STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data and Other Information

The Issuer engaged Sproule Associates Ltd. to provide an evaluation of the Petroleum & Natural Gas ("P&NG") proved and proved plus probable reserves as at March 31, 2022 of the Company's Interests in the Beaton area of Alberta, Canada. The effective date of the Sproule Report is March 31, 2022 and the Preparation Date of the Sproule Report is June 9, 2022. This report was prepared for the purpose of evaluating the Company's P&NG Reserves according to the Canadian Oil and Gas Evaluation Handbook ("COGEH") resource definitions that are consistent with the standards of National Instrument 51-101.

The reserves data presented in the tables below are based on Sproule's forecast pricing as of March 31, 2022 and there is no assurance that such forecast prices and costs assumptions will be attained and variances could be material. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. The recovery and reserve estimates of the Company's crude oil, natural gas and natural gas liquids provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves
As of March 31, 2022
Forecast Prices and Costs

	Light and Medium Crude Oil		Total BOE	
Reserves Category	Gross (MBbl)	Net (MBbl)	Gross (Mboe)	Net (Mboe)
Proved Developed Producing	123.2	88.4	123.2	88.4
Proved Developed Non-Producing	11.8	11.2	11.8	11.2
Proved Undeveloped	152.9	118.5	152.9	118.5
Total Proved	**287.9**	**218.1**	**287.9**	**218.1**
Total Probable	217.3	163	217.3	163.0
Total Proved + Probable	**505.1**	**381.1**	**505.1**	**381.1**

Summary of Net Present Values of Future Net Revenue
As of March 31, 2022
Forecast Prices and Costs

	Before Income Taxes Discounted at (%/year)					**Before Tax Net Value**
Reserves Category	**0% M$**	**5% M$**	**10% M$**	**15% M$**	**20% M$**	**10%/yr ($/boe)**
Proved Developed Producing	7,134	6,973	6,820	6,676	6,540	77.17
Proved Developed Non-Producing	792	806	815	820	823	72.83
Proved Undeveloped	6,621	6,119	5,673	5,276	4,922	47.87

Total Proved	**14,547**	**13,899**	**13,308**	**12,772**	**12,285**	**61.02**
Total Probable	12,932	12,032	11,251	10,570	9,972	69.03
Total Proved + Probable	**27,479**	**25,930**	**24,559**	**23,342**	**22,257**	**64.45**

Total Future Net Revenue (Undiscounted)
As of March 31, 2022
Forecast Prices and Costs

Reserves Category	Revenue **M$**	Royalties **M$**	Operating Costs **M$**	Development Costs **M$**	Abandonment and Reclamation Costs **M$**	Future Net Revenue Before Income Taxes **M$**
Total Proved	25,284	6,149	1,695	2,600	293	14,547
Total Proved + Probable	43,222	10,637	2,207	2,600	299	27,479

Future Net Revenue by Product Type
As of March 31, 2022
Forecast Prices and Costs

Reserves Category	**Product Type**	**Future Net Revenue Before Income Taxes (Discounted at 10%/Year)**	**Unit Value Before Income Taxes (Discounted at 10%/Year)**
		M$	**$/boe**
Total Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	13,308	61.02
	Total	13,308	
Total Proved + Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	24,559	64.45
	Total	24,559	

Notes to Reserves Data Tables

1. Columns may not add due to rounding
2. The reserve definitions presented herein are those set out in National Instrument 51-101 (“NI 51-101”) and/or the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the “COGE Handbook”), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and incorporated into NI 51-101 by reference.

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

• analyses of drilling, geological, geophysical and engineering data;

• the use of established technology;

• specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and

• a remaining reserve life of 50 years.

Reserves are classified according to the degree of certainty associated with the estimates.

a) *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.

b) *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.

Other criteria that must also be met for the categorization of reserves are provided in Section 1.4.7.2.1 of the COGE Handbook.

Development and Production Status

Each of the reserves categories (proved, probable) may be divided into developed or undeveloped categories.

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (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:

a) *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.

b) *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 and completing a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned and are 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 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.

Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

a) There is a 90% probability that at least the estimated proved reserves will be recovered.

b) There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.

c) There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.7 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

3. Forecast Costs and Price Assumptions:

Forecast costs and prices are those:

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

b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company 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).

Summary of Pricing and Inflation Rate assumptions

As of March 31, 2022

Forecast Prices and Costs (1)

Table Prepared by Sproule Associates Ltd.

