NG ENERGY INTERNATIONAL CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2022

The following is management's discussion and analysis ("MD&A") of the operating and financial results of NG Energy International Corp. ("NG Energy" or the "Company"), for the year ended December 31, 2022, as well as information and expectations concerning NG Energy's outlook based on currently available information.

This MD&A should be read in conjunction with NG Energy's audited annual consolidated financial statements for the year ended December 31, 2022 (the "Financial Statements") prepared in accordance with International Financial Reporting Standards ("IFRS," as defined below), together with the accompanying notes.

This MD&A contains forward-looking information about our current expectations, estimates, projections, and assumptions. See the reader advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Additional information on the Company, its Financial Statements, this MD&A and other factors that could affect NG Energy's operations and financial results are included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated June 30, 2023 ("AIF") and may be accessed through the SEDAR website (www.sedar.com).

All dollar values are expressed in US dollars, unless otherwise indicated, and are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standard Board ("IASB").

This MD&A is prepared as of June 30, 2023.

Non-IFRS Measures

Certain financial measures in this document may not have a standardized meaning as prescribed by IFRS, and therefore are considered non-IFRS measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in the Operating Results, Financial Results and Liquidity and Capital Resources sections of this MD&A.

In addition to the above, management uses the operating netback measure. Operating netback is a benchmark common in the oil and gas industry and is calculated as revenue, net of transportation expense, less royalties, less operating expenses, calculated on a per unit basis of sales volumes. Operating netback is an important measure in evaluating operational performance as it demonstrates profitability relative to current commodity prices. Operating netback as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of Proved, Probable and Possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgement combined with geological and engineering knowledge to assess whether specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates for natural gas liquids ("NGLs") and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of the disclosed natural gas reserves does not represent the fair market value of these reserves.

Caution Regarding Use of Barrels of Oil Equivalent (BOEs)

BOEs/boes may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Definitions

Certain terms and abbreviations used in this MD&A, but not defined or described, are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") or the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and, unless the context otherwise requires, shall have the meanings herein as in NI 51-101 or the COGE Handbook.

Resources

"**Contingent resources**" are those quantities of oil or natural gas 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 are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe.

Contingent resources may be further categorized according to their specific project maturity sub-class, which represents the maturity of the project and sets out the associated actions required to move the project towards commercial production:

- **Development Not Viable:** This is the lowest level for contingent resources and represents a discovered accumulation for which there are contingencies resulting in there being no current plans to develop or acquire additional data at the time due to limited commercial potential.
- **Development Not Clarified**: This is the second lowest level for contingent resources and is a discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. A plan for future evaluation should exist but further study or appraisal work will be ongoing to establish the actions necessary to move the project forward to commercial maturity.
- **Development On Hold**: This is the second highest level for contingent resources and represents a discovered accumulation where project activities are on hold and where justification as a commercial development may be subject to significant delay.
- **Development Pending**: This is the highest level for contingent resources and represents a discovered accumulation where development activities are ongoing to justify commercial development in the foreseeable future.

"**Prospective resources**" are those quantities of oil or natural gas estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by applying future development projects. Prospective resources have both an associated Chance of Discovery (the chance that an exploration project will result in the discovery of oil or natural gas) and a Chance of Development (the chance that an accumulation will be commercially developed).

Prospective and contingent resources are further categorized according to the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity:

- **Low Estimate**: This is a conservative estimate of the quantity that will be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities recovered will equal or exceed the low estimate.
- **Best Estimate**: This is the best estimate of the quantity that will be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities recovered will equal or exceed the best estimate.
- **High Estimate**: This is an optimistic estimate of the quantity that will be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities recovered will equal or exceed the high estimate.

Prospective resources are not, and should not be confused with, reserves or contingent resources. Prospective resources are those quantities of oil or natural gas estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources or that the Company will produce any portion of the volumes currently classified as prospective resources. Thus, for an undiscovered accumulation the Chance of Commerciality is the product of two risk components – the Chance of Discovery and the Chance of Development.

The estimates of prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exist in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. Actual prospective resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein. The accuracy of any resources estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While resources presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

The resource estimates presented in this MD&A are subject to certain risks and uncertainties, including those associated with the drilling and completion of future wells, limited available geological and geophysical data and uncertainties regarding the actual production characteristics of the reservoirs, all of which have been assumed for the preparation of the resource estimates.

Reserves

Reserves are estimated remaining quantities of commercially recoverable oil, natural gas, and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status.

"**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.

"**Possible reserves**" are those additional reserves that are less certain to be recovered than Probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible reserves. There is a 10 percent probability that the quantities recovered will equal or exceed the sum of Proved plus Probable plus Possible 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 recovered will equal or exceed the estimated Proved reserves; and
- at least a 50% probability that the quantities recovered will equal or exceed the sum of estimated Proved plus Probable reserves.

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

Each of the reserve categories (Proved and Probable) may be divided into developed and undeveloped categories as follows:

"**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 expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves' classification (Proved, Probable and Possible) to which they are assigned and expected to be developed within a limited time.

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

Interests in Reserves, Production, Wells and Properties

"**Gross**" means:

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

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

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

"**Net**" means:

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

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

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

Description of Exploration and Development Wells and Costs

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

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

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

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

(d) provide improved recovery systems.

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

"**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property.

Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

Condensate

"**Condensate**", also called condensate, gas condensate, or gas liquids, is a low-density mixture of hydrocarbon liquids that are present as gaseous components in the raw gas produced from many gas fields. Some gas species within the raw gas will condensate to a liquid state if the temperature is reduced to below the hydrocarbon dew point temperature at a set pressure. Raw gas may come from any one of three types of gas wells:

(a) **Crude Oil Wells:** Raw gas that comes from crude oil wells is called "associated gas". This gas can exist separate from crude oil in the underground formation or be dissolved in the crude oil. Condensate produced from oil wells is often referred to as "lease condensate";
(b) **Dry Gas Wells:** These wells typically produce only raw gas that contains no hydrocarbon liquids. Such gas is called "non-associated gas". Condensate from dry gas is extracted at gas processing plants and is often called "plant condensate"; and
(c) **Condensate Wells:** These wells produce raw gas along with NGLs. Such gas is also called "associated gas" and is often referred to as "wet gas".

OPERATING INCOME AND NETBACK

"Operating Income" is calculated by deducting operating expense from total revenue. Total revenue is comprised of natural gas sales, net of royalties. The Company refers to Operating Income expressed per unit of production as an "Operating Netback". "Operating Income Profit Margin" is calculated by the Company as Operating Income as a percentage of natural gas sales. A reconciliation of the measures for the year ended December 31, 2022, is as follows:

	2022	**2021**
Natural Gas Sales	1,766,325	-
Royalties	(315,289)	-
Operating Expenses	(511,248)	-
Operating Income	939,788	-
Sales volume (Mcf)	321,815	-
Per Mcf		
Natural Gas Sales	5.49	-
Royalties	(0.98)	-
Operating Expenses	(1.59)	-
Operating Netback per Mcf	2.92	-
Operating Income Profit Margin	53.2%	

CORPORATE OVERVIEW AND UPDATE

NG Energy is an oil and gas company incorporated in Canada and is engaged in the acquisition, exploration, development, and exploitation of oil and natural gas assets in Colombia. The Company's current asset portfolio consists of one appraisal and two exploration natural gas assets in Colombia. NG Energy's common shares (each a "Common Share") are listed on the TSX Venture Exchange ("TSXV") under the symbol "GASX".

Advance payments on future financings

Between March and June 2023, the Company entered into simple agreements for future equity ("SAFE"), for total proceeds of C$11,000,000, of which C$1,000,000 was with a third-party fund to which a certain director and officer of the Company provides investment recommendations. In accordance with the terms of the SAFE agreements, the full value of the C$11,000,000 will be converted into securities of the Company in accordance with the terms and upon the closing of a future finance offering of the Company, with said offering to be finalized by August 31, 2023. In the event that an offering is not finalized, proceeds received will be constituted as a promissory note for future repayment, bearing annual interest of 10%.

Appointment of new Chief Financial Officer

In December 2022, the Company announced that it had appointed Mr. Jorge Fonseca as its Chief Financial Officer ("CFO"), effective December 1, 2022. In conjunction with this appointment, Mrs. Marianella Bernal transitioned from her role as CFO to become the Senior Vice President of Finance and Country Manager of Colombia.

Drilling of the Brujo-1 Well

In October 2022, the Company announced the successful drilling of the Brujo-1X well, at a final total depth of 8,019 feet (7,200 feet true vertical depth) in the Lower Magdalena Basin, located within the SN-9 Block, encountering 680 feet of net gas bearing zone in the Cienaga de Oro ("CDO") formation and 103 feet in the Porquero formation, for a total of 783 feet of net gas pay. Subsequently, in November 2022, the Company announced the completion of testing of the well with 3 successful Drill Stem Tests ("DSTs") in the intermediate and upper section of the CDO formation. A total of 276.5 feet (out of a total of 389 feet of thickness in this formation) were perforated with resulting gas production rate of: 11.2 MMcf/d from DST-2; 18.2 MMcf/d from DST-3; and 21.2 MMcf/d from DST-4. Based on the successful tests in the CDO formation, the Company has decided to analyze the best way to complete the well and test the remaining prospective zones, including 103 feet of thickness in the Porquero formation, to achieve the maximum possible production from the three zones.

Commencement of Gas Production from Aruchara-1 Well

In August 2022, the Company announced the initiation of gas production from the area of the Maria Conchita Block where the Aruchara-1 and the Istanbul-1 wells are connected ("Istanbul Platform"). With the completion of the connection point to the Colombian National Gas Transportation System ("SNTE") through the gas trunk line of Transportadora de Gas Internacional ("TGI"), delivery of early-stage gas production commenced in late September while the surface plant continues the stabilization process of current gas flow that is injected into the SNTE from the Aruchara-1 well. Refer to the Discussion of Operating results below for more details.

Magico-1 Well Gas Discovery

In July 2022, the Company announced the discovery of significant gas within the Ciénaga de Oro sandstone formation from the newly drilled Magico-1 well located in the SN-9 Block. Upon reaching target depth, the Company conducted two successful DSTs and a comingled test within three prospective zones in the Magico-1 well, realizing over 15 MMcf/d of dry gas with no water from the sandstone formation between 3,572 feet and 3,754 feet measured depth ("MD") with a combined net pay of 76 feet. Other identified prospective zones will be tested in the future.

Non-brokered Private Placement

In November 2022, the Company closed a non-brokered private placement ("November 2022 Offering") of 35,000 convertible debenture units of the Company at a price of C$1,000 per convertible debenture unit for total gross proceeds of C$35,000,000. Each convertible debenture unit consisted of one 10.0% senior secured convertible debenture of the Company in the principal amount of C$1,000 and 1,000 Common Share purchase warrants of the Company. Each warrant entitles the holder thereof to purchase one Common Share at an exercise price of C$1.08 until November 30, 2025.

The principal amount of each convertible debenture will be convertible, for no additional consideration, at the option of the holder, in whole or in part, at any time and from time to time, into Common Shares at a price equal to C$0.90 per Common Share.

Prospectus Offering of Convertible Debentures

In May 2022, the Company closed a best-efforts, fully marketed prospectus offering ("May 2022 Offering") of 17,147 convertible debenture units of the Company at a price of C$1,000 per convertible debenture unit for total gross proceeds of C$17,147,000. Each convertible debenture unit consisted of one 8.0% unsecured convertible debenture of the Company in the principal amount of C$1,000 and 400 Common Share purchase warrants of the Company. Each warrant entitles the holder thereof to purchase one Common Share at an exercise price equal to C$1.40 until May 20, 2027.

The convertible debentures bear interest at a rate of 8.0% per annum from the date of issue, payable monthly in arrears on the last day of each month. The convertible debentures will mature on May 20, 2027. An amount equal to the interest payable under the convertible debentures from May 20, 2022 until May 20, 2023 was placed in escrow upon closing of the May 2022 Offering and shall be paid out to holders of the convertible debentures monthly. Interest thereafter shall be paid out of the Company's cash flow.

