NEW STRATUS ENERGY INC.

Statement of Reserves Data and Other Oil and Gas Information
(NI 51-101F1)

Effective March 31, 2022

TABLE OF CONTENTS

ABBREVIATIONS AND CONVERSION FACTORS

Abbreviations

In this document, the abbreviations set forth below have the following meanings:

bbl	barrel	M$	thousands of United States dollars
Mbbl	thousands of barrels	Mcf	thousand cubic feet
bopd	barrels of oil per day	MMcf	million cubic feet

ac	acre
API	American Petroleum Institute
C$	Canadian dollars
m	metre
scf	standard cubic feet
WI	working interest
US$ or $	United States dollars

Conversion Factors

1 metre	3.28 feet
1 cubic metre of gas	35.31467 cubic feet of gas
1 cubic metre of liquid	6.28981 barrels
1 hectare (10,000 square metres)	2.471054 acres

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

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

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

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

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

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

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

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

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

"**Undeveloped reserves**" are those reserves 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 category (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

The following terms used in this document have the following meanings:

"**Abandonment and reclamation costs**" means all costs associated with the process of restoring a reporting issuer's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

"**Associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

"**BOE**" or "**boe**" means barrel of oil equivalent. 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.

"**Company**" or "**New Stratus**" means New Stratus Energy Inc.

"**Crude oil**" means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

"**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.

"**Field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "state", "play" or "area of interest".

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

(a) generally accepted as being a reasonable outlook of the future;

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

"**Future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"**Future net revenue**" is a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

"**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.

"**Natural gas**" means a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

"**Natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as liquids including but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

"**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.

"**Non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

"**Operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**Production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**Property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**Property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**Proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**Reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"**Solution gas**" means natural gas dissolved in crude oil.

"**Stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**Support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**Unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

PART 1 - DATE OF STATEMENT

The effective date of the information being provided in this Form 51-101F1 is March 31, 2022 and is for the year ended March 31, 2022. The date of this statement is July 28, 2022 and the preparation date of the information being provided in this statement is July 14, 2022.

PART 2 - DISCLOSURE OF RESERVES DATA

2.1 **Reserves Data (Forecast Prices and Costs)**

The reserves data set forth below (the "**Reserves Data**") is based upon a report prepared by Petrotech Engineering Ltd., independent qualified reserves evaluators of Burnaby, British Columbia, Canada ("**Petrotech**"), evaluating the reserves attributable to the Company's interests in its Ecuador properties, as at March 31, 2022, dated July 14, 2022 (the "**Petrotech Report**"). The Reserves Data summarizes the proved, probable and possible heavy crude oil reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs.

The Petrotech Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) (the "**COGE Handbook**") and the reserve definitions contained in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators ("**NI 51-101**") and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which New Stratus believes is important to the readers of this information. The Company engaged Petrotech to provide an evaluation of proved, probable and possible reserves.

All of the Company's reserves are located in onshore Ecuador. On January 14, 2022, the Company acquired an indirect 35% working interest in Block 16 and Block 67 in Ecuador (the "**Blocks**") pursuant to Service Operating Contracts. The Service Operating Contracts expire on December 31, 2022. The Company is negotiating with the Government of Ecuador to extend the Company's rights to the Blocks through a production sharing contract.

New Stratus determined the future net revenue and present value of future net revenue after income taxes by utilizing Petrotech's before income tax future net revenue and New Stratus's estimate of income tax. New Stratus's estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of its tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of New Stratus's oil and gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of New Stratus as a business entity, which may be significantly different.

All evaluations of future net revenue are before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Petrotech represent the fair market value of those reserves. There is no assurance that the forecast price and cost assumptions contained in the Petrotech Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized herein. The recovery and reserve estimates described herein are estimates only. The actual reserves associated with New Stratus's properties may be greater or less than those calculated.

The tables below summarize the data contained in the Petrotech Report and, as a result, may contain slightly different numbers than such report due to rounding. Due to rounding, certain columns may not add exactly to the totals listed.

