NG ENERGY INTERNATIONAL CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE MONTHS ENDED MARCH 31, 2024

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, 2024, as well as information and expectations concerning NG Energy's outlook is based on currently available information.

This MD&A should be read in conjunction with NG Energy's interim condensed consolidated financial statements for the three months ended March 31, 2024, as well as the audited annual consolidated financial statements for the year ended December 31, 2023 (the "**Financial Statements**") which were prepared by management in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("**IFRS Accounting Standards**").

This MD&A contains forward-looking information about our current expectations, estimates, projections, and assumptions. See the reader advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Additional information on the Company, its Financial Statements, this MD&A and other factors that could affect NG Energy's operations and financial results are included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated April 26, 2024 ("**AIF**") as approved by the Company's Board of Directors, and may be accessed through SEDAR+ at www.sedarplus.ca.

All financial amounts are expressed in United States (US) dollars, unless otherwise indicated.

The Company's functional currency is the Canadian dollar while each of its subsidiaries with significant activity has US dollar functional currency, which is the primary economic environment in which each subsidiary operates.

This MD&A is prepared as of May 29, 2024.

Non-IFRS Measures

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

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

PRESENTATION OF OIL AND GAS RESERVES, RESOURCES AND PRODUCTION INFORMATION

Caution Respecting Reserves Information

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

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

Caution Regarding Use of Barrels of Oil Equivalent (BOEs)

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

Definitions

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

Resources

"**Contingent resources**" are those quantities of oil or natural gas estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe.

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

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

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

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

- **Play:** This is the lowest and least defined level of prospective resources and is a project associated with a prospective trend of potential prospects, but which requires more data acquisition and evaluation to define specific leads or prospects.
- **Lead:** This is the next level of prospective resources and is a project that is poorly defined and requires additional data acquisition and evaluation.
- **Prospect:** This is the best-defined level of prospective resources and represents a project that is sufficiently well defined to represent a viable drilling target, although remains undiscovered.

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

- **Low Estimate**: This is a conservative estimate of the quantity that will be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities recovered will equal or exceed the low estimate.

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

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

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

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

Reserves

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

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

"**Probable reserves**" are those additional reserves that are less certain to be recovered than Proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved + 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 + Probable + Possible reserves. There is a 10 percent probability that the quantities recovered will equal or exceed the sum of Proved + Probable + Possible reserves.

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

- at least a 90% probability that the quantities recovered will equal or exceed the estimated Proved reserves; and

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

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

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

"**Developed Producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Non-Producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

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

Interests in Reserves, Production, Wells and Properties

"**Gross**" means:

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

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

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

"**Net**" means:

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

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

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

Description of Exploration and Development Wells and Costs

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

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

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

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

(d) provide improved recovery systems.

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

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

Condensate

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

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

OPERATING INCOME AND NETBACK

"Operating Income" is calculated by deducting operating expense from total revenue. Total revenue is comprised of natural gas and natural gas liquids sales, net of royalties. The Company refers to Operating Income expressed per unit of production as an "Operating Netback". "Operating Income Profit Margin" is calculated by the Company as Operating Income as a percentage of natural gas sales. A reconciliation of the measures for three months ended March 31, 2024 and 2023, is as follows:

	Q1 2024	Q1 2023
Natural Gas Sales	10,190,283	2,096,853
NGL Sales	46,830	-
Royalties	(1,676,048)	(393,342)
Operating Expenses	(1,104,973)	(566,605)
Operating Income	7,456,092	1,136,906
Gas Sales volume (Mcf)	1,273,373	406,186
Natural Gas Sales (per Mcf)	8.00	5.16
Royalties (per Mcf)	(1.32)	(0.97)
Operating Expenses (per Mcf)	(0.87)	(1.39)
Natural Gas Operating Netback per Mcf	5.81	2.80
Natural Gas Operating Income Profit Margin	72.6%	54.3%
NGL Sales volume (Bbls)	893	-
NGL Sales (per Bbl)	52.44	-

CORPORATE OVERVIEW AND UPDATE

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

Macquarie Financing

In February 2024, the Company announced that it had entered into a definitive credit and guarantee agreement (the "**Credit Agreement**") with Macquarie Group ("**Macquarie**") for a financing of up to $100 million of which $50 million is committed funding (the "**Macquarie Financing**"). The Macquarie Financing is secured by a first priority lien over all the assets of the Company, its wholly owned subsidiaries and a trust formed in Colombia and matures on December 29, 2028.

In March 2024, the Company received an initial advance of $40 million pursuant to the terms of the Macquarie Financing, with the remaining $10 million in committed funding to be advanced to the Company on a date to be determined pursuant to the terms of the Credit Agreement. The Company intends to use the net proceeds to: (i) simplify the Company's capital structure; (ii) optimise the Company's balance sheet; (iii) reduce the overall leverage of the Company; and (iv) for general corporate purposes as the Company continues to develop its asset base. The additional $50 million in uncommitted funding will be made available to the Company by Macquarie under an accordion feature.

In addition, the Company obtained an uncommitted letter of credit facility from Macquarie of up to an additional $13.6 million (the "**LC Facility**"). The Company intends to use the net proceeds of the LC Facility to guarantee work commitments under the Company's contracts with midstream partners and with the ANH.

In connection with the Macquarie Financing, the Company issued 20,742,857 Common Share purchase warrants to Macquarie (the "**Bonus Warrants**"). Each Bonus Warrant entitles Macquarie to purchase one Common Share at an exercise price equal to C$1.00 until December 29, 2028.

Conversion and Redemption of Outstanding Convertible Debentures

In March 2024, in connection with the Macquarie Financing, 100% of the holders of the Company's debentures issued in November 2022 and July 2023 (the "**Debentures**"), elected to convert or redeem their Debentures in accordance with their terms. Holders of C$2.4 million face value of Debentures chose to redeem, resulting in payment of C$3.0 million in principal, interest and redemption premium per the Debenture terms. Holders of the remaining C$67.2 million face value of Debentures chose to convert, resulting in the issuance of 85,731,098 common shares and payment of C$30.3 million in interest and conversion premium per the Debenture terms. Upon completion of the conversion and redemption of the Debentures, the remaining balance of $1.2 million of existing deposits in escrow was released to the Company.

Changes to Company Officers

In March 2024, the Company announced, in conjunction with the closing of the Macquarie Financing, that Mr. Brian Paes-Braga had been appointed as Chief Executive Officer of the Company. Former Chief Executive Officer, Mr. Serafino Iacono transitioned to the role of Co-Chair of the Board alongside Mr. Paes-Braga.

Shares for Debt Settlement with Plus+

In March 2024, the Company announced that it completed a shares for debt settlement with Plus+ SAS ESP ("**Plus+**"), whereby the Company issued 2,000,000 Common Shares to Plus+ at a deemed issuance price of C$1.00 per Common Share in full satisfaction of $1,502,000 owing to Plus+ pursuant to the terms of a termination agreement entered into between the Company and Plus+ in relation to the termination of the existing natural gas supply contract between the parties. For more information concerning the termination agreement, please see the "*Maria Conchita Block*" section.

Commercialization of Maria Conchita Gas Production

In December 2023, the Company announced that it had signed a long-term take-or-pay contract with Vanti SA ESP ("**Vanti**"), Gases del Caribe SA ESP ("**Gases del Caribe**") and Gases del Occidente S.A ESP ("**Gases del Occidente**") pursuant to which the Company will realize sales of natural gas from the Maria Conchita Block for a period for a duration of three years commencing on December 1, 2023 (the "**Take-or-Pay Contracts**"). The Company further announced that it had commenced realizing sales of natural gas from the Maria Conchita Block at prices ranging from $7.70 - $8.20 per Mcf. The Take-or-Pay Contracts are significant for the Company's future development as they provide a stable cash flow for the Company moving forward.

In April 2024, the Company announced that it had signed additional long-term natural gas sales contracts with Vanti, Gases del Caribe, Gases del Occidente, Grupo Energetico de las Americas SAS ESP – GEAM ("**GEAM**") and Empresas Publicas de Medellin E.S.P. ("**EPM**") (the "**Additional Natural Gas Sales Contracts**"). With the Additional Natural Gas Sales Contracts in place, the Company has now sold approximately 14.8 MMcf/d from the Maria Conchita Block under long-term natural gas sales contracts. The balance of the production from the Maria Conchita Block is being sold into the spot market on an interruptible basis.

Commercialization of SN-9 Gas Production

In September 2023, the Company announced that it, together with Clean and Desarolladora Oleum had reached agreements with Surenergy, INFRAES and Grupo Energetico de las Americas SAS ESP – GEAM ("**GEAM**") to accelerate the schedule for commercial production from the SN-9 Block (the "**Offtake Agreements**"). Pursuant to the terms of the Offtake Agreements, 30 MMcf/d of natural gas will be brought online in Q2 2024**,** with an additional 10 MMcf/d of production to be brought online by no later than the end of Q1 2025; however, the Company expects this to occur prior to the end of Q4 2024. Once brought online, total initial production volumes will reach 40 MMcf/d.

Drilling of the Aruchara-3 Well

In Q3 2023, the Company drilled the Aruchara-3 well from the same pad as the Aruchara-1 well to a total depth of 9,050 feet. The Company encountered 570 feet of net pay in the Jimol formation between 6,000 and 7,500 feet after experiencing gas showings throughout the 1,500 feet. The Company completed the testing of the well with 3 successful Drill Stem Tests ("**DSTs**"), with resulting peak gas productions rate of: 16.7 MMcf/d from DST-1; 23.5 MMcf/d from DST-2; and 25 MMcf/d from DST-3. The Company concluded that more than 1,200 feet of naturally fractured section is present, which includes the presence of gas and condensate. Initially, the Aruchara-3 well was producing, in conjunction with the Aruchara-1 well, a baseline of 14 MMcf/d. In December 2023, production volumes were further increased to 16.4 MMcf/d and as of February 2024, natural gas production from the Maria Conchita Block had increased to 19.4 MMcf/d with 100% of natural gas volumes sold.