The principal amount of each convertible debenture is convertible, for no additional consideration, at the option of the holder in whole or in part at any time into Common Shares prior to the earlier of: (i) the close of business on May 20, 2027, and (ii) the business day immediately preceding the date specified by the Company for redemption of the convertible debentures upon a change of control, at a conversion price equal to C$1.20 per Common Share, subject to adjustment in certain events.

In connection with the offering, the underwriters received cash commissions of C$662,585 on gross proceeds raised.

The Company is entitled, at its sole option at any time after the second anniversary of the closing date of the offering to accelerate the expiry date of all of the outstanding warrants on not less than 30 days nor more than 60 days' notice, if the volume weighted average trading price of the Common Shares on the TSXV is greater than C$2.00 for the ten consecutive trading days preceding the notice. The convertible debentures and warrants were listed on the TSXV under the symbols “GASX.DB” and “GASX.WT.A,” respectively, and began trading on June 2, 2022.

SN-9 Loan Conversion to Royalty

In August 2022, debt holders of the SN-9 loan (see below) exercised the conversion option to convert the loan principal and cumulative interest payable to the additional 3.0% overriding royalty on NG Energy’s working interest in the gross production of the SN-9 Block. Due to the conversion, the Company no longer has an outstanding balance owed to the SN-9 debt holders.

Strategic Alliance with COX Energy America S.A.B. de C.V.

In December 2022, the Company announced that it had entered a strategic alliance with COX Energy America S.A.B. de C.V. (“COX Energy”), a regional Latin America developer, operator, and producer of renewable energy with more than 2,400-megawatt peak of solar energy products in its portfolio. With this strategic alliance, the Company and COX Energy will explore opportunities to develop, build and own solar power plants in Colombia. The Company, in collaboration with COX Energy, will launch a new renewable energy division to decarbonize and minimize the environmental impact of its operations and contribute to Colombia’s emission reduction commitment.

Non-brokered Private Placement

In October 2021, the Company closed a non-brokered placement of 8,000,000 units, at a price of C$1.00 per unit, for gross proceeds of $6,474,063 (C$8,000,000). Each unit consisted of one Common Share and one Common Share purchase warrant entitling the holder to purchase one additional Common Share at a price of C$1.20 for a period of 24 months from the date of issuance, expiring on October 22, 2023, and are subject to potential accelerated expiry in the event the closing price of the Common Shares on the TSXV is equal to or exceeds C$2.00 for twenty consecutive trading days.

In connection with the completion of the placement, the Company has paid a C$6,000 cash commission and issued an aggregate 141,600 units, on the same terms as those issued in the financing, to eligible parties who introduced subscribers.

Bought Deal Financing

In February 2021, the Company closed a bought deal private placement, pursuant to which a syndicate of underwriters purchased 7,400,000 units and exercised its option to purchase an additional 1,110,000 units, for an aggregate of 8,510,000 units at a price of C$1.15 per unit for aggregate gross proceeds to the Company of $7,712,586 (C$9,786,500). Each unit consisted of one Common Share and one-half of one

Common Share purchase warrant, with each whole warrant entitling the holder to purchase one Common Share at a price of C$1.75 until February 10, 2024.

In connection with the offering, the underwriters received a cash commission equal to 6% of the gross proceeds raised and 510,600 non-transferable broker warrants equal to 6% of the aggregate number of units sold. Each broker warrant is exercisable into one Common Share at a price of C$1.15 per Common Share until February 10, 2024.

Repayment of Maria Conchita Loan by way of Non-Brokered Private Placement

In parallel with the aforementioned bought deal financing, the Company completed a non-brokered private placement offering of 429,300 units, on the same terms as those issued pursuant to the bought deal financing, for a deemed value of $388,452 (C$493,695). No fees or commissions were paid to the underwriters in connection with the private placement. The issuance of these units was completed as repayment of the outstanding balance of the Maria Conchita Loan of $350,000 plus accrued interest. Of the units issued, 253,000 units were indirectly acquired by two of the Company's directors.

Settlement of Services for Shares

In February 2021, pursuant to a memorandum of understanding with Panacol Oil and Gas Corp. ("Panacol"), the Company issued an aggregate of 4,000,000 Common Shares at a deemed price of C$1.49 per Common Share. 2,800,000 Common Shares were issued in satisfaction of project management services provided by Panacol and 1,200,000 Common Shares to Landsons Investment Corp. ("Landsons") for services provided towards obtaining the environmental and social licenses for the SN-9 project.

COLOMBIAN OIL AND NATURAL GAS PROPERTIES

The Company is engaged in the acquisition, exploration, development and exploitation of oil and natural gas assets in Colombia. The Company's current asset portfolio consists of one appraisal and two exploration natural gas assets in Colombia. NG Energy has working interests in the Maria Conchita Block, the SN-9 Block and the Tiburon Block.

The Company has a Colombian-based management team with significant in-country experience, strong technical experience within the Colombian basin, and strong capital markets expertise having led large public resource companies in the past.

Maria Conchita Block

The Maria Conchita Block is in the Department of La Guajira, Colombia, and neighbors the Chuchupa Block to its north, which is one of Colombia's largest gas fields with an initial 103 GBtu in place and currently accounts for approximately 10% of Colombia's daily natural gas output. The Chuchupa Block has been under production for over 35 years, operated by Chevron Corp. in association with Ecopetrol, S.A. Production from the Chuchupa Block has been decreasing over the last several years, creating a need for new natural gas discoveries to replace it. The Maria Conchita Block is near both of Colombia's gas trunk lines, TGI and Promigas.

The Exploration & Production ("E&P") contract for the Maria Conchita Block (the "Maria Conchita E&P Contract") is a 2009 contract between the Agencia Nacional de Hidrocarburos ("ANH") of Colombia and MKMS Enerji Sucursal Colombia ("MKMS"), a Colombian branch of MKMS Enerji AS (BVI), a wholly owned subsidiary of NG Energy, for the exploration and production of conventional hydrocarbons in the Maria Conchita area. The Company maintains an 80% working interest in the Maria Conchita Block with 20% being held by private joint operation partners. MKMS is the operator of the Maria Conchita Block. The Maria Conchita E&P Contract had an initial exploration term consisting of 6 one-year exploration phases, which are followed by a 24-year production period from the date when commerciality is declared. Phase 1 was completed with the acquisition, processing, and interpretation of 120 km^2 of 3D seismic. The Phase 2 commitment was fulfilled with the drilling of the Istanbul-1 well (see below). In late 2018, NG Energy notified the ANH of its intention not to proceed to Phase 3 of the exploration program and to relinquish the areas of the Maria Conchita Block not covered by the ongoing evaluation program. The Maria Conchita Block originally covered an area of approximately 60,076 acres. Subsequent to the relinquishment, the Company maintains 32,518 acres under the evaluation program.

Over the course of the fiscal year ended December 31, 2022, the Company put in place all the necessary infrastructure required to monetize the Maria Conchita Block. In March 2022, the Company received an amended environmental license from the National Authority of Environmental Licenses ("ANLA"), which expires at the time the Company enters the commercialization phase at the Aruchara-1 well. This amended license was crucial for the Company, as it permitted production from the Aruchara-1 well and allowed the Company to lay the remaining 40 meters of flow line, which connected the Istanbul Platform to GTX International Corp.'s ("GTX") gas plant located within the Maria Conchita Block. Additionally, it allowed the Company to complete the connection point to the SNTE, which was completed in August 2022, through TGI, and was necessary to transport gas from the Maria Conchita Block to market. Furthermore, in August 2022, the Company entered into a Build-Own-Operate-Maintain-Transfer agreement ("BOOMT Agreement") with GTX. Pursuant to the BOOMT Agreement, GTX operates the Pipeline Facilities, which have a capacity of 20 MMcf/d. The Guaranteed Commitment (as herein defined) under the BOOMT Agreement expires after six years and ownership of the Pipeline Facilities will transfer to the Company following the expiry of the ten-year term of the BOOMT Agreement (for more information concerning the BOOMT Agreement see Contractual Commitments – Gas Transportation Services). Lastly, in December 2022, Surenergy SAS ESP ("Surenergy") completed the delivery of the third gas compressor, thereby allowing Surenergy to provide daily gas compression services to the Company.

On September 24, 2022, the Company initiated gas delivery from the Istanbul Platform, which allowed the Company to begin monetizing its gas delivery agreements. The Company had previously entered a gas delivery contract with Energy Transitions SAS ESP ("Energy Transitions") for commercial gas production within the Maria Conchita Block (the "Gas Delivery Contract"). Pursuant to the terms of the Gas Delivery Contract, the Company is to deliver gas production volumes of 16 MMcf/d to Energy Transitions following the Initial Period, with gas sales prices commencing at $5.08 per MMBtu and indexed annually with the Producers Price Index (PPI) series WPSFD41312. In October 2022, the Gas Delivery Contract was amended and 50% of the gas production volumes (8 MMcf/d) was transferred to Plus+ SAS ESP ("Plus+ SAS"). In May 2022, the Company received an initial advance payment ("Prepayment") from Plus+ SAS for the first fifteen (15) days of gas production from the Maria Conchita Block ("Initial Period"). The Prepayment was for the acquisition of 3.5 MMcf/d of gas at a price of $5.08 per MMbtu, which totaled $277,368 for 100% of the gas production volume from the Maria Conchita Block during the Initial Period. During the Initial Period, the quantity of gas flow from the Aruchara-1 well was initially 3.5 MMcf/d, so as to not stress the future performance of the well and to allow the Company to maximize its long-term operations. By the end of 2022, the quantity of gas flow had increased to 5.2 MMcf/d. Currently, the interruptible supply period continues, and the quantity of gas flow has increased to 7.2 MMcf/d. The Company expects the quantity of natural gas flow to continue to increase to 8 MMcf/d.

Additionally, now that gas delivery from the Maria Conchita Block has commenced, the Company has sought new partners to increase revenue generation. In October 2022, the Company entered a binding letter of intent ("Binding LOI") with Plus+ SAS for the purchase and sale of natural gas produced from the Aruchara-1 well and subsequent future wells located within the Maria Conchita Block. The Binding LOI is for the acquisition of up to 8,000 MMbtu per day on a firm volume purchase agreement, or the equivalent volume corresponding to the Company's 80% working interest in the Maria Conchita Block's production. The Binding LOI has a term of three years, with gas delivery expected between November 2023 and February 2026, with a set price of $6.50 per MMbtu (or Mcf/d). A gas delivery contract will be entered into once the Company is able to fulfill the obligations of a full contract.

On February 27, 2023, the Company, through MKMS, entered into a gas supply contract ("Natural Gas Contract") with Plus+ SAS, whereby MKMS has agreed to deliver gas up to 3,600 MMbtu per day from the Aruchara-1 well to Plus+ SAS, and Plus+ SAS has agreed to receive, pay and allocate such gas in accordance with the terms of the Natural Gas Contract. The Natural Gas Contract has a term of eighteen (18) months, during which time the gas price is set at $5.08 per MMbtu, less a fee of $0.25 per MMbtu ("Gas Price"). In the event Plus+ SAS sells the gas above $5.08; the Gas Price will increase by the value corresponding to 50% of the difference between the final price at which Plus+ SAS has sold the gas and the Gas Price.

The connection with the SNTE has turned the Company into a revenue producing entity and the Company expects to increase production to 20 MMcf/d in August 2023 with the drilling of an additional well, Aruchara-3. Colombian law provides that companies can only enter into definitive firm agreements when they have two or more wells in production. As of the date of this MD&A, the Company only has the Aruchara-1 well in production, therefore, the Company currently is only able to enter interruptible supply contracts with its clients. As of December 31, 2022, the date of the Company's Financial Statements, the Company has earned $1.8 million in income from the sale of gas produced from the Maria Conchita Block.

Reserves Analysis

In June 2023, the Company filed its Form 51-101F1 - *Statement of Reserves Data and Other Oil and Gas Information*, for the fiscal year ended December 31, 2022, which was prepared with Sproule International Limited in accordance with the COGE Handbook and has an effective date of December 31, 2022, ("2022 51-101F1"). The reserves and resources attributed to the H1A, H1A1, H1B, H2, H2B and LM2 zones have been included in the 2022 51-101F1. The Company reported Company gross Proved plus Probable plus Possible reserves of 7.9 MMboe (46.8 Bcf (58.5 Bcf project gross) of gas and 72 Mbbl of condensate) for a before-tax NPV10 of $50.1 million. This represents a 71% year-over-year increase in Proved plus Probable plus Possible reserves, which can be broken down as follows:

- Company gross Proved reserves of 3.6 MMboe (21.5 Bcf of gas and 47 Mbbl of condensate), which represents a 74% year-over-year increase in Proved reserves;
- Company gross Probable reserves of 2.9 MMboe (17.5 Bcf of gas and 15 Mbbl of condensate), which represents a 16% year-over-year increase in Probable reserves; and
- Company gross initial Possible reserves of 1.3 MMboe (7.9 Bcf and 11 Mbbl of condensate).