All dollar amounts presented below are expressed in United States dollars, unless otherwise indicated.

2.1.1 Breakdown of Reserves (Forecast Case)

SUMMARY OF OIL AND GAS RESERVES
(Forecast Prices and Costs)

Reserves Category	Light and Medium Oil Gross (Mbbl)	Light and Medium Oil Net (Mbbl)	Heavy Oil Gross (Mbbl)	Heavy Oil Net (Mbbl)	Natural Gas Gross (MMcf)	Natural Gas Net (MMcf)	Natural Gas Gross (Mbbl)	Natural Gas Net (Mbbl)	BOEs Gross (Mbbl)	BOEs Net (Mbbl)
Proved										
Developed Producing	-	-	1,155.0	1,155.0	-	-	-	-	1,155.0	1,155.0
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	-	-	1,155.0	1,155.0	-	-	-	-	1,155.0	1,155.0
Total Probable	-	-	9.7	9.7	-	-	-	-	9.7	9.7
Total Proved Plus Probable	-	-	1,164.7	1,164.7	-	-	-	-	1,164.7	1,164.7
Total Possible	-	-	9.8	9.8	-	-	-	-	9.8	9.8
Total Proved Plus Probable Plus Possible	-	-	1,174.5	1,174.5	-	-	-	-	1,174.5	1,174.5

Note:

(1) All of the Company's reserves are derived from the Services Operating Contracts. No royalties are payable pursuant to the terms of the Services Operating Contracts and as a result the net reserves of the Company are the same as the gross reserves of the Company.

2.1.2 Net Present Value of Future Net Revenue (Forecast Case)

NET PRESENT VALUES OF FUTURE NET REVENUE
BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)
(Forecast Prices and Costs)

	Before Tax Net Present Value @				
Reserves Category	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**
Proved					
Developed Producing	19,470.0	19,006.4	18,585.0	18,200.2	17,847.1
Developed Non- Producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total Proved	19,470.0	19,006.4	18,585.0	18,200.2	17,847.1
Total Probable	267.0	260.7	254.9	249.6	244.8
Total Proved Plus Probable	19,737.0	19,267.0	18,839.8	18,449.8	18,091.9
Total Possible	269.7	263.2	257.4	252.1	247.2
Total Proved Plus Probable Plus Possible	20,006.6	19,530.3	19,097.2	18,701.9	18,339.1

NET PRESENT VALUES OF FUTURE NET REVENUE
AFTER INCOME TAXES DISCOUNTED AT (%/YEAR)
(Forecast Prices and Costs)

	After Tax Net Present Value @				
Reserves Category	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**
Proved					
Developed Producing	19,470.0	19,006.4	18,585.0	18,200.2	17,847.1
Developed Non- Producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total Proved	19,470.0	19,006.4	18,585.0	18,200.2	17,847.1
Total Probable	267.0	260.7	254.9	249.6	244.8
Total Proved Plus Probable	19,737.0	19,267.0	18,839.8	18,449.8	18,091.9
Total Possible	269.7	263.2	257.4	252.1	247.2
Total Proved Plus Probable Plus Possible	20,006.6	19,530.3	19,097.2	18,701.9	18,339.1

2.1.3 Additional Information Concerning Future Net Revenue (Forecast Case)

FUTURE NET REVENUE (UNDISCOUNTED)
(Forecast Prices and Costs)

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment And Reclamation Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved	62,724.5	-	28,379.2	9,625.4	5,250.0	19,470.0	-	19,470.0
Total Proved Plus Probable	63,247.9	-	28,635.6	9,625.4	5,250.0	19,737.0	-	19,737.0
Total Proved Plus Probable Plus Possible	63,777.0	-	28,894.6	9,625.4	5,250.0	20,007.0	-	20,007.0

FUTURE NET REVENUE BY PRODUCT TYPE
(Forecast Prices and Costs)

	Heavy Oil	
Reserves Category	**Future Net Revenue Before Income Taxes (Discounted At 10%/Year) ($000s)**	**Unit Value Before Income Taxes (Discounted At 10%/Year) ($/Boe)**
Total Proved	18,585.0	16.09
Total Proved Plus Probable	18,839.8	16.18
Total Proved Plus Probable Plus Possible	19,097.2	16.26

PART 3- PRICING ASSUMPTIONS

The following pricing assumptions were provided by Petrotech.