Joint Operating Agreement / VMM39 Block Option

In August 2023, the Company announced that it had entered into an investment and option agreement with Clean and had acquired the option (the "**VMM39 Option**") to acquire a 25% working interest in the VMM39 Block, located in the center of Colombia in the Middle Magdalena Basin (the "**VMM39 Block**"). The VMM39 Option is exercisable by the Company, in its sole discretion and for no additional consideration, upon the completion of the San Diego-1X exploration well in the VMM39 Block.

In consideration for the VMM39 Option, the Company issued a total of 6,592,000 Common Shares to Clean at a deemed issuance price of C$0.80 per Common Share for total Common Share consideration of approximately $4 million. Additionally, the Company placed cash into escrow in the amount of $5.5 million specifically allocated for investment into the drilling and development activities at the San Diego-1X well.

Changes to the Board of Directors

In August 2023, the Company announced changes to the Board of Directors with Mr. Brian Paes-Braga joining the Board as the Company's Chairman and Mr. Don Sewell and Mr. Brian T. O'Neill joining the Board as Directors. In conjunction with these appointments, Mr. Ronald Pantin transitioned out of his role as Chair, but remained on the Board as a director and Mr. Gordon Keep and Mr. Jeffrey Harder retired from the Board. In January 2024, the Company announced that Mrs. Patricia Herrera Paba had been appointed to the Board at the annual and general and special meeting of shareholders held on January 15, 2024.

2023 Non-Brokered Private Placement

In July 2023, the Company completed a non-brokered private placement offering (the "**July 2023 Offering**") of 35,000 senior secured convertible debenture units of the Company at a price of C$1,000 per debenture unit for aggregate gross proceeds of C$35,000,000. Each convertible debenture unit consisted of: (i) one 10% senior secured convertible debenture with a principal amount of C$1,000; and (ii) 1,000 Common Share purchase warrants of the Company, with each warrant entitling the holder thereof to purchase one Common Share at an exercise price equal to C$0.90 until July 31, 2026.

The principal amount of each convertible debenture was convertible at the option of the holder, for no additional consideration, into Common Shares at a price equal to C$0.70 per Common Share. In connection with the Macquarie Financing, 100% of the holders from the July 2023 Offering elected to convert or redeem their debentures.

Net proceeds from the July 2023 Offering were used by the Company: (i) to complete the drilling and rework activities at the Aruchara-3 and Aruchara-1 wells, respectively, to fill pipeline capacity at the Maria Conchita Block; (ii) for the continued development of the SN-9 Block, including to satisfy ongoing social and environmental costs and ANH guarantees; (iii) to advance the Company's oil strategy with drilling activities at the VMM39 Block; and (iv) for working capital and general corporate requirements.

Cease Trade Order

In May 2023, the Company received a cease trade order pursuant to Multilateral Instrument 11-103 – Failure-to-File Cease Trade Orders in Multiple Jurisdictions from the British Columbia Securities Commission for its failure to file its audited annual financial statements, corresponding management's discussion and analysis and certification of annual filings for the year ended December 31, 2022 (the "**Financial Materials**") by the prescribed deadline. The Company filed the Financial Materials on June 30, 2023, and the BCSC subsequently lifted the cease trade order and trading of the Company's securities resumed on July 10, 2023.

COLOMBIAN OIL AND NATURAL GAS PROPERTIES

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

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

Maria Conchita Block

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

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

Over the course of the quarter ended March 31, 2024, the Company continued to monetize the natural gas produced from the Maria Conchita Block, while focusing on growing the Company's production base. In February 2023, the Company entered into a natural gas supply contract (the "**Natural Gas Contract**") with Plus+, whereby the Company agreed to deliver natural gas up to 3,600 MMbtu per day to Plus+, and Plus+ agreed to receive, pay and allocate such natural gas for a period of eighteen months in accordance with the terms of the Natural Gas Contract. The Natural Gas Contract was originally crucial for the Company in its efforts to monetize the natural gas produced at the Maria Conchita Block. However, due to changes in market conditions, the Company and Plus+ agreed to terminate the Natural Gas Contract effective December 31, 2023. Additionally, in March 2023, the Company entered into an interruptible supply contract with Gases del Caribe to sell natural gas produced from the Aruchara-1 well until November 30, 2023.

In December 2023, the Company entered into the Take-or-Pay Contracts with Vanti, Gases del Caribe and Gases del Occidente, pursuant to which the Company will realize sales of natural gas from the Maria Conchita Block for a period of three years commencing on December 1, 2023. The Take-or-Pay Contracts are significant for the Company's future development as they provide a stable cash flow for the Company moving forward. Additionally, in April 2024, the Company entered into the Additional Natural Gas Sales Contracts with Vanti, Gases del Caribe, Gases del Occidente, GEAM and EPM, pursuant to which the

Company will realize sales of natural gas from the Maria Conchita Block for a period of three to five years. With the Additional Natural Gas Sales Contracts in place, the Company has now sold approximately 14.8 MMcf/d of production from the Maria Conchita Block under long-term natural gas sales contracts. The balance of the production from the Maria Conchita Block is being sold into the spot market on an interruptible basis.

In terms of expanding the Company's production base at the Maria Conchita Block, in May 2023, the Company received approval from the ANH to commence the drilling of the Aruchara-3 well. Drilling of the Aruchara-3 well commenced and was completed in August 2023, and the Company unexpectedly encountered a large zone with a natural open fracture with 570ft of net pay in the H4 and H3 sections of the Jimol formation. In the meantime, the Aruchara-1 well achieved consistent production flow rates of 7 MMcf/d and as of October 2023, the Aruchara-1 well was producing gross natural gas at an average of 6.85 MMcf/d, which represented an increase from its initial base of 4 MMcf/d. The Aruchara-3 well began producing natural gas in November 2023, when the Company was granted approval from the ANH for extended production testing and the connection to the GTX Gas Plant was completed. Initially, the Aruchara-3 well was producing, in conjunction with the Aruchara-1 well, a baseline of 14 MMcf/d. In December 2023, production volumes were further increased to 16.4 MMcf/d and as of February 2024, natural gas production from the Maria Conchita Block had increased to 19.4 MMcf/d with 100% of natural gas volumes sold. As at the date of this MD&A, the Company is producing 18.5 MMcf/d from the Maria Conchita Block.

Reserves Analysis

In April 2024, the Company filed its Form 51-101F1 - *Statement of Reserves Data and Other Oil and Gas Information* for the fiscal year ended December 31, 2023, which was prepared with Sproule International Limited ("**Sproule**") in accordance with the COGE Handbook and has an effective date of December 31, 2023 (the "**2023 51-101F1**"). As per the requirements of Form 51-101F1, since the Maria Conchita Block and the SN-9 Block are both located in Colombia, the Company has disclosed its reserves in the 2023 51-101F1 on an aggregated basis. The reserves in the 2023 51-101F1, which are attributed to the Maria Conchita Block are based on the report entitled "Evaluation of the P&NG Reserves and Resources of NG Energy International in the Maria Conchita Block, Colombia" prepared by Sproule, in accordance with the COGE Handbook, with an effective date of December 31, 2023 (the "**2023 Maria Conchita Reserves and Resources Report**").

The Company disclosed the results of the 2023 Maria Conchita Reserves and Resources Report in its news release dated December 27, 2023, which included reserves and resources attributed to the H1A, H1A1, H1B, H2, H2B, H3, H4 and LM2 zones. The 2023 Maria Conchita Reserves and Resources Report incorporates the recently drilled Aruchara-3 well and includes the newly encountered section in zone H4 in addition to zones H1 and H2. The Company reported gross Proved + Probable + Possible reserves of 59.5 Bcf (74.3 Bcf project gross) of natural gas and 94 Mbbl (117 Mbbl gross project) of condensate for a before-tax NPV10 of $135.8 million, which can be broken down as follows:

- Company gross Proved reserves of 25.0 Bcf (31.3 Bcf project gross) of natural gas and 50 Mbbl (63 Mbbl project gross) of condensate for before-tax NPV10 of $75.4 million; and
- Company Proved + Probable reserves of 47.2 Bcf (59 Bcf project gross) of natural gas and 75 Mbbl (94 Mbbl project gross) of condensate for before-tax NPV10 of $109.4 million.

As mentioned above, the 2023 51-101F1 includes aggregated reserves from both the Maria Conchita Block and the SN-9 Block. In the 2023 51-101F1 the Company reported gross Proved + Probable + Possible reserves of 304,816 MMcf (approximately 304.9 Bcf) of natural gas and 94 Mbbl of condensate for a before-tax NPV10 of 466.8 million, which can be broken down as follows:

- Company gross Proved reserves of 51,683 MMcf (approximately 51.7 Bcf) of natural gas and 50 Mbbl of condensate for a before-tax NPV10 of 97.4 million; and
- Company Proved + Probable reserves of 161,589 (approximately 161.6 Bcf) of natural gas and 75 Mbbl of condensate for a before-tax NPV10 of 259.7 million.

