (as defined in Form 51-102F2 – *Annual Information Form* of the Canadian securities regulatory authorities) of McDaniel, as a group, beneficially owned, directly or indirectly, no outstanding Common Shares. NSAI prepared the NSAI Report in respect of the reserves and contingent resources attributable to the Corporation's interests in the Marcellus property, a summary of which is contained in this Annual Information Form. As of the date of the NSAI Report, the designated professionals of NSAI, as a group, beneficially owned, directly or indirectly, no outstanding Common Shares.

KPMG LLP ("**KPMG**") was appointed as the auditors of the Corporation on May 31, 2017 and have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations, and also that they are independent accountants with respect to the Corporation under all relevant U.S. professional and regulatory standards.

Transfer Agent and Registrar

The transfer agent and registrar for the Common Shares is TSX Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario. American Stock Transfer & Trust Company, LLC at its principal office in Brooklyn, New York is the transfer agent for the Common Shares in the United States.

Additional Information

Additional information relating to the Corporation may be found on the Corporation's profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and on the Corporation's website at www.enerplus.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, as applicable, will be contained in the Corporation's information circular and proxy statement with respect to its 2023 annual meeting of shareholders. Furthermore, additional financial information relating to the Corporation is provided in the MD&A and the Financial Statements. Shareholders who wish to receive printed copies of these documents free of charge should contact the Corporation's Investor Relations Department using the contact information on the back cover of this Annual Information Form.

APPENDIX A

Appendix A – Contingent Resources Information

NOTE TO READER REGARDING DISCLOSURE OF CONTINGENT RESOURCES INFORMATION

All of the Corporation's contingent resources have been evaluated in accordance with NI 51-101. NSAI has evaluated the Corporation's contingent resources attributable to its Marcellus properties located in Pennsylvania, United States, using the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2023. McDaniel has evaluated the Corporation's contingent resources associated with properties located in North Dakota, United States, using the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2023.

The following sections and tables summarize, as at December 31, 2022, the Corporation's "best estimate" (as defined below) contingent resources, including risked contingent resource volumes and risked net present value of future net revenue of contingent resources in development pending project maturity sub-class, together with certain information, estimates and assumptions associated with such estimates. The data contained in the tables is a summary of the evaluations, and as a result the tables may contain slightly different numbers than the evaluations themselves due to rounding. Additionally, the columns and rows in the tables may not add due to rounding.

All estimates of future net revenues are stated prior to provision for interest and general and administrative expenses and after deduction of royalties and estimated future capital spending, and are presented before deducting income taxes. For additional information, see "*Business of the Corporation – Tax Horizon*", "*Industry Conditions*" and "*Risk Factors*" in the Annual Information Form.

With respect to pricing information in the following resources information, the wellhead oil prices were adjusted for quality and transportation based on historical actual prices. The natural gas prices were adjusted, where necessary, based on historical pricing based on heating values and transportation. The NGLs prices were adjusted to reflect historical average prices received.

The estimated future net revenue to be derived from the production of the contingent resources set out in this Appendix A is based on the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2023, and was utilized by NSAI and McDaniel in their evaluations for consistency in the Corporation's reporting, and the inflation and exchange rate assumptions set forth under "*Oil and Natural Gas Reserves – Forecast Prices and Costs*" in the Annual Information Form. Also see "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information – Description of Price and Cost Assumptions*" in the Annual Information Form.

It should not be assumed that the summary of risked net present value of estimated future cash flows shown in the tables below is representative of the fair market value of the contingent resources. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and contingent resources estimates of the Corporation's crude oil, natural gas liquids and natural gas contingent resources provided herein are estimates only. Actual resources may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained below.

Contingent Resources Categories and Levels of Certainty for Reported Resources

In this Appendix A, the Corporation has disclosed estimated volumes of economic "contingent resources" which relate to the Corporation's interests in its crude oil properties located in North Dakota and its Marcellus shale gas property located in Pennsylvania.

"**resources**" are petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced.

"**contingent resources**" are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are economically recoverable based on the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2023.

The economic contingent resources estimates in this Appendix A are presented as the "**best estimate**" of the quantity that will actually be recovered, meaning that it is equally likely that the actual remaining quantities recovered will be greater or less than the “best estimate”, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the “best estimate”.

"**risked**" means that the applicable volumes or revenues have been adjusted for the probability of loss or failure in accordance with the COGEH. See "*Description of Properties*" below.

Resources and contingent resources do not constitute, and should not be confused with, reserves. See "*Business of the Corporation – Description of Properties*" and "*Risk Factors – The Corporation's actual reserves and resources will vary from its reserves and resources estimates, and those variations could be material*".

Contingent Resources Development Status

Contingent resources may be divided into the following project maturity sub-classes:

"**development pending**" resources sub-class is assigned to contingent resources for a particular project where resolution of the final conditions for development is being actively pursued (there is a high chance of development) and the project is expected to be developed in a reasonable timeframe;

"**development on hold"** resources sub-class is assigned to contingent resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator;

"**development unclarified**" resources are those for which additional information is being acquired;

"**development not viable**" resources are those where no further data acquisition or evaluation is currently planned and there is a low chance of development.

All of the Corporation's contingent resources fall into the "development pending" sub-class.

CONTINGENT RESOURCES DATA

The following tables set forth the "best estimate" of gross and net risked contingent resources volumes and risked net present value of future net revenue attributable to the Corporation's contingent resources in the development pending project maturity sub-class, at December 31, 2022, using forecast price and cost cases. **An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Corporation proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is no certainty that the estimate of risked net present value of future net revenue will be realized.**

Summary of Risked Oil and Gas
Contingent Resources (Forecast Prices and Costs)
As of December 31, 2022

PROJECT MATURITY SUB-CLASS	Tight Oil		Natural Gas Liquids		Shale Gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)	(MBOE)
Development Pending	78,185	62,777	9,862	7,948	568,837	458,412	182,853	147,127

Risked Net Present Value of Future Net Revenue
Contingent Resources (Forecast Prices and Costs)
As of December 31, 2022

RISKED NET PRESENT VALUE OF FUTURE NET REVENUE DISCOUNTED AT (%/Year)					
	Before Deducting Income Taxes				
PROJECT MATURITY SUB-CLASS	**0%**	**5%**	**10%**	**15%**	**20%**
	(in US$ millions)				
Development Pending	3,634.2	1,652.9	816.7	429.3	236.2

DESCRIPTION OF PROPERTIES

Outlined below is a description of the Corporation's "best estimate" of economic contingent resources for its U.S. crude oil and natural gas properties and assets. There is no certainty it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources".