3.1 **Forecast Prices Used in Estimates**

The following table sets out the WTI reference oil prices and the forecast oil prices, effective March 31, 2022. Forecast prices are only provided for 2022 because the Service Operating Contract in respect of the Blocks expires on December 31, 2022. The pricing assumptions were obtained from Sproule, an independent qualified reserves evaluator. The oil prices for each block have been adjusted for quality. The Napo oil price is the WTI price discounted by 12%.

Year	WTI Price ($/bbl)	Napo Price ($/bbl)	Block 16 Adjusted Price ($/bbl)	Block 67 Adjusted Price ($/bbl)
2022	$93.00	$81.84	$78.65	$83.27

The forecast oil prices used in the Petrotech Report were US$78.65 per barrel for Block 16, and US$83.27 per barrel for Block 67. The weighted average historical price realized by the Company for the most recent financial year ended March 31, 2022 was C$65.48/bbl for heavy crude oil, being the agreed tariff C$48.41/bbl plus the carry forward recovery of C$17.07/bbl.

PART 4 - RECONCILIATION OF CHANGES IN RESERVES

4.1 **Reserves Reconciliation**

The reserves information presented herein has been summarized from the Petrotech Report. The Company acquired its interest in the Blocks in January 2022. The Company did not have any reserves for the year ended March 31, 2021, and consequently no evaluation report was prepared for the Company. As there were no reserves for the Company for the year ended March 31, 2021, pursuant to the applicable provisions of NI 51-101, a reserves reconciliation is not required to be disclosed.

PART 5 - ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 **Undeveloped Reserves**

The Company has not attributed proved or probable undeveloped reserves.

5.2 **Significant Factors or Uncertainties Affecting Reserves Data**

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company. Some of these risks are noted below.

The process of estimating reserves is complex. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. 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 natural gas prices and costs change. Estimates are reviewed and revised, either upward or downward, as warranted by newly acquired information.

The evaluation and drilling of hydrocarbon targets may be curtailed, delayed or cancelled by the unavailability or prevailing cost of drilling rigs or technical contractors, mechanical difficulties, adverse weather and ocean conditions, environmental issues, political or social unrest, technical hazards, such as unusual or unexpected formations or pressures or because of issues related to compliance with government regulations or requirements. Drilling may result in unprofitable efforts, not only with respect to dry wells, but also with respect to wells which, though yielding some hydrocarbons, are not sufficiently productive to economically justify commercial development. Furthermore, the successful completion of a well does not assure a profit on investment or the recovery of drilling, completion and operating costs.

Under the current Service Operating Contract of Consorcio Petrolero in Blocks 16 and 67 in Ecuador, the abandonment and reclamation costs are estimated at $15 million, and the Company is responsible for 35% of these costs. The abandonment and reclamation costs have been included in the Petrotech Report.

5.3 Future Development Costs

The table below sets forth the development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories based upon the Petrotech Report. Information is only provided for 2022 because the Service Operating Contract in respect of the Blocks expires on December 31, 2022.

	Development Costs (Forecast Prices and Costs)	
	Total Proved (M$)	**Total Proved Plus Probable (M$)**
2022		
Total (undiscounted)	9,625.4	9,625.4
Total (discounted at 10% per year)	9,188.0	9,188.0

The Company expects to use a combination of internally generated cash from operations and working capital to fund future development costs set out in the Petrotech Report. There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributable in the Petrotech Report. Failure to develop those reserves could have a negative impact on the Company's future cash flow. Further, the Company may choose to delay development depending upon a number of circumstances including the existence of higher priority expenditures and available cash flow. Interest expense or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Company does not anticipate that interest or other funding costs would make further development of any of the Company's properties uneconomic.