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

Resources Analysis

In the 2023 51-101F1, the Company further reported gross unrisked best estimate contingent resources (development pending) of 65,572 MMcf (approximately 65.6 Bcf) for before-tax NPV10 of $69.9 million and gross unrisked best estimate prospective resources (prospects) of 53,044 MMcf (approximately 53.0 Bcf) for before-tax NPV10 of $36.0 million. The Company's contingent resources in the Maria Conchita Block are petroleum and natural gas classified as "development pending" and are attributed a chance of development risk factor of 0.73. The Company's prospective resources in the Maria Conchita Block are subclassified as "prospect" and are attributed a chance of geologic discovery risk factor of 0.41 and a chance of development risk factor of 0.73. However, the Company believes the unrisked best estimate contingent resources and prospective resources, respectively, provides the most appropriate indication of volumes that will become Proved + Probable reserves.

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

Current Objectives

The Company's primary focus in the Maria Conchita Block is the overall expansion of its production base and the monetization of natural gas production by capitalizing on a premium pricing market in Colombia. To do so, over the course of the fiscal year ended December 31, 2024, the Company intends to complete various production enhancing activities in the Maria Conchita Block, as well complete a geophysics study on the H3 and H4 sections of the Jimol formation. Additionally, the Company will undergo an evaluation of various different production growth development programs.

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, including production tests through production facilities connected to the TGI main pipeline. These production tests were initially extended to February 2024 with the option to present a development plan for the Aruchara-4 well to the ANH in Q1 2024. However, in Q1 2024, the ANH granted the Company an extension of the Istanbul evaluation program until August 2025.

In May 2023, the Company received approval from the ANH to commence with the drilling of the Aruchara-3 well. In August 2023, the Company commenced the drilling of the Aruchara-3 well from the same pad as the Aruchara-1 well with a 22° deviation, targeting the Jimol formation to develop the H1A and H1B accumulations and define the potential extension of more reserves and resources in the H2B section. The well was drilled to a total depth of 9,050 ft in three phases and in Phase II of the drilling the Company encountered 570 ft of net pay in the H4 and H3 sections of the Jimol formation. This new zone was identified between 6,000 ft and 7,500 ft after experiencing gas showings throughout the 1,500 ft. This zone was confirmed as a possible new finding after successfully logging the well using leading drilling and logging technology. Additionally, in Phase III of the drilling the Company identified 150 ft of net pay. As a result, in September 2023, the Company conducted three successful DST procedures within the prospective zones. The first DST procedure was conducted in the Jimol Inferior Formation between 8,379 ft and 8,470 ft and produced 16.5 MMcf/d of natural gas with five barrels of 43.7 API condensate recovered. The second DST procedure was conducted in the H2 zone of the Jimol Inferior Formation and produced 23.5 MMcf/d of natural gas with 5.3 barrels of 43.5 API condensate recovered. The third DST procedure was conducted in the H4 zone of the Jimol Inferior Formation and produced 25 MMcf/d of natural gas. The total amount of natural gas produced from the three DST procedures was 65.2 MMcf/d across the 3 zones tested. The Company concluded from the three DST procedures that a more than 1,200 ft naturally fractured section is present, which includes the presence of gas and condensate. This discovery ultimately redefines the scope and potential of the Maria Conchita Block. However, it is important to note that the above data should be considered preliminary and that the above test results are not necessarily indicative of long term performance or of ultimate recovery.

Existing Agreements

In May 2016, Turkish Petroleum International Company Limited Sucursal Colombia, MKMS and Multiservicios RJT S.A.S, as sellers, and Bochica, as buyer, entered into a master sales and purchase agreement with respect to the Maria Conchita Block, pursuant to which Bochica granted the following overriding royalty's on the gross production of the block:

- 3.000% to Turkish Petroleum International Company;
- 1.052% to MS Petrol ve Petrol Mamulleri Tic A.S.; and
- 1.348% to Oruc Reis Denizcilik Isi A.S.

In December 2019, the Company and certain lenders entered into a loan agreement in the amount of $1,600,000 to finance certain activities in relation to the Maria Conchita Block. As consideration for the loan, the Company granted the lenders a 2.5% overriding royalty on the gross production of the block. Pursuant to the terms of the loan agreement, the lenders exercised their rights to receive payment of the outstanding loan by way of an additional 2.5% overriding royalty on the gross production of the block. Therefore, in total, the Company has granted the lenders a 5% overriding royalty on the gross production of the block (the "**MC Royalty**").

SN-9 Block

The SN-9 Block is in the Lower Magdalena Valley, 75 km from Colombia's Caribbean coast. The SN-9 Block, which covers an area of approximately 311,353 acres in the Department of Córdoba, Colombia, has a 6-year exploration period, divided in two phases of three years each, followed with a 24-year production period from the date when commerciality is declared. The SN-9 Block is adjacent to blocks held by Canacol

Energy Ltd. and Hocol S.A. The area has excellent infrastructure with good roads and access to the northern natural gas trunk line. In 1992, the Hechizo well was drilled on the block by Ecopetrol, S.A. and tested natural gas in the CDO 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**"), was entered into between the ANH and Clean in October 2014. Phase 1 of the exploration program for the SN-9 E&P Contract includes a minimum work obligation of acquiring 125 km^2 of 3D seismic and drilling one exploration well. During the fiscal year ended December 31, 2022, the ANH approved Clean's submission to drill a new exploration well, the Brujo-1X well, rather than acquire the 125 km^2 of 3D seismic. Additionally, this resulted in Phase 1 of the exploration program being extended to January 2023. Subsequently, Clean has requested a further 18 month extension of the Phase 1 deadline by either acquiring 60 km^2 of 3D seismic or drilling another exploration well. As of the date of this MD&A, this submission is still under consideration by the ANH. The Company's working interest in the SN-9 Block is 72%, subject to payment of ANH sliding scale royalties.

In September 2021, the Company received the necessary environmental license from the ANLA required to commence exploratory drilling in the SN-9 Block, including the construction of civil works, production infrastructure and the construction of up to 11 locations for a total of 22 wells to be developed.

During the fiscal year ended December 31, 2022, the Company and its contractors completed the drilling of the Magico-1X well in July 2022, and completed drilling and testing activities at the Brujo-1X well in November 2022. Significant natural gas was encountered in both the Magico-1X well and the Brujo-1X well and further testing was undertaken throughout the course of the year. The results of such testing are outlined and discussed below under "*Exploration Activities*".

To move towards commercial production in the SN-9 Block, the Company entered into the Clean JOA on July 31, 2023, whereby the Company solidified its 72% working interest in the SN-9 Block. Additionally, in September 2023, the Company entered into the Offtake Agreements with Surenergy, INFRAES and GEAM. Pursuant to the terms of the Offtake Agreements, 30 MMcf/d of natural gas will be brought online in Q2 2024, with an additional 10 MMcf/d of production to be brought online by no later than the end of Q1 2025; however, the Company expects this to occur prior to the end of Q4 2024. Once brought online, total initial production volumes will reach 40 MMcf/d. The Company will deliver 30 MMcf/d of natural gas under its take-or-pay arrangement with INFRAES and Surenergy, and 10 MMcf/d on a transport and commercialization arrangement with INFRAES and GEAM, both of which have a term of ten years. The strategy to partner with midstream construction experts during the first phase of commercial production from the SN-9 Block provides the Company with the opportunity for early monetization with minimal capital expenditures and significantly reduced construction risk, while maintaining pricing upside. Additionally, it allows the Company to focus on its upstream business of growing and upgrading its reserves and resources at both the SN-9 Block and the Maria Conchita Block.

In November 2023, the Company, along with Clean and Desarolladora Oleum, entered into definitive agreements (the "**SN-9 Infrastructure Agreements**") with INFRAES and Surenergy S.A.S E.S.P. ("**Surenergy**") to complete the construction of the infrastructure required to begin commercial production at the SN-9 Block. Pursuant to the terms of the Company's agreement with Surenergy, Surenergy will provide processing, treatment and compression of natural produced from the SN-9 Block for the gas pipeline that will connect the SN-9 Block with the Jobo delivery point for the SNTE. Surenergy will install three compression packages of 10 MMcf/d and a dehydration plant of 40 MMcf/d at onset, with an additional 10 MMcf/d of compression available at the Company's sole election. Surenergy will be responsible for all capital expenditures and will retain ownership over the assets. The Company will pay Surenergy a volume-based fee for utilization of such assets over the ten-year term of the agreement.

Pursuant to the terms of the Company's agreement with INFRAES, INFRAES will construct a 32km, 5.5" pipeline, which will connect the SN-9 Block to the Promigas Jobo section in the SNTE, which transports gas to the northern region of Colombia. INFRAES will be responsible for all capital expenditures and maintenance and will retain ownership of the pipeline. The Company will pay INFRAES a fixed transportation fee for natural gas volumes transported over the ten-year term of the agreement. Both Surenergy and INFRAES, have obtained the required permits and completed the required social work with respect to the right-of-way and have procured the required equipment for the gathering and processing plant and pipeline.

Additionally, in November 2023, the Company entered into an interruptible supply contract with GEAM for the sale of up to 10,000 MMBtu/d (approximately 10 MMcf/d) until November 30, 2024, which needs to be defined in terms of definite prices. The Company intends to enter into firm contracts following the expiry of this interruptible supply contract once production is flowing and stabilized from the SN-9 Block. In March 2024, the Company entered into an interruptible supply contract with Vanti for a period of five years.

In April 2024, the Company underwent the Reorganization (as defined herein), whereby Pentanova (BVI) Ltd. (wholly owned subsidiary of the Company) ("**Pentanova**") assigned all its right, title and interest in the SN-9 Block to MKMS BVI. The Reorganization represents a positive step towards MKMS Colombia becoming the operator of the SN-9 Block. For more information concerning the Reorganization see "*Reorganization*".