Crude Oil Properties

An evaluation of the Corporation's interests in the Bakken and Three Forks formations in the Corporation's North Dakota properties was conducted independently by McDaniel, which has attributed an unrisked "best estimate" of 108.7 MMBOE (96.1 MMBOE risked) of economic contingent resources to these formations, effective as of December 31, 2022, a decrease of 32% from the estimate as of December 31, 2021. The decrease compared to 2021 was primarily the result of 51.2 MMBOE of unrisked contingent resources being converted to undeveloped reserves. The recovery of these tight oil contingent resources is under a primary solution gas drive through horizontal wells completed with multiple fracture treatments. These contingent resources represent approximately 214.1 net future drilling locations over and above 366.5 net booked drilling locations identified in the Corporation's booked proved plus probable reserves. The capital required to drill these locations is estimated to be $1,717.9 million between 2030 and 2035. These estimates are based primarily upon a drilling density of up to 10 wells per drilling spacing unit in the Bakken and Three Forks formations combined. The contingent resources average expected ultimate recovery per well is estimated at 553.9 MBOE. These contingent resources are economic using established technologies and under current forecast commodity prices. Given the drilling density to date, these contingent resources represent a non-reserve land utilization of 100% for the operated lands. All of these contingent resources are classified into "development pending" project maturity sub-class, with an estimated chance of development of 88% (80% for 1-mile lateral length horizontal wells and 90% for 2- and 3-mile lateral length horizontal wells) as their development is expected to immediately follow the reserves development. After application of the chance of development, the risked NPV discounted at 10% is $626.3 million. The Corporation has approximately 757.8 net reserves wells currently on production in this area.

The primary contingency which currently prevents the classification of the Corporation's disclosed contingent resources associated with its North Dakota properties as reserves is the development timeline beyond what is already assigned for the Corporation's undeveloped reserves. Significant positive factors related to the estimate include continued advancement of drilling and completion technology, and performance of producing wells that continues to exceed expectations resulting in positive revisions to reserves. Another factor related to the estimate is the limited long-term performance history in the immediate area of the contingent resources. There are a number of inherent risks and contingencies associated with the development of the interests in the property including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on industry partners in project development, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in the Annual Information Form.

Natural Gas Properties

NSAI has conducted an independent assessment of the contingent resources attributable to the Corporation's interests in the Marcellus property and has provided an unrisked "best estimate" of economic shale gas contingent resources of approximately 650.9 Bcf (520.7 Bcf risked) at December 31, 2022. The unrisked NPV (discounted at 10%) associated with these contingent resources is $238.0 million ($190.4 million risked). Approximately 59.4 Bcf of unrisked contingent resources were reclassified as reserves in 2022. An additional 91.1 Bcf of unrisked contingent resources (72.9 Bcf risked) were removed due to a technical review of offsetting development. The remaining contingent resources are economic based on the forecast price and cost assumptions used for the Corporation's year-end 2022 reserves evaluations. This estimate represents a non-reserve land utilization rate of 95% and average well ultimate recovery of approximately 15.5 Bcf. These contingent resources are classified into "development pending" project maturity sub-class as it is anticipated their development will be a continuation of the current reserves development. These contingent resources have an estimated 80% chance of development. It is also estimated that $380.5 million of capital will be required to develop these contingent resources with multifractured horizontal wells, and development will occur from 2027 to 2040.

The primary contingencies which currently prevent the classification of the Corporation's disclosed contingent resources associated with its Marcellus interests as reserves consist of limitations to development based on adverse topography or other surface restrictions, the receipt of all required regulatory permits and approvals to develop the land, and limited access to confidential information of operators' long-term development plans that would support the recognition of reserves on the Corporation's areas of interest. Significant negative factors related to the estimate include the following: the pace of development, including drilling and infrastructure, is slower than the forecast, risk of adverse regulatory and tax changes, and other issues related to gas development in populated areas. There are a number of inherent risks and contingencies associated with the development of the Corporation's interests in the Marcellus property including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in the Annual Information Form.

Appendix B - Supplemental Information About Crude Oil and Natural Gas Producing Activities (unaudited)

The following disclosures, including proved reserves, future net cash flows, and costs incurred attributable to the Corporation’s crude oil and natural gas operations have been prepared in accordance with the provisions of the Financial Accounting Standards Board’s ASC Topic 932 Extractive Activities – Oil and Gas, which generally utilize definitions and estimations of proved reserves that are consistent with Rule 4-10 of Regulation S-X promulgated by the SEC, but does not necessarily include all of the disclosure required by the SEC disclosure requirements set forth in Subpart 1200 of Regulation S-K.

A. ESTIMATED PROVED CRUDE OIL AND NATURAL GAS RESERVE QUANTITIES

Users of this information should be aware that the process of estimating quantities of "proved" crude oil, natural gas and natural gas liquids reserves is very complex, requiring significant subjective decisions in the evaluation of available geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors, including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Future fluctuations in prices and costs, production rates, or changes in political or regulatory environments could cause the Corporation’s reserves to be materially different from that presented.

The U.S. Rules require the use of a 12-month average price to estimate proved reserves calculated as the unweighted arithmetic average of first day-of-the-month prices within the 12-month period prior to the end of the reporting period (the “**Constant Price**”). Proved reserves and production volumes are presented net of royalties in accordance with U.S. practice.

The reserves data disclosed are effective December 31, 2022. Concurrent to the evaluation of the Corporation’s Canadian NI 51-101 Standards reserves, McDaniel and NSAI prepared and reviewed estimates of the Corporation’s reserves under the U.S. Rules.

Proved reserves, proved developed reserves and proved undeveloped reserves are defined under the U.S. Rules. Proved crude oil and natural gas reserves are those quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulation. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

The reserves data presented in this Appendix B are a summary of evaluations, and as a result the tables may contain slightly different quantities than the evaluations themselves due to rounding. The Corporation also presents reserves estimates in accordance with National Instrument 51-101 “Standard of Disclosure for Oil and Gas Activities” which can differ significantly to those prepared under the U.S. Rules. Additionally, the columns and rows in the tables may not add due to rounding. See "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information – Notice to U.S. Readers"* in this Annual Information Form.

