NG ENERGY INTERNATIONAL CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE MONTHS ENDED MARCH 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 three months ended March 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's interim condensed consolidated financial statements for the three months ended March 31, 2022 as well as the audited annual consolidated financial statements for the year ended December 31, 2021 (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 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 May 17, 2022.

Non-GAAP Measures

Certain financial measures in this document may not have a standardized meaning as prescribed by IFRS, and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order 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-GAAP measure is presented in the Operating Results, Financial Results and Liquidity and Capital Resources sections of this MD&A.

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 judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, 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 oil and 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 NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the meanings herein as in NI 51-101 or the COGE Handbook.

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 actually 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 actually recovered will equal or exceed the estimated Proved reserves; and

- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated Proved plus Probable reserves.

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

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.

CORPORATE OVERVIEW AND UPDATE

NG 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 are listed on the TSX Venture Exchange ("TSXV") under the symbol "GASX".

Prospectus Offering of Convertible Debentures

In April 2022, the Company filed its final short form prospectus in connection with the distribution of a best-efforts, fully marketed offering (the "Offering") of up to 20,000 convertible debenture units (the "Debenture Units") of the Company at a price of C$1,000 per Debenture Unit for total gross proceeds of up to C$20,000,000. Each Debenture Unit will consist of one 8.0% unsecured convertible debenture of the Company in the principal amount of C$1,000 (each a "Convertible Debenture") and 400 common share purchase warrants of the Company (each a "Warrant"). Each Warrant will entitle the holder thereof to purchase one common share at an exercise price equal to C$1.40 for a period of five years following the closing date of the Offering.

The Convertible Debentures will 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, with the first interest payment covering accrued interest for the period from the closing date to June 30, 2022. The Convertible Debentures will mature on the date which is five years from the closing of the Offering (the "Maturity Date"). An amount equal to the interest payable under the Convertible Debentures from the closing date of the Offering until the first anniversary of the Offering shall be placed in escrow upon closing of the Offering, and shall be paid out to holders of 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 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 of the Company prior to the earlier of: (i) the close of business on the Maturity Date, 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, subject to adjustment in certain events.

The Company shall be 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 but not less than 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 TSX-V is greater than $2.00 for the ten consecutive trading days preceding the notice.

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 share purchase warrant entitling the holder to purchase one additional 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 of the Company 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, 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 of the Company 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 share until February 10, 2024. The net proceeds of the Offering will be used for working capital and general corporate purposes.

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 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.

Appointment of New Directors

In July 2021, the Company announced the appointment of D. Jeffrey Harder and Humberto Calderon Berti as directors of the Company. At the same time, the Company announced the resignation of Mr. Frank Giustra as a director of the Company.

COVID-19 Pandemic

The ongoing impact of COVID-19 on the Company’s operations and future financial performance is uncertain. The continued impact of COVID-19 will depend on future developments that are uncertain and unpredictable, its continued impact on capital and financial markets on a macro-scale and any new information that may emerge COVID-19 continues to present uncertainty and risk with respect to the Company, its performance, and estimates and assumptions used by management in the preparation of its financial results.

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. It has also identified light oil unrisked prospective resources (leads) at its SN-9 Block 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 located in the Department of La Guajira, Colombia, and neighbours the Chuchupa Block to its north, which is one of Colombia's largest gas fields with an initial 900 MMboe in place and currently accounts for approximately 7.2% of Colombia's daily natural gas output. The Chuchupa Block has been under production for over 35 years, operated by Chevron 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 in close proximity to both of Colombia's gas trunk lines, Transportadora de Gas Internacional ("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.

Reserves Analysis

In March 2022, the Company announced the results of the year end 2021 reserves report for the Maria Conchita Block prepared by Petrotech and Associates Ltd. ("Petrotech") in accordance with the COGE Handbook. Using available 3D seismic data and amplitude-variation-with offset seismic techniques in the Maria Conchita Block, the structures with potential gas reservoirs of Miocene were mapped within the areas of the Aruchara 1 and Tinka 1 wells. The volumetric method is then used to estimate the proved and probable undeveloped reserves. The Company currently has total proved plus probable reserves of 27,666 MMcf gross, 25,859 MMcf net in the Maria Conchita Block, which is consistent with MMcf certified for the prior year ended December 31, 2020. Since the results of the tests conducted in the Istanbul-1 well were not considered to be stable, and the gas production was estimated, no reserves have been assigned to the Istanbul-1 well until actual results are available. Recently, the operator has received a modification to the existing environmental license to allow testing of the Aruchara-1 well, which will lead to a more complete evaluation of the block when combined with the results of the Istanbul-1 well.