The Company expects to be able to begin to market the natural gas produced in the SN-9 Block within the next three months.

Reserves Analysis

In April 2024, the Company filed the 2023 51-101F1. As per the requirements of Form 51-101F1, since the Maria Conchita Block and the SN-9 Block are both located in Colombia, the Company has disclosed its reserves in the 2023 51-101F1 on an aggregated basis. The reserves in the 2023 51-101F1, which are attributed to the SN-9 Block are based on the report entitled "Evaluation of the P&NG Reserves and Resources of NG Energy International in the Sinu-9 Block, Colombia" prepared by Sproule, in accordance with the COGE Handbook, with an effective date of December 31, 2023 (the "**2023 SN-9 Reserves and Resources Report**").

The Company disclosed the results of the 2023 SN-9 Reserves and Resources Report in its news release dated December 27, 2023, which included reserves and resources attributed to the Hechizo, Brujo, Magico, Mago, Hechicero, Encanto, Milagroso, Porquero, Embrujo, Ensalmo and Sortilegio zones. The Company reported gross Proved + Probable + Possible reserves of 245.3 Bcf (340.8 Bcf project gross) of natural gas for before-tax NPV10 of $331.0 million, which can be broken down as follows:

- Company gross Proved reserves of 26.7 Bcf (37.0 Bcf project gross) of natural gas for before-tax NPV10 of $22.0 million; and

- Company Proved + Probable reserves of 114.36 Bcf (158.8 Bcf project gross) of natural gas for before-tax NPV10 of $150.3 million.

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

For more information regarding the aggregated reserves disclosure in the 2023 51-101F1 see "*Colombian Oil and Natural Gas Properties – Maria Conchita Block – Reserves Analysis*" above.

Resources Analysis

In the 2023 51-101F1, the Company further reported gross unrisked best estimate contingent resources (development pending) of 130,172 MMcf (approximately 130.2 Bcf) for before-tax NPV10 of $78.5 million and gross unrisked best estimate prospective resources of 130,984 MMcf (approximately 131.0 Bcf) for before-tax NPV10 of $264.4 million. The Company's contingent resources in the SN-9 Block are petroleum and natural gas classified as "development pending" and are attributed a chance of development risk of 80%. The prospective resources assigned to the Brujo-Porquero, Hechicero-Porquero and Milagroso fields are subclassified as "prospects" and are attributed a chance of discovery of 58-60% and a chance of development of 66%. The prospective resources assigned to the Embrujo, Ensalmo and Sortilegio fields are subclassified as "lead" and are attributed a chance of discovery of 25-30% and a chance of development of 66%. However, the Company believes the unrisked best estimate contingent resources and prospective resources, respectively, provides the most appropriate indication of volumes that will become Proved + Probable reserves.

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

Current Objectives

Achieving commercial production is the Company's primary focus in the SN-9 Block in 2024. The Company anticipates that all the infrastructure required to begin commercial production, as well as the tie-in of the Brujo-1X and Magico-1X wells will be completed by the end of Q2 2024. The Company expects to have 30 MMcf/d of processing and transportation capacity online at the SN-9 Block by the end of Q2 2024, with an additional 10 MMcf/d online by no later than the end of Q1 2025; however, the Company expects this to occur prior to the end of Q4 2024. Additionally, the Company expects to drill an additional well in the SN-9 Block, the Hechicero-1X well, by the end of 2024.

Exploration Activities

In the fiscal year ended December 31, 2023, the Company continued its geological and geophysical analysis of the Magico-1X and Brujo-1X wells at the SN-9 Block. Additionally, the Company received approval from the ANH to extend the timeline of its Phase 1 exploration activities by agreeing to explore the seismic activities in the natural gas area of the SN-9 Block.

As of the date of this MD&A, the Company is awaiting leave from ANH to complete the Brujo well.

In the fiscal year ended December 31, 2022, the Company completed the following exploration activities with respect to the Magico-1X and Brujo-1X wells located in the SN-9 Block.

In May 2022, the Company completed the construction of the pad at the Magico-1X well and commenced drilling. The well was drilled to a true vertical depth of 3,918 ft in three phases using a 1,500-horsepower hydraulic rig. The Company identified three intervals to be tested, with the CDO sandstone reservoir being the primary objective. The Company encountered natural gas within the well in the lower first structure, which measured 50 ft in the CDO sandstone reservoir. The Company further identified several prospective natural gas bearing zones through well logs at a depth of between 3,200 – 3,350 ft for a total gross pay of 150 ft and net pay of 100 ft.

Following the completion of the Magico-1X well, in July 2022, the Company conducted two successful DST procedures and one comingled test within the three prospective zones. The first DST procedure occurred at a measured depth of between 3,694 – 3,724 ft and produced 4.0983 MMcf at a rate of 5.7 MMcf/d of natural gas with no water. The specific gravity of the natural gas from this test was 0.5579. The second DST procedure occurred at a measured depth of between 3,572 – 3,582 ft and 3,632 – 3,640 ft and produced 5.0997 MMcf at a rate of 9.8 MMcf/d of natural gas and no water. The specific gravity of the natural gas from this test was 0.5576. The comingled test occurred at a measured depth of between 3,572 – 3,582 ft, 3,632 – 3,640 ft and 3,694 – 3,724 ft and produced 4.0347 MMcf at a rate of 15.1 MMcf/d of natural gas and no water. The specific gravity of the natural gas from this test was 0.5576. The total amount of natural gas produced from these three tests was 13.2326 MMcf with no water. Based on these results the Company concluded the Magico-1X well tested over 15 MMcf/d of dry natural gas with no water on a comingled production completion from the three prospective zones located within the CDO sandstone reservoir between 3,572 – 3,724 ft with a combined net pay of 76 ft.

It is important to note that the above data should be considered preliminary until pressure transient analysis or well-test interpretation has been conducted. Therefore, the above test results are not necessarily indicative of long-term performance or of ultimate recovery.

In October 2022, the Company announced the successful drilling at the Brujo-1X well at a final total depth of 8,019 ft (7,200 ft true vertical depth) in the Lower Magdalena Basin, located with the SN-9 Block, in three phases using a 1,500-horsepower hydraulic rig. The Company had identified several intervals of interest using geological and geophysical evidence, with the CDO sandstone reservoir as the primary target. The Company encountered 680 ft of net natural gas bearing zones in the CDO sandstone reservoir and 103 ft in the Porquero formation, for a total of 783 ft of net pay. As a result, in November 2022, the Company conducted 4 DST procedures, with 3 successful DST procedures in the intermediate and upper section of the CDO formation. The first DST procedure occurred between a measured depth of 6,127 – 6,789 ft, however this test was unsuccessful. The second DST procedure occurred between a measure depth of 5,055 – 5,365 ft and produced 3.1306 MMcf of natural gas and no water over a period of 11.3 hours. The specific gravity of the natural gas from this test was 0.56044. The third DST procedure occurred between a measure depth of 4,563.5 – 4,910 ft and produced 6.2279 MMcf of natural gas with no water over a period of 15.1 hours. The specific gravity of the natural gas from this test was 0.56044. The fourth DST procedure occurred between a measured depth of 4,086 – 4,530 ft and produced 5.442 MMcf of natural gas with no water over a period of 13.6 hours. The natural gas-bearing thickness in the CDO formation was perforated for these tests with natural gas production rates of: 11.2 MMcf/d from the second DST procedure, 18.2 MMcf/d from the third DST procedure and 21.2 MMcf/d from the fourth DST procedure. It is important to note that the above data should be considered preliminary until pressure transient analysis or well-test interpretation has been conducted. Therefore, the above test results are not necessarily indicative of long-term performance or of ultimate recovery.

Existing Agreements

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

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

Payment to the Company for either option will be received through the sale of 62.5% of Clean's production on the SN-9 Block corresponding to this 5% interest. Furthermore, the Common Share of Net Profit Interest and Overriding Royalties (as defined in the SN-9 purchase and sale agreement) related to this additional 5% working interest will be the obligation of Clean and not carried by the Company. In November 2023, Clean filed the application to the ANH for the official transfer of 51% participation interest in the SN-9 E&P Contract to MKMS Colombia. Upon completion of the Phase 2 commitments of the SN-9 E&P Contract, Clean will formally transfer of the remaining 21% participation interest in the SN-9 Block to MKMS Colombia.

In August 2020, the Company and certain lenders entered into a loan agreement in the amount of $2.5 million to finance certain activities in relation to the SN-9 Block. As consideration for the loan, the Company granted the lenders a 3% overriding royalty on the gross production of the block. Pursuant to the terms of the loan agreement, the lenders exercised their rights to receive payment of the outstanding loan by way of an additional 3% overriding royalty on the gross production of the block. Therefore, in total, the Company has granted the lenders a 6% overriding royalty on the gross production of the block (the "**SN-9 Royalty**").

Tiburon Block

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

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

In April 2024, the Company underwent the Reorganization (as defined herein), whereby Pentanova assigned all its right, title and interest in the Tiburon Block to MKMS. The Reorganization represents a positive step towards MKMS Colombia becoming the operator of the Tiburon Block. For more information concerning the Reorganization see "*Reorganization*".

Exploration Activities

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

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

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

Existing Agreements

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

- 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. If NG Energy does not fulfill the Phase 3 commitment, except for reasons beyond its control, NG Energy will cede a 1.5% carried working interest in the SN-9 Block to ColPan and forfeit the aforementioned $120,000 payment.