Year	Canadian Light Sweet Crude 40° API ($Cdn/bbl)	Western Canada Select 20.5 API ($Cdn/bbl)	Alberta AECO-C Spot ($Cdn/MMbtu)	Edmonton Pentanes Plus ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Edmonton Propane ($Cdn/bbl)	Operating Cost Inflation Rate(2) (%/Yr)	Capital Cost Inflation Rate(2) (%/Yr)	Exchange Rate(3) ($US/$Cdn)
Historical									
2017	61.85	50.24	2.19	67.21	44.11	28.77	1.7%	2.4%	0.77
2018	68.49	52.34	1.53	79.31	33.65	27.00	2.4%	4.2%	0.77
2019	68.87	58.77	1.8	71.39	23.71	17.16	-0.7%	0.4%	0.75
2020	45.39	35.59	2.24	49.85	21.87	16.31	-5.0%	-5.0%	0.75
2021	80.31	68.73	3.64	85.88	51.64	43.39	3.3%	6.6%	0.80
Forecast									
2022	114.38	100.63	5.13	116.25	73.24	58.20	0.0%	0.0%	0.80
2023	100.00	87.81	4.29	103.75	62.25	47.06	2.0%	2.0%	0.80
2024	86.25	74.99	3.02	91.25	52.93	38.11	2.0%	2.0%	0.80
2025	87.98	76.49	3.08	93.08	53.98	38.87	2.0%	2.0%	0.80
2026	89.73	78.02	3.14	94.94	55.06	39.65	2.0%	2.0%	0.80
2027	91.53	79.58	3.21	96.84	56.16	40.45	2.0%	2.0%	0.80
2028	93.36	81.18	3.27	98.77	57.29	41.25	2.0%	2.0%	0.80
2029	95.23	82.8	3.34	100.75	58.43	42.08	2.0%	2.0%	0.80
2030	97.13	84.46	3.40	102.76	59.60	42.92	2.0%	2.0%	0.80
2031	99.07	86.14	3.47	104.82	60.79	43.78	2.0%	2.0%	0.80
2032	101.06	87.87	3.54	106.91	62.01	44.65	2.0%	2.0%	0.80
Escalation Rate of 2.0% thereafter									

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.

(2) Inflation rates for forecasting costs only. Prices inflated at 2% where applicable.

(3) Exchange rates used to generate the benchmark reference prices in this table.

Notes:

Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Reconciliation of Changes in Reserves and Future Net Revenue

Reconciliation of Company Gross[1] Reserves by Product Type
As of March 31, 2022
Forecast Prices and Costs

	Light and Medium Crude Oil (Combined)			**Total Equivalent**		
Factors	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**
March 31, 2021	0	0	0	0	0	0
Discoveries	165.4	114.6	279.9	165.4	114.6	279.9
Extensions	152.9	102.7	255.6	152.9	102.7	255.6
Infill Drilling	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Technical Revisions [2]	0	0	0	0	0	0
Production	30.4	0	30.4	30.4	0	30.4
March 31, 2022	287.9	217.3	505.1	287.9	217.3	505.1

Notes:

- The following Proved Reserves additions this year were previously booked as probable Reserves within stand-alone probable Reserves entities, in prior years

-These revisions are not included in the Total Company Technical Revisions but are included above in the applicable proved reconciliation category in which they were first booked

-Probable revisions have been calculated as the difference between the Proved plus Probable and Proved totals.

Extensions	0.0	0.0		0.0	0.0	
Infill Drilling	0.0	0.0		0.0	0.0	
Improved Recovery	0.0	0.0		0.0	0.0	
Discoveries	0.0	0.0		0.0	0.0	
Total	0.0	0.0		0.0	0.0	

Notes:

(1) Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

(2) Technical Revisions also include changes in reserves associated with changes in operating costs, capital costs, and commodity price offsets.

Additional Information Relating to Reserves Data

The following table discloses, for each product type, the volumes of Proved Undeveloped and Probable Undeveloped reserves that were first attributed in each of the most recent three financial years.

