TAG OIL LTD.

FORM 51-101F1
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION

INTRODUCTION

The oil and gas reserves and operational information of TAG Oil Ltd. and its subsidiaries (the "**Company**" or "**TAG Oil**") contained in this Form 51-101F1 contains the information required to be included in the Statement of Reserves Data and Other Oil and Gas Information pursuant to National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") adopted by the Canadian securities regulatory authorities. Readers should also refer to the Form 51-101F2 - *Report on Reserves Data by Independent Qualified Reserves Evaluator* and the Form 51-101F3 - *Report of Management and Directors on Oil and Gas Disclosure*, which are both accessible through SEDAR+ at www.sedarplus.ca.

Forward Looking Statements

This Form 51-101F1 contains certain forward-looking statements and forward-looking information (collectively referred to herein as "**forward-looking statements**") within the meaning of Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as "anticipate", "estimate", "forecasts", "schedule", "potential", "believe", "plan", "continuous", "expect", "may", "will", "should", "could", or similar words suggesting future outcomes. In particular, this Form 51-101F1 contains forward-looking statements pertaining to the estimated future net revenue of reserves; forecast price and cost assumptions; changes to reserve estimates; future development plans of undeveloped reserves; costs associated with converting undeveloped reserves to developed reserves; potential impacts of fluctuating commodity prices and their affect on future net revenue of the Company; availability of funds for any future development costs; accuracy of timing and impacts of any future development projects; anticipated oil production from operating wells; production optimization; success of future interventions to improve and stabilize well flow rates; future oil and gas prospects; plans to develop wells for future use; future partnerships or joint ventures and any new business opportunities; success of maintaining existing or new permits; expiry of existing unproved acreage or permits; and amount of income taxes payable.

The forward-looking statements contained in this document are based on certain assumptions and, although management considers these assumptions to be reasonable based on information currently available to them, there can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based, will in fact be realized. Undue reliance should not be placed on the forward-looking statements because the Company can give no assurances that they may prove to be correct. This includes, but is not limited to, assumptions related to, among other things: forecast price and cost assumptions based on the independent reserve evaluator report; the Company's current commodity price and other cost assumptions will generally be accurate; interest and foreign exchange rates will remain consistent; the Company's ability to develop future natural gas and oil production levels in the manner contemplated; the Company's ability to maintain and acquire key permits; the Company having sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; the Company's ability to add production and reserves through development and exploration activities will be consistent with its expectations; the information provided by its independent reserve evaluator is accurate; the estimates of the Company's reserves volumes and the assumptions related thereto are accurate in all material respects; and the Company has the ability to obtain labour and equipment in a timely manner to carry out development activities contemplated.

Forward-looking statements are subject to certain risks and uncertainties (both general and specific) that could cause actual events or outcomes to differ materially from those anticipated or implied by such forward-looking statements. Such risks and other factors include, but are not limited to political, social, and other risks inherent in daily operations for the Company, including: risks associated with oil and gas exploration; operational risks; development and operating costs; ability to access sufficient capital from internal and external sources; volatility of natural gas and oil prices; government regulation; health, safety and environmental risks; interest rate risks; dependence on key personnel; delays or changes in plans with respect to growth projects or capital expenditures; availability of drilling equipment and access; variations in foreign exchange rates; expiration of licenses and leases; reserves estimates; competition and risks associated with the industries in which the Company operates; and litigation. Further information regarding these factors may be found under the heading "Risk Factors" in the Company's Annual Information Form for the year ended December 31, 2023. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive.

The forward-looking statements contained in this Form 51-101F1 are made as of the date hereof and TAG Oil does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Currency and Measurement

All currency amounts in this Form 51-101F1 are stated in Canadian dollars unless otherwise indicated.

Abbreviations

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	Barrel or barrels	Mcf	Thousand cubic feet
bbl/d	Barrels per day	MMcf	Million cubic feet
Mbbl	Thousand barrels	Mcf/d	Thousand cubic feet per day
MMbbl	Million barrels	MMcf/d	Million cubic feet per day
boe	Barrel or barrels of oil equivalent of natural gas and crude oil, unless otherwise indicated	Bcf	Billion cubic feet
boe/d	Barrel or barrels of oil equivalent per day		

MMboe	Million barrels of oil equivalent
NGL	Natural gas liquids

Conversion

The following table sets forth certain standard conversions from Standard Imperial units to the International System of Units (or metric units).

To Convert from	To	Multiply by
Mcf	Thousand cubic meters	0.0282
Thousand cubic meters	Mcf	35.494
bbl	Cubic meters	0.159
Cubic meters	bbl	6.290
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

Disclosure provided herein in respect of boe (barrels of oil equivalent) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 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.