Current Objectives

The Company's primary focus is establishing the necessary infrastructure to connect the Aruchara-1 well to the nearby main gas line, with the objective of monetizing its natural gas resources and capitalizing on a premium pricing market in Colombia of over $5 per million British thermal units (“MMBtu”). In December 2020, the Company announced that it had entered into a Memorandum of Understanding (the "MOU") with GTX International Corp. ("GTX") pursuant to which GTX would build and operate the production facilities and pipeline (the "Pipeline Facilities") that extends from the Company's Maria Conchita field in Colombia to existing national gas transportation infrastructure. The MOU provides that the Company and GTX will enter into a take-or-pay agreement (the "ToP Agreement") pursuant to which NG Energy will agree 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 per MMBtu of gas. The Company's Guaranteed Commitment will convert after six years into payment for only the capacity that is used. The ToP Agreement will have a term of 18 years, after which ownership of the Pipeline Facilities will transfer to the Company. In January 2022 GTX completed the construction of the production facilities and commenced its pre-commissioning testing; upon start-up, the production facilities will be programmed to produce between 16 and 20 MMcf/d.

In March 2022, the National Authority of Environmental Licenses (the "ANLA") granted to the Company an amended environmental license for Maria Conchita to include the Aruchara-1 well. The ANLA license shall expire at the time that the Company enters into the commercialization phase at the Aruchara-1 well. This permits production from the Aruchara-1 well and allows the Company to lay the remaining 40 meters of flow line connecting the well to the GTX production facilities. It also enables the Company to complete the connection point to the TGI main pipeline which will transport natural gas from Maria Conchita to market.

In October 2021, the Company signed an agreement with TGI for the tie in of the Maria Conchita pipeline, enabling the Company to transport the gas produced from Aruchara-1 well and subsequent wells at Maria Conchita through TGI's main pipeline and sell it in central consumption centers of the country. The prior consultation agreement with the Ministry of Interior and the community where the connection point is located will be finalized, and the remaining pipeline will be laid and tied into the TGI main line, in Q2 2022.

The consultation process with local communities is currently being completed; the process has experienced delays due to the need for the Company and the government to ensure that all social circumstances relating to indigenous communities (i.e., relating to ESG factors like community engagement and involvement, net benefits to the community, etc.) have been accounted for. The Company continues to advance the studies and procedures required by Colombian government agencies to begin the production phase of the Aruchara-1 well and the Istanbul-1 well. Currently, all permits are in the process of being procured, with final adjustments and remaining minimal infrastructure construction being completed for gas production to begin in Q2 2022.

The connection with the TGI main line is expected to turn the Company into a revenue producing entity as it will allow it to feed up to 20 MMcf/d into the Colombian gas system. In Colombia, take-or-pay contracts cannot be signed except in December of each year; prior to then, a producer can sign contracts for interruptible supply, which provide for one-off acquisitions of volumes when available. Given the current shortage of gas in Colombia, the Company has a reasonable expectation that any gas that it produces will be purchased. In that regard, the Company has signed two letters of intent for interruptible supply from two utilities, and has received a proposal from a trading company, committing for up to an aggregate of 20 MMcf/d at indicative prices of $5.08/MMBtu. The commencement of this revenue stream is expected to facilitate the Company to fund the interest payable on the Convertible Debentures.

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 2022 with the option to present a development plan of the field in late 2022. 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 to 8,416 feet and 8,426 to 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.

Currently the Company is awaiting the authorization of the ANH for extended well testing and minimum gas vent.

NG Energy engaged professional consultants to design the re-entry (without rig) of the Istanbul-1 well and to deploy de-watering capillary technology to deal with water that exists downhole. The objectives of the program are designed to determine the effectiveness of the technology to remove water and to estimate the real capacity and potential of the gas production from the well without the liquid load.

The Istanbul-1 well re-entry is part of the ongoing evaluation program of the Maria Conchita field after the successful re-entry in the Aruchara-1 well (drilled by Texaco in 1980) and on the recent geological evaluation of prospective resources as required by the ANH. The re-entry of the Aruchara-1 well was completed in August 2020 as a result of implementing the work program approved by the ANH to (1) repair a gas leak detected during 2020 which was duly reported to the ANLA, and (2) confirm the gas accumulation tested in the year 1980. After drilling the cement plugs and controlling the well, drill stem tests ("DSTs") were carried out to determine the origin, pressure, and volume of natural gas to repair, complete, and secure the well. As previously mentioned, the Aruchara-1 well was drilled by Texaco in 1980 to a total depth of 9,715 feet and tested gas between 8,111 and 8,121 feet and between 8,051 and 8,061 feet varying from 3.4 to 9.8 MMcf/d from these two zones at that time. As part of the re-entry program, three DST procedures of this well were conducted by NG Energy. The first DST procedure occurred between 8,052 and 8,062 feet measured depth with a maximum rate of 7.75 MMcf/d through a 48/64" choke at a pressure of 2,075 psig and a final shut-in pressure of 3,505 psig. The second DST procedure occurred between 8,111 and 8,121 feet measured depth with a maximum rate of 10.98 MMcf/d through a 48/64" choke at a pressure of 2,437 psig and a final shut-in pressure of 3,547 psig. The third DST procedure occurred between 8,088 to 8,094 feet and from 8,111 to 8,121 feet measured depth, with a maximum rate of 10.420 MMcf/d through a 48/64" choke at a pressure of 2,271 psig and a final shut-in pressure of 3,521 psig. The absolute open flow potential was estimated at 19.0 MMcf/d and a potential of 14.3 MMcf/d with a 50% drawdown. DST results were reviewed by John Yu, P. Eng. as an independent Qualified Reserves Evaluator and Auditor as defined in NI 51-101, obtaining the following results: Proved Undeveloped reserves of 15,670 MMcf and Probable Undeveloped reserves of 18,912 MMcf for a total Proved + Probable reserves of 34,582 MMcf. Subsequent to testing results, the well was completed and secured, ready to produce once all necessary permits and building the required production and transportation facilities have been completed.