OUTLOOK

The Company's primary focus in the short-term is the monetization of its natural gas resources and capitalizing on a premium pricing market in Colombia. The connection of the Aruchara-1 well to the SNTE turned the Company into a revenue producing entity. With the tie-in of the Aruchara-3 well in Q4 2023, the Company expects to be able to realize potential production levels of up to 20 MMcf/d with the Company's current pipeline facilities capacity. Given the current shortage of gas in Colombia and the high probability of an El Niño phenomenon coming in the next months, the Company has a reasonable expectation that any gas that it produces will be purchased. The commencement of this revenue stream will assist the Company with improving its working capital position and service debt payments for interest payable on its convertible debentures.

The Company's consistent joint efforts with joint venture partners to accelerate the commercial production from the SN-9 Block provide favorable outlook for continued growth of natural gas revenue. As mentioned, pursuant to the Offtake Agreements, 30 MMcf/d of natural gas will be brought online in Q3 2024, with an additional 10 MMcf/d of production brought online in Q1 2025, for total initial production volumes of 40 MMcf/d. This direction provides opportunity for early monetization with minimal capital expenditures and significantly reduced construction risk, while maintaining pricing upside. The Company continues to move forward with its planned exploration and development program in the Maria Conchita Block and SN-9 Block, as discussed above. The Company believes the SN-9 Block could be an important new source of natural gas in Colombia. Through a phased approach, NG Energy expects to increase reserves and provide a stable supply of natural gas in Colombia. The evaluation program is underway in the Maria Conchita Block to define total resources and determine the most appropriate development plan for the Uitpa and Jimol formations.

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

Reorganization

In April 2024, the Company underwent an internal reorganization of its assets, whereby Pentanova assigned all its rights, title and interest in the SN-9 Block, the Tiburon Block and all related agreements to MKMS (the "**Reorganization**"). The Reorganization represents a positive step towards MKMS Colombia (the Colombian branch of MKMS) becoming the operator of the SN-9 Block and Tiburon Block in front of the ANH under the terms of the SN-9 E&P Contract and the Tiburon E&P Contract, respectively.

DISCUSSION OF OPERATING RESULTS

Revenue

	Q1 2024	**Q1 2023**
Natural gas sales	10,190,283	2,096,853
Natural gas volume (Mcf/d)	13,993.1	4,513.2
Natural gas realized price ($/Mcf)	8.00	5.16
NGL sales	46,830	-
NGL volume (bbls)	893	-
NGL realized price ($/bbl)	52.44	-

All revenue is generated from the Colombia operating segment of the Company. Increased revenue from Q1 2023 to Q1 2024 is the direct result of increased natural gas production rates that were realized in 2024 from the Maria Conchita Block as well as increased natural gas prices. For Q1 2024, the Company averaged 13,993.1 Mcf/d (Q1 2023 – 4,513.2 Mcf/d), which resulted in gross natural gas sales for the quarter of $10.2 million (Q1 2023 - $2.1 million). The realized sales price for natural gas per Mcf for Q1 2024 was $8.00 compared to $5.16/Mcf for Q1 2023. The Company has Natural gas liquids sales of $46,830 for 893 Bbls of NGL volumes for a realized sales price of $52.44/bbl. All production results are from production from the Maria Conchita Block.

Royalties

	Q1 2024	**Q1 2023**
Total royalties	1,676,048	393,342
Total royalties (% of sales)	16.45%	18.76%
Total royalties ($/Mcf)	1.32	0.97

Royalties as a percentage of total natural gas sales are highly sensitive to commodity prices. Thus, royalty rates can fluctuate from quarter-to-quarter and year-to-year. Royalties as a percentage of revenues for three months ended March 31, 2024 and 2023, were 16.45% and 18.76%, respectively. The royalties incurred in Q1 2024 consisted of Colombia government royalties of $645,182 and overriding royalties of $1,030,866 (Q1 2023 - $145,286 and $248,056, respectively).

Operating Expenses

	Q1 2024	**Q1 2023**
Total operating expenses	1,104,973	566,605
Total operating expenses ($/Mcf)	0.87	1.39

Operating costs for Q1 2024, were $1,104,973 (Q1 2023 - $566,605) and include commercialization fees, lifting costs, municipal taxes, and other field and maintenance costs that are incurred to operate the Aruchara-1 and Aruchara-3 wells, gather and treat production volumes and to perform well and facility repairs and maintenance.

General and Administrative Expenses

General and administrative ("**G&A**") expenses for the three months ended March 31, 2024, totaled $1,247,704 (2023 comparative period - $1,395,729). The G&A expenses relate to the normal course of the Company's operations, and are constituted as follows:

	Q1 2024	**Q1 2023**
Wages & Salaries	664,495	486,607
Professional Fees	318,056	711,510
Other	265,153	197,612
Total	**1,247,704**	**1,395,729**

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. Q1 2024 reflects how the Company has hired further qualified personnel to support ongoing growth. Less reliance on consultants and contractors as a result of more Company personnel is reflected in the reduced professional fees of the Company in

2024 when compared to Q1 2023. Legal and consultant expenses are still incurred to support the Company through its ongoing development in corporate structuring, technical planning, and public relations.

Share-Based Payments

The value of the stock options vesting in the three months ended March 31, 2024, equated to $214,022 (2023 comparative period - $nil) in share-based compensation expense related to ongoing vesting of 2,850,000 stock options granted in September 2023, whereas no share-based compensation expense was recognized in Q1 2023 as no stock options were vesting during the quarter. Prior to September 2023, all granted stock options vested immediately upon grant with the full amount of share-based compensation expense for those granted option being recognized completely in the period when granted. Stock options granted in September 2023 have vesting terms over a three-year period. As such, share-based compensation expense in Q1 2024 consisted of the gradual vesting over time of these options for the portion of the year over which they were vesting from the date of grant.

Restricted share units ("**RSUs**"), deferred share units ("**DSUs**") and restricted share units with performance criteria ("**PSUs**") were issued in September 2023. The value of vesting of these compensation units for Q1 2024 was $1,553,841 (2023 comparative periods - $nil).

Net finance expense

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

	Q1 2024	Q1 2023
Interest income	(214,138)	(138,300)
Bank fees	47,607	55,442
Interest and fees on convertible debentures	1,538,195	895,310
Interest and fees on promissory notes	57,422	-
Interest and fees on Macquarie debt	77,107	-
Accretion on decommissioning obligation	24,027	23,845
Accretion on liability component of convertible debentures	632,888	377,410
Accretion on lease liabilities	967,020	973,145
Amortization of transaction costs on Macquarie debt	70,661	-
Total net finance expense	**3,200,789**	**2,186,852**

Debt Settlement Costs

In March 2024, in connection with the Macquarie Financing, 100% of the holders of the Company's debentures issued in November 2022 and July 2023, elected to convert or redeem their Debentures in accordance with their terms. Holders of C$2.4 million face value of Debentures chose to redeem, resulting in payment of C$3.0 million in principal, interest and redemption premium per the Debenture terms. Holders of the remaining C$67.2 million face value of Debentures chose to convert, resulting in the issuance of 85,731,098 common shares and payment of C$30.3 million in interest and conversion premium per the Debenture terms. Total of all such aforementioned disbursements in relation to the redemption and conversion of Debentures equated to total debt settlement costs of $22.9 million in Q1 2024.

Terminations Costs

In March 2024, the Company announced that it completed a shares for debt settlement with Plus+, whereby the Company issued 2,000,000 common shares to Plus+ at a deemed issuance price of C$1.00 per common share in satisfaction of $1,502,000 owing to Plus+ pursuant to the terms of a termination agreement entered into between the Company and Plus+ in relation to the termination of the existing natural gas supply contract between the parties. This settlement was recognized as a one-time Termination Costs expense of $1.5 million in for the three months ended March 31, 2024.

Foreign Exchange

The Company incurred a foreign exchange loss of $146,763 for the three months ended March 31, 2024 (2024 comparative period - $37,849). Foreign exchange gains are due to the increase in the value of the Canadian dollar and the Colombian peso when compared to the US dollar in the period. Conversely, foreign exchange losses are due to a decrease in the value of these other currencies in comparison to the US dollar.

Cash provided by (used in) Operating Activities

For the three months ended March 31, 2024, the Company generated cash from operating activities of $7,369,429 (2023 comparative period – cash used in operating activities of $458,635). Increased sales revenue in Q1 2024 has resulted in net positive cash flow after period expenses. Conversely, the cash used in operations in Q1 2023 is primarily comprised of G&A expenses and business development expenses incurred during the period reduced by lower sales revenue, net of royalties and operating expenses.

CAPITAL ADDITIONS

For the three months ended March 31, 2024, the Company had additions (prior to recognition of any impairments, disposals, or revisions of estimates) of $3.8 million relating to exploration and evaluation assets, and $8,624 related to corporate fixed assets additions. Additions to exploration and evaluation assets relate primarily to the drilling program of the San Diego-1X well under the option to acquire a 25% working interest in the VMM39 Block as well as the ongoing SN-9 development program, community relations and environmental license compliance work.

LIQUIDITY AND CAPITAL RESOURCES AND GOING CONCERN

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

During the three months ended March 31, 2024, the Company recognized a net loss of $26.3 million and cash provided in operating activities of $7.4 million. As of March 31, 2024, the Company had a working capital deficit of $8.6 million, including cash and cash equivalents of $10.7 million. For 2024, the Company has contractually committed exploration and development amounts of $12.4 million remaining out of

$34.7 million (as outlined below) and $7.3 million for lease obligations. The Company anticipates during 2024 to see increased gas production on from existing gas concessions, but reaching these objectives is contingent upon successful development of necessary surface infrastructure to commence commercial production in the SN-9 Block. As such, the Company continues to need additional capital to fund the Company's ongoing operations, and commitments, and the continued development of the Company's exploration and evaluation assets.