It is important to note that Possible reserves are those additional reserves that are less certain to be recovered than Probable reserves. There is a 10% probability that the quantities recovered will equal or exceed the sum of Proved plus Probable plus Possible reserves.

Resources Analysis

In the 2022 51-101F1, the Company further reported Company gross unrisked best estimate contingent resources (development pending) of 11.1 MMboe (65.8 Bcf (82.2 Bcf project gross) and 136 Mbbl of condensate) for before-tax NPV_{10} of $49.7 million. The Company's contingent resources in the Maria Conchita Block are petroleum and gas classified as "development pending" and are attributed a chance of development risk factor of 0.73. However, the Company believes the unrisked best estimate contingent resources provides the most appropriate indication of volumes that will become Proved plus Probable reserves.

It is important to note that there is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Current Objectives

The Company's primary focus on the Maria Conchita Block is the monetization of gas production and capitalizing on a premium pricing market in Colombia. To do so, the Company intends to drill an additional well in the Maria Conchita Block, the Aruchara-3 well, as management expects this additional well will allow for gas production to be stabilized between 16 - 20 MMcf/d. The Company expects to commence drilling at the Aruchara-3 well by mid-July 2023. The drilling is set to commence from the same pad and into the same geological formation as the Aruchara-1 well and carries minimal geological risk.

Exploration Activities

The current evaluation program for the Maria Conchita Block consists of geological and geophysical studies and an evaluation of re-entries on the existing wells, which has been extended into November 2023 with the option to present a development plan of the field in late 2023. In early 2021, the Company decided to complete a feasibility study on the covered Istanbul-1 well prospective area, evaluating the following aspects: condition of environmental licensing; social aspects of the area of direct influence of the project; mechanical integrity; integral costs of intervention; and new wells to be drilled to sustain a production capacity close to 20 MMcf/d. Based on the results of this study, in May 2021, the Company re-entered the Istanbul-1 well and preliminary testing in several zones encountered gas that was tested for flow rates. The purpose of the re-entry of the Istanbul-1 well was to repair wellbore damage, evaluate the potential extension of the Aruchara-1 well producing zones, and define the production potential of new identified gas zones.

The existence of gas was tested in all the evaluated zones, with presence of water, and it was established that the 8,396 - 8,416 feet and 8,426 - 8,438 feet intervals present good gas production potential, expanding the prospects of the area. Based on the above, it was decided by management to complete the well temporarily, while identifying the best procedure to prevent water from influencing gas production. With this objective, existing dewatering technologies were analyzed, and the best mechanism defined. The Company has received authorization from the ANH for well testing and minimum gas vent and is planning to move forward with these objectives in 2023.

SN-9 Block

The SN-9 Block is in the Lower Magdalena Valley, 75 km from Colombia's Caribbean coast. The SN-9 Block, which covers an area of approximately 311,353 acres in the Department of Córdoba, Colombia, has a 6-year exploration period, divided in two phases of three years each, followed with a 24-year production period from the date when commerciality is declared. The SN-9 Block is adjacent to blocks held by Canacol Energy Ltd and Hocol S.A. The area has excellent infrastructure with good roads and access to the northern gas trunk line. In previous years, the Hechizo well was drilled on the block by Ecopetrol, S.A. in 1992 and tested gas in the CDO formation at a depth of approximately 4,250 feet. The SN-9 Block has 730 km of 2D seismic.

The E&P contract for the SN-9 Block (the "SN-9 E&P Contract"), dated October 2014, was entered into between the ANH and Clean Energy Resources S.A.S., a Colombian corporation ("Clean"). The SN-9 E&P Contract is currently in the first phase of the exploration program which includes a minimum work obligation of drilling two exploration wells. The current deadline of January 2023 was approved by the ANH after an extension request was made by NG Energy. Subsequently, Clean has requested a further extension of Phase 1, which is still under consideration by the ANH. The Company's working interest is 72%, subject to payment of ANH sliding scale royalties.

In September 2021, the Company received the necessary environmental license from the ANLA required to commence exploratory drilling in the SN-9 Block, including the construction of civil works, production infrastructure and the construction of up to eleven locations for a total of twenty-two wells to be developed. The ANLA license shall expire at the time that the Company enters the commercialization phase at the Mágico-1 or Brujo-1 well.

During the fiscal year ended December 31, 2022, the Company and its contractors completed the drilling of two wells in the SN-9 Block, the Magico-1X well, which was completed in July 2022, and the Brujo-1X well, which was completed in November 2022. Significant gas was encountered in both the Magico-1X well and the Brujo-1X well and further testing was undertaken throughout the course of the year. The results of such testing are outlined and discussed below under “Exploration Activities”.

To move towards commercial production in the SN-9 Block, the Company along with Clean and Desarolladora Oleum are currently in advanced negotiations with Kronos to construct 32 km of pipeline, which will connect the SN-9 Block to Promigas’ national Jobo-Majagua pipeline. Production is expected to be completed within the next 12 months pending execution of the construction agreement, with key permits and licenses already in place. The pipeline is expected to have a capacity of 30 MMcf/d. Furthermore, the Company, along with Clean and Desarolladora Oleum, signed a memorandum of understanding with another transportation company, whereby a full capacity pipeline will be constructed as well as the required processing plant and pumping facilities. The total estimated cost to develop such infrastructure is currently unknown, as the above-mentioned agreements are yet to be finalized. However, it is the Company’s expectation that such proposals will be in line with current market standards and any fees will be paid based on a defined tariff. The Company fully expects to be able to market the gas produced in the SN-9 Block within the next fourteen (14) months.

Resources Analysis

In June 2023, the Company filed the 2022 51-101F1. Resources attributed to the Hechizo, Brujo, Magico, Mago, Hechicero, Encanto, Milagroso, Porquero, Embrujo, Ensalmo and Sortilegio zones have been included in the 2022 51-101F1. The Company reported Company gross unrisked best estimate contingent resources (development pending) of 249.5 Bcf for a before-tax NPV10 of $294.4 million. The Company's contingent resources in the SN-9 Block are petroleum and gas classified as "development pending" and are attributed to a chance of development risk of 80%. However, the Company believes the unrisked best estimate contingent resources provides the most appropriate indication of volumes that will become Proved plus Probable reserves.

It is important to note that there is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Current Objectives

The development of the SN-9 Block is a major focus for the Company in 2023. The Company's objectives for the SN-9 for the fiscal year ended December 31, 2023, are as follows:

- secure a large-scale pipeline partner for the construction of infrastructure within the SN-9 Block;
- secure a long-term production agreement for gas and oil produced within the SN-9 Block;
- evaluate options and commence early production from successfully completed wells within the SN-9 Block; and
- evaluate oil prospects located in the western region of the SN-9 Block.

Exploration Activities

In May 2022, the Company completed the construction of the pad at the Magico-1X well and commenced drilling. The well was drilled to a true vertical depth of 3,918 feet in three phases using a 1,500-horsepower hydraulic rig. The Company identified three intervals to be tested, with the CDO sandstone reservoir being the primary objective. The Company encountered gas within the well in the lower first structure, which measured 50 feet in the CDO sandstone reservoir. The Company further identified several prospective gas bearing zones through well logs at a depth of between 3,200 – 3,350 feet for a total gross pay of 150 feet and net pay of 100 feet. As a result, in July 2022, the Company conducted two successful DST procedures and one comingled test within the three prospective zones. The first DST procedure occurred at a measured depth of between 3,694 – 3,724 feet and produced 4.0983 MMcf of gas with no water. The specific gravity of the gas from this test was 0.5579. The second DST procedure occurred at a measured depth of between 3,572 – 3,582 feet and 3,632 – 3,640 feet and produced 5.0997 MMcf of gas and no water. The specific gravity of the gas from this test was 0.5576. The comingled test occurred at a measured depth of between 3,572 – 3,582 feet, 3,632 – 3,640 feet and 3,694 – 3,724 feet and produced 4.0347 MMcf of gas and no water. The specific gravity of the gas from this test was 0.5576. The total amount of gas produced from these three tests was 13.2326 MMcf with no water. Based on these results the Company concluded the Magico-1X well tested over 15 MMcf/d of dry gas with no water on a comingled production completion from the three prospective zones located within the CDO sandstone reservoir between 3,572 – 3,724 feet with a combined net pay of 76 feet. It is important to note that the above data should be considered preliminary until pressure transient analysis or well-test interpretation has been conducted. Therefore, the above test results are not necessarily indicative of long-term performance or of ultimate recovery.

In September 2022, the Company commenced drilling at the Brujo-1X well to a true vertical depth of 7,200 ft in three phases using a 1,500-horsepower hydraulic rig. The Company had identified several intervals of interest using geological and geophysical evidence, with the CDO sandstone reservoir as the primary target. The Company encountered 680 ft of net gas bearing zones in the CDO sandstone reservoir and 103 feet in the Porquero formation, for a total of 783 feet of net gas pay. As a result, in November 2022, the Company conducted 4 DST procedures, with 3 successful DST procedures in the intermediate and upper section of the CDO formation. The first DST procedure occurred between a measured depth of 6,127 – 6,789 feet, however this test was unsuccessful. The second DST procedure occurred between a measure depth of 5,055 – 5,365 feet and produced 3.1306 MMcf of gas and no water over a period of 11.3 hours. The specific gravity of the gas from this test was 0.56044. The third DST procedure occurred between a measure depth of 4,563.5 – 4,910 feet and produced 6.2279 MMcf of gas with no water over a period of 15.1 hours. The specific gravity of the gas from this test was 0.56044. The fourth DST procedure occurred between a measured depth of 4,086 – 4,530 feet and produced 5.442 MMcf of gas with no water over a period of 13.6 hours. The gas-bearing thickness in the CDO formation was perforated for these tests with gas production rates of 11.2 MMcf/d from the second DST procedure, 18.2 MMcf/d from the third DST procedure and 21.2 MMcf/d from the fourth DST procedure. It is important to note that the above data should be considered preliminary until pressure transient analysis or well-test interpretation has been conducted. Therefore, the above test results are not necessarily indicative of long-term performance or of ultimate recovery.

Existing Agreements

The terms of the original agreement between the Company and Clean regarding the Company's acquisition from Clean of an economic beneficial interest in the SN-9 Block are as follows:

- The Company's participation interest is 72%. Clean's participation in the SN-9 Block will be 13%, and will comprise two components:
    - First component - carried working interest of 8%
    - Second component - Clean will acquire an additional 5% by one of two options:
        - Option 1 - payment of $1.2 million to the Company if Clean chooses to only participate in the first phase of the exploration program.
        - Option 2 - payment of $2.9 million to the Company if Clean chooses to participate in both phases of the exploration program.

Payment to the Company for either option will be received through the sale of 62.5% of Clean's production on the SN-9 Block corresponding to this 5% interest. Furthermore, the Common Share of Net Profit Interest and Overriding Royalties (as defined in the SN-9 purchase and sale agreement) related to this additional 5% working interest will be the obligation of Clean and not carried by the Company.

Tiburon Block

The Tiburon Block currently covers an area of approximately 245,850 acres in the Department of La Guajira, Colombia. The E&P Contract for the Tiburon Block (the "Tiburon E&P Contract") is a contract for the exploration and production of conventional hydrocarbons, dated June 2006 and entered between the ANH and Omimex de Colombia Ltd., which later changed its name to ColPan Oil & Gas Ltda. ("ColPan").

The Tiburon E&P Contract initially provided for an exploration period divided into six phases of twelve months each. The Tiburon E&P contract is currently in Phase 3 of the exploration period with an existing minimum work obligation to acquire, process, and interpret 69.75 km^2 of 3D seismic. The Phase 3 commitment is currently suspended due to "Force Majeure and Third-Party Acts" due to local community issues within the region outside the control of the Company.