The Company originally drilled the Istanbul-1 well in Q1 2018 and reached a total depth of 8,740 feet measured depth ("MD"). Based on the interpretation of the open hole logs and mud log, 12 separate intervals covering a total thickness of 62.4 feet were selected and perforated for testing between 7,912 feet MD and 8,608 feet MD. The well was tested with gas and water produced to surface. Although steady state conditions were never achieved, the well was flowed for a period of seven hours at an average rate of 350,000 cubic feet of gas per day and 2,100 barrels of water per day. A production log ("PLT") confirmed that the majority of water and gas production was coming from 26 feet of perforations in the upper sand package. NG Energy subsequently filed a technical discovery notice for Istanbul-1, and an evaluation program covering an area of 32,518 acres was declared around the well in which the reserves and prospective resources exist and are covered by the existing 3D seismic.

Given that the PLT results of the Istanbul-1 well were inconclusive, it was decided to perform an in-depth re-evaluation of the 3D seismic for the area and the amplitude variation with offset (AVO) anomalies based on the new geological interpretation results. The new interpretation indicated the possibility that significant gas resources could exist for sustained development of the field. To confirm these volumes, it was necessary to carry out a sustained test in the Aruchara-1 well through a re-entry project to (1) repair a gas leak detected during 2020, and (2) confirm the accumulation tested in the year 1980. Based on the results of this testing, the re-entry in the Istanbul-1 well and the opportunities afforded by the de-watering capillary technology. This same analysis is anticipated to also be carried out in the area near the Tinka-1 well (drilled in 1988 by Ecopetrol, S.A., testing daily approximate production of 4 MMcf/d) in 2022 to define the maximum commercial capacity of the field and the possibility of drilling two more wells in the Tinka area.

Further, given the original PLT results, the Company decided to workover the well by isolating the water producing intervals in order to flow test the other potential gas bearing zones independently. These tests were conducted between March 30 and May 26, 2021, and in the new 8,396 to 8,416 feet and 8,426 to 8,438 feet intervals. A report prepared for the Company by the Scientia Group (the "Scientia Istanbul Report") dated June 28, 2021, states the following (translated from the original Spanish):

- the DST tests carried out on the Istanbul-1 well did not provide measurable information in a stable manner that would allow for a certain determination of the productive capacity of the evaluated intervals. Considering then the relevance of establishing an inferred level on the productivity of the well, theoretical exercises were carried out with the available data in order to issue a supported technical concept; and
- during the tests carried out in the Istanbul-1 well between April 2 and May 25, 2021, there was gas production that was evidenced in the torch for a period of time, but without a stable measurement record, as such (of 24 hours). However, based on the log of events that were constantly recorded, and the operating conditions, it was possible to make an estimate of gas production expressed in thousands of standard cubic feet (“Mcf”) based on these parameters.

Due to the fact that the results of the tests were not considered to be stable, and the gas production was estimated (as shown above in the excerpts from the Scientia Istanbul Report), no reserves have been assigned to the Istanbul-1 well until actual results are available.

Based on the test results described above, the Company has decided to commence the re-entry program at Istanbul-1, deploying de-watering capillary technology to lift the water that exists downhole. The Company has the following objectives:

- to determine the effectiveness of the technology;
- to lighten and move the column of liquid in the tubing;
- to achieve a surface gas volumetric response (production point test); and
- to estimate the real capacity and potential of the gas production from the well without the liquid load.

SN-9 Block

The SN-9 Block is located 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 Cienaga de Oro formation at a depth of approximately 4,250 ft. 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 acquiring 125 km^2 of 3D seismic and drilling one exploration well. Due to the ongoing COVID-19 outbreak, the Company requested from the ANH a one-year extension of the exploration commitment. This request was approved by the ANH, and the Company expects that an extension request to the ANH for an additional six months on the current deadline of July 2022 will also be granted. 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 in order to commence exploratory drilling in the SN-9 Block, including the construction of civil works, production infrastructure and the construction of up to 11 locations for a total of 22 wells to be developed. The ANLA license shall expire at the time that the Company enters into the commercialization phase at the Mágico-1 well. The Company has decided to start the SN-9 Phase 1 drilling campaign in the Mágico area due to the fact that, in February 2022, as part of the continuous evaluation of SN-9, a new seismic review of the Mágico area, including AVO anomalies re-interpretation, was carried out and it showed the presence of several class 3 bright spots and new evidence of deeper prospective zones with possible higher production expectations. Accordingly, management of the Company decided to instead start the drilling program with the Mágico-1 well followed by the other attractive Milagroso, Hechicero, and Brujo areas. The drilling in the Mágico-1 area also considers the social impacts from drilling activities - agreements with local communities in the area surrounding Mágico have been reached, including rights of way and local hiring for a faster start of civil work and drilling activities.