Subsequent to December 31, 2022, no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of proved reserves as of that date.

Enerplus’ proved crude oil, natural gas and NGLs reserves are located in the United States, primarily in the states of Colorado, North Dakota and Pennsylvania. The Corporation’s net proved reserves summarized in the following table represent the Corporation’s lessor royalty, overriding royalty, and working interest share of reserves, after deduction of lessor royalties and overriding royalties as of December 31, 2022.

	United States		Canada		Total		Total
	Crude Oil and NGLs (Mbbls)	Natural Gas (MMcf)	Crude Oil and NGLs (Mbbls)	Natural Gas (MMcf)	Crude Oil and NGLs (Mbbls)	Natural Gas (MMcf)	All Products (Mboe)
Reserves at December 31, 2019	**92,777**	**719,816**	**23,680**	**17,756**	**116,456**	**737,572**	**239,385**
Purchases of reserves in place	-	-	-	-	-	-	-
Sales of reserves in place	-	-	-	-	-	-	-
Discoveries and extensions	1,931	16,613	-	-	1,931	16,613	4,700
Revisions of previous estimates	(39,543)	(263,700)	(5,115)	943	(44,658)	(262,757)	(88,451)
Improved recovery	-	-	-	-	-	-	-
Production	(12,690)	(65,672)	(2,382)	(4,239)	(15,072)	(69,911)	(26,724)
Proved Developed and Undeveloped							
Reserves at December 31, 2020	**42,475**	**407,056**	**16,182**	**14,461**	**58,657**	**421,517**	**128,910**
Purchases of reserves in place	60,468	59,185	-	-	60,468	59,185	70,332
Sales of reserves in place	(3,419)	(7,838)	(118)	(1,514)	(3,537)	(9,352)	(5,095)
Discoveries and extensions	75,587	336,511	1,316	503	76,903	337,014	133,072
Revisions of previous estimates	14,984	153,647	4,024	4,960	19,009	158,607	45,443
Improved recovery	-	-	-	-	-	-	-
Production	(18,426)	(75,644)	(2,138)	(2,942)	(20,564)	(78,586)	(33,662)
Proved Developed and Undeveloped							
Reserves at December 31, 2021	**171,669**	**872,917**	**19,267**	**15,468**	**190,936**	**888,385**	**339,000**
Purchases of reserves in place	255	143	-	-	255	143	279
Sales of reserves in place	(1,275)	(1,109)	(17,534)	(13,240)	(18,809)	(14,349)	(21,200)
Discoveries and extensions	17,984	122,762	-	-	17,984	122,762	38,444
Revisions of previous estimates	8,207	(34,877)	-	-	8,207	(34,877)	2,394
Improved recovery	-	-	-	-	-	-	-
Production	(20,787)	(82,368)	(1,733)	(2,228)	(22,520)	(84,596)	(36,619)
Proved Developed and Undeveloped							
Reserves at December 31, 2022	**176,053**	**877,468**	**-**	**-**	**176,053**	**877,468**	**322,298**
Proved Developed Reserves							
December 31, 2019	49,852	475,155	20,480	17,684	70,332	492,839	152,472
December 31, 2020	37,966	360,446	15,421	14,447	53,387	374,893	115,869
December 31, 2021	89,337	560,221	17,417	15,418	106,754	575,639	202,694
December 31, 2022	**97,151**	**624,988**	**-**	**-**	**97,151**	**624,988**	**201,316**
Proved Undeveloped Reserves							
December 31, 2019	42,925	244,661	3,200	73	46,124	244,733	86,913
December 31, 2020	4,508	46,610	761	13	5,270	46,624	13,040
December 31, 2021	82,332	312,696	1,850	50	84,182	312,746	136,306
December 31, 2022	**78,902**	**252,480**	**-**	**-**	**78,902**	**252,480**	**120,982**

Purchases of reserves in place

In 2020, the Corporation acquired no additional working interest reserve volumes through purchases.

In 2021, the Corporation purchased 60,468 Mbbls of net proved crude oil and NGLs reserves and 59,185 MMcf of natural gas reserves through the acquisition of the Bruin and Dunn County assets within the Bakken/Three Forks formations in North Dakota.

In 2022, the Corporation purchased a number of small third party working interests in Enerplus operated wells in North Dakota, acquiring 255 Mbbls of net crude oil and NGLs reserves and 143 MMcf of natural gas reserves.

Sales of reserves in place

In 2020, the Corporation did not sell working interests of any of its reserves in place.

In 2021, the Corporation divested 3,419 Mbbls of net proved crude oil and NGLs reserves and 7,838 MMcf of natural gas reserves from the sale of its crude oil property in the Sleeping Giant area in Montana.

In 2021, the Corporation also sold working interests in developed and undeveloped land in one crude oil property and six natural gas properties located in Alberta, accounting for 118 Mbbls of net proved crude oil and NGLs reserves and 1,514 MMcf of natural gas reserves.

In 2022, the Corporation divested 17,534 Mbbls of net proved crude oil and NGLs reserves and 13,240 MMcf of natural gas reserves from the sale of all Canadian properties with reserves volumes assigned, namely Ante Creek, Giltedge and Medicine Hat Glauconitic C Unit (in Alberta) and the Ratcliffe property(Saskatchewan).

In 2022, the Corporation divested 1,275 Mbbls of net proved oil and NGLs reserves and 1,109 MMcf of natural gas reserves in North Dakota through farming out interests in a pair of development units.

Discoveries and extensions

The Corporation added 1,655 Mbbls, 73,683 Mbbls and 17,984 Mbbls of net proved crude oil and NGLs reserves on its Bakken/Three Forks properties in 2020, 2021 and 2022, respectively. The Company added 15,299 MMcf, 271,393 MMcf and 109,250 MMcf of net proved natural gas reserves in 2020, 2021 and 2022, respectively, on its Marcellus natural gas property. These discoveries and extensions were primarily related to booking additional locations, as well as successful well development.

In 2020, there were no discoveries or extensions in Canadian crude oil or natural gas properties.