Exploration Activities

In light of the force majeure situation, the Company has carried out technical studies of the area in order to present for the consideration of the ANH a request to change the identified area within the Tiburon Block where the current minimum work obligation of 3D seismic is to be completed, and alternatively, complete the acquisition, processing and interpretation of 112 km of 2D seismic in the Bahia Honda area within the Tiburon Block, which is equivalent to the current Phase 3 commitment of the Tiburon E&P Contract of 69.75 km^2 of 3D seismic.

On September 16, 2016, the Tiburon E&P Contract was suspended due to the pre-existing community issues that are impeding any progress in the area. The Company will comply with the Phase 3 commitments of the Tiburon E&P Contract once the community conflicts existing in the area have been resolved. The timing of any conflict resolution is unknown at this time.

Meanwhile, the Company is developing environmental and social analyses to execute seismic activities.

Existing Agreements

The terms of the original agreement between the Company and ColPan outlining the Company's acquisition from ColPan of an economic beneficial interest in the Tiburon Block are based on the execution of the following work program:

- Ten percent working interest upon the completion of the Phase 3 3D seismic commitment.
- An additional 15% working interest upon the drilling and testing of one exploration well.
- A further 15% working interest upon the drilling and testing of a second exploration well.

After completing the seismic commitment, NG Energy is not obligated to drill any of the exploration wells and can exit the contract with no further commitments but will lose the original $300,000 performance guarantee currently held on deposit with the ANH. Alternatively, NG Energy may elect to stay in the license with a 10% working interest. $120,000 of management fees paid by the Company will be returned to NG Energy if the Company is still participating in the block when the ANH performance guarantee is returned at the end of the Phase 3 commitment. If NG Energy does not fulfill the Phase 3 commitment, except for reasons beyond its control, NG Energy will cede a 1.5% carried working interest in the SN-9 Block to ColPan and forfeit the aforementioned $120,000 payment.

OUTLOOK

The Company's primary focus in the short-term is the monetization of its natural gas resources and capitalizing on a premium pricing market in Colombia. The connection of the Aruchara-1 well to the SNTE has turned the Company into a revenue producing entity. The Company expects to be able to realize potential production levels of 20 MMcf/d and pump such natural gas into the Colombia gas market, given the Company's Pipeline Facilities will be programmed to produce between 16 and 20 MMcf/d. Given the current shortage of gas in Colombia and the high probability of an El Niño phenomenon coming in the next months, the Company has a reasonable expectation that any gas that it produces will be purchased. The commencement of this revenue stream will assist the Company with improving its working capital position and service debt payments for interest payable on its convertible debentures.

The Company continues to move forward with its planned exploration program in the Maria Conchita Block and SN-9 Block, as discussed above. The Company believes the SN-9 Block could be an important new source of natural gas in Colombia. Through a phased approach, NG Energy expects to increase reserves and provide a stable supply of natural gas in Colombia. The evaluation program is underway in the Maria Conchita Block to define total resources and determine the most appropriate development plan for the Uitpa and Jimol formations.

The Company continues to pursue asset prioritization strategies, additional and alternative production and exploration opportunities, and the development of its reserves. The Company may choose to delay development, depending on several circumstances including the existence of higher priority expenditures, prevailing commodity prices and the availability of funds.

DISCUSSION OF OPERATING RESULTS

	2022	2021
Natural gas sales	1,766,325	-
Natural gas production (Mcf/d)	3,209.8	-
Natural gas ($/Mcf)	5.49	-

In Q4 2022, the Maria Conchita Block commenced commercial production. Since the commencement of production, the Company averaged 3,209.8 Mcf/d which resulted in gross natural gas sales for the year of $1,766,325. The realized sales price for natural gas per Mcf was $5.98.

Royalties

	2022	2021
Total royalties	315,289	-
Total royalties (% of sales)	17.86%	-
Total royalties ($/Mcf)	1.07	-

Royalties as a percentage of total natural gas sales are highly sensitive to commodity prices. Thus, royalty rates can fluctuate from quarter-to-quarter and year-to-year. Royalties as a percentage of revenues in 2022 were 17.86%. The royalties paid in 2022 consisted of royalties paid to the Colombia government in the amount of $107,560, gross overriding royalties to partners of $96,286 and royalties paid in conjunction with the settlement of the Aruchara loan in the amount of $111,443.

Operating Expenses

	2022	2021
Total operating expenses	511,248	-
Total operating expenses ($/Mcf)	1.58	-

Operating costs for 2022 were $511,248 and include commercialization fees, lifting costs, gas compression services and other municipal taxes that are incurred to operate the well, gather and treat production volumes and to perform well and facility repairs and maintenance.

General and Administrative Expenses

General and administrative ("G&A") expenses for the year ended December 31, 2022, totaled $3,936,244 (2021 comparative period - $3,784,265). The G&A expenses relate to the normal course of the Company's operations, and are constituted as follows:

USD $	Year 2022	Year 2021	Q4 2022	Q3 2022	Q2 2022	Q1 2022
Wages & Salaries	900,285	467,690	285,439	200,946	224,960	188,940
Professional Fees	1,538,052	1,595,073	722,463	237,749	348,317	229,523
Other	1,497,907	1,721,502	205,985	367,916	293,908	630,098
Total	**3,936,244**	**3,784,265**	**1,213,887**	**806,611**	**867,185**	**1,048,561**

Professional fees are composed of legal, audit, tax, and other fees that have been incurred by the Company for operations. Wages and salaries are amounts paid to employees of the Company. Other expenses comprise the normal operations of the Company and include office rent, public relations, insurance, travel, and other general and administrative expenses.

Share-Based Payments

In August 2022, the Company granted 2,640,893 options to acquire Common Shares to certain directors, officers employees and consultants of the Company at a price of C$1.14 per Common Share. The options were for a ten-year term, expiring on August 8, 2032. All options granted vested immediately on the date of grant.

The value of the stock options vesting in the year ended December 31, 2022, equated to $1,860,743 (2021 comparative periods - $ 1,298,396).

Finance Income and Expense

The Company's finance-related income and expenses for each of the reporting periods are as follows:

USD $	Year 2022	Year 2021	Q4 2022	Q3 2022	Q2 2022	Q1 2022
Interest income	(273,892)	(82,377)	(105,235)	(84,183)	(59,759)	(24,715)
Interest expenses and bank charges	1,275,007	609,836	579,648	332,582	246,826	115,951
Commitment fees	-	47,583	-	-	-	-
Accretion on decommissioning obligation	35,242	6,456	21,884	6,498	4,011	2,849
Accretion on liability component of convertible debentures	410,838	-	213,698	141,961	55,179	-
Interest expense on lease liabilities	853,628	-	790,894	62,734	-	-
Amortization of transaction costs on loans	20,205	45,898	-	3,362	8,551	8,292
Total net finance expense	**2,321,028**	**627,396**	**1,500,889**	**462,954**	**254,808**	**102,377**

Foreign Exchange

The Company incurred a foreign exchange loss of $2,386,415 for the year ended December 31, 2022 (2021 comparative period – $801,776). Foreign exchange losses are due to the decrease in the value of the Canadian dollar and the Colombian peso when compared to the US dollar in the period. Conversely, foreign exchange gains are due to an increase in the value of these other currencies in comparison to the US dollar.

Cash used in Operating Activities

For the year ended December 31, 2022, the Company used cash in operating activities of $3,588,326 (2021 comparative period - $5,237,098). The cash used in operations is primarily comprised of G&A expenses and business development expenses incurred during the period.

CAPITAL ADDITIONS

For the year ended December 31, 2022, the Company had additions (prior to recognition of any impairments, disposals or revisions of estimates) of $31.0 million relating to exploration and evaluation assets, $33,551 relating to property, plant and equipment, $24.9 million relating to right-of-use leased assets and $14.3 million related to oil and gas assets. Additions to exploration and evaluation assets relate primarily to SN-9 drilling and testing program, as well as community relations and environmental license compliance work. During the year ended December 31, 2022, the Company asserted commercial viability related to the Maria Conchita Block and accordingly, all additions to oil and gas assets relate to development costs associated with the Maria Conchita Block.

LIQUIDITY AND CAPITAL RESOURCES AND GOING CONCERN

The Company's capital management objective is to have sufficient capital to be able to execute its business plan. The Company manages its capital structure and adjusts it in the light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The continued development of the Company's oil and natural gas assets is dependent on the ability of the Company to secure sufficient funds through operations, credit facilities and other sources. Such funds may not be available on acceptable terms or at all.

During the year ended December 31, 2022, the Company recognized a net loss of $10.0 million and cash used in operating activities of $3.6 million. As of December 31, 2022, the Company had a working capital deficit of $1.8 million, including cash and cash equivalents of $7.0 million. For 2023, the Company has contractually committed exploration and development amounts of $3.0 million and $6.6 million for lease obligations. Although in 2022, the Company commenced early-stage gas production on the Maria Conchita Block, current gas flow is only stabilizing, and production volumes are still below expectations such that the Company is anticipating that cash will continue to be used in operations. As such, the Company will need to obtain capital to fund the Company's ongoing operations, commitments, and the ultimate continued development of the Company's exploration and evaluation assets.

The Company, in May 2022 and November 2022, closed separate convertible debenture offerings for aggregate gross proceeds of $13.4 million and $25.9 million, respectively. For the year ended December 31, 2022, the Company also received proceeds of $1.2 million on the exercise of purchase warrants and stock options. These proceeds are and continue to be used to fund general working capital needs and capital work programs as well as to settle outstanding liabilities. However, as indicated above, these proceeds combined with cash flows from early-stage gas production on the Maria Conchita Block are not sufficient to fund the Company's ongoing operations and commitments, which include for 2023 committed exploration and development amounts of $3.0 million as outlined in Note 20 of the Financial Statements and $6.6 million for lease obligations as outlined in Note 12 of the Financial Statements. The Company will require additional sources of capital to fund ongoing operations and commitments. There is no assurance the Company will be able to secure funding from debt or equity financing when required.

As such, there remains a material uncertainty surrounding the Company's ability to obtain sufficient capital to meet its operational requirements and commitments. These conditions noted above indicate a material uncertainty exists that may cast significant doubt with respect to the Company's ability to continue as a going concern.

Management believes that the going concern assumption is appropriate for the Financial Statements and that the Company will be able to meet its operational requirements and commitments during the upcoming year and beyond. There is no guarantee that the Company will be successful in its endeavors and no certainty as to the timing of the Company's impending exploration commitments. Should the going concern assumption not be appropriate and the Company is not able to realize its assets and settle its liabilities, the Financial Statements would require adjustments to the amounts and classifications of assets and liabilities, and these adjustments could be significant.

The Company's Colombian oil and gas interests are in the exploration stage and the Company has yet to establish operations to achieve sustainable production from its oil and gas assets. Accordingly, the recoverability of amounts recorded as oil and natural gas properties is dependent upon successful development of its assets to put them into production and then achieve future profitable production, the ability of the Company to secure adequate sources of financing to continue to fund the development of its assets and the political stability of Colombia. The outcome of these matters cannot be predicted with certainty at this time.

SN-9 Loan

In August 2020, the Company entered into a loan in the amount of $2.5 million, secured by the assets of the Company. The loan was denominated in US dollars, was to mature in August 2022 and bore interest at the rate of 15% per annum. The proceeds of the loan were utilized for the costs of exploratory activities in the SN-9 Block. Under the terms of the loan agreement, the lenders were also granted a 3% overriding royalty on NG Energy's working interest in the gross production of the SN-9 Block. Total interest and principal was payable at the maturity date, although the lenders had an option to convert the loan principal and interest into another 3% overriding royalty on NG Energy's working interest in the gross production of the SN-9 Block at the lenders' discretion at any point prior to the maturity date.

As mentioned previously, in August 2022, debt holders of the SN-9 loan exercised the conversion option to convert the loan principal and cumulative interest payable to the additional 3.0% overriding royalty on NG Energy's working interest in the gross production of the SN-9 Block. Due to the conversion, the Company no longer has an outstanding balance owed to the SN-9 debt holders.

Convertible Debentures

As previously mentioned, in May 2022 and November 2022, the Company completed the separate offerings of convertible debenture units for aggregate proceeds of $13.4 million (C$17.1 million) and $25.9 million (C$35.0 million), respectively.