Notes and Definitions

Certain of the following definitions and guidelines are contained in the Glossary to NI 51-101 contained in CSA Notice 51-324, which incorporates certain definitions from the COGE Handbook. Readers should consult CSA Notice 51-324 and the Canadian Oil and Gas Evaluation Handbook ("**COGE**") Handbook for additional explanation and guidance.

Interests in Reserves, Production, Wells and Properties

In this Form 51-101F1, the following terms have the meaning assigned thereto in CSA Notice 51-324 and the COGE Handbook:

"gross" means:

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

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

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

"net" means:

(i) 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 the Company's royalty interests in production or reserves;
(ii) 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
(iii) 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.

Reserves Categories and Levels of Certainty for Reported Reserves

In this Form 51-101F1, the following terms have the meaning assigned thereto in CSA Notice 51-324 and the COGE Handbook:

"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: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves may be divided into proved and probable categories 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.

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 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and

- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

Development and Production Status

Each of the reserves categories reported by the Company (proved and probable) may be divided into developed and 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 (for example, 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; and
- "undeveloped reserves" are those reserves that are expected to be recovered from known accumulations where a significant expenditure (for example, 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 or probable) to which they are assigned.

Description of Price and Cost Assumptions

"Forecast prices and costs" means future prices and costs that are:

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

(ii) 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 or costs referred to in paragraph (i).

PART 1 DATE OF STATEMENT

This statement of reserves data and other oil and gas information is dated April 30, 2025. The effective date of the information being provided herein as set forth below is December 31, 2024. The information provided herein was prepared as of April 30, 2025.

References to light and medium crude oil combined, heavy crude oil, conventional natural gas, natural gas liquids, reserves (gross, net, proved, developed, developed producing, developed non-producing, undeveloped), forecast prices and costs, constant prices and costs, operating costs, development costs, future net revenue and future income tax expenses shall, unless expressly stated to be to the contrary, have the meaning attributed to such terms as set out in NI 51-101, the Companion Policy to NI 51-101 and all forms referenced.

PART 2 DISCLOSURE OF RESERVES DATA

The reserves data set forth below is based upon a report prepared by ERC Equipoise Ltd. ("**Sproule ERCE**"), an independent qualified reserves evaluator appointed by the Company, entitled "TAG Oil Ltd. – Evaluation of New Zealand Reserves as at 31 December 2024" (the "**Sproule ERCE Report**"). All the Company's reserves are associated with royalty interests as it does not own any working interests.

The following tables, based on the Sproule ERCE Report of TAG Oil's royalty assets located in the onshore Taranaki Basin, New Zealand, was prepared in accordance with the COGE Handbook, which shows the estimated share of the Company's light and medium crude oil combined and conventional natural gas reserves associated with the properties and the net present value of estimated future net revenue for these reserves, using forecast prices and costs as indicated. The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Sproule ERCE Report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the Sproule ERCE Report. The recovery and reserve estimates of the Company's oil and natural gas reserves stated herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates stated herein. Readers should note that the totals in the following tables may not add due to rounding. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Summary of Oil and Gas Reserves as of December 31, 2024 using Forecast Prices and Costs

	RESERVES							
	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	0	4	0	0	0	5	0	0
Developed Non-Producing	0	0	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	0	4	0	0	0	5	0	0
PROBABLE	0	29	0	0	0	49	0	0
TOTAL PROVED PLUS PROBABLE	0	33	0	0	0	54	0	0
POSSIBLE	0	47	0	0	0	120	0	0
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	0	81	0	0	0	173	0	0

Notes:

1. Columns may not add due to rounding.
2. Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include royalties receivable. Net reserves are comprised of working interests minus royalties payable plus royalties receivable. Unlike typical oil and natural gas production companies which hold working interests, all of the Company's interests are royalties. As a result, the Company does not have any gross reserves attributed to its properties.

Summary of Net Present Values of Future Net Revenue as of December 31, 2024 using Forecast Prices and Costs

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (C$ MM)	5 (C$ MM)	10 (C$ MM)	15 (C$ MM)	20 (C$ MM)	0 (C$ MM)	5 (C$ MM)	10 (C$ MM)	15 (C$ MM)	20 (C$ MM)
PROVED										
Developed Producing	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Developed Non-Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PROVED	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
PROBABLE	3.1	2.7	2.4	2.1	1.9	3.1	2.7	2.4	2.1	1.9
TOTAL PROVED PLUS PROBABLE	3.5	3.1	2.8	2.5	2.3	3.5	3.1	2.8	2.5	2.3
POSSIBLE	5.9	4.4	3.4	2.7	2.2	5.9	4.4	3.4	2.7	2.2
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	9.4	7.5	6.2	5.2	4.5	9.4	7.5	6.2	5.2	4.5

Notes:

1. Columns may not add due to rounding.

Total Future Net Revenue (Undiscounted) as of December 31, 2024 using Forecast Prices and Costs