The Company and its contractors have begun to mobilize the drilling rig and related equipment to the location where the Mágico-1 well will be drilled and tested. The road to the platform has been completed and construction of the pad is in progress.

Resources Analysis

In March 2022, the Company announced the results of the evaluation in the Prospective Resources within the SN-9 Block with an effective date of February 28, 2022 (the “Oil Resources Report”) as prepared by Petrotech Engineering Ltd. (“Petrotech Engineering”) in accordance with the COGE Handbook. The Company confirmed best estimate unrisked prospective resources (leads) (at 100% working interest) of 279,336.90 Mbbl, low estimate unrisked prospective resources (leads) of 76,231.50 Mbbl and high estimate unrisked prospective resources (leads) of 608,665 Mbbl at the SN-9 Block. Of the Company's 72% working interest in the SN-9 Block, the best estimate unrisked prospective resources (leads) at the SN-9 Block are 201,122.57 Mbbl, low estimate unrisked prospective resources (leads) are 54,886.68 Mbbl and high estimate unrisked prospective resources (leads) are 438,238 Mbbl. No risk assessment has been conducted until the leads can be upgraded to prospects. It is important to note that there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

In completing their evaluation, Petrotech Engineering noted that there was limited seismic coverage to conduct a complete structural/stratigraphic interpretation in the northwestern portion of the SN-9 Block. In addition, not all the 2-D seismic lines were available and some of the images of the lines were not clear. Four 2-D seismic lines (with a total length of 258.2 km) were used to interpret the occurrence of a sedimentation section resulting in two seismic reflectors in the top and the base of the sedimentary section. The sedimentary section is likely to contain the San Cayetano and Maco Formations in the SN-9 Block. Using isochron data and the ANH LA X-1 stratigraphic well, which contains good oil shows in various sections of the cores, as the reference point, the low, best and high estimated areas of this lead was mapped. The ANH LA X-1 Stratigraphic Well was drilled in 2015 to a total depth of 4,130 ft. Various cores were taken in nine intervals totaling 369 ft between 564 ft and 4,108 ft together with an electric (SP and resistivity) log to a depth of 3,505 ft. The volumetric method was used to estimate the recoverable unrisked prospective resources (lead). The Company intends to drill a twin well offsetting the ANH LA X-1 stratigraphic well to evaluate and test the light oil in the sedimentary section of the cores.

Current Objectives

The Company is in the process of carrying out the exploration activities in stages which will satisfy the minimum work obligations. The first stage consisted of the finalization of the environmental impact study and prior consulting processes in order to obtain the necessary environmental licenses to be able to drill. The Company finished the environmental impact study and received the requisite environmental licenses to commence drilling operations. Current plans are the drilling of two initial exploration wells in the Magico and Milagroso areas. The second stage will focus on evaluating the Hechicero/Brujo areas and Hechizo areas, including drilling two additional exploration wells and acquiring 3D seismic for the development of the field. However, due to the ongoing COVID-19 outbreak, activities related to obtaining the environmental license have been delayed. As such, Clean (the field operator) requested an extension of the Phase 1 exploration commitment, which was approved by the ANH until July 2022. The Company has commenced civil works for the construction of the drilling site in anticipation for the mobilization of the drilling rig by Q2 2022 to commence the initial drilling plan previously outlined.

Exploration Activities

During December 2020, the Company announced that it had received a binding commercial offer from CPVEN (the "Binding Offer"). Under the Binding Offer, the companies will enter into a market pricing-based preferred supply agreement for drilling and gas well services activities for all phases of the SN-9 exploration program. CPVEN has initially committed to construct and complete four gas wells, including mobilization, demobilization, engineering, drilling and completion, for an aggregate cost of $27.2 million. CPVEN has developed its own technology and has the managerial and technical personnel capable of executing complex operations, utilizing state-of-the-art infrastructure and equipment design.

Service providers have completed building the civil infrastructure as well as the drilling pad for the Magico-1 well required to drill and test the well, which is expected to commence in late May 2022. At least three intervals of interest have been identified and will be tested.

In relation to the SN-9 permitting process, the Environmental Impact Study for the exploratory drilling area was delivered to ANLA in December 2020 with the follow up requirements being attended to in May 2021. The governmental authority issued the administrative environmental licensing act in September

2021. Magico-1 is the first of four wells to be drilled in the SN-9 Block, with focus on the Cienaga de Oro Formation, similar to the Aguas Vivas-1 well and other producing wells in the area.

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 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 into 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 that are 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.

Due to the ongoing COVID-19 outbreak, the Company requested from the ANH a one-year extension of the exploration commitment. This request was not approved as the Phase 3 commitments are still currently suspended due to the aforementioned 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 intends to start environmental and social analyses to execute seismic activities, pending the outcome of the ongoing COVID-19 outbreak and the resolution of the local community conflicts that are impeding any progress in the area.