In the November 2022 Offering, each convertible debenture unit is denominated in Canadian dollars and consists of: (i) one 10.0% convertible senior secured debenture with a principal amount of $1,000 maturing on November 30, 2025; and (ii) 1,000 Common Share purchase warrants of the Company, with each warrant entitling the holder thereof to purchase one Common Share at an exercise price of C$1.08 per Common Share for a period of three years ending November 30, 2025. The principal amount of each convertible debenture will be convertible, for no additional consideration, at the option of the holder, in whole or in part, at any time and from time to time, into Common Shares at a conversion price equal to C$0.90 per Common Share.

In the May 2022 Offering, each convertible debenture unit is denominated in Canadian dollars and consisted of: (i) one 8% convertible unsecured debenture in the principal amount of $1,000 maturing on May 20, 2027; and (ii) 400 Common Share purchase warrants of the Company, with each warrant entitling the holder thereof to purchase one Common Share at an exercise price of C$1.40 per Common Share for a period of five years ending May 20, 2027. Under the terms of the convertible debentures, the lenders may at any time prior to the maturity date convert any or all the principal amount of the debentures into Common Shares of the Company at a conversion price of C$1.20 per Common Share.

Interest on the debentures is payable monthly in arrears on the last day of each month. An amount equal to the interest payable for the first year under each of the debentures was placed in escrow upon closing of each of the May 2022 Offering and the November 2022 Offering and shall be paid out to holders of debentures monthly. Interest thereafter shall be paid out of the Company's cash flow.

In August 2022, certain convertible debenture holders from the May 2022 Offering elected to convert C$350,000 face value of their debentures to Common Shares of the Company at the conversion price of C$1.20 per Common Share, resulting in the issuance of 291,666 Common Shares.

Restricted Cash

As of December 31, 2022, funds totaling $1,968,873 (December 31, 2021 - $2,340,244) were classified as restricted cash. The composition of this amount is as follows:

	2022	2021
SN-9 ANH Guarantee	1,704,618	2,039,321
Tiburon ANH Guarantee	264,255	300,923
	1,968,873	**2,340,244**

Term deposits of $2.4 million and $0.3 million were originally established to secure performance guarantees required by the Colombian National Hydrocarbon Agency ("ANH") under the Exploration and Production ("E&P") Contracts for the SN-9 and Tiburon Block. The SN-9 and Tiburon deposits amounts were defined in US dollars by the ANH but are held in Colombian pesos with Colombian banks and are subject to foreign currency fluctuation risks in relation to the US dollar, which may result in additional funding towards these term deposits from time to time at the discretion of the ANH. These deposits are to be released to the Company once current phase commitments under each E&P Contract are completed. As of December 31, 2022, the balances of the SN-9 term deposit and Tiburon term deposit were $1,704,618 and $264,255 respectively.

SHARE CAPITAL

Common shares

As of December 31, 2022, the Company was authorized to issue an unlimited number of Common Shares, with no par value, with holders of Common Shares entitled to one vote per Common Share and to dividends, if declared. Outstanding Common Shares as of December 31, 2022, are as follows:

	Common shares	Amount ($)
Balance, December 31, 2020	89,597,033	89,676,395
Shares issued through private placements (net of costs)	17,080,900	9,800,062
Shares issued to service provider	4,000,000	1,099,592
Shares issued through warrant exercise	9,082,222	2,923,959
Shares issued through option exercise	170,000	72,797
Balance, December 31, 2021	119,930,155	103,572,805
Shares issued through warrant exercise	5,011,111	1,205,561
Shares issued through option exercise	30,000	11,108
Conversion of debentures	291,666	198,245
Shares cancelled through share buyback	(140,800)	(106,279)
Balance, December 31, 2022	**125,122,132**	**104,881,440**

May 2022 Convertible Debenture Offering

In May 2022, the Company closed the May 2022Offering of 17,147 convertible debenture units of the Company at a price of C$1,000 per convertible debenture unit for total gross proceeds of C$17,147,000.

Each convertible debenture unit consisted of one 8.0% unsecured convertible debenture of the Company in the principal amount of C$1,000 and 400 Common Share purchase warrants of the Company. Each warrant entitles the holder thereof to purchase one Common Share at an exercise price equal to C$1.40 expiring on May 20, 2027.

The convertible debentures bear interest at a rate of 8.0% per annum from the date of issue, payable monthly in arrears on the last day of each month. The convertible debentures will mature on May 20, 2027. An amount equal to the interest payable under the convertible debentures from May 20, 2022until May 20, 2023 was placed in escrow upon closing of the May 20, 2022 Offering and shall be paid out to holders of the convertible debentures on a monthly basis. Interest thereafter shall be paid out of the Company's cash flow.

The principal amount of each convertible debenture is convertible, for no additional consideration, at the option of the holder in whole or in part at any time into Common Shares prior to the earlier of: (i) the close of business on May 20, 2027, and (ii) the business day immediately preceding the date specified by the Company for redemption of the convertible debentures upon a change of control, at a conversion price equal to C$1.20 per Common Share, subject to adjustment in certain events.

In connection with the offering, the underwriters received cash commissions of C$662,585 on gross proceeds raised.

The Company is entitled, at its sole option at any time after the second anniversary of the closing date of the offering to accelerate the expiry date of all of the outstanding warrants on not less than 30 days nor more than 60 days' notice, if the volume weighted average trading price of the Common Shares on the TSXV is greater than C$2.00 for the ten consecutive trading days preceding the notice. The convertible debentures and warrants were listed on the TSXV under the symbols “GASX.DB” and “GASX.WT.A”, respectively, and began trading on June 2, 2022.

The net proceeds from the May 2022 Offering were used by the Company to drill the Magico-1X well, located within the SN-9 Block and for working capital and general corporate requirements. As of December 31, 2022, the date of the Company’s Financial Statements, all of the net proceeds have been used for such purposes.

November 2022 Convertible Debenture Offering

In November 2022, the Company closed the November 2022 Offering of 35,000 convertible debenture units of the Company at a price of C$1,000 per convertible debenture unit for total gross proceeds of C$35,000,000. Each convertible debenture unit consisted of one 10.0% senior secured convertible debenture of the Company in the principal amount of C$1,000 and 1,000 Common Share purchase warrants of the Company. Each warrant entitles the holder thereof to purchase one common share at an exercise price of C$1.08 until November 30, 2025.

The principal amount of each convertible debenture will be convertible, for no additional consideration, at the option of the holder, in whole or in part, at any time and from time to time, into Common Shares at a price equal to C$0.90 per Common Share.

Transactions on Convertible Debentures

During the year ended December 31, 2022, certain convertible debenture holders from the May 2022 Offering elected to convert C$350,000 face value of their debentures to Common Shares of the Company at the conversion price of C$1.20 per Common Share, resulting in the issuance of 291,666 Common Shares.

Normal Course Issuer Bid

In July 2022, the Company announced its intention to proceed with a normal course issuer bid (“NCIB”) for up to 6,248,563 Common Shares over the course of the next 12 months, at which time, represented 5% of the total issued and outstanding Common Shares. All Common Shares purchased under the NCIB would be purchased on the open market, through the facilities of the TSXV, in accordance with the applicable regulatory requirements. Such Common Shares would be purchased at the prevailing market price and subsequently returned to treasury and cancelled. The NCIB is being conducted through Haywood Securities Inc., in accordance with the policies of the TSXV. The Company may not purchase more than 2% of the issued and outstanding Common Shares in any 30-day period. The NCIB will expire on or about July 18, 2023.

In August 2022, the Company announced that it had purchased 38,300 Common Shares under the NCIB at a weighted average price of $0.98 per Common Share through the facilities of the TSXV. In the latter half of August 2022, the Company purchased an additional 102,500 Common Shares under the NCIB. To date the Company has purchased a total of 140,800 Common Shares under the NCIB.

February 2021 Bought Deal and Non-brokered Private Placement

In February 2021, the Company completed a bought deal private placement, pursuant to which a syndicate of underwriters purchased 7,400,000 units and exercised its option to purchase an additional 1,110,000 units, for an aggregate of 8,510,000 units at a price of C$1.15 per unit for aggregate gross proceeds to the Company of $7,712,586 (C$9,786,500) before transaction costs. Each unit consisted of one Common Share and one-half of one Common Share purchase warrant, with each whole warrant entitling the holder to purchase one Common Share at a price of C$1.75 until February 10, 2024.

In connection with the offering, the underwriters received a cash commission equal to 6.0% of the gross proceeds raised and 510,600 non-transferable broker warrants equal to 6.0% of the aggregate number of units sold. Each broker warrant is exercisable into one Common Share at a price of C$1.15 per Common Share until February 10, 2024. The net proceeds of the offering were used for working capital and general corporate purposes.

In parallel with the bought deal financing, the Company completed a non-brokered private placement offering of 429,300 units, on the same terms as those issued pursuant to the bought deal financing, for a deemed value of $388,452 (C$493,695). No fees or commissions were paid to the underwriters in connection with the private placement. The issuance of these units was completed as repayment of the outstanding balance of the Maria Conchita Loan of $350,000 plus accrued interest.

October 2021 Non-brokered Private Placement

In October 2021, the Company closed a non-brokered private placement of 8,000,000 units, at a price of C$1.00 per unit, for gross proceeds of $6,474,063 (C$8,000,000). Each unit consisted of one Common Share and one Common Share purchase warrant, with each warrant entitling the holder to purchase one additional Common Share at a price of C$1.20 per Common Share for a period of 24 months from the date of issuance, expiring on October 22, 2023, and are subject to potential accelerated expiry in the event the closing price of the Common Shares of the Company on the TSXV is equal to or exceeds C$2.00 for twenty consecutive trading days.

In connection with completion of the placement, the Company has paid a C$6,000 cash commission and issued an aggregate 141,600 in units, on the same terms as those issued in the financing to eligible parties who introduced subscribers.

The net proceeds from this offering were used by the Company to build roads and drilling pads in the SN-9 Block and to install a de-watering capillary system at the Instanbul-1 well, located within the Maria Conchita Block.

Settlement of Services for Shares

Pursuant to a memorandum of understanding with Panacol and Landsons, the Company formalized the definitive agreement in December 2020 to issue an aggregate of 4,000,000 Common Shares. In February 2021, the terms of the definitive agreement were completed as the Company issued 2,800,000 Common Shares to Panacol in satisfaction of project management services provided and 1,200,000 Common Shares to Landsons for services provided towards obtaining the environmental and social licenses for the SN-9 project.

Stock Options

The Company's stock option plan provides for the issue of stock options to directors, officers, employees, charities, and consultants. The plan provides that stock options may be granted up to a number equal to 10% of the Company's outstanding Common Shares. Vesting terms are determined by the Board of Directors as they are granted and currently include periods ranging from immediately to one-third on each anniversary date over three years. The options' maximum term is ten years.

As of December 31, 2022, a total of 12,526,293 (December 31, 2021 – 9,915,400) options were issued and outstanding under this plan. Options which are forfeited/expired are available for reissue. A summary of the changes in stock options is presented below:

	Stock options	Weighted average exercise price (C$)
Balance, December 31, 2020	7,912,600	1.01
Options issued	2,250,000	0.91
Options exercised	(170,000)	0.33
Options forfeited	(77,200)	7.95
Options amended (old price)	(125,000)	8.00
Options amended (new price)	125,000	0.91
Balance, December 31, 2021	9,915,400	0.85
Options issued	2,640,893	1.14
Options exercised	(30,000)	0.275
Balance, December 31, 2022	**12,526,293**	**0.91**

In August 2022, the Company granted 2,640,893 options to acquire Common Shares to certain directors, officers, employees, consultants of the Company and certain charitable organizations with an exercise price of C$1.14 per Common Share, exercisable for a period of 10 years from August 8, 2022, the date of the grant.

In July 2021, the Company granted 2,250,000 options to acquire Common Shares to certain directors, officers, employees, consultants of the Company and certain charitable organizations with an exercise price of C$0.91 per Common Share, exercisable for a period of 10 years from July 15, 2021, the date of the grant. In addition, the Company also re-priced 125,000 stock options previously granted to charitable organizations to an exercise price of C$0.91 per Common Share.