In 2021, Canadian discoveries and extensions accounted for an increase of 1,293 Mbbls of net proved crude oil reserves and 50 MMcf of natural gas reserves in the Giltedge and Medicine Hat Glauconitic C crude oil properties, and 23 Mbbls of net proved crude oil and NGLs reserves and 453 MMcf of net proved natural gas reserves in the Ferrier property, all located in Alberta.

In 2022, there were no discoveries or extensions in Canadian reserves properties as they were sold during the year.

Revisions of previous estimates

In 2020, negative revisions to United States crude oil reserves were primarily due to a decrease in the crude oil Constant Price, which caused economic truncation of producing volumes and the removal of undeveloped locations that were no longer economic. Negative revisions to United States natural gas reserves were also primarily due to a decrease in the natural gas Constant Price, which caused economic truncations of producing volumes and the removal of no longer economic undeveloped locations.

In 2021, positive revisions to United States crude oil reserves were primarily due to an increase in the crude oil Constant Price compared to 2020. Positive revisions to United States natural gas reserves were also primarily due to an increase in the natural gas Constant Price compared to 2020.

In 2022, positive revisions to United States crude oil reserves were primarily due to an increase in the crude oil Constant Price compared to 2021. Negative revisions to United States natural gas reserves were also primarily due to revised development plans and deletion of proved undeveloped locations in the Marcellus natural gas property.

In 2020, negative revisions to Canadian crude oil reserves were due to negative revisions to previous estimates in the Medicine Hat Glauconitic C polymer flood and a decrease in the crude oil Constant Price compared to 2019. Conversely, an increase in the Constant Price for Canadian natural gas compared to 2019 resulted in positive revisions to Canadian natural gas reserves.

In 2021, the positive revisions to Canadian crude oil reserves were primarily due to an increase in the crude oil Constant Price compared to 2020. Positive revisions to Canadian natural gas reserves were also primarily due to an increase in the natural gas Constant Price compared to 2020.

In 2022, there were no revisions of previous estimates in Canadian reserves properties as they were sold during the year.
Improved Recovery

There were no improved recovery revisions for the years 2020, 2021 and 2022.

B. CAPITALIZED COSTS RELATED TO CRUDE OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation and depletion, including impairments, relating to the Corporation's crude oil and natural gas exploration, development and producing activities are as follows:

	2022	2021	2020
		(in US$ thousands)	
Capitalized costs[1]	$ 7,214,993	$ 13,075,987	$ 11,966,258
Less accumulated depletion, depreciation and impairment	(5,892,090)	(11,822,482)	(11,513,956)
Net capitalized costs	$ 1,322,903	$ 1,253,505	$ 452,302

Note:
(1) Includes capitalized costs of proved and unproved properties.

C. COSTS INCURRED IN CRUDE OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred in connection with crude oil and natural gas acquisition, exploration and development activities are presented in the table below. Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire crude oil and natural gas properties, including an allocation of purchase price on business combinations that result in property acquisitions. Development costs include asset retirement costs capitalized and the costs of drilling and equipping development wells and facilities to extract, gather and store crude oil and natural gas, along with an allocation of overhead. Exploration costs include costs related to the discovery and the drilling and completion of exploratory wells in new crude oil and natural gas reservoirs.

	For the Year Ended December 31, 2022		
	United States	Canada	Total
		(in US$ thousands)	
Acquisition of properties:			
Proved	$ 21,290	$ 1,225	$ 22,515
Unproved	-	-	-
Exploration costs	1,493	244	1,737
Development costs	429,306	60,453	489,759
	$ 452,089	$ 61,922	$ 514,011

	For the Year Ended December 31, 2021		
	United States	Canada	Total
		(in US$ thousands)	
Acquisition of properties:			
Proved	$ 832,808	$ 2,339	$ 835,147
Unproved	-	-	-
Exploration costs	861	73	934
Development costs	331,341	25,528	356,869
	$ 1,165,010	$ 27,940	$ 1,192,950

	For the Year Ended December 31, 2020		
	United States	Canada	Total
		(in US$ thousands)	
Acquisition of properties:			
Proved	$ -	$ 225	$ 225
Unproved	5,522	1,744	7,266
Exploration costs	480	98	578
Development costs	200,986	18,136	219,122
	$ 206,988	$ 20,203	$ 227,191

D. RESULTS OF OPERATIONS FOR CRUDE OIL AND GAS PRODUCING ACTIVITIES

The following table sets forth revenue and direct cost information relating to the Corporation's crude oil and natural gas producing activities for the years ended December 31, 2022, 2021 and 2020:

	For the Year Ended December 31, 2022		
	United States	Canada	Total
	(in US$ thousands)		
Revenue			
Sales[1]	$ 2,205,876	$ 147,499	$ 2,353,374
Deduct[2]			
Production costs[3]	639,279	48,075	687,354
Depletion, depreciation and accretion ("DD&A")	286,438	22,929	309,367
Impairment	-	-	-
Current and deferred income tax provision (recovery)	246,006	47,290	293,296
Results of operations for oil and gas producing activities	$ 1,034,153	$ 29,204	$ 1,063,357
DD&A per net BOE unit of production	$ 8.30	$ 10.90	$ 8.45

	For the Year Ended December 31, 2021		
	United States	Canada	Total
	(in US$ thousands)		
Revenue			
Sales[1]	$ 1,355,253	$ 127,322	$ 1,482,575
Deduct[2]			
Production costs[3]	472,849	49,846	522,695
Depletion, depreciation and accretion ("DD&A")	246,949	24,387	271,336
Impairment	-	3,420	3,420
Current and deferred income tax provision (recovery)	151,620	(50,176)	101,444
Results of operations for oil and gas producing activities	$ 483,835	$ 99,845	$ 583,680
DD&A per net BOE unit of production	$ 7.96	$ 9.28	$ 8.06

	For the Year Ended December 31, 2020		
	United States	Canada	Total
	(in US$ thousands)		
Revenue			
Sales[1]	$ 480,822	$ 72,917	$ 553,739
Deduct[2]			
Production costs[3]	284,071	49,124	333,195
Depletion, depreciation and accretion ("DD&A")	183,226	34,892	218,118
Impairment	799,997	100,943	900,940
Current and deferred income tax provision (recovery)	(178,551)	(20,425)	(198,976)
Results of operations for oil and gas producing activities	$ (607,921)	$ (91,617)	$ (699,538)
DD&A per net BOE unit of production	$ 7.75	$ 11.30	$ 8.16

Notes:

(1) Sales are presented net of royalties.