Undeveloped Reserve Vintage by Product Type
As of March 31, 2022
Forecast Prices and Costs

	Light and Medium Crude Oil (Combined)		**Total Equivalent**	
Factors	First Attributed Gross Mbbl	Booked Gross Mbbl	First Attributed Gross Mbbl	Booked Gross Mbbl
Proved Undeveloped				
March 31, 2020	0.0	0.0	0.0	0.0
March 31, 2021	0.0	0.0	0.0	0.0
March 31, 2022	152.9	152.9	152.9	152.9
Probable Undeveloped				
March 31, 2020	0.0	0.0	0.0	0.0
March 31, 2021	0.0	0.0	0.0	0.0
March 31, 2022	102.7	102.7	102.7	102.7

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently 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 contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserve categories noted below:

Future Development Costs
As of March 31, 2022
Forecast Prices and Costs

Year	Proved M$	Proved plus Probable M$
2022	2,600	2,600
2023	0	0
2024	0	0
2025	0	0
2026	0	0

Oil and Gas Properties

The Company's main property is located in the Beaton area of Alberta, Canada. There are 2 producing oil wells (1-30-87-2 W6 and 4-29-87-2 W6) and one main multiwell oil facility – 13-20-87-2 W6. All wells and facilities are onshore.

The following table sets forth the number and status of wells in which the Company had a working interest as at March 31, 2022.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta, Canada	2.0	2.0	0.0	0.0	0.0	0.0	7.0	7.0

Properties with No Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at March 31, 2022.

Region	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta, Canada	1,280	1,280	88,160	87,482	89,440	88,762

The Corporation has 36,494 net acres in Alberta, Canada that we expect to expire prior to March 31, 2023. The Corporation does not have any work commitments related to properties with no attributable reserves.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Resources

There are no significant economic factors or uncertainties that are reasonably expected to affect the anticipated development or production activities on properties with no attributed resources. The Issuer does not own any wellbores or surface land leases that could incur any significant abandonment or reclamation costs, unusually high development costs or operating costs, or contractual obligations to produce or sell a significant portion of production at prices substantially below those which could be realized but for those contractual reasons.

For additional information concerning the Company's abandonment and reclamation costs (ARO), please see Note 7 in the Company's financial statements as at March 31, 2022.

Forward Contracts

The Company does not have any forward contracts.

Tax Horizon

First Helium was not required to pay income taxes during the year ended March 31, 2022, as the Company had sufficient income tax deductions available to shelter taxable income. First Helium does not expect to pay cash income taxes for the next year based upon current legislation, the Company's planned capital expenditures, production rates and commodity price forecasts for fiscal 2023, and various other assumptions. A higher (lower) level of capital expenditures than those currently contemplated, decreases (increases) in production rates, decreases (increases) in commodity price assumptions, as well as potential future acquisitions (dispositions), could further extend (reduce) the estimated tax horizon. First Helium estimates that fiscal 2024 may be the first year that income taxes may become payable.

Capital Expenditures

All of First Helium's properties are located in Alberta, Canada. For additional information on the Company's proved and unproved properties please see Notes 4 and 5 of the Company's financial statements for the year ended March 31, 2022.

(a) *property acquisition costs*, separately for *proved properties* and *unproved properties*;

Property Acquisition Costs

Proved	**Unproved**
$7,705	$1,268,608

(b) exploration costs;

Exploration Costs

Proved	**Unproved**
$2,147,729	$1,882,381

(c) development costs.

Development Costs

Proved	**Unproved**
$2,723,212	N/A

Exploration and Development Activities

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	1.0	1.0	1.0	1.0
Gas Wells	0.0	0.0	0.0	0.0
Service Wells	0.0	0.0	0.0	0.0
Stratigraphic Test Wells	0.0	0.0	0.0	0.0

None of the Company's wells were dry holes.

For fiscal 2022, First Helium is planning to drill 5 (5 net) wells comprised of 4 (4.0 net) wells targeting natural gas containing potential commercial concentrations of helium, and 1 (1.0 net) well targeting light oil.

Production Estimates

The following tables disclose, by product, the total volumes of the Company's gross production estimated by Sproule in the first year:

Total Proved

Region	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Barrels of Oil Equivalent (BOE/d)
Beaton, Alberta	524	0	0	0	524

Total Proved plus Probable

Region	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Barrels of Oil Equivalent (BOE/d)
Beaton, Alberta	692	0	0	0	692

Production History

Y/E March 31, 2022	Q1	Q2	Q3	Q4
Avg gross daily production volume (bbl/day)	0	0	0	320
Price received ($/bbl)	0	0	0	121.05
Royalties Paid ($/bbl)	0	0	0	5.70
Production Cost ($/bbl)	0	0	0	2.17
Transportation Cost ($/bbl)	0	0	0	10.74
Resulting Netback ($/bbl)	0	0	0	102.44

For the year ended March 31, 2022 the Company produced a total of 28,788 barrels of light oil from the Beaton, Alberta field.