PART 6 - OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

6.1.1 Oil and Gas Properties

Since the acquisition of the Blocks in January 2022, New Stratus's principal properties are located in Ecuador. Prior thereto, New Stratus did not have any reserves.

Ecuador

On January 14, 2022, the Company acquired all of the issued and outstanding share capital of Repsol Ecuador, S.A. ("**Repsol Ecuador**") from Repsol Exploración S.A. and Repsol Petróleo S.A. of Madrid, Spain. The share transfer was approved by the Ministry of Energy and Non-Renewable Natural Resources of Ecuador and the Ecuadorian Antitrust Authority. As a result of the acquisition, the Company indirectly owns the 35% participating interest operated by Repsol Ecuador in the Service Operating Contract of Consorcio Petrolero in Blocks 16 and 67 in Ecuador. The Service Operating Contract expires on December 31, 2022 and the Company is negotiating with the Government of Ecuador to extend the Company's rights to the Blocks through a production sharing contract. Subsequent to the Company's acquisition of the Blocks, Repsol Ecuador S.A. was renamed Petrolia Ecuador S.A.

Both Blocks 16 and 67 are located onshore in the Orellana Province in the Oriente Basin of Ecuador. The main producing reservoirs in both blocks are from the Upper Cretaceous Napo U, T and M1 sands and the production is maintained with strong water drive. Heavy oil production comes from eight fields: Amo, Bogi-Capiron, Dabo Sur, Daimi, Ginta, Iro, and Wati fields in Block 16; and the Tivacuno field (which includes the Tivacuno SW field) in Block 67.

Consortium

Through Petrolia Ecuador S.A., the Company owns participation rights in consortiums for the management of Block 16, through the Block 16 Oil Consortium, and Block 67 through the Tivacuno Block Oil Consortium (the "**Consortia**"), pursuant to which the Company owns an indirect 35% interest.

Joint Operation Agreement

By means of a joint operating agreement, the members of the Consortia appointed YPF Ecuador Inc., Branch Ecuador as operator for the exploration and exploitation of Block 16 and the Tivacuno Area. The operations of Block 16 and the Tivacuno Area were assigned to Repsol Ecuador S.A. (now Petrolia Ecuador S.A.).

This joint operating agreement establishes that the members of the Consortia maintain the rights over the assets, the obligation over the liabilities, the benefit of the revenues and the responsibility for the costs and expenses of the joint operation in accordance with their portion of the participating interest.

Services Operating Contracts

On July 27, 2010, the Reformatory Law to the Hydrocarbons Law and the Internal Tax Regime Law was enacted in the Official Gazette No. 244, which gave way to the modification of participation contracts to service rendering contracts.

Modifying Contract to the Service Contract for the Exploration and Exploitation of Hydrocarbons in Block 16 of the Amazon Region

On November 23, 2010, the Consortium signed with the Secretariat of Hydrocarbons (an entity that was absorbed by the Ministry of Energy and Non-Renewable Resources, hereinafter the "**Ministry**") on behalf of the Ecuadorian State, the modifying contract to the contract for provision of services for the exploration and exploitation of hydrocarbons in Block 16 of Ecuador (the "**Block 16 Services Contract**"); which was registered in the Hydrocarbons Registry on December 23, 2010, and originally had an effective date until December 31, 2018.

The purpose of the contract is to provide services, with its own resources and at the Consortium's risk, for the exploration and exploitation of hydrocarbons, including crude oil in the contract area. The Consortium is obliged to carry out the activities of exploration, confirmation of reserves, development, exploitation and production, contributing the technology, capital requirement, goods and machinery necessary for the fulfillment of the obligations established in the contract, in accordance with the plan of activities. Under the Block 16 Services Contract, the committed and estimated investments amounted to US$280 million (US$98 million for Repsol Ecuador S.A.) during the contract period. The committed activity plan under the Block 16 Services Contract has been fully complied with.