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

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

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

Macquarie Debt

In February 2024, the Company announced that it had entered into the Credit Agreement for the Macquarie Financing of up to $100 million of which $50 million is committed funding. The Macquarie debt is secured by a first priority lien over all the assets of the Company, its wholly owned subsidiaries and a trust formed in Colombia and matures on December 29, 2028. The Macquarie debt bears interest at the bank's assessed prime or SOFR terms rates plus applicable margins. The applicable margin charged by the bank is dependent upon criteria including loan life coverage ratio and short-term gas production results, with an applicable margin rate range between 6.25% to 8.5%. As at March 31, 2024, the Macquarie debt had an effective interest rate of 13.8% per annum. Repayments of principal are mandated on a quarterly basis. The first repayment of $2.5 million is scheduled for September 2024. Subsequent repayments will follow quarterly thereafter until the final installment.

In March 2024, the Company received an initial advance of $40 million pursuant to the terms of the Macquarie Financing, with the remaining $10 million in committed funding to be advanced to the Company on a date to be determined pursuant to the terms of the Credit Agreement. The additional $50 million in uncommitted funding will be made available to the Company by Macquarie under an accordion feature.

In connection with the Macquarie Financing, the Company issued the 20,742,857 Bonus Warrants. Each Bonus Warrant entitles Macquarie to purchase one Common Share at an exercise price equal to C$1.00 until December 29, 2028.

Convertible Debentures

In May 2022, November 2022, and July 2023 the Company completed the separate offerings of convertible debenture units for aggregate proceeds of $13.4 million (C$17.1 million), $25.9 million (C$35.0 million) and $26.6 million (C$35.0 million) respectively.

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

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

In the July 2023 Offering, each convertible debenture unit consisted of: (i) one 10.0% convertible senior secured debenture with a principal amount of $1,000 maturing on July 31, 2026; and (ii) 1,000 Common Share purchase warrants of the Company, with each warrant entitling the holder thereof to purchase one Common Share at an exercise price of C$0.90 per Common Share until July 31, 2026. The principal amount of each convertible debenture will be convertible, for no additional consideration, at the option of the holder, in whole or in part, at any time and from time to time, into Common Shares at a conversion price equal to C$0.70 per Common Share.

Interest on the debentures is payable monthly in arrears on the last day of each month. An amount equal to the interest payable for the first year under each of the debentures was placed in escrow upon closing of each of the May 2022 Offering, the November 2022 Offering and and the July 2023 Offering and shall be paid out to holders of debentures monthly. Interest thereafter shall be paid out of the Company's cash flow.

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

In September 2023, certain convertible debenture holders from the November 2022 Offering elected to convert C$210,000 face value of their debentures to Common Shares of the Company at the conversion price of C$0.90 per Common Share, resulting in the issuance of 233,333 Common Shares.

In October 2023, a certain debenture holder from the November 2022 Offering elected to convert C$250,000 face value of their debentures to Common Shares of the Company at the conversion price of C$0.90 per Common Share, resulting in the issuance of 277,777 Common Shares.

On March 22, 2024, in connection with the Macquarie Financing, 100% of the Debenture holders under the November 2022 Offering and the July 2023 Offering elected to convert or redeem their debentures, resulting in the issuance of 85,731,098 common shares and payment of C$33.3 million to Debenture holders.

Restricted Cash

As of March 31, 2024, funds totaling $8,648,984 (December 31, 2023 - $8,011,108) were classified as restricted cash. The composition of this amount is as follows:

	March 31, 2024	December 31, 2023
Debt Service Reserve	5,301,365	-
SN-9 ANH Guarantee Deposit	2,645,457	2,651,358
Tiburon ANH Guarantee Deposit	350,665	351,935
VMM39 Escrow	351,497	2,797,923
INFRAES Construction Contract Letter of Credit	-	2,209,892
Restricted cash	**8,648,984**	**8,011,108**

Term deposits are established to secure performance guarantees required by the Colombian National Hydrocarbon Agency (“ANH”) under the Exploration and Production (“E&P”) Contracts for the SN-9 and Tiburon Block. The SN-9 and Tiburon deposit amounts were defined in US dollars by the ANH but are held in Colombian pesos with Colombian banks and are subject to foreign currency fluctuation risks in relation to the US dollar, which may result in additional funding towards these term deposits from time to time at the discretion of the ANH. These deposits are to be released to the Company once current phase commitments under each E&P Contract are completed. As at March 31, 2024, the balances of the SN-9 term deposit and Tiburon term deposit were $2,645,457 and $350,665, respectively.

Under the terms of the VMM39 Block option agreement, NG placed $5.5 million into escrow for direct utilization in the drilling and completion of the San Diego-1X exploration well. Funds are disbursed from this escrow account as exploration activities are completed, until such funds are fully employed. As of March 31, 2024, approximately $5.1 million of escrowed funds had been disbursed from the escrow account towards exploration expenditures, leaving a balance of $351,497.

Per the terms of the Credit Agreement under the Macquarie Financing, an amount equal to the sum of certain upcoming scheduled debt service payments is to be calculated, and for the funds equal to such upcoming scheduled payments to be maintained within a restricted “Debt Service Reserve” account at all times. Such Debt Service Reserve deposit is to be periodically calculated and maintained throughout the life of the debt arrangement. As of March 31, 2024, the Company maintained a deposited balance of $5,301,365 in the requisite Debt Service Reserve.

In November 2023, the Company entered into definitive agreements with third parties to complete the construction of the surface infrastructure required to start commercial production in the SN-9 Block.

Among those agreements, INFRAES was contracted to construct a pipeline to connect SN-9 facilities to the Colombian transportation network. Under the terms of the INFRAES construction agreement, the Company was required to provide an initial letter of credit of approximately $2.0 million, which was secured with the local bank with a restricted deposit denominated in Colombian pesos. During the three months ended March 31, 2024, the initial deposit-secured letter of credit was replaced with an unsecured standby letter of credit, resulting in the release of the restricted deposit previously required by the local bank.

SHARE CAPITAL

Common Shares

The Company is 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 at March 31, 2024 are as follows:

	Common shares	Amount ($)
Balance, December 31, 2022	125,122,132	104,881,440
Shares issued through warrant exercise	4,625,500	5,177,634
Shares issued through option exercise	600,000	261,474
Shares issued on VMM39 Block option acquisition	6,592,000	4,002,135
Conversion of debentures	511,110	318,861
Balance, December 31, 2023	137,450,742	114,641,544
Shares issued for debt settlement	2,000,000	1,502,000
Conversion of debentures	85,731,098	47,317,917
Balance, March 31, 2024	**225,181,840**	**163,461,461**

Shares for Debt Settlement with Plus+

In March 2024, the Company announced that it completed a shares for debt settlement with Plus+ SAS ESP ("Plus+"), whereby the Company issued 2,000,000 common shares to Plus+ at a deemed issuance price of C$1.00 per common share in satisfaction of $1,502,000 owing to Plus+ pursuant to the terms of a termination agreement entered into between the Company and Plus+ in relation to the termination of the existing natural gas supply contract between the parties.

Conversion of Convertible Debentures

In March 2024, in connection with the Macquarie Financing, 100% of the holders of the Company's debentures issued on November 2022 and July 2023, elected to convert or redeem their Debentures in accordance with their terms. Holders of C$67.2 million face value of Debentures chose to convert, resulting in the issuance of 85,731,098 common shares.

Stock Options

The Company's stock option plan provides for the issue of stock options to directors, officers, employees, charities, and consultants. The plan provides that stock options may be granted up to a number equal to 10% of the Company's outstanding Common Shares. Vesting terms are determined by the Board of

Directors as they are granted and currently include periods ranging from immediately to one-third on each anniversary date over three years. The options' maximum term is ten years.

As at March 31, 2024, a total of 12,801,893 (December 31, 2023 – 12,801,893) 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, 2022	12,526,293	0.91
Options issued	2,850,000	1.18
Options exercised	(600,000)	0.33
Options forfeited	(1,974,400)	1.43
Balance, December 31, 2023 and March 31, 2024	**12,801,893**	**0.92**

The following summarizes information about stock options outstanding as at March 31, 2024:

Exercise prices (C$)	Number of options outstanding	Weighted average term to expiry (years)	Number of options exercisable
0.275	971,000	5.11	971,000
0.45	1,860,000	4.49	1,860,000
0.91	2,000,000	4.99	2,000,000
1.00	2,850,000	5.54	2,850,000
1.14	2,260,893	6.55	2,260,893
1.18	2,850,000	4.50	-
8.00	10,000	3.36	10,000
	12,801,893	**5.21**	**9,951,893**

Warrants

As at March 31, 2024, a total of 96,701,657 (December 31, 2023 - 80,634,050) 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, 2022	56,712,062	1.20
Warrants issued with convertible debentures	35,000,000	0.90
Warrants expired	(6,452,512)	1.29
Warrants exercised	(4,625,500)	1.18
Balance, December 31, 2023	80,634,050	1.06
Warrants issued on Macquarie Financing	20,742,857	1.00
Warrants expired	(4,675,250)	1.69
Balance, March 31, 2024	**96,701,657**	**1.02**

The following summarizes information about total purchase warrants outstanding as at March 31, 2024:

Exercise prices (C$)	Number of warrants outstanding	Weighted average term to expiry (years)	Number of warrants exercisable
0.90	35,000,000	2.33	35,000,000
1.00	20,742,857	4.75	20,742,857
1.08	34,100,000	1.67	34,100,000
1.40	6,858,800	3.14	6,858,800
	96,701,657	**2.67**	**96,701,657**

As of the date of this MD&A, the Company has 225,181,840 common shares, 12,801,893 stock options, and 96,701,657 warrants issued and outstanding.