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:

- 10% 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. In the event that 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 short-term focus is completing the connection of the Aruchara-1 well to the nearby TGI main line, with the objective of monetizing its natural gas resources and capitalizing on a premium pricing market in Colombia of over $5 MMBtu. The connection with the TGI main line, which will transport natural gas from Maria Conchita to market, is expected to turn the Company into a revenue producing entity as it will allow it to feed up to 20 MMcf/d into the Colombian gas system; the Company's production facilities will be programmed to produce between 16 and 20 MMcf/d. Given the current shortage of gas in Colombia, the Company has a reasonable expectation that any gas that it produces will be purchased. In that regard, it is negotiating gas supply contracts and has signed two letters of intent for interruptible supply from two utilities, and has received a proposal from a trading company, committing for up to an aggregate of 20 MMcf/d at indicative prices of $5.08/MMBtu. The commencement of this revenue stream is expected to assist the Company with improving on its working capital deficiency and facilitate funding the interest payable on the Convertible Debentures.

The Company continues to move forward with its planned exploration program in the Maria Conchita and SN-9 Block as was mentioned 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 the country. The Company currently expects exploration activities to begin in Q2 2022 with the commencement of the drilling activities outlined above.

Furthermore, the aforementioned 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 re-entry project of the Aruchara-1 well did assist in confirming the size of the accumulation of natural gas in the Aruchara area, which allowed the Company to design the best development plan for this area of the field and to establish production and transportation facilities. Extended tests of prospective gas zones are expected to take place in Q2 2022. After the re-entry of Istanbul-1 well in 2021, re-entry of the Tinka-1 at a future date could test several prospective zones based on new geological and seismic re-interpretation and the results of the capillary dewatering technology deployment at the Istanbul-1 well.

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

DISCUSSION OF OPERATING RESULTS

General and Administrative Expenses

General and administrative ("G&A") expenses for the three months ended March 31, 2022, totaled $1,048,561 (2021 comparative period - $766,921). The G&A expenses relate to the normal course of the Company's operations, and are constituted as follows:

	Q1 2022	Q1 2021	Q4 2021	Q3 2021	Q2 2021
Professional Fees	229,523	335,278	658,393	173,368	428,034
Wages & Salaries	188,940	51,790	242,130	122,675	51,095
Other	630,098	379,853	715,156	324,953	301,540
Total	**1,048,561**	**766,921**	**1,615,679**	**620,996**	**780,669**

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

No stock options were issued during the three months ended March 31, 2022. The value of the stock options vesting in the three months ended March 31, 2022 equated to $nil (March 31, 2021 - $nil).

Finance Income and Expense

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

	Q1 2022	Q1 2021	Q4 2021	Q3 2021	Q2 2021
Interest income	(24,715)	(22,665)	(22,607)	(18,319)	(18,786)
Interest expenses and bank charges	115,951	144,650	143,243	169,281	152,662
Commitment fee	-	25,333	-	-	22,250
Accretion on decommissioning obligation	2,849	1,374	2,326	1,380	1,376
Amoritzation of transaction costs on Loans	8,292	11,444	11,258	11,926	11,270
Net finance expenses	**102,377**	**160,136**	**134,220**	**164,268**	**168,772**

Foreign Exchange

The Company incurred a foreign exchange gain of $402,750 for the three months ended March 31, 2022 (2021 comparative period – foreign exchange loss of $370,079). Foreign exchange losses are due to the decrease in the value of the US dollar when compared to the Canadian dollar and the Colombian peso in the period. Conversely, foreign exchange gains are due to an increase in the value of the US dollar in comparison to these other currencies.

Cash used in Continuing Operations

For the three months ended March 31, 2022, the Company used cash in continuing operations of $1,128,408 (2021 comparative period - $1,060,720). The cash used in operations is primarily comprised of G&A expenses and finance expenses incurred during the period.

CAPITAL ADDITIONS

For the three months ended March 31, 2022, the Company had additions (prior to recognition of any impairments, disposals or revisions of estimates) of $0.6 million relating to exploration and evaluation assets and $7,903 relating to property, plant and equipment. Additions to exploration and evaluation assets relate primarily to 1) on-going capital activities for the Aruchara well tie-in to pipeline infrastructure; and 2) preparatory work for the upcoming drilling program in the SN-9 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 makes adjustments to 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.

The Company currently has no production and had no source of revenue. Further, during the three months ended March 31, 2022, the Company recognized a net loss of $0.8 million and cash used in operating activities of $1.1 million. As of March 31, 2022, the Company had a working capital deficit of $0.3 million. For 2022, the Company has contractually committed exploration and development amounts of $25.3 million as outlined below. The need to obtain capital to fund the Company’s ongoing operations, and capital commitments, and the ultimate development of the Company’s exploration and evaluation assets give rise to a material uncertainty that creates significant doubt on the Company’s ability to continue as a going concern.