(2) The costs deducted in this schedule exclude corporate overhead, interest expense and other costs which are not directly related to crude oil and gas producing activities.

(3) Production costs include operating costs, transportation costs and production taxes.

E. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED CRUDE OIL AND NATURAL GAS RESERVE QUANTITIES

The following tables set forth the standardized measure of discounted future net cash flows from projected production of the Corporation's crude oil and natural gas reserves:

	As at December 31, 2022		
	United States	Canada	Total
	(in $US millions)		
Future cash inflows	$ 17,173	$ -	$17,173
Future production costs	4,010	-	4,010
Future development and asset retirement costs	1,705	-	1,705
Future income tax expenses	2,523	-	2,523
Future net cash flows	$ 8,935	$ -	$ 8,935
Deduction: 10% annual discount factor	3,406	-	3,406
Standardized measure of discounted future net cash flows	$ 5,529	$ -	$ 5,529

	As at December 31, 2021		
	United States	Canada	Total
	(in $US millions)		
Future cash inflows	$ 10,499	$ 1,023	$11,522
Future production costs	3,293	425	3,718
Future development and asset retirement costs	1,486	140	1,626
Future income tax expenses	1,064	-	1,064
Future net cash flows	$ 4,655	$ 459	$ 5,114
Deduction: 10% annual discount factor	1,552	149	1,701
Standardized measure of discounted future net cash flows	$ 3,103	$ 309	$ 3,413

	As at December 31, 2020		
	United States	Canada	Total
	(in $US millions)		
Future cash inflows	$ 1,375	$ 427	$ 1,802
Future production costs	832	256	1,088
Future development and asset retirement costs	174	199	373
Future income tax expenses	-	-	-
Future net cash flows	$ 370	$ (29)	$ 341
Deduction: 10% annual discount factor	41	(69)	(27)
Standardized measure of discounted future net cash flows	$ 329	$ 40	$ 368

F. CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED CASH FLOW RELATING TO PROVED CRUDE OIL AND NATURAL GAS RESERVES

	2022	2021	2020
	(in $US millions)		
Beginning of year	**$** 3,413	**$** 368	**$** 1,476
Sales of oil and natural gas produced, net of production costs	(1,666)	(960)	(221)
Net changes in sales prices and production costs	4,845	2,347	(2,030)
Changes in previously estimated development costs incurred during the period	410	302	217
Changes in estimated future development costs	(548)	(1,278)	557
Extension, discoveries and improved recovery, net of related costs	981	2,285	30
Purchase of reserves in place	1	1,214	-
Sales of reserves in place	(229)	(12)	-
Net change resulting from revisions in previous quantity estimates	(1,062)	(251)	122
Accretion of discount	300	26	136
Net change in income taxes	(917)	(630)	82
Other significant factors (Exchange rate)	-	3	(2)
End of year	**$** 5,529	**$** 3,413	**$** 368

ADDITIONAL RESERVES INFORMATION CALCULATED IN ACCORDANCE WITH U.S. RULES

G. NET RESERVES PROVED RESERVES SUMMARY

The following table sets forth a summary of the Corporation's total proved reserves based on volumes that are calculated in accordance to U.S. Rules, using net reserves and Constant Prices and Costs, and presented by product types that the Corporation used to report under the Canadian Standards.

	Tight Oil (Mbbls)	Total Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Shale Gas (MMcf)	Total (MBOE)
Net					
Proved developed producing	78,342	78,342	15,993	621,563	197,928
Proved developed non-producing	2,468	2,468	348	3,425	3,387
Proved undeveloped	68,144	68,144	10,758	252,480	120,982
Total Proved	**148,953**	**148,953**	**27,100**	**877,468**	**322,298**

H. NET PROVED RESERVES RECONCILIATION

The following table sets forth a summary of the Corporation's total proved reserves based on volumes that are calculated in accordance to U.S. Rules, using net reserves and Constant Prices and Costs, and presented by product types that the Corporation used to report under the Canadian Standards.

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2021	5,213	13,464	144,697	163,374	27,561	15,117	873,268	888,385	339,000
Purchases of reserves in place	-	-	231	231	24	-	143	143	278
Sales of reserves in place	(4,502)	(12,531)	(1,148)	(18,181)	(628)	(12,955)	(1,395)	(14,349)	(21,200)
Discoveries and extensions	-	-	15,554	15,554	2,430	-	122,762	122,762	38,444
Revisions of previous estimates	-	-	6,961	6,961	1,246	-	(34,876)	(34,876)	2,394
Improved recovery	-	-	-	-	-	-	-	-	-
Production	(712)	(933)	(17,342)	(18,986)	(3,534)	(2,162)	(82,433)	(84,596)	(36,619)
Proved Reserves at Dec. 31, 2022	-	-	148,953	148,953	27,100	-	877,468	877,468	322,298

I. FUTURE DEVELOPMENT COSTS

The following table sets forth a summary of the amount of development costs deducted in the estimation of the net present value of future cash flows associated with the Corporation's proved reserves.

	U.S. Standards(1)
Future Development Costs	**Proved Reserves**
(US$ millions)	
2023	484
2024	344
2025	457
2026	236
2027	1
2028	-
Remainder	-
Total FDC Undiscounted	**1,523**
Total FDC Discounted at 10%	**1,297**

(1) FDC under U.S. Standards are not inflated.

Appendix C – Report on Reserves Data and Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor

To the board of directors of Enerplus Corporation (the "Corporation"):

- We have audited, evaluated and reviewed, as applicable, the Corporation's reserves data and contingent resources data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2022, estimated using forecast prices and costs.

- The reserves data and contingent resources data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data and contingent resources data based on our audit, evaluation and review.

- We carried out our audit, evaluation and review, as applicable, 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).