In consideration for its services, the Consortium will receive an original fee of US$35.95 per barrel of net crude oil extracted and delivered to the inspection and delivery center, which is reviewed annually, due to an operating cost inflation factor established in the contract. For the 12 month period ended December 31, 2021, the approved crude oil tariff was US$37.74. Payment to the Consortium may be made in cash, in kind or a mixture of the two, depending on the agreement between the parties.

The existence or not of available income to cover the fee mentioned in the previous paragraph will be determined as follows: of the income from the audited production corresponding to the area covered by the contract, the Ecuadorian State reserves 25% as a sovereignty margin. From the remaining value, the transportation and commercialization costs incurred by the State of Ecuador and the taxes corresponding to the Institute for the Ecodevelopment of the Amazon Region and Esmeraldas and the Law for the Creation of Substitute Income for the provinces of Napo, Esmeraldas and Sucumbios will be covered. Once these deductions have been made, the fee for the provision of the services will be covered.

In the event that the available income is not sufficient to cover the payment of the fee for fields in production and the fee for the new fields or for incremental production from enhanced recovery, the monthly shortfall will be accumulated during the relevant month or fiscal year. The difference between the amounts paid for the tariffs and the available income of the same month or fiscal year will be carried forward to the following month or fiscal year, without interest and in case it could not have been covered during the respective or subsequent month or fiscal year it will be accumulated successively during the term of this amendment agreement. Any difference carried forward, originated by insufficiency of available income, which has not been paid to the Consortium, and the Ministry shall be automatically released from this payment obligation at that time.

Upon termination of this contract, the Consortium shall deliver to the Ecuadorian State, at no costs and in good condition, except for normal wear and tear, the wells that are in production and all equipment, tools, machinery, installations and other furniture and real estate that have been destined for the purposes of the contract.

On June 3, 2013 and December 17, 2013, the Ministry and the Consortium entered into amendment agreements number one and two to the Block 16 Services Contract. The referred amendments were registered with the Ministry on July 1, 2013 and January 8, 2014 respectively, and mainly contemplate the following aspects: (i) adjustment to the fee for the provision of the services originated in the modification of the income tax rate; (ii) extension of the contractual term of Block 16 until December 31, 2022; and (iii) modification of the area of Block 16, assigning to the Consortium an additional area of 1,993 hectares to incorporate the Wati field and committing an estimated investment for its development of approximately US$73 million (US$25.6 million for Repsol Ecuador S.A.). The committed investment has been fully realized.

Modifying Contract to the Service Agreement for the Exploration and Exploitation of Hydrocarbons in the Tivacuno Block in the Amazon Region (Block 67)

On January 22, 2011 the Consortium signed with the Ministry, on behalf of the Ecuadorian State, a modifying contract to the contract for the provision of services for the exploration and exploitation of hydrocarbons in the Tivacuno Block of the Amazon Region (the "**Block 67 Services Contract**"); the contract was registered in the Hydrocarbons Registry on February 21, 2011, and originally had an effective date until December 31, 2018.

The purpose of the contract is to provide services, with its own resources and at the Consortium's risk, for the exploration and exploitation of hydrocarbons, including crude oil, in the contract area. The Consortium undertakes to carry out the activities of exploration, confirmation of reserves, development, exploitation and production, contributing to the technology, capital and equipment, goods and machinery necessary for the fulfillment of the obligations established in the contract, in accordance with the plan of committed activities under the Block 67 Services Contract and estimated investment amount to US$22.8 million (US$7.9 million for Repsol Ecuador S.A.) during the contract period. The committed activity plan under the Block 67 Services Contract has been fully complied with.

In consideration for its services, the Consortium will receive an original fee of US$27.25 per barrel of net crude oil extracted and delivered to the inspection and delivery center, which is reviewed annually due to an operating cost inflation factor established in the contract. For the year ended December 31, 2021, the approved crude rate was US$28.58. Payment to the Consortium may be made in cash, in kind or a mixture of the two, depending on the agreement between the parties.