The Company, in February 2021 and October 2021, closed separate private placements for aggregate gross proceeds of $7.7 million and $6.5 million, respectively. For the year ended December 31, 2021, the Company received proceeds of $1.7 million on the exercise of purchase warrants. The Company also received proceeds of $0.6 million on the exercise of purchase warrants during the first quarter of 2022. 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 are not sufficient to fund the Company's ongoing operational and capital commitments. While the Company is also currently undertaking a best-efforts financing arrangement as mentioned above, there can be no certainty as to the amount, if any, of proceeds that will be raised. The Company will require additional sources of capital to fund ongoing operational requirements and capital commitments which may not be available when needed.

Due to the conditions noted above, there remains a material uncertainty surrounding the Company's ability to obtain sufficient financing to meet its operational requirements and capital 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 these Financial Statements and that the Company will be able to meet its operational requirements and capital commitments as well its other potential capital 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, these 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 in order 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 is denominated in US dollars, matures in August 2022, and bears interest at the rate of 15% per annum. The proceeds of the loan are to be utilized for the costs of exploratory activities in the SN-9 Block. Under the terms of the loan agreement, the lenders have also been granted a 3% overriding royalty on NG Energy's working interest in the gross production of the SN-9 Block. Total interest and principal is payable at the maturity date, although the lenders have 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. Currently, no value has been attributed to the 3% overriding royalty or the conversion option for an additional 3% overriding royalty as this is contingent upon the successful realization of commercially viable operations within the SN-9 Block.

Restricted Cash

As of March 31, 2022, funds totaling $2,487,186 (December 31, 2021 - $2,340,244) comprised the balance represented in restricted cash. The composition of this amount is as follows:

	2022	2021
SN-9 ANH Guarantee	2,165,423	2,039,321
Tiburon ANH Guarantee	321,763	300,923
	2,487,186	**2,340,244**

Term deposits of $2.4 million and $0.3 million were originally established to secure performance guarantees required by the ANH under the E&P Contracts for the SN-9 and Tiburon Block. The SN-9 and Tiburon deposits amounts are 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. These deposits are to be released to the Company once current phase commitments under each E&P Contract are completed. As of March 31, 2022, the balances of the SN-9 term deposit and Tiburon term deposit were $2,165,423 and $321,763 respectively.

SHARE CAPITAL

Common shares

As at March 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 share and to dividends, if declared. Outstanding common shares as of March 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	2,633,333	705,369
Shares issued through option exercise	30,000	11,108
Balance, March 31, 2022	**122,593,488**	**104,289,282**

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 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 at March 31, 2022, a total of 9,885,400 (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 exercised	(30,000)	0.275
Balance, March 31, 2022	**9,885,400**	**0.85**

The following summarizes information about stock options outstanding as at March 31, 2022:

Exercise prices (C$)	Number of options outstanding	Weighted average term to expiry (years)	Number of options exercisable
0.275	1,346,000	8.23	1,346,000
0.45	2,125,000	7.26	2,125,000
0.91	2,375,000	9.08	2,375,000
1.00	3,900,000	8.65	3,900,000
6.10	29,400	4.39	29,400
8.00	110,000	5.36	110,000
	9,885,400	**8.35**	**9,885,400**

Warrants

As at March 31, 2022, a total of 22,856,040 (December 31, 2021 – 25,489,373) 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 exercised	(2,633,333)	0.28
Balance, March 31, 2022	**22,856,040**	**3.51**

The following summarizes information about total purchase warrants outstanding as at March 31, 2022:

Exercise prices (C$)	Number of warrants outstanding	Weighted average term to expiry (years)	Number of warrants exercisable
0.23	2,377,778	0.16	2,377,778
1.15	475,600	1.86	475,600
1.20	8,141,600	1.56	8,141,600
1.50	2,036,412	1.75	2,036,412
1.75	4,199,650	1.86	4,199,650
10.50	5,625,000	0.33	5,625,000
	22,856,040	**1.19**	**22,856,040**

As of the date of this MD&A, the Company has 123,171,266 common shares, 9,885,400 stock options, and 22,278,262 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	2022	2023	Total
SN-9 Block (1)	22.3	-	**22.3**
Tiburon Block (2)	3.0	-	**3.0**
Total	**25.3**	**-**	**25.3**

1) NG Energy's ANH commitment to carry out the minimum requirement to process and interpret 204.4 km of 2D seismic and drill one exploration well (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. On account of the ongoing COVID-19 outbreak during which non-essential oil & gas operations were suspended by the Government of Colombia for several months, program extensions are being provided by the ANH. The Company expects that the extension request to the ANH for an additional 6 months on the current deadline of July 2022 will be granted.
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 2022.

The expenditures provided in the above table only represent the Company's estimated cost to satisfy contract requirements. Actual expenditures to satisfy these commitments, initiate production or create 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 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 in order to provide daily natural gas compression services for a capacity of 16 MMcf/d of natural gas production for a term of six years from the commencement of commercial natural gas production within the Maria Conchita Block. For these services, the Company has committed to pay a monthly service fee of $96,240 to Surenergy over the six-year term of the service contract. The monthly service fee is to be paid to Surenergy each month regardless of whether the Company fully utilizes the daily stipulated gas compression capacity made available by Surenergy under the terms of the service contract. Future amendments to the service contract may be made upon mutual agreement of both parties. The Company may unilaterally terminate the service contract prior to the completion of the six-year term with 30 days notices, but a final fee equal to 20% of the monthly service fee for the remaining life of the service contract would be assessed and paid by the Company. As of the date hereof, commercial natural gas production has not commenced within the Maria Conchita Block.