LONG-TERM INCENTIVE COMPENSATION

The long-term incentive compensation includes RSUs, PSUs and DSUs. Each of these compensation units are expected to be settled by way of the issuance of NG common shares when settled. As such, they are recognized as contributed surplus on a graded vesting basis over the vesting term of each grant.

The details of RSUs, PSUs and DSUs as at March 31, 2024, were as follows:

Units	Vesting Criteria	Outstanding
DSUs	50% vesting in September 2024, 50% vesting in September 2025	4,540,000
RSUs	50% vesting in September 2024, 50% vesting in September 2025	2,525,000
PSUs	3 tranches vesting based on milestone criteria, with minimum vesting period of one year (vest date of September 2024)	2,635,000

COMMITMENT SUMMARY UPDATE

Capital Commitments

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

Block	2024	2025	Total
SN-9 Block (1)	26.7	-	**26.7**
Tiburon Block (2)	3.0	-	**3.0**
Maria Conchita Block (3)	-	5.0	**5.0**
Total	**29.7**	**5.0**	**34.7**

1) NG's ANH commitment to carry out the minimum requirement to drill two exploration wells (for which the Company will pay 100% of the costs under the terms of the SN-9 Acquisition) for an estimated cost of $22.3 million according to Phase 1 of the contractual exploration program. The ANH commitment was approved by the ANH in May 2022 to replace the previous minimum requirement to process and interpret 204.4 km of 2D seismic and drill one exploration well. The first exploration well (Magico-1X) was completed in August 2022 and drilling of the second exploration well (Brujo-1X) was completed in November 2022. With the completion of the Brujo-1X well, the Company

has sought confirmation from the ANH that this Phase 1 exploration commitment has been fulfilled. A further ANH commitment to acquire, process, and interpret 60 km^2 of 3D seismic for an estimated cost of $4.4 million has been assumed by the Company as part of an 18-month extension request granted by the ANH under the current phase of the contractual exploration program. The current deadline for completion of the seismic program is July 2024.

2) Relates to NG'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 2024 if the dispute is resolved by the Colombian Ministry of the Interior.

3) New ANH commitment to drill one exploration well for an estimated cost of $5.0 million. This new commitment was assumed by the Company as part of an 18-month extension request granted by the ANH under the current phase of the contractual evaluation program. The current deadline for completion of the drilling program is August 2025.

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

Contractual Commitments

Natural Gas Transportation Services

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

Natural Gas Compression Services

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

RELATED PARTIES

During the three months ended March 31, 2024 and 2023, there were separate related party transactions as follows:

a) For the three months ended March 31, 2024, the Company incurred expenditures of $391,216 in royalties paid to organizations that are affiliated with directors of NG. For the three months ended March 31, 2023, the Company incurred expenditures of $133,077 in royalties paid to organizations that are affiliated with directors or former directors of NG as well as payments directly to a former director of NG who departed from the Company in August 2023.

b) For the three months ended March 31, 2024 and 2023, the Company incurred expenditures of $9,906 and $7,418, respectively, in office rental costs in Colombia. The related office space is rented from an entity affiliated with a certain director of the Company. As at March 31, 2024, a payables balance of $16,068 was owed to the lessor entity.

c) As of March 31, 2024, the Company maintains a balance of $2,000,000 in promissory notes owed and outstanding. Of those proceeds received, $500,000 was provided by a certain director of the Company.

d) In July 2023, the Company completed a non-brokered private placement of convertible debentures of 35,000 debenture units at C$1,000 per unit, with 1,000 common share purchase warrants issued per unit. Of the units issued, 6,100 units were issued for subscriptions by directors and key personnel of the Company.

e) In June 2023, the Company entered into a simple agreement for future equity ("SAFE") with an investor related to a certain director of the Company for total proceeds of C$5,000,000. In accordance with the terms of the SAFE, the full value of C$5,000,000 was converted into 5,000 senior secured convertible debenture units of the Company in accordance with the terms and upon the closing of the July 2023 Offering.

f) The Company maintains a BOOMT Agreement with service provider, GTX (see above). Of the ownership of GTX, 13.9% is held by directors or affiliates of directors of the Company.

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 2024	Q4 2023	Q3 2023	Q2 2023
Total revenue	10,237,113	4,642,373	2,486,991	2,815,329
Net loss	(26,324,404)	(5,040,567)	(4,919,241)	(2,922,760)
Comprehensive loss	(24,883,061)	(6,346,247)	(3,996,929)	(3,718,115)
Net loss per share (basic & diluted)	(0.18)	(0.04)	(0.04)	(0.02)

	Q1 2023	Q4 2022	Q3 2022	Q2 2022
Total revenue	2,096,853	1,766,325	-	-
Net loss	(3,795,008)	(3,468,820)	(3,844,417)	(1,856,666)
Comprehensive loss	(3,743,149)	(3,673,960)	(3,362,029)	(1,730,924)
Net loss per share (basic & diluted)	(0.03)	(0.03)	(0.03)	(0.02)

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 sales revenue, costs of debt arrangements, G&A expenses, share-based compensation expense, fair value results on derivative liabilities, and fluctuations in exchange rates. Net finance expenses are primarily due to the interest expense incurred in relation to the convertible debentures and the lease liabilities that commenced in the prior year as well as an increase on decommissioning obligations.

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

In the first quarter of 2024, the Company had gross natural gas revenue of $10,190,283, NGL revenue of $46,830, royalties of $1,676,048 and operating costs of $1,104,973. Continuing depletion and depreciation expenses, G&A and finance expenses were ongoing factors in the net loss for the quarter. The Company incurred G&A expenses of $1,247,704, depletion and depreciation expenses of $2,513,021 and net finance expenses of $3,200,789. The Company also incurred one-time debt settlement costs of $22,927,667 and one-time termination costs of $1,502,000. While the Company realized its best quarter for sales revenue, the aforementioned one-time costs, which related predominantly to the conversion and redemption of convertible debentures in parallel with the Macquarie Financing, greatly impacted the net loss for Q1 2024.

In the fourth quarter of 2023, the Company had gross natural gas revenue of $4,568,843, NGL revenue of $73,530, royalties of $786,420 and operating costs of $1,671,793. Continuing depletion and depreciation expenses, G&A and finance expenses were ongoing factors in the net loss for the quarter. The Company incurred G&A expenses of $1,035,491, depletion and depreciation expenses of $1,419,132 and net finance expenses of $2,833,841. Ongoing G&A consisted of similar wages and salaries, but reduced professional expenses and fees, rent, investor relations, and other expenses when compared to other quarters in 2023.

In the third quarter of 2023, the Company had gross natural gas revenue of $2,430,805, NGL revenue of $56,186, royalties of $428,766 and operating costs of $1,086,477. Increases to depletion and depreciation expenses, G&A and finance expenses also contributed to the quarterly net loss. The Company incurred G&A expenses of $1,608,804, depletion and depreciation expenses of $1,467,066 and net finance expenses of $2,815,506. Increased finance expenses were due to additional interest expense incurred in the quarter in relation to the convertible debentures issued in connection with the May 2023 Offering convertible debentures The increase to G&A from the last quarter was due to increases in wages and salaries, professional fees and fees, rent, investor relations, and other expenses.

In the second quarter of 2023, the Company had gross natural gas revenue of $2,797,821, NGL revenue of $17,508, royalties of $365,425 and operating costs of $517,599. Increases to depletion and depreciation expenses, G&A and finance expenses also contributed to the quarterly net loss. The Company incurred G&A expenses of $1,459,968, depletion and depreciation expenses of $1,381,924 and net finance expenses of $2,257,721. The increase to G&A from the last quarter was primarily due to increases in wages and salaries and professional fees partially offset by decreases to fees, rent, investor relations, and other expenses.

In the first quarter of 2023, the Company had gross natural gas revenue of $2,096,853, royalties of $393,342 and operating costs of $566,605. Increases to depletion and depreciation expenses, G&A and finance expenses also contributed to the quarterly net loss. The Company incurred G&A expenses of $1,395,729, depletion and depreciation expenses of $1,262,589 and net finance expenses of $2,186,852. The increase to G&A from the last quarter was primarily due to increases in wages and salaries partially offset by decreases to fees, rent, investor relations, and other expenses.

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

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

In the second quarter of 2022, G&A expenses of $867,185 as well as increased net finance expenses of $254,808 and foreign exchange losses of $997,668 contributed to the quarterly net loss. Reductions in investor relation expenses during Q2 2022 when compared to these same expenses in Q1 2022 was the primary cause of the reduction in G&A expenses, quarter to quarter. Increased finance expenses were due to the additional interest expense incurred in Q2 2022 with the completion of the May 2022 Offering.

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.