The following summarizes information about stock options outstanding as of December 31, 2022:

Exercise prices (C$)	Number of options outstanding	Weighted average term to expiry (years)	Number of options exercisable
0.275	1,346,000	7.48	1,346,000
0.45	2,125,000	6.51	2,125,000
0.91	2,375,000	8.33	2,375,000
1.00	3,900,000	7.90	3,900,000
1.14	2,640,893	9.61	2,640,893
6.10	29,400	3.64	29,400
8.00	110,000	4.61	110,000
	12,526,293	**8.02**	**12,526,293**

Warrants

As of December 31, 2022, a total of 56,712,062 (December 31, 2021 – 25,489,373) Common Share purchase warrants were issued and outstanding. A summary of the change in total warrants is presented below:

	Warrants	Weighted average exercise price (C$)
Balance, December 31, 2020	21,449,745	3.03
Warrants issued on private placement	12,469,650	1.40
Broker warrants issued on private placement	652,200	1.16
Warrants exercised	(9,082,222)	0.23
Balance, December 31, 2021	25,489,373	3.18
Warrants issued with convertible debentures	41,858,800	1.13
Warrants expired	(5,625,000)	10.50
Warrants exercised	(5,011,111)	0.26
Balance, December 31, 2022	**56,712,062**	**1.20**

Warrants issued with Convertible Debentures

Pursuant to the May 2022 Offering (see above) the Company issued 17,147 units, each consisting of one 8.0% unsecured convertible debenture and 400 Common Share purchase warrants of the Company. Each full warrant can be exercised to purchase one additional Common Share at a price of C$1.40 until May 20, 2027.

Pursuant to the November 2022 Offering (see above) the Company issued 35,000 units, each unit consisted of one 10.0% senior secured convertible debenture and 1,000 Common Share purchase warrants of the Company. Each full warrant can be exercised to purchase one additional Common Share at a price of C$1.08 until November 30, 2025.

Purchase warrants on bought deal and non-brokered private placements

Pursuant to the bought deal and non-brokered private placement of units in February 2021 (see above), the Company issued 8,510,000 units and 429,300 units, respectively, each consisting of one Common Share and one-half Common Share purchase warrant. Each full warrant can be exercised to purchase one additional Common Share at a price of C$1.75 until February 10, 2024. In connection with the above, the underwriters received 510,600 non-transferable broker warrants equal to 6.0% of the aggregate number of units sold. Each broker warrant is exercisable into one Common Share at a price of C$1.15 per Common Share until February 10, 2024.

Pursuant to the non-brokered private placement of units in October 2021 (see above), the Company issued 8,000,000 units at a price of C$1.00 per unit. Each unit consists of one Common Share and one Common Share purchase warrant. Each warrant can be exercised to purchase one additional Common Share at a price of C$1.20 for a period of 24 months from the date of issuance, expiring on October 22, 2023, and are subject to potential accelerated expiry in the event the closing price of the Common Shares on the TSXV is equal to or exceeds $2.00 for twenty consecutive trading days. In connection with the above, the underwriters received 141,600 non-transferable broker warrants. Each broker warrant is exercisable into one Common Share at a price of C$1.20 per share.

The following summarizes information about total Common Share purchase warrants outstanding as of December 31, 2022:

Exercise prices (C$)	Number of warrants outstanding	Weighted average term to expiry (years)	Number of warrants exercisable
1.08	35,000,000	2.92	35,000,000
1.15	475,600	1.11	475,600
1.20	8,141,600	0.81	8,141,600
1.40	6,858,800	4.39	6,858,800
1.50	2,036,412	1.00	2,036,412
1.75	4,199,650	1.11	4,199,650
	56,712,062	**2.57**	**56,712,062**

On July 31, 2022, 5,625,000 warrants at an exercise price of C$10.50 expired, reducing the balance of outstanding warrants to 21,712,062

As of the date of this MD&A, the Company has 125,122,132 common shares, 12,461,293 stock options, and 56,712,062 warrants issued and outstanding.

COMMITMENT SUMMARY UPDATE

Capital Commitments

A summary of the Company's estimated capital commitments (in millions of dollars) are as follows:

Block	2023	2024	Total
SN-9 Block (1)	22.3	0.0	**22.3**
Tiburon Block (2)	3.0	0.0	**3.0**
Total	**25.3**	**0.0**	**25.3**

1) NG Energy's ANH commitment to carry out the minimum requirement to drill two exploration wells (for which the Company will pay 100% of the costs under the terms of the SN-9 Acquisition) according to Phase 1 of the contractual exploration program. The ANH commitment was approved by the ANH in May 2022 to replace the previous minimum requirement to process and interpret 204.4 km of 2D seismic and drill one exploration well, with an extension up to January 2023 for the completion of the Phase 1 exploration program. The first exploration well (Magico-1) was completed in August 2022 and drilling of the second exploration well (Brujo-1) was completed in November 2022. With the completion of the Brujo-1 well, the Company has sought confirmation from the ANH that the Phase 1 exploration commitments have been fulfilled.

2) Relates to NG Energy's share of the ANH commitment to carry out the minimum requirement to acquire, process, and interpret 69.75 km^2 of 3D seismic according to Phase 3 of the contractual exploration program. Currently, operations are delayed due to community disputes in the region, with 148 days to fulfil the commitment after the local disputes are resolved and the activities carried out in the previously proposed area. The Company assumes that activities related to the permits for the new seismic survey will commence in 2023 if the dispute is resolved by the Colombian Ministry of the Interior.

The expenditures provided in the above table only represent the Company's estimated cost to satisfy contractual requirements. Actual expenditures to satisfy these commitments, initiate production or create Proved plus Probable natural gas reserves may differ from these estimates. The expenditures in the above table are based on the latest possible date required per contract and may be incurred at an earlier date.

Contractual Commitments

Natural Gas Transportation Services

In August 2022, the Company entered into a Build-Own-Operate-Maintain-Transfer agreement (the "BOOMT") with GTX International Corp. ("GTX") pursuant to which GTX has built and will operate production facilities and pipeline (the "Pipeline Facilities") with capacity of 20 million cubic feet per day ("MMcf/d") that will extend from the Company's Maria Conchita Block in Colombia to existing national infrastructure. The BOOMT Agreement outlines the take-or-pay arrangement ("ToP") pursuant to which NG has agreed to transport, or pay for, 16 MMcf/d through the Pipeline Facilities for a period of six years (the "Guaranteed Commitment") at a tariff of $0.90/Mcf of gas, which commenced on September 23, 2022. Following the end of the term of the Guaranteed Commitment, the Company will no longer be required to pay for the full capacity of 16 MMcf/d but rather will only pay for that capacity which is used. The BOOMT Agreement has a term of ten years, after which ownership of the Pipeline Facilities will transfer to the Company. The BOOMT Agreement was reviewed as per guidelines in IFRS 16 to determine if it was for financial reporting purposes considered a right-of-use asset and lease liability. It was determined that the agreement met the criteria to be accounted for as a right-of-use asset and lease liability within the Company's Financial Statements.

Natural Gas Compression Services

In November 2021, the Company entered into a take-or-pay service contract with Surenergy SAS ESP ("Surenergy") for the compression of natural gas production derived from the Maria Conchita Block. Under the terms of the contract, Surenergy will install and maintain necessary infrastructure and equipment required to provide daily natural gas compression services for a natural gas production capacity of 20 MMcf/d, for a period of six years from the commencement of commercial natural gas production within the Maria Conchita Block. For these services, the Company will pay Surenergy a monthly service fee of $96,240 plus tax, annually adjusted to the Consumer Price Index, regardless of whether the Company fully utilizes the daily stipulated natural gas compression capacity. In December 2022, Surenergy completed the delivery of the third gas compressor, thereby satisfying the last outstanding condition required to turn the Surenergy Agreement into a binding obligation on the Company. The agreement with Surenergy was reviewed as per guidelines in IFRS 16 to determine if it was for financial reporting purposes considered a right-of-use asset and lease liability. It was determined that the agreement met the criteria to be accounted for as a right-of-use asset and lease liability within the Company's Financial Statements.

RELATED PARTIES

During the years ended December 31, 2022 and 2021, there were separate related party transactions as follows:

I. The Company paid a monthly advisory fee to a firm affiliated with a director of NG Energy. As per the consulting agreement, NG Energy paid the firm $102,244 (C$133,050) and $105,336 (C$132,000) for the years ended December 31, 2022 and 2021, respectively. Furthermore, additional fees were paid pursuant to the closing of successful financing arrangements, divestitures, or acquisitions for which the firm provides advisory services. Administrative success fees were paid upon closing of the 2022 and 2021 financing transactions summarized in Note 11 and 14 of the Financial Statements which resulted in the Company paying $133,661 (C$171,470) to the firm for the year ended December 31, 2022, and $145,575 (C$182,801) for the year ended December 31, 2021. For the years ended December 31, 2022 and 2021, the Company issued

75,000 and 125,000 stock options, respectively, to members of the firm. The Black-Scholes fair value recognized in the form of the expense associated with the vesting of these options for each year was $52,845 (C$67,942) and $70,321 (C$88,599), respectively. As of December 31, 2022, there were no outstanding payables owed to the firm.

II. For the year ended December 31, 2022, the Company incurred expenditures of $76,617 in royalty payments paid to service providers and firms that are affiliated with directors of NG Energy as well as payments to a director of NG Energy.

III. For the years ended December 31, 2022 and 2021, the Company incurred expenditures of $1,869,704 and $958,320, respectively, in professional fees for general corporate services as well as technical services related to exploration activities in Colombia. Such services were provided by a contracted service provider affiliated with a certain director of the Company, with such affiliation ended in December 2022. For the years ended December 31, 2022 and 2021, the Company issued 356,000 and 175,000 stock options, respectively, to members of the service provider. The Black-Scholes fair value recognized in the form of the expense associated with the vesting of these options was $250,837 (C$322,497) and $98,449 (C$124,038), respectively. As of December 31, 2022, there were no outstanding payables owed to the service provider.

IV. For the years ended December 31, 2022 and 2021, the Company incurred expenditures of $69,792 and $88,361, respectively, in office rental costs in Colombia. The related office space was rented from an entity affiliated with a certain director of the Company. As of December 31, 2022, a payables balance of $15,214 was owed to the to the lessor entity.

V. In November 2022, the Company completed the November 2022 Offering. Of the units issued, 3,250 units were issued for subscriptions by directors of the Company or investors related to directors of the Company.

VI. In May 2022, the Company completed the May 2022 Offering. Of the units issued, 7,135 units were issued for subscriptions by directors of the Company or investors related to directors of the Company.

VII. In August 2022, debt holders of the SN-9 loan exercised the conversion option to convert the loan principal and cumulative interest payable to the additional 3.0% overriding royalty on NG Energy's working interest in the gross production of the SN-9 Block (see Note 10 of the Financial Statements). Of the original loan proceeds of $2,500,000, approximately $1,512,500 was provided by the directors of the Company.

VIII. In August 2022, the Company entered into the BOOMT Agreement with GTX (see Note 20 of the Financial Statements). Of the ownership of GTX, 26% is owned by directors or affiliates of directors of the Company.

IX. In February 2021, the Company completed the aforementioned non-brokered private placement offering of 429,300 units, on the same terms as those issued pursuant to the bought deal financing, for a deemed value of $388,452 (C$493,695). The issuance of the non-brokered private placement through units was completed as repayment for the outstanding balance of the Maria

Conchita Loan of $350,000 plus accrued interest. Of the units issued, 253,000 units were issued to Company directors.

X. In October 2021, the Company completed the aforementioned non-brokered private placement through units for proceeds of $6,474,063 (C$8,000,000) before issue costs. Of the total proceeds, approximately $50,579 (C$62,500) were from subscriptions by directors or by investors related to directors of the Company.

XI. For the year ended December 31, 2021, 100,000 stock options were issued and 125,000 previously issued stock options were re-priced to charitable organizations. The Black-Scholes fair value recognized in the form of the expense associated with the vesting and re-pricing of these options was $88,956 (C$112,078).