Natural Gas Delivery Contract

The Company has entered into a take-or-pay natural gas delivery contract with Energy Transitions SAS ESP (the "Buyer") for a ten-year period that was initially to commence December 1, 2021, pending initiation of commercial natural gas production within the Maria Conchita Block. The Company is to deliver natural gas production volumes of 16 MMcf/d (the "Daily Committed Production") to Energy Transitions SAS ESP once production testing has been completed after well tie-in (the "Committed Period"), with gas sales prices commencing at $5.08 per MMBtu and indexed annually with the Producers Price Index (PPI) series WPSFD41312. During the Committed Period, in the event that the Company is unable to deliver the Daily Committed Production, the Company will be required to compensate the Buyer the monetary equivalent of the production deficiency. As of the date hereof, commercial natural gas production has not commenced within the Maria Conchita Block. Management is currently negotiating with the Buyer to convert the agreement so that it is on an "as available", rather than a take or pay basis.

Natural Gas Transportation Services

As previously mentioned, in December 2020, the Company entered into the MOU with GTX pursuant to which GTX is to build and 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 field in Colombia to existing national infrastructure. The MOU outlines that the Company and GTX will enter into a take-or-pay agreement (the "ToP Agreement") pursuant to which NG Energy will agree 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 per MMBtu of gas. The Company's Guaranteed Commitment will convert after six years into payment for only the capacity that is used. The ToP Agreement will have a term of 18 years, after which ownership of the Pipeline Facilities will transfer to the Company. Under the terms of the MOU, the execution of the ToP Agreement is conditional upon 1) the successful raise by GTX of $10 million in financing (which was accomplished), and 2) the construction of the Pipeline Facilities and the satisfactory results of operational trials of the infrastructure by GTX. As of the date hereof, construction of the Pipeline Facilities by GTX has been completed, with the testing and commissioning of the Pipeline Facilities still in progress.

RELATED PARTIES

During the periods ended March 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. As per the consulting agreement, NG paid the firm $26,062 and $26,334 for the three months ended March 31, 2022 and 2021, respectively. Furthermore, additional fees are 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 2021 private placements through units which resulted in the Company paying $81,017 to the firm for the three months ended March 31, 2021. As at March 31, 2022, there were no outstanding payables owed to the firm.

II. The Company incurred professional fees for general corporate services as well as technical services related to exploration activities in Colombia of $153,165 and $76,323 for the three months ended March 31, 2022 and 2021, respectively. Such services were provided by a contracted service provider affiliated with a certain director of the Company. As at March 31, 2022, there were no outstanding payables owed to the service provider.

III. The Company incurred office rental costs in Colombia expenditures of $19,684 and $15,816 for the three months ended March 31, 2022 and 2021, respectively. The related office space was rented from an entity affiliated with a certain director of the Company. As at March 31, 2022, a payables balance of $7,854 was owed to the to the lessor entity.

IV. In February 2021, the Company completed a non-brokered private placement offering of 429,300 units, on the same terms as those issued pursuant to the February 2021 bought deal financing, for a deemed value of $388,452. 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.

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.

	Q1 2022	Q4 2021	Q3 2021	Q2 2021
Net loss	(798,255)	(2,128,480)	(2,350,803)	(936,492)
Comprehensive loss	(826,278)	(2,297,814)	(2,231,135)	(897,121)
Net loss per share (basic & diluted):	(0.01)	(0.02)	(0.02)	(0.01)

	Q1 2021	Q4 2020	Q3 2020	Q2 2020
Net loss from continuing operations	(1,298,672)	(4,509,344)	(15,210,453)	(2,449,415)
Loss from discontinued operations	-	-	(1,232,194)	(106,130)
Net loss	(1,298,672)	(4,509,344)	(16,442,647)	(2,555,545)
Comprehensive loss	(1,282,873)	(4,659,277)	(17,047,824)	(2,735,973)
Net loss per share (basic & diluted):				
Continuing operations	(0.01)	(0.05)	(0.32)	(0.07)
Discontinued operations	-	-	(0.03)	(0.00)
Net loss	(0.01)	(0.05)	(0.35)	(0.07)

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 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 exchange 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.

In the fourth quarter of 2020, no further income or loss from discontinued operations was recognized given the Company's departure from Argentina. $1,920,397 in share-based compensation expenses was recognized as the Company issued stock options in the quarter that vested immediately upon grant. G&A expenses of $212,033 were incurred in the quarter. $2,663,000 in transaction costs were also recognized in the quarter as transaction costs of a private placement in December 2020.

In the third quarter of 2020, the Company recognized a $1,175,063 impairment loss within the Company's quarterly loss from discontinued operations relating to the Company's Argentinian subsidiary as it was determined that the carrying amount of the Argentina assets was unlikely to be recovered in full upon completion of the sale. There was also a $14,302,667 million fair value loss on a derivative liability incurred in the quarter. Furthermore, G&A expenses of $647,619 were incurred in Q3 2020.