The existence or not of an available income to cover the fee mentioned in the previous paragraph will be determined as follows: of the income from the audited production corresponding in the area covered by the contract, the Ecuadorian State reserves 25% as a sovereignty margin. From the remaining value, the transportation and commercialization costs incurred by the State of Ecuador and the taxes corresponding to the Institute for the Ecodevelopment of the Amazon Region and Esmeraldas and the Law for the Creation of Substitute Income for the provinces of Napo, Esmeraldas and Sucumbios will be covered. Once these deductions have been made, the fee for the provision of services will be covered.

In the event that the available income is not sufficient to cover the payment of the tariff for producing fields and the tariff for new fields or for incremental production from enhanced recovery, the monthly balance will be accumulated during the relevant month or fiscal year. The difference between the amounts paid for the tariffs and the available income of the same month or fiscal year will be carried forward to the following month or fiscal year, without interest and in case it could not have been covered during the respective or subsequent month or fiscal year it will be accumulated successively during the term of this amendment agreement. Any difference carried forward, originated by insufficiency of available income, which has not been paid to the Ministry at the termination of this amending contract, shall be extinguished and shall not be paid to the Consortium, and the Ministry shall be automatically released from this payment obligation at that time.

Upon termination of the Block 67 Services Contract, the Consortium shall deliver to the Ecuadorian State, at no cost and in good condition, except for normal wear and tear, the wells that were in production and all equipment tools, machinery, facilities and other furniture and real estate that has been destined for the purposes of the contract.

On October 29, 2015, the Ministry and the Consortium signed modifying contract number one to the Block 67 Services Contract. The referred to modifying contract was registered in the Hydrocarbons Registry on November 9, 2015 and mainly contemplates the extension of the contractual term of the Block 67 Services Contract until December 31, 2022.

Colombia

In Colombia, the Colombian National Hydrocarbons Agency ("**ANH**") is the administrator of the hydrocarbons in the country and therefore is responsible for regulating the Colombian oil and gas industry, including managing all exploration lands. The ANH uses an exploration risk contract (an "**E&P Contract**"), which provides full risk/reward benefits for the contractor. Under the terms of this contract, the successful operator retains the rights to all reserves, production and income from any new exploration block, subject to existing royalty and tax regulations. Each contract contains an exploration phase and a production phase. The exploration phase contains a number of exploration periods and each period has an associated work commitment. The production phase lasts a number of years (usually 24) from the declaration of a commercial hydrocarbon discovery.

When operating under a contract, the contractor is the owner of the hydrocarbons extracted from the contract area during the performance of operations, except for royalty volumes which are collected by the ANH (or its designee). The contractor can market the hydrocarbons in any manner whatsoever, subject to a limitation in the case of natural emergencies where the law specifies the manner of sale.

VMM 18 E&P Contract

The Company's principal property in Colombia is the VMM 18 E&P Contract, which was signed between the ANH and Montajes JM S.A. ("**Montajes**") on March 15, 2011. The production is subject to the ANH sliding scale royalties plus 1% for the X-Factor and Additional Participation Interests (PAP). The original area of the block was 63,949.815 hectares. The VMM 18 E&P Contract is highly prospective for light and medium gravity oil and is located onshore in the Middle Magdalena Basin of Colombia covering a total retained area of 30,743 hectares (the balance was relinquished on August 22, 2016).

Pursuant to a purchase agreement executed on November 28, 2018 between New Stratus and Montajes, the Company acquired a 100% working interest in the VMM 18 E&P Contract in consideration for agreeing to fund the exploration commitments in Phase 2 of the exploration period of the E&P Contract of Block VMM-18 ("**Phase 2**"). As part of Phase 2, the Company has agreed to finance the exploratory costs (including all decommissioning costs and payments due to ANH). Pursuant to two contract amendments (otrosíes) granted by the ANH dated April 19, 2016 and July 2, 2019, and a further extension granted by the ANH on August 24, 2020, the Company is obligated to perform seismic reprocessing valued at US$250,000 and either (i) drill an exploration well valued at US$3 million and relinquish 50% of the contract area; or (ii) drill two exploration wells with no relinquishment, in each case on or before August 21, 2021. Montajes is to receive a 5% of the net income from the Company's sale of the crude oil produced after deduction of the ANH and X-Factor royalties. The transfer of the working interest from Montajes to the Company in the VMM 18 E&P Contract remains subject to ANH approval.