RESERVES CATEGORY	REVENUE (C$ M)	ROYALTIES (C$ M)	OPERATING COSTS (C$ M)	DEVELOPMENT COSTS (C$ M)	ABANDONMENT AND RECLAMATION COSTS (C$ M)	FUTURE NET REVENUE BEFORE INCOME TAXES (C$ M)	INCOME TAXES (C$ M)	FUTURE NET REVENUE AFTER INCOME TAXES (C$ M)
PROVED	434.3	0.0	0.0	0.0	0.0	434.3	0.0	434.3
PROVED PLUS PROBABLE	3,514.1	0.0	0.0	0.0	0.0	3,514.1	0.0	3,514.1
PROVED PLUS PROBABLE PLUS POSSIBLE	9,376.1	0.0	0.0	0.0	0.0	9,376.1	0.0	9,376.1

Notes:

1. Columns may not add due to rounding.

Future Net Revenue by Reserves Category and Product Type as of December 31, 2024 using Forecast Prices and Costs

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (C$ M)	UNIT VALUE (C$/Mcf) (C$/bbl)
Proved Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	-	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	414.1	78.4
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-
Proved Plus Probable Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	-	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	2,782.8	66.0
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-
Proved Plus Probable Plus Possible Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	-	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	6,183.3	56.5
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-

Notes:

1. Columns may not add due to rounding.
2. Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include royalties receivable. Net reserves are comprised of working interests minus royalties payable plus royalties receivable. Unlike typical oil and natural gas production companies which hold working interests, all of the Company's interests are royalties. As a result, the Company does not have any gross reserves attributed to its properties.

PART 3 PRICING ASSUMPTIONS

The following pricing assumptions were provided by ERCE.

Summary of Pricing and Inflation Rate Assumptions as of December 31, 2024

Year	Brent Oil Price (U$/bbl) (Nominal)	Cheal A Sales Gas Price (US$/Mscf) (Nominal)	Cheal E Sales Gas Price (US$/Mscf) (Nominal)	Sidewinder Sales Gas Price (US$/Mscf) (Nominal)	INFLATION RATES (%/Year)	EXCHANGE RATE (NZ$/US$)	EXCHANGE RATE (US$/C$)
Historical (average over year)							
1 JAN 2021 - 31 DEC 2021	70.68						
1 JAN 2022 - 31 DEC 2022	100.78						
1 JAN 2023 - 31 DEC 2023	82.47						
1 JAN 2024 - 31 DEC 2024	80.53						
Forecast							
1 JAN 2025 - 31 DEC 2025	76.15	7.24	4.43	9.25	2.0	0.61	1.37
1 JAN 2026 - 31 DEC 2026	75.73	7.39	4.52	9.43	2.0	0.61	1.37
1 JAN 2027 - 31 DEC 2027	78.38	7.53	4.61	9.62	2.0	0.61	1.37
1 JAN 2028 - 31 DEC 2028	79.81	7.68	4.70	9.81	2.0	0.61	1.37
1 JAN 2029 - 31 DEC 2029	81.40	7.84	4.80	10.01	2.0	0.61	1.37
Thereafter	+2%/yr	+2%/yr		+2%/yr	2.0	0.61	1.37

Notes:

1. Prices are averaged according to TAG's financial year, which covers January 1 to December 31. For example, financial year 2024 represents January 1, 2024, to December 31, 2024.

For the financial year ended December 31, 2024, the Company's average price received for oil was CDN$89.98 per bbl and for natural gas was CDN$14.38 per Mcf.

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Reserves Reconciliation

The following table sets forth a reconciliation of the changes in the Company's net reserves within Petroleum Mining Permit ("**PMP**") 38156 (Cheal A/B), PMP 60291 (Cheal E) and PMP 53803 (Sidewinder), and located in the onshore portion of the Taranaki Basin, New Zealand as at December 31, 2024, against such reserves as at December 31, 2023 (summarized in the table below) based on the forecast price and cost assumptions evaluated in accordance with NI 51-101 definitions. As the Company only owns royalty interests, all of its reserves are net reserves.

Reconciliation of Company Gross Reserves By Product Type

Factors	Light and Medium Oil			Natural Gas			Natural Gas Liquids			BOE		
	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MBOE)	Net Probable (MBOE)	Net Proved Plus Probable (MBOE)
December 31, 2023	29	28	57	30	59	89	0	0	0	34	37	72
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	(16)	9	(15)	(14)	2	(24)	0	0	0	(19)	10	(19)
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	(8)	(8)	(8)	(11)	(11)	(11)	0	0	0	(10)	(10)	(10)
December 31, 2024	4	29	33	5	49	54	0	0	0	5	37	42

Notes:

1. Columns may not add due to rounding.
2. Reserves reconciliation has been completed based on Company Net Reserves. The Reserves reconciliation would typically be completed based on