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

- The following table sets forth 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 Corporation evaluated and reviewed for the year ended December 31, 2022, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation or Review Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (in US$ thousands)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	December 31, 2022	North Dakota & Colorado, USA	-	$6,048,905.3	$ -	$ 6,048,905.3
Netherland, Sewell & Associates, Inc.	December 31, 2022	Pennsylvania, USA Pennsylvania, USA	-	$ 949,061.9	$ -	$ 949,061.9
TOTALS				$ 6,997,967.3	$ -	$ 6,997,967.3

- The following table sets forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Corporation's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources that we have audited and evaluated and reported on to the Corporation's management:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Audit or Evaluation Report	Location of Resources Other than Reserves	Risked Volume (MMBOE)	Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (in US$ thousands) Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	McDaniel & Associates Consultants Ltd.	December 31, 2022	North Dakota, USA	96.1	$ -	$ 626,327.00	$ 626,327.0
Development Pending Contingent Resources (2C)	Netherland, Sewell & Associates, Inc.	December 31, 2022	Pennsylvania, USA	86.8	$ -	$ 190,371.3	$ 190,371.3

- In our opinion, the reserves data and contingent resources data, respectively, audited and 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.
- We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the respective effective dates of our reports.
- Because the reserves data and contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.
- Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by B. Hamm"
B. Hamm, P.Eng.
President & CEO

Calgary, Alberta, Canada

February 22, 2023

NETHERLAND, SEWELL & ASSOCIATES, INC.

"signed by Richard B. Talley"
Richard B. Talley, Jr., P.E.
Chief Executive Officer

Texas Registered Engineering Firm F-2699
Dallas, Texas, USA

February 22, 2023

Appendix D – Report of Management and Directors on Oil and Gas Disclosure

Terms to which a meaning is described in CSA Staff Notice 51-324 – Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Enerplus Corporation (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and contingent resources data.

Independent qualified reserves evaluators have evaluated, reviewed and audited, as applicable, the Corporation's reserves data and contingent resources data. The report of the independent qualified reserves evaluators is presented as Appendix C to this Annual Information Form.

The Reserves Committee of the board of directors of the Corporation has:

1. reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators

2. met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation and

3. reviewed the reserves data and contingent resources data with management and the independent qualified reserves evaluators

The Reserves Committee of the board of directors of the Corporation has reviewed the Corporation'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 of the Corporation has, on the recommendation of the Reserves Committee, approved:

- the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and other oil and gas information

- the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves and resources data and

- the content and filing of this report

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

ENERPLUS CORPORATION

"*Ian C. Dundas*"	"*Wade D. Hutchings*"
Ian C. Dundas President & Chief Executive Officer	Wade D. Hutchings Senior Vice-President & Chief Operating Officer
"*Hilary Foulkes*"	"*Sheldon B. Steeves*"
Hilary Foulkes Director	Sheldon B. Steeves Director

February 23, 2023

Appendix E – Audit & Risk Management Committee Disclosure Pursuant to National Instrument 52-110

A. THE AUDIT & RISK MANAGEMENT COMMITTEE'S CHARTER

The charter of the Audit & Risk Management Committee (the "**Committee**") of the board of directors of the Corporation is included in this Appendix E.

B. COMPOSITION OF THE AUDIT & RISK MANAGEMENT COMMITTEE

The current members of the Committee are Jeffrey W. Sheets (Committee Chair), Sherri A. Brillon, Judith D. Buie, Mark A. Houser and Sheldon B. Steeves. Each member of the Committee is independent and financially literate within the meaning of National Instrument 52-110 and the NYSE listing standards.

C. RELEVANT EDUCATION AND EXPERIENCE

Name (Director Since)	Principal Occupation and Biography
Jeffrey W. Sheets (B.Sc. (Chemical Engineering), MBA (Finance)) (Director since December 2017) Other Public Directorships • Schlumberger Limited (global oilfield services & equipment) • Westlake Chemical Corporation (chemicals & plastics sales & manufacturing)	Mr. Sheets served as executive vice president and chief financial officer of ConocoPhillips Company from October 2010 to February 2016. Mr. Sheets was associated with ConocoPhillips and its predecessor companies for more than 36 years and served in a variety of roles, including senior vice president of planning and strategy as well as vice president and treasurer. He began his career in 1980 as a process engineer with Phillips Petroleum Company. Mr. Sheets serves on the board of directors of Schlumberger Limited and Westlake Chemical Corporation and is a former director of DCP Midstream Partners LP. Mr. Sheets received a Bachelor's degree in Chemical Engineering from the Missouri University of Science and Technology and an MBA from the University of Houston. Mr. Sheets is a member of the Board of Trustees at the Missouri University of Science and Technology.
Sherri A. Brillon (B. Arts (Economics)) (Director since October 2022)	Ms. Brillon has over 35 years of experience in the oil and gas industry. From 1985 to 2019, Ms. Brillon held various positions of increasing responsibility at Encana Corporation (now known as Ovintiv Inc.) which included serving as Executive Vice-President and Chief Financial Officer for a decade prior to her retirement in 2019. At Encana, Ms. Brillon was responsible for directing the financial operations of the organization as well as implementing Encana's business strategy through multiple strategic transactions. Ms. Brillon currently serves on the board of directors for Delek Logistics Partners LP and is a past director of the Canadian Chamber of Commerce, Alberta Energy Regulator, Tim Hortons Inc., and PrairieSky Royalty Ltd. She attended the University of Calgary, where she graduated with a Bachelor of Arts degree in economics.