In each of the first and second quarter of 2020, G&A expenses of $297,581 and $389,751, respectively, were incurred. Fair value changes on derivative liability were the other main contributor to operating results in Q1 and Q2 2020. A fair value gain of $1,658,548 was recognized in Q1 2020, and a fair value loss of $2,067,377 was recognized in Q2 2020.

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 and crude oil assets and processing facilities are grouped into cash generating units ("CGUs") identified as having largely independent cash flows 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*
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 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, that 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 and probable reserves and prospective resource estimates include estimates regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves and prospective resources may change from period to period. Changes in reported reserves and prospective resources can impact the carrying values of the Company's petroleum and 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 petroleum and natural gas reserves, if any, represent the estimated quantities of petroleum, 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 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 petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. 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 petroleum and gas reserves and prospective resources are determined pursuant to National Instrument 51-101, Standard of Disclosures for Oil and Gas Activities.

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 have to 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 profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse.

Risks and Uncertainties

Exploration, development, production of oil and natural gas involves a wide variety of inherent risks as a result 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:

- Unforeseen title defects;
- Inability to obtain additional capital required to implement business plan;
- Joint venture risks;
- Global financial conditions;
- COVID-19 pandemic;
- Personnel;
- Directors and officers;
- Changes in laws or regulations;
- Forward-looking statements may prove inaccurate;
- Going concern risk;
- E&P contracts;
- Volatility of pricing for oil and natural gas;
- Exploration, production and general operational risks;
- The company may not be able to develop oil and natural gas reserves on an economically viable basis;
- Estimated oil resources and gas reserves are based on assumptions that may prove inaccurate;
- Delays in production, marketing and transportation;
- Drilling costs and availability of equipment;
- Drilling wells could result in liabilities;
- Insurance;
- Inability to obtain necessary facilities;
- Decommissioning costs;
- Licenses and permits;
- Competition;
- Difficulty transporting and distributing production;

- Environmental, health and safety risks;
- Climate change;
- Natural disasters and weather-related risks;
- Operations in emerging market country;
- Economic and political developments in Colombia;
- Oil and natural gas companies in Colombia do not own any of the oil and natural gas reserves in the country;
- Sanctions by the United States on Colombia;
- Violence and instability in Colombia;
- Natural gas industry in Colombia is less developed;
- Land, communities, prior consultation and zoning restrictions;
- Activities in areas classified as Indigenous reserves and Afro-Colombian lands; and
- Volatility in the prices of crude oil, oil products and natural gas.

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 actually 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 April 13, 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, accounts receivable, VAT receivable and restricted cash represent the maximum credit exposure. As at March 31, 2022, the Company had $2,487,186 (December 31, 2021 - $2,340,244) in restricted cash towards development activity and joint operations in Colombia.

As at March 31, 2022, the Company had $1,601,601 (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 $2,538,525 as of March 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 $3,524,557 (December 31, 2021 - $5,848,957) as at March 31, 2022. The Company manages the credit exposure related to cash and cash equivalents and short-term investments by selecting counter parties (e.g., banks) based on 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 at March 31, 2022:

	Less than 1 year	1-2 years	Thereafter	Total
Trade accounts payable	2,021,476	-	-	2,021,476
Capital payables	330,881			330,881
SN-9 loan - principal	2,500,000	-	-	2,500,000
SN-9 loan - finance costs	606,250	-	-	606,250
	5,458,607	**-**	**-**	**5,458,607**

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 at March 31, 2022 nor were there any in 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 as a result of changes in commodity prices. Commodity prices for petroleum and 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 currently has no production revenue as of March 31, 2022.

Foreign currency risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate as a result 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$). In addition, the majority of the Company's financing and a portion of the administrative costs will be based and paid in Canadian dollars and COP$. Therefore, the Company is exposed to the risk of fluctuations in foreign exchange rates between US dollars, COP$ and Canadian dollars.

As at March 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 as a result of changes in prevailing market interest rates. Fluctuations of interest rates for the three months ended March 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, labour 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 April 13, 2022, 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 in light of 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 a number of 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 favourable 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 April 13, 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 National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("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. In particular, 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 as a result 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 Canadian Oil and Gas Evaluation 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 .

Barrels of Oil Equivalent

Where amounts are expressed in a barrel of oil equivalent (“boe”), or barrel of oil equivalent per day (“boe/d”), natural gas volumes have been converted to barrels of oil equivalent on the basis that 6 thousand cubic feet (“Mcf”) is equal to one barrel of oil. Use of the term boe may be misleading, particularly if used in isolation. This boe conversion ratio is based on an energy equivalence methodology and does not represent a value equivalency. Indeed, the energy and value relationships may differ widely with market conditions. The conversion does conform to the Canadian Securities Regulators’ National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities.

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/d	*million cubic feet per day*
NGLs	*natural gas liquids*
API	*American Petroleum Industry gravity*
m^3	*meters cubed*
ppm	*parts per million*
psig	*pounds per square in gauge*