Compensation of Key Management

The Company considers its directors and officers to be key management personnel. Compensation expenses paid to key management personnel were as follows:

For the years ended December 31	**2022**	**2021**
Salaries, consulting fees, benefits	379,785	231,415
Director fees	247,261	107,496
Share-based compensation	1,155,545	900,108
Total	**1,782,591**	**1,239,019**

KEY FINANCIAL RESULTS

The following table summarizes the Company's key financial results over the past three years:

	Year 2022	**Year 2021**	**Year 2020**
Loss from continuing operations	(9,968,158)	(6,714,447)	(22,009,042)
Income (loss) from discontinued operations	-	-	(1,691,363)
Net loss	(9,968,158)	(6,714,447)	(23,700,405)
Loss per share (basic & diluted):			
Loss from continuing operations	(0.08)	(0.06)	(0.44)
Income (loss) from discontinued operations	-	-	(0.03)
Net loss	(0.08)	(0.06)	(0.47)
Total assets	83,146,660	23,145,833	14,473,289
Total non-current liabilities	55,178,633	806,830	2,612,502

NG Energy is still primarily in the exploratory and early development phase of its natural prospects. In 2022, NG Energy benefited from early production revenue that commenced in October. Net losses to date are largely a result of general and administrative expenses, share-based compensation expenses, and business development expenses incurred over each financial year. Some of the losses in 2020 were offset by oil and natural gas revenue realized from former Argentinian operations, which were disposed of in October 2020. Fair value losses on derivative liabilities of $14.7 million were also recognized in 2020. Such derivative liabilities no longer existed by year end 2020, thus having no continued effect for the 2021 and

2022 years. Additionally, an impairment loss of $0.2 million was recognized in 2020, in relation to various exploration and evaluation ("E&E") and property, plant and equipment ("PP&E) assets, further contributing to the overall losses recognized in those years. Finance costs have increased in each subsequent year contributing to net losses in each period. Increased finance costs are primarily due to additional debt financing being obtained by the Company year over year.

SELECTED QUARTERLY INFORMATION

The following table sets out selected quarterly financial information of NG Energy and is derived from unaudited quarterly financial data prepared by management in accordance with IFRS.

	Q4 2022	Q3 2022	Q2 2022	Q1 2022
Net loss	(3,468,820)	(3,844,417)	(1,856,666)	(798,255)
Comprehensive loss	(3,673,960)	(3,362,029)	(1,730,924)	(826,278)
Net loss per share (basic & diluted):	(0.03)	(0.03)	(0.02)	(0.01)

	Q4 2021	Q3 2021	Q2 2021	Q1 2021
Net loss from continuing operations	(2,128,480)	(2,350,803)	(936,492)	(1,298,672)
Comprehensive income (loss)	(2,297,814)	(2,231,135)	(897,121)	(1,282,873)
Net loss per share (basic & diluted):	(0.02)	(0.02)	(0.01)	(0.01)

Over the past eight quarters, trends in the net losses have been impacted significantly which has caused fluctuations on a quarter-over-quarter basis due to such factors as G&A expenses, impairment expenses, results from discontinued operations, share-based compensation expense, fair value results on derivative liabilities, and fluctuations in exchange rates.

The following outlines the significant events over the past eight quarters:

In the fourth quarter of 2022, increased G&A expenses of $1,213,887, increased finance expenses of $1,500,889, foreign exchange losses of $916,355, and depletion and depreciation expenses of $945,343 contributed to the quarterly net loss. Increases in professional fees were the primary cause of the overall G&A expense increase quarter over quarter. Increased finance expenses were due to additional interest expense incurred in Q4 2022 in relation to the convertible debentures as well as the GTX and Surenergy lease liabilities that have commenced. Also, in Q4 2022, production of natural gas resulted in gross revenue of $1,766,325 less royalties of $315,289 and operating costs of $511,248. As there were assets transferred from E&E to D&P, Q4 saw a significant increase in the depletion and depreciation expenses, this is due to the right-of-use asset depreciation for the full quarter as well depletion on the producing assets that were transferred from E&E.

In the third quarter of 2022, G&A expenses of $806,611, increased finance expenses of $462,954, share-based compensation expense of $1,860,743, and foreign exchange losses of $875,142 contributed to the quarterly net loss. Reductions in professional services rendered to the Company during Q3 2022 when compared to these same expenses in Q2 2022 was the primary cause of the reduction in G&A expenses, quarter to quarter. Increased finance expenses were due to the additional interest expense incurred in Q3 2022 in relation to the convertible debentures as well as the GTX lease liability that commenced September 23, 2022.

In the second quarter of 2022, G&A expenses of $867,185 as well as increased finance expenses of $265,038 and foreign exchange losses of $997,668 contributed to the quarterly net loss. Reductions in investor relation expenses during Q2 2022 when compared to these same expenses in Q1 2022 was the primary cause of the reduction in G&A expenses, quarter to quarter. Increased finance expenses were due to the additional interest expense incurred in Q2 2022 with the completion of the May 2022 Offering.

In the first quarter of 2022, the Company incurred G&A expenses of $1,048,561, partially offset by foreign exchange gains of $402,750. The decreased G&A expenses are due to reduced expenses for professional services rendered to the Company in the quarter in comparison to Q4 2021.

In the fourth quarter of 2021, the Company experienced foreign exchanges losses of $182,944 as well as increased G&A expenses of $1,615,679. The increased G&A expenses are due to increased growth and activity of the Company in anticipation of revenue-generating operations in 2022.

In the third quarter of 2021, the Company issued stock options with an assessed fair value of $1,298,396 that was recognized as share-based compensation expense in the quarter, with G&A expenses of $620,996 and foreign exchange loss of $265,416.

The results of the first two quarters of 2021 consisted primarily of G&A expenses ($766,921 and $780,669 for Q1 and Q2 2021, respectively) and foreign exchange gains/losses. Foreign exchange losses of $370,049 were recognized in Q1 2021 while a small foreign exchange gain of $16,663 was recognized in Q2 2021.

ADOPTION OF NEW AND REVISED ACCOUNTING STANDARDS

The Company has adopted certain new and revised IFRSs that have been issued effective January 1, 2022. Detailed discussions of new accounting policies that may affect the Company are provided in the Financial Statements.

USE OF ESTIMATES AND JUDGMENTS

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of the financial statements are outlined below.

Critical Judgments in Applying Accounting Policies

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in the Financial Statements:

i) *Identification of cash-generating units*
   Natural gas assets and processing facilities are grouped into cash generating units ("CGUs") identified as having largely independent cash inflows and are geographically integrated. The

determination of the CGUs was based on management's interpretation and judgment. The recoverability of development and production asset carrying values is assessed at the CGU level. The asset composition of a CGU can directly impact the recoverability of the assets included therein.

ii) *Impairment of property, plant and equipment and exploration and evaluation assets*
Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land, transaction values and other relevant assumptions.

iii) *Exploration and evaluation assets*
The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found in assessing economic and technical feasibility.

iv) *Income taxes*
The Company conducts business internationally and therefore is required to comply with tax laws and regulations in various tax jurisdictions. Significant judgment, such as the interpretation of tax laws and regulations in each tax jurisdiction are required by management in determining the income tax balances and disclosures. The Company engages independent third-party tax specialists to assist with the interpretation of international tax laws and regulations.

Additionally, judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

v) *VAT recoverability*
Judgment is required by management in evaluating the likelihood of whether or not value added tax ("VAT") on purchases is recoverable from the Colombian government.

Key Sources of Estimation Uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, which have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

i) *Reserves and resource assessment*
The assessment of reported recoverable quantities of Proved plus Probable natural gas reserves and prospective resource estimates include estimates regarding forecasted production volumes, natural gas commodity prices, operating costs, royalty costs and future development costs. Additional estimates are made in relation to geological and geophysical models in anticipated recoveries. The economical, geological, and technical factors used to estimate Proved plus Probable natural gas reserves and prospective resources may change from period to period.

Changes in reported Proved plus Probable natural gas reserves and prospective resources can impact the carrying values of the Company's natural gas properties and exploration and evaluation assets and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows.

The Company's Proved plus Probable natural gas reserves, if any, represent the estimated quantities of natural gas and natural gas liquids which geological, geophysical, and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially viable. Such Proved plus Probable natural gas reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Proved plus Probable natural gas reserves may only be considered proven and probable if the ability to produce is supported by either actual production or conclusive formation tests. Prospective resources are determined using an externally prepared valuation report which reflects estimated prospective resources and external pricing and costs assumptions reflective of the current market. The Company's Proved plus Probable natural gas reserves and prospective resources are determined pursuant to NI 51-101.

The Company uses estimated Proved plus Probable natural gas reserves to deplete its natural gas assets included in PP&E, to assess for indicators of impairment on the Company's CGU and if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGUs and to assess E&E costs for impairment when transferred to PP&E.

ii) *Decommissioning obligations*

The Company estimates future remediation costs of production facilities, wells, and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

iii) *Share-based payments*

All equity-settled, share-based awards issued by the Company are recorded at fair value using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates must be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate, and estimated forfeitures at the initial grant date. Share-based payments to non-employees are measured at the date when goods and services are received. Where the fair value of goods and services received cannot be reliably measured, the measure of the goods and services received and the corresponding increase in equity indirectly by reference to the fair value of the equity instruments granted, measured at the date goods are obtained or services rendered. Assessing the fair value based on services rendered are subject to measurement uncertainty given that it is dependent upon obtaining reasonable data as to the value of services rendered or good obtained based on readily available market metrics.

iv) *Tax provisions*
Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in the period of the change and future periods. In periods of rate change, the Company estimates the period of anticipated reversal of the associated deferred income tax liability to determine the appropriate tax rate to apply to temporary differences. Deferred income tax assets are recognized to the extent future recovery is probable in management's judgment. Deferred income tax assets are reduced to the extent that it is no longer probable that sufficient taxable earnings will be available to allow all or part of the asset to be recovered. Deferred income tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods. Income tax filings are subject to audits and reassessments and changes in facts, circumstances and interpretations of the standards may result in a material increase or decrease in the Company's provision for income taxes.

Risks and Uncertainties

Exploration, development, production of oil and natural gas involves a wide variety of inherent risks because of the geological, social, and economic conditions in the various areas of operation. Therefore, the Company is subject to several financial, operational, and political risks that could have a significant impact on its profitability and levels of operating cash flows. Although the Company assesses and minimizes these risks by applying high operating standards, including careful management, and planning of its facilities, hiring qualified personnel, and developing their skills through training and development programs, these risks cannot be eliminated. Such risks include:

- risks related to the Common Shares;
- inability to obtain additional capital required to implement business plan;
- limited customer base;
- directors and officers;
- personnel;
- going concern risk;
- dilution;
- internal controls;
- Forward-Looking Statements may prove inaccurate;
- diversification;
- expansion into new activities;
- climate change;
- income taxes;
- cash from subsidiaries;
- pending or future litigation, arbitration, and other regulatory proceedings;
- climate change related litigation;
- technology;
- information technology or cybersecurity;
- breach of confidentiality;

- earnings & accounting estimates;
- Shareholder activism;
- global financial conditions;
- COVID-19 pandemic;
- Russia – Ukraine conflict;
- estimated oil resources and natural gas reserves are based on assumptions that may prove inaccurate;
- E&P Contracts;
- volatility of pricing for oil and natural gas;
- exploration, production, and general operational risk;
- replacement reserves; competition;
- changing investor sentiment about the oil and gas industry;
- reputational risk;
- environmental, health and safety risk;
- natural disaster and weather-related risks;
- joint venture risks;
- gathering and processing facilities and pipeline systems;
- delays in production, marketing, and transportation;
- difficulty transporting and distributing production;
- drilling costs and availability of equipment;
- drilling wells could result in liabilities;
- decommissioning costs;
- insurance;
- inflation and cost management;
- oil and gas companies in Colombia do not own any of the oil and gas reserves in the country;
- unforeseen title defects;
- seizure or expropriation of assets;
- risks of foreign operations;
- risks associated with geographically concentrated operations;
- gas industry in Colombia is less developed;
- operations in emerging market country;
- economic and political developments in Colombia;
- political uncertainty in Colombia, Canada and elsewhere;
- changes in laws or regulations;
- corruption;
- money laundering and other illegal and improper activities;
- licenses and permits; land, communities, prior consultation, and zoning restrictions;
- activities in areas classified as Indigenous reserves and Afro-Colombian lands;
- social disruptions and instability;
- sanctions by the United States of America on Colombia;
- Canada's relations with Colombia; and
- violence and instability in Colombia.