Name (Director Since)	Principal Occupation and Biography
Judith D. Buie (B.Sc. (Chemical Engineering)) (Director since January 2020)	Ms. Buie has spent over 30 years in the upstream oil and gas business leading business development initiatives and managing oil and gas assets through different commodity and life cycles. From 2012 to 2017, Ms. Buie was Co-President and Senior Vice President Engineering for RPM Energy Management LLC, a private company which worked exclusively with KKR, a leading global investment firm, to evaluate and manage oil and gas investments. Prior to RPM, Ms. Buie held a variety of leadership and technical positions with Newfield Exploration Company from 2001 to 2011, and prior thereto she served in various technical roles at BP, Vastar Resources and ARCO. Ms. Buie currently serves on the board of directors of a private oil and gas company. She also serves as an oil and gas industry advisor. Ms. Buie received a Bachelor of Science in Chemical Engineering from Texas A&M University.
Mark A. Houser (B. Sc. (Petroleum Engineering), MBA (Director since March 2022)	Mr. Houser is the founder and principal of Symphero Energy Solutions, LLC, an advisory services company in the oil and gas and renewable energy development markets. From 2015 to 2021, he served as Chief Executive Officer of University Lands, which manages the surface and mineral interests of 2.1 million acres of land in West Texas. Prior to that, he held multiple executive roles for Enervest, Ltd. from 1999 to 2015, including Executive Vice President and Chief Operating Officer. Mr. Houser served in a variety of executive and senior management roles with Occidental Petroleum & Canadian Occidental Petroleum, Ltd. from 1989 to 1999. He began his career in 1984 with Kerr-McGee Corporation in various production and reservoir engineering positions. Mr. Houser currently serves on the Investment Committee for a privately held oil and gas investment firm. He also serves on the Board of Directors of the Houston Methodist Hospital System and is a member of the Board of Stewards of Chapelwood United Methodist Church. He received a Bachelor of Science degree in Petroleum Engineering from Texas A&M University, College Station Texas and an MBA from Southern Methodist University.
Sheldon B. Steeves (B. Sc. (Geology) (Director since June 2012) Other Public Directorships • NuVista Energy Ltd. (oil & gas company) • PrairieSky Royalty Ltd. (oil & gas royalty)	Mr. Steeves has over 40 years of experience in the North American oil and gas industry and is currently a corporate director. From January 2001 until April 2012, Mr. Steeves was Chairman and Chief Executive Officer of Echoex Ltd., a junior private oil and gas company focused on greenfield organic growth in Western Canada. Mr. Steeves spent over 15 years at Renaissance Energy Ltd. where he was appointed Chief Operating Officer in 1997. He holds a Bachelor of Science in Geology from the University of Calgary.

D.PRE-APPROVAL POLICIES AND PROCEDURES

The Committee has implemented a policy restricting the services that may be provided by the Corporation's auditors and the fees paid to the Corporation's auditors. Prior to the engagement of the Corporation's auditors to perform both audit and non-audit services, the Committee pre-approves the provision of the services. In making their determination regarding non-audit services, the Committee considers the compliance with the policy and the provision of non-audit services in the context of avoiding impact on auditor independence. All audit and non-audit fees paid to KPMG in 2022 and 2021 were pre-approved by the Committee. Based on the Committee's discussions with management and the independent auditors, the Committee is of the view that the provision of the non-audit services by KPMG described above is compatible with maintaining that firm's independence from the Corporation.

E. EXTERNAL AUDITOR SERVICE FEES

The aggregate fees owed by the Corporation to KPMG, an Independent Registered Public Accounting Firm, and the independent auditor of Enerplus, for professional services rendered in Enerplus' last two fiscal years are as follows:

	2022	2021
	(in US$ thousands)	
Audit fees[(1)]	$ 835.9	$ 897.6
Audit-related fees[(2)]	-	-
Tax fees[(3)]	377.1	190.0
All other fees[(4)]	-	-
TOTAL	**$ 1,213.0**	**$ 1,087.6**

Notes:

1. Audit fees were for professional services rendered for the audit of the Corporation's annual financial statements and review of the Corporation's quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements.
2. Audit-related fees are for assurance and related services reasonably related to the performance of the audit or review of the Corporation’s financial statements and not reported under "Audit fees" above.
3. Tax fees were for tax compliance, tax advice and tax planning and review to identify recovery opportunities.
4. All other fees related to products and services other than those described as “Audit fees”, “Audit-related fees” and “Tax fees”.

AUDIT & RISK MANAGEMENT COMMITTEE CHARTER

I. AUTHORITY

The Audit & Risk Management Committee (the "Committee") of the Board of Directors (the "Board") of Enerplus Corporation (the "Corporation") shall be comprised of three or more Directors as determined from time to time by resolution of the Board. Consistent with the appointment of other Board committees, the members of the Committee shall be elected by the Board at the first meeting of the Board following each annual meeting of Shareholders of the Corporation or at such other time as may be determined by the Board. The Chair of the Committee shall be designated by the Board, provided that if the Board does not so designate a Chair, the members of the Committee, by majority vote, may designate a Chair.

Members of the Committee do not receive any compensation from the Corporation other than compensation as directors and committee members. Prohibited compensation includes fees paid, directly or indirectly, for services as consultant or as legal or financial advisor, regardless of the amount, but excludes any compensation approved by the Board and that is paid to the directors as members of the Board and its committees.

II. PURPOSE OF THE COMMITTEE

The Committee's mandate is to assist the Board in fulfilling its oversight responsibilities with respect to:

1. financial reporting and continuous disclosure of the Corporation
2. the Corporation's internal controls and policies, the certification process and compliance with regulatory requirements over financial matters
3. evaluating and monitoring the performance and independence of the Corporation's external auditors
4. monitoring the manner in which the business risks of the Corporation are being identified and managed

The Committee shall report to the Board on a regular basis with regard to such matters. The Committee has direct responsibility to recommend the appointment of the external auditors and approve their remuneration. The Committee may take such actions as it deems necessary to satisfy itself that the Corporation's auditors are independent of management. It is the objective of the Committee to maintain free and open communication among the Board, the external auditors, and the financial senior management of the Corporation.

III. COMPOSITION AND COMPETENCY OF THE COMMITTEE

Each member of the Committee shall be unrelated to the Corporation and, as such, shall be free from any relationship that may interfere with the exercise of that person's independent judgement as a member of the Committee. All members of the Committee shall be financially literate and at least one member of the Committee shall have accounting or related financial management expertise - "literate" or "literacy" and "expertise" as defined by applicable securities legislation. Members are encouraged to enhance their understanding of current issues through means of their preference.

IV. MEETINGS OF THE COMMITTEE

The Committee shall meet with such frequency and at such intervals as it shall determine is necessary to carry out its duties and responsibilities. The presence in person, virtually, or by telephone of a majority of the Committee's members shall constitute a quorum for any meeting of the Committee. All actions of the Committee will require the vote of a majority of its members present at a meeting of the Committee at which a quorum is present. As part of its purpose to foster open communications, the Committee shall meet at least quarterly with management and the Corporation's external auditors in separate executive sessions to discuss any matters that the Committee or each of these groups or persons believes should be discussed privately. The Chair works with the Chief Financial Officer to establish the agendas for Committee meetings, ensuring that each party's expectations are understood and addressed. The Committee, in its discretion, may ask members of management or others to attend its meetings (or portions thereof) and to provide pertinent information as necessary. The Committee shall maintain minutes of its meetings and records relating to those meetings and the Committee's activities and provide copies of such minutes to the Board.