Significant Judgments in Applying Accounting Policies

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

i) *Identification of cash-generating units*

Natural gas assets and processing facilities are grouped into cash generating units ("**CGUs**") identified as having largely independent cash inflows and are geographically integrated. The determination of the CGUs was based on management's interpretation and judgment. The recoverability of development and production asset carrying values is assessed at the CGU level. The asset composition of a CGU can directly impact the recoverability of the assets included therein.

ii) *Depletion, depreciation and reserves*

Depletion is based on the Proved + Probable natural gas reserves as evaluated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**") and incorporating the estimated future cost of developing and extracting those. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates are based on current production forecasts, forecasted natural gas prices and future development costs. As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions of reserve estimates are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to determine that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end natural gas prices and reservoir performance. Such revisions can be either positive or negative. Changes in reserve estimates impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion.

iii) *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.

iv) 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.

v) Income taxes

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

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

vi) VAT recoverability

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

Key Sources of Estimation Uncertainty

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

i) Going concern

Management is required to assess the Company's ability to continue as a going concern. In assessing whether the going concern assumption is appropriate, management assesses all available information about the future, considering the possible outcomes of events and changes in conditions and the realistically possible responses that are available to such events and conditions. Such available information may include updates to Company forecasts and relevant sensitivities, as considered appropriate, taking into account the risk factors identified and the different possible outcomes. Management also assesses its plans to mitigate events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. Ultimately, this requires assumptions that the Company's assessment concludes that its plans are achievable and realistic based on the information available at the time.

ii) Reserves and resource assessment

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

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

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

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

iii) 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.

iv) Share-based payments

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

v) *Convertible debentures*
The fair value of the liability component of the convertible debentures utilizes observable market data, including interest rates. As a result of changes in key assumptions, actual amounts may vary significantly from estimated amounts.

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

Risks and Uncertainties

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

- risks related to the Common Shares;
- inability to obtain additional capital required to implement business plan; debt matters; operational constraints due to debt;
- rising interest rates;
- limited customer base;
- directors and officers;
- personnel;
- going concern risk;
- dilution;
- internal controls;
- Forward-Looking Statements may prove inaccurate;
- diversification;
- expansion into new activities;
- climate change;

- income taxes;
- cash from subsidiaries;
- pending or future litigation, arbitration and other regulatory proceedings;
- climate change related litigation;
- technology;
- information technology or cybersecurity;
- breach of confidentiality;
- earnings & accounting estimates;
- Shareholder activism; global financial conditions;
- the COVID-19 pandemic;
- pandemics and their effect on the global economy;
- Russia-Ukraine conflict;
- The Israel-Palestine conflict;
- foreign location of assets;
- estimated natural gas resources and reserves are based on assumptions that may prove inaccurate;
- E&P Contracts;
- Volatility of pricing for oil and natural gas;
- inability to market natural gas production and change in natural gas sale prices;
- exploration, production and general operational risk;
- replacement reserves;
- minimum work commitments on exploration blocks;
- competition;
- changing investor sentiment about the oil and natural gas industry;
- weakness in the oil and natural gas industry;
- alternatives to/changing demand for petroleum products;
- reputational risk;
- environmental, health and safety risk;
- natural disaster and weather-related risks;
- joint venture risks;
- gathering and processing facilities and pipeline systems;
- operational risks with pipelines;
- delays in production, marketing and transportation;
- difficulty transporting and distributing production;
- drilling costs and availability of equipment;
- drilling wells could result in liabilities;
- decommissioning costs;
- insurance;
- uninsurable risks;
- inflation and cost management;
- oil and natural gas companies in Colombia do not own any of the oil and natural gas reserves in the country;
- unforeseen title defects;
- seizure or expropriation of assets;
- risks of foreign operations;

- risks associated with geographically concentrated operations;
- oil & natural gas industry in Colombia is less developed; operations in emerging market country;
- economic and political developments in Colombia;
- political uncertainty in Colombia, Canada and elsewhere;
- changes in laws or regulations;
- corruption;
- money laundering and other illegal and improper activities;
- licenses and permits;
- land, communities, prior consultation and zoning restrictions;
- activities in areas classified as Indigenous reserves and Afro-Colombian lands;
- social disruptions and instability;
- sanctions by the United States of America on Colombia;
- Canada's relations with Colombia; and
- violence and instability in Colombia.

If any of these risks materialize into actual events or circumstances or other possible additional risks and uncertainties of which the Company is currently aware or which it considers to be material in relation to the Company's business occur, the Company's assets, liabilities, financial condition, results of operations (including future results of operations), business and business prospects, are likely to be materially and adversely affected. In such circumstances, the prices of the Company's securities could decline, and investors may lose all or part of their investment.
Readers are encouraged to read and consider the risk factors listed above, which are more specifically described in the Company's Annual Information Form dated April 26, 2024, which is available on SEDAR+ at www.sedarplus.ca. Such risk factors could materially affect the future operating results of the Company and could cause actual events to differ materially from those described in forward-looking statements relating to the Company.

Management's Report on Internal Control over Financial Reporting

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

FINANCIAL AND OTHER INSTRUMENTS

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

- Credit risk
- Liquidity risk
- Market risk

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

Credit risk

Credit risk reflects the risk of loss if counterparties do not fulfill their contractual obligations. The carrying amount of cash and cash equivalents, deposits in escrow, accounts receivable, VAT receivable and restricted cash represent the maximum credit exposure. As at March 31, 2024, the Company had $8,648,984 (December 31, 2023 - $8,011,108) in restricted cash towards development activity and joint operations in Colombia (see above).

As at March 31, 2024, the Company had $6,021,712 (December 31, 2023 - $3,545,419) in accounts receivable. The Company does not consider any of its receivables past due.

The Company maintained a VAT receivable balance of $3,596,393 as of March 31, 2024 (December 31, 2023 - $3,129,360), 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.

As at March 31, 2024, the Company held cash and cash equivalents of $10,687,899 (December 31, 2023 - $1,294,422) and deposits in escrow of $nil (December 31, 2023 - $1,584,608). The Company manages the credit exposure related to cash and cash equivalents and deposits in escrow by ensuring counterparties (e.g., banks) maintain satisfactory credit ratings and monitors all investments to ensure a stable return.

Liquidity risk

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

The following table outlines the contractual maturities of the Company's financial liabilities at March 31, 2024:

	Within 1 Year	Year 2	Years 3-5	Thereafter	Total
Trade accounts payable	6,868,564	-	-	-	6,868,564
Royalties payable	2,742,438	-	-	-	2,742,438
Capital payables	3,172,954	-	-	-	3,172,954
Promissory Notes	2,061,922	-	-	-	2,061,922
Lease obligation payments	7,292,544	7,292,544	18,335,287	-	32,920,375
Convertible debentures - interest	991,705	991,705	1,129,442	-	3,112,852
Convertible debentures - principal	-	-	12,396,310	-	12,396,310
Macquarie Debt - interest (1)	5,262,904	3,796,701	3,265,023	-	12,324,628
Macquarie Debt - principal	8,000,000	12,000,000	20,000,000	-	40,000,000
	36,393,031	**24,080,950**	**55,126,062**	**-**	**115,600,043**

1) Presumed interest rate of 13.8% over the life of the debt.

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, 2024 nor were there financial derivative contracts or embedded derivatives outstanding at December 31, 2023.

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 natural gas are affected not only by the United States dollar, but also by world economic events that dictate the levels of supply and demand.

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

Foreign currency risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate 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, 2024, 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, 2023.

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, 2024 and 2023, 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 oil and natural gas exploration, development, exploitation, production, marketing and transportation, the volatility of oil 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 oil and natural gas acquisition and drilling programs, delays resulting from inability to obtain required regulatory approvals, delays resulting from inability to obtain drilling rigs and other services, labor supply risks, environmental risks, competition from other producers, imprecision of reserve estimates, changes in general economic conditions, ability to execute farm-in and farm-out opportunities, and other factors, all of which are more fully described under the caption "*Risk Factors*" in the Company's Annual Information Form dated April 26, 2024, which is available for review on SEDAR+ at www.sedarplus.ca.

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 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 cash flow, market prices and costs;
- the supply and demand for natural gas and oil;
- expectations regarding the ability to raise equity and debt capital on acceptable terms and to add continually to reserves through acquisitions and development, including the ability to negotiate and complete the agreements contemplated in this MD&A;
- the timing for receipt of regulatory approvals; and
- treatment of the Company under governmental regulatory regimes and tax laws.

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

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

- the availability on acceptable terms of funds for capital expenditures;
- the availability in a cost-efficient manner of equipment and qualified personnel when required,
- continuing favorable relations with Colombian 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 reserves or resources, as applicable;
- the existence and recoverability of any 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 26, 2024, which is available on SEDAR+ at www.sedarplus.ca.

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.

To the extent any forward-looking statement in this MD&A constitutes "future-oriented financial information" or "financial outlooks" within the meaning of applicable Canadian securities laws, such information is being provided to demonstrate the anticipated use of proceeds as impacted by the commencement of revenue generation, and the reader is cautioned that this information may not be appropriate for any other purpose and the reader should not place undue reliance on such future-oriented financial information and financial outlooks. Future-oriented financial information and financial outlooks, as with forward-looking statements generally, are, without limitation, based on the assumptions and subject to the risks set out above under this "Forward-Looking Statements". The actual financial position and results of operations of the Company may differ materially from management's current expectations and, as a result, the Company's revenue and expenses may differ materially from the revenue and expenses profiles provided in this MD&A. Such information is presented for illustrative purposes only and may not be an indication of the Company's actual financial position or results of operations.

Prospective investors are cautioned not to put undue reliance on forward-looking statements, and investors should not infer that there has been no change in the Company's affairs since the date of this MD&A that would warrant any modification of any forward-looking statement made in this document, other documents periodically filed with or furnished to the relevant securities regulators or documents presented on the Company's website. All subsequent written and oral forward-looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by this notice. The Company disclaims any intent or obligation to update publicly or otherwise revise any forward-looking statements or the foregoing list of assumptions or factors, whether as a result of new information, future events or otherwise, subject to the Company's disclosure obligations under applicable Canadian securities regulations. Investors are urged to read the Company's filings with Canadian securities regulatory agencies, which are available for review under the Company's SEDAR+ profile at www.sedarplus.ca.

Analogous Information

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

Abbreviations

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