If any of these risks materialize into actual events or circumstances or other possible additional risks and uncertainties of which the Company is currently aware or which it considers to be material in relation to the Company's business occur, the Company's assets, liabilities, financial condition, results of operations (including future results of operations), business and business prospects, are likely to be materially and adversely affected. In such circumstances, the prices of the Company's securities could decline, and investors may lose all or part of their investment.

Readers are encouraged to read and consider the risk factors listed above, which are more specifically described in the Company's Annual Information Form dated June 30, 2022, which is available at www.sedar.com. Such risk factors could materially affect the future operating results of the Company and could cause actual events to differ materially from those described in forward-looking statements relating to the Company.

Management's Report on Internal Control over Financial Reporting

In connection with National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings ("NI 52-109") adopted by each of the securities commissions across Canada, the Chief Executive Officer and Chief Financial Officer of the Company are required to file a Venture Issuer Basic Certificate with respect to the financial information contained in the unaudited interim financial statements and the audited annual financial statements and respective accompanying Management's Discussion and Analysis. The Venture Issuer Basic Certificate does not include representations relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting, as defined in NI 52- 109.

FINANCIAL AND OTHER INSTRUMENTS

The Company has exposure to the following risks from its use of financial instruments:

- Credit risk
- Liquidity risk
- Market risk

This note presents information about the Company's exposure to each of the above risks and the Company's objectives, policies, and processes for measuring and managing these risks, and the Company's management of capital. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

Credit Risk

Credit risk reflects the risk of loss if counterparties do not fulfill their contractual obligations. The carrying amount of cash and cash equivalents, deposits in escrow, accounts receivable, VAT receivable and restricted cash represent the maximum credit exposure. As of December 31, 2022, the Company had $1,968,873 (December 31, 2021 - $2,340,244) in restricted cash towards development activity and joint operations in Colombia.

As of December 31, 2022, the Company had $920,947 (December 31, 2021 - $682,799) in accounts receivable and prepaids, the majority of which related to prepaid expenses. The Company does not consider any of its receivables past due.

The Company maintained a VAT receivable balance of $2,354,633 as of December 31, 2022 (December 31, 2021 - $2,284,965), which is classified as a non-current asset. The Company considers these VAT balances to be collectible in the future as such VAT amounts will be utilized to offset future VAT charged on sales realized by the Company on future oil and gas production that would otherwise be required to be paid to the Colombian tax authorities.

The Company held cash and cash equivalents of $6,962,228 (December 31, 2021 - $5,848,957) and deposits in escrow of $2,788,368 (December 31, 2021 - $nil) as of December 31, 2022. The Company manages the credit exposure related to cash and cash equivalents and deposits in escrow by ensuring counterparties (e.g., banks) maintain satisfactory credit ratings and monitors all investments to ensure a stable return.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due and describes the Company's ability to access cash. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient cash resources to finance operations, fund capital expenditures, and to repay debt and other liabilities of the Company as they come due, without incurring unacceptable losses or risking harm to the Company's reputation. The Company's processes for managing liquidity risk include preparing and monitoring capital and operating budgets, coordinating and authorizing project expenditures, and authorization of contractual agreements. The Company seeks additional financing based on the results of these processes. The budgets are updated when required as conditions change.

The following table outlines the contractual maturities of the Company's financial liabilities on December 31, 2022:

	Less than 1 year	1-3 years	Thereafter	Total
Trade accounts payable	2,842,701	-	-	2,842,701
Capital payables	6,476,463	-	-	6,476,463
Lease liability payments	6,555,586	13,125,573	18,103,622	37,784,781
Convertible debentures - principal	-	-	38,243,503	38,243,503
	15,874,750	**13,125,573**	**56,347,125**	**85,347,448**

Market Risk

Market risk is the risk or uncertainty that changes in price, such as commodity prices, foreign exchange rates, and interest rates will affect the Company's net earnings and the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. From time to time, the Company may utilize financial derivative contracts to manage market risks in accordance with the risk management policy that has been approved by the

Board of Directors. There were no financial derivative contracts or embedded derivatives outstanding on December 31, 2022 nor were there any at the previous year ended December 31, 2021.

Commodity Price Risk

Commodity price risk is the risk that the fair value of the future cash flows will fluctuate because of changes in commodity prices. Commodity prices for natural gas are affected not only by the United States dollar, but also by world economic events that dictate the levels of supply and demand.

The Company's natural gas revenue is derived from natural gas production on the Maria Conchita block.

Foreign Currency Risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate because of changes in foreign currency exchange rates. Some of the Company's business transactions and commitments occur in currencies other than US dollars. A portion of the Company's oil and natural gas activities in Colombia transact in Colombian Peso (COP$). In addition, most of the Company's financing and a portion of the administrative costs will be based and paid in Canadian dollars and COP$. Therefore, the Company is exposed to the risk of fluctuations in foreign exchange rates between US dollars, COP$ and Canadian dollars.

The impact to the accumulated other comprehensive loss for the year ended December 31, 2022, had the US dollar to Canadian dollar exchange rate changed by 1%, would amount to approximately $71,000 ($43,000 – December 31, 2021), and the impact to the net loss and comprehensive loss for the year had the US dollar to COP$ exchange rate changed by 1% would amount to approximately $21,000 ($49,000 – December 31, 2021).

As of December 31, 2022, the Company had not entered into any foreign currency derivatives to manage its exposure to currency fluctuations, nor were there any foreign currency derivatives as at the previous year ended December 31, 2021.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate because of changes in prevailing market interest rates. Fluctuations of interest rates for the years ended December 31, 2022 and 2021, would not have had a significant impact on cash and cash equivalents and short-term investments. Furthermore, the Company is not currently exposed to interest rate risk on its interest-bearing loans given these debt instruments are all subject to fixed interest rates.

READER ADVISORIES

Forward-Looking Statements

This MD&A may include forward-looking statements including opinions, assumptions, estimates and management's assessment of future plans and operations, capital expenditures and the timing and funding thereof. When used in this document, the words "anticipate," "believe," "estimate," "expect," "intent," "may," "project," "plan", "should" and similar expressions are intended to be among the statements that identify forward-looking statements. Forward-looking statements are subject to a wide range of risks and uncertainties, and although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will be realized. Any number of important factors could cause actual results to differ materially from those in the forward-looking statements including, but not limited to, risks associated with petroleum and natural gas exploration, development, exploitation, production, marketing and transportation, the volatility of petroleum and natural gas prices, currency fluctuations, the ability to implement corporate strategies, the state of domestic capital markets, the ability to obtain financing, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, changes in petroleum and natural gas acquisition and drilling programs, delays resulting from inability to obtain required regulatory approvals, delays resulting from inability to obtain drilling rigs and other services, labor supply risks, environmental risks, competition from other producers, imprecision of reserve estimates, changes in general economic conditions, ability to execute farm-in and farm-out opportunities, and other factors, all of which are more fully described under the caption "*Risk Factors*" in the Company's Annual Information Form dated as of June 30, 2023, which is available for review on SEDAR at www.sedar.com..

Management believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct. Such forward-looking information included in this MD&A should not be unduly relied upon as the plans, assumptions, intentions, or expectations upon which it is based may not occur. Actual results or events may vary from the forward-looking information.

In particular, this MD&A may contain forward-looking information pertaining to the following:

- the resource potential of the Company's assets;
- the Company's strategy and opportunities;
- performance characteristics of the Company's oil and gas properties and estimated capital commitments and probability of success;
- gas production and recovery estimates and targets;
- the existence and size of the oil and gas reserves and resources, if any;
- the Company's drilling plans;
- capital expenditure programs and estimates, including the timing of activity;
- the Company's plans for, and results of, exploration and development, activities, and factors that may affect such activities;
- projections of market prices and costs;
- the supply and demand for natural gas and oil;
- expectations regarding the ability to raise equity and debt capital on acceptable terms and to add continually to reserves through acquisitions and development, including the ability to negotiate and complete the agreements contemplated in this MD&A;
- the timing for receipt of regulatory approvals; and
- treatment of the Company under governmental regulatory regimes and tax laws.

The purpose of providing any financial outlook in this MD&A is to illustrate how the business of the Company might develop without the benefit of specific historical financial information. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking information herein is based on certain assumptions and analysis by the management of the Company considering its experience and perception of historical trends, current conditions and expected future developments and other factors that it believes are appropriate and reasonable under the circumstances. The forward-looking information herein is based on several assumptions, including but not limited to:

- the availability on acceptable terms of funds for capital expenditures;
- the availability in a cost-efficient manner of equipment and qualified personnel when required;
- continuing favorable relations with Latin American governmental agencies;
- continuing strong demand for natural gas and oil;
- the stability of the regulatory framework governing royalties, taxes and environmental matters in Colombia and any other jurisdiction in which the Company may conduct its business in the future;
- the Company's future ability to market production of natural gas or oil successfully to customers;
- the Company's future production levels and natural gas and oil prices;
- the applicability of technologies for recovery and production of the Company's natural gas and oil reserves or resources, as applicable;
- the existence and recoverability of any oil and gas reserves;
- geological and engineering estimates in respect of the Company's resources and reserves;
- the geography of the areas in which the Company is exploring; and
- the impact of increasing competition on the Company.

The actual results, performance and achievements of the Company could differ materially from those anticipated in these forward-looking statements as a result of the risks and uncertainties set forth elsewhere in the MD&A and the risks and uncertainties more specifically described in the Company's Annual Information Form dated June 30, 2022, which is available at www.sedar.com.

Readers are cautioned that the foregoing lists of assumptions, risks, and uncertainties are not exhaustive; there may be other factors that cause actions, events, or results not to be anticipated, estimated or intended. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement. The forward-looking information speaks only as of the date of this MD&A, and the Company does not undertake any obligation to publicly update or revise any forward-looking information if circumstances or management's estimates or opinions should change except as required by applicable securities laws.

Analogous Information

Certain information in this MD&A may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to areas, assets, wells, industry activity and/or operations that are in geographical proximity to or believed to be on-trend with lands held by NG Energy. This document notes specific analogous oil and gas discoveries and corresponding details of said discoveries in the Chuchupa Block as well as blocks owned by Canacol Energy Ltd. and makes certain assumptions about the Maria Conchita Block and SN-9 Block because of such analogous information and potential recovery rates as a result thereof. Such information has been obtained from public sources, government sources, regulatory agencies, or other industry participants. Management of NG Energy believes the information may be relevant to help define the reservoir characteristics within lands on which NG Energy holds an interest and such information has been presented to help demonstrate the basis for NG Energy's business plans and strategies. However, management cannot confirm whether such analogous information has been prepared in accordance with NI 51-101 and the CO GE Handbook and NG Energy is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. NG Energy has no way of verifying the accuracy of such information. There is no certainty that the results of the analogous information or inferred thereby will be achieved by NG Energy and such information should not be construed as an estimate of future production levels or the actual characteristics and quality NG Energy 's assets. Such information is also not an estimate of the reserves or resources attributable to lands held or to be held by NG Energy and there is no certainty that such information will prove to be analogous in the future. The reader is cautioned that the data relied upon by NG Energy may be in error and/or may not be analogous to such lands to be held by NG Energy.

Abbreviations

$/bbl	*dollars per barrel*
$/boe	*dollars per barrel of oil equivalent*
$/GJ	*dollars per gigajoule*
$/Mcf	*dollars per thousand cubic feet*
bbl	*barrel*
bbl/d	*barrels per day*
bcf	*billion cubic feet*
boe	*barrel of oil equivalent*
boe/d	*barrel of oil equivalent per day*
GJ	*gigajoule*
GJ/d	*gigajoules per day*
km	*kilometer*
Mcf	*thousand cubic feet*
Mcf/d	*thousand cubic feet per day*
Mbbl	*thousand barrels*
MMbbl	*million barrels*
MMboe	*million barrels of oil equivalent*
MMcf	*million cubic feet*
MMcf/d	*million cubic feet per day*
NGLs	*natural gas liquids*
API	*American Petroleum Industry gravity*
m^3	*Cubic meters*
ppm	*parts per million*
psig	*pounds per square in gauge*
NPV_{10}	*Net present value using a 10% forward discount rate*