V. DUTIES AND ACTIVITIES OF THE COMMITTEE

Evaluating and monitoring the performance and independence of external auditors

1. Make recommendations to the Board on the appointment of external auditors of the Corporation

2. Review and approve the Corporation's external auditors' annual engagement letter, including the proposed fees contained therein

3. Review the performance of the external auditors and make recommendations to the Board regarding their replacement when circumstances warrant. The review shall take into consideration the evaluation made by management of the external auditors' performance and shall include:

   a) review annually the external auditors' quality control, any material issues raised by the most recent quality control review, or peer review, of the firm, or any inquiry or investigation by governmental or professional authorities of the firm within the preceding five years, and any steps taken to deal with such issues

   b) obtain assurances from the external auditors that the audit was conducted in accordance with Canadian and US generally accepted auditing standards

   c) ensure that management interacts professionally with the auditors and confirm such behavior annually with both parties

4. Oversee the independence of the external auditors by, among other things:

   a) requiring the external auditors to deliver to the Committee on a periodic basis a formal written statement detailing all relationships between the external auditors and the Corporation

   b) reviewing and approving the Corporation's hiring policies regarding partners, employees and former partners and employees of current and former external auditors

   c) actively engaging in a dialogue with the external auditors with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditors and recommending that the Board take appropriate action to satisfy itself of the auditors' independence

   d) pre-approving the nature of non-audit related services and the fees thereon

   e) conducting private sessions with the external auditors and encouraging direct communications between the Chair of the Committee and the audit partner

   f) instructing the Corporation's external auditors that they are ultimately accountable to the Committee and the Board and that the Committee and the Board are responsible for the selection (subject to Shareholder approval), evaluation and termination of the Corporation's external auditors

   g) have a private meeting with the external auditors at every quarterly Committee meeting

   h) obtain annually the auditors' views on competency and integrity of the Committee and senior financial executives

Oversight of annual and quarterly financial statements, management discussion and analysis and press releases

5. Review and approve the annual audit plan of the external auditors, including the scope of audit activities, and monitor such plan's progress and results quarterly and at year end

6. Confirm, through private discussions with the external auditors and management, that no restrictions are being placed on the scope of the external auditors' work

7. Review the appropriateness of management's representation letter transmitted to the external auditors

8. Receipt of certifications from the CEO and CFO

9. Review with management the adequacy of annual and quarterly financial statements and disclosure in the management discussion and analysis and press release and recommend approval to the Board of:

   a) satisfactory answers from management following the review of the annual and quarterly financial statements and management discussion and analysis and press release

   b) the qualitative judgments of the external auditors about the appropriateness, not just the acceptability, of accounting principles and financial disclosure practices used or proposed to be adopted by the Corporation and, particularly, their views about alternate accounting treatments and their effects on the financial results

   c) the methods used to account for significant unusual transactions

d) the effect of significant accounting policies in controversial or emerging areas for which there is a lack of authoritative guidance or consensus

e) management's process for formulating sensitive accounting estimates and the reasonableness of these estimates

f) significant recorded and unrecorded audit adjustments

g) any material accounting issues among management and the external auditors

h) other matters required to be communicated to the Committee by the external auditors under generally accepted auditing standards and

i) management's acknowledgement of its responsibility towards the financial statements

j) significant legal, compliance or regulatory matters that may have a material effect on the financial statements or the business of the organization (including material notices to, or inquiries received from, governmental agencies) and

k) receive the report from the Reserves Committee over the appropriateness of reported reserves and resources

Oversight of financial reporting process, internal controls, the continuous disclosure and certification process and compliance with regulatory requirements

10. Establishment of the Corporation's Whistleblower Policy for the submission, receipt, retention and treatment of complaints and concerns regarding accounting and auditing matters, and review any developments and responses on reports received thereunder

11. Review the adequacy and effectiveness of the financial reporting system and internal control policies and procedures with the external auditors and management. Ensure that the Corporation complies with all new regulations in this regard

12. Review with management the Corporation's internal controls, and evaluate whether the Corporation is operating in accordance with prescribed policies and procedures

13. Review with management and the external auditors any reportable condition and material weaknesses affecting internal controls

14. Review the management disclosure and oversight Committee's CEO and CFO certification processes to ensure compliance with US and Canadian requirements

15. Receive periodic reports from the external auditors and management to assess the impact of significant accounting or financial reporting developments proposed by the CICA, the AICPA, the Financial Accounting Standards Board, the SEC, the relevant Canadian securities commissions, stock exchanges or other regulatory body, or any other significant accounting or financial reporting related matters that may have a bearing on the Corporation and

16. Review annually the report of the external auditors on the Corporation's internal controls over financial reporting describing any material issues raised by the most recent reviews of internal controls and management information systems or by any inquiry or investigation by governmental or professional authorities and any recommendations made and steps taken to deal with any such issues

Review of Business Risks

17. Oversight over management's process for conducting the Corporation's key risk assessment and approve the policies to monitor, mitigate and report such business risks.

18. Assess the effectiveness of management's protocols and strategies regarding cyber and business critical information security.

Other Matters

19. Review of appointment or dismissal of senior financial executives

20. Conduct or authorize investigations into any matters within the Committee's scope of responsibilities, including retaining outside counsel or other consultants or experts for this purpose

21. Review the disclosure made in the Annual Information Form, 40-F and the Information Circular regarding the Committee

22. Establish and maintain a free and open means of communication between the Board, the Committee, the external auditors, and management

23. Perform such additional activities, and consider such other matters, within the scope of its responsibilities, as the Committee or the Board deems necessary or appropriate and

24. Once a year, review the adequacy of its Charter and bring to the attention of the Board required changes, if any, for approval. The Committee is also reviewed annually by the Corporate Governance and Nominating Committee, which reports its findings to the Board

25. Hold an in-camera session of the independent members of the Committee at each meeting of the Committee

While the Committee has the duties and responsibilities set forth in this Charter, the Committee is not responsible for planning or conducting the audit or for determining whether the Corporation's financial statements are complete and accurate and are in accordance with generally accepted accounting principles. Similarly, it is not the responsibility of the Committee to resolve disagreements, if any, between management and the external auditors. While it is acknowledged that the Committee is not legally obliged to ensure that the Corporation complies with all laws and regulations, the spirit and intent of this Charter is that the Committee shall take reasonable steps to encourage the Corporation to act in full compliance therewith.

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