The impact of the COVID-19 pandemic affected the Company's ability to continue with its work commitments within the originally established timelines as many of its tasks have been delayed. On December 12, 2021, the ANH informed the Company of an extension of additional 86 calendar days, hence May 19, 2022, was established as the revised end date of Phase 2. Subsequent to year end, on April 12, 2022, the Company requested an extension from the ANH to extend Phase 2 for a period of 113 calendar days. The ANH has confirmed 27 of these 113 requested days and the Company has asked for an additional 109 days. The Company is awaiting a response from the ANH.

The presentation of the Environmental Impact Study to the National Authority for Environmental Licenses ("**ANLA**") was made and On February 23, 2022, the ANLA began the evaluation process to grant the Environmental License for the drilling of VMM-18.

Between March 8 and 11, 2022, the ANLA carried out an environmental assessment, by visiting the project. On April 4, 2022, the ANLA required additional information. The Company sent the additional information on May 10, 2022 and has not received notification of any further requirements. The Company is awaiting approval of the Environmental Impact Study and the corresponding issuance of the Environmental License by the ANLA.

Work Program

The initial committed work program for the VMM 18 E&P Contract is set forth below. The commitments for Phase 1 and Phase 1A have been fully complied with.

Phase	Duration	Exploratory Commitment	Investment Agreed
1	36 Months	Acquisition, reprocessing and interpretation of 60km2 of 3D seismic	USD$3,840,000
1A		Reprocessing and interpretation of 400km of 2D seismic	USD$40,000
		Surface Geology	USD$160,000
		Structural modeling	USD$100,000
		Geochemical modeling	USD$100,000
2	48 Months	Reprocessing of 963km of 2D seismic and 60km2 of 3D seismic	USD$250,000
		Drilling of an exploratory well A3 and return of 50% of the area	USD$3,000,000
			USD$7,490,000

Evaluation

The recently reprocessed 2D and 3D seismic data had been used by the Company to map the prospects and leads on VMM 18 Block. Both Pulí Field and VMM 18 prospects are part of a trend of shallow west – vergent thrust sheets of the Cambao fault system, as regional decollèment. The trend extends south to north more than 50 km, from the south of Pulí to north of the Quintero discovery (in the La Pola Block) near the Guaduas Field. Production in the play comes from Cretaceous Monserrate sandstones capped by Paleogene Seca shale.

All the wells drilled along trend from Pulí to Quintero and beyond found good quality Monserrate sands. Good quality 2D seismic, controlled with nearby wells and tied to detailed surface geology, indicates that Monserrate sands are present in the VMM 18 prospects with stratigraphic thickness in the hundreds of feet.

The proven functional petroleum system in the region is sourced by the Villeta Fm. –organic shale; the oil charge of Hercules is expected to be migrated from the Guaduas syncline some 6 km to the east. The Paleocene Seca Formation, mainly composed by muds is present along the Pulí-Hercules prospect trend and further north representing the regional seal.

The depth range in Pulí and Hercules is in the same range, and reservoir pressures and oil type are expected to be similar with gravity ranging 30º API to 34º API.

Analogue Production Data

To the south of the VMM 18 Block, the Pulí Field is used as the analogue to the VMM 18 prospects. The Guaduas and Toqui-Toqui Fields also have production in the area.

6.1.2 Oil and Gas Wells

The following table sets forth the number of wells in which the Company held a working interest as at March 31, 2022, all of which are located in Ecuador.

	Natural Gas				Oil			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ecuador	-	-	-	-	107	37.45	240	84
Total	**-**	**-**	**-**	**-**	**107**	**37.45**	**240**	**84**

6.2 Properties With No Attributed Reserves

The following table sets out the Company's unproved properties as at March 31, 2022.

	Gross Area	Net Area
Colombia	30,743 hectares	30,743 hectares

The VMM 18 E&P Contract is awaiting extension approval from the ANH. If the extension for VMM 18 is not received the lands in Colombia will have expired.

The Company is required to make substantial capital expenditures in order to prove, exploit, develop and produce from its properties with no attributed reserves. The ability of the Company to access sufficient capital for the exploration and development of these properties is uncertain, and the inability of the Company to do so will have an adverse effect on its ability to execute its business strategy to develop its properties.

6.3 Forward Contracts

The Company does not currently have exposure to any forward contracts.

6.5 Tax Horizon

As at March 31, 2022, the Company had federal tax pools of approximately $11,485,410. The statutory corporate income tax rate applicable to the Company is approximately 25%. A corporation's taxable income is based on total revenue, other income and expenses.

6.6 Costs Incurred

The following table sets out the Company's property acquisition costs, exploration costs and development costs for the most recent financial year ended March 31, 2022:

Year	Property Acquisition Costs	Exploration Costs	Development Costs
Mar 31, 2022	$8.2 million	-	-

Note:
(1) On January 14, 2022, the Company acquired 100 percent of shares of Petrolia Ecuador S.A. for $5.8 million, comprised of a $5.0 million purchase price payable in two equal instalments of $2.5 million each on the first and second anniversary dates of the closing of the transaction, and a preliminary closing adjustment of approximately $750,000. In addition, acquisition costs incurred for the acquisition were approximately $2.4 million.

6.7 Exploration and Development Activities

No exploration and development wells were drilled and completed during year ended March 31, 2022 in Ecuador or Colombia.

6.8 Production Estimates

The following table discloses for each product type the total volume of production estimated by Petrotech for March 31, 2022 to December 31, 2022 which is the expiry date of the contract reflected in the estimates of gross proved reserves and gross probable reserves disclosed above under the heading "Disclosure of Reserves Data".

	Heavy Oil	
Reserves Category	**Gross (bbls/d)**	**Net (bbls/d)**
Proved	4,200	4,200
Probable	35	35
Total Proved Plus Probable	4,235	4,235

Other than the Amo and Iro fields, no field accounts for more than 20% of the production estimate. The Company's production estimated for the year ended March 31, 2023 from the Amo field is 1,250 bbls/d for proved and 1,256 bbls/d for proved plus probable and from the Iro field is 1,797 bbls/d for proved and 1,816 bbls/d for proved plus probable of heavy oil.

6.9 Production History

The following tables summarize certain information in respect of the Company's average gross daily production volume for the periods indicated below:

	Heavy Oil			
	March 31, 2022	**December 31, 2021**	**September 30, 2021**	**June 30, 2021**
Average Gross Daily Production Volume (bbl/d)	5,304.6	-	-	-
Average Product Price Received ($/bbl)	51.90	-	-	-
Average Royalties Paid ($/bbl)	-	-	-	-
Average Production Costs ($/bbl)	22.79	-	-	-
Resulting Netback ($/bbl)	29.11	-	-	-

Note:
(1) Represents production from the date the properties were acquired to the end of the fiscal year, being from January 14, 2022 to March 31, 2022.

Production Volume by Field

The following table discloses the Company's production volumes for each important field for the year ended March 31, 2022:

Field	Production Volumes				
	Light and Medium Oil	Heavy Oil	NGL	Natural Gas	Total
Ecuador	**bbl/d**	**bbl/d**	**bbl/d**	**Mcf/d**	**boe/d**
Block 16					
Amo	-	1,222.4	-	-	-
Iro	-	1,873.4	-	-	-

Note:
(1) Average daily rate from January 14, 2022 to March 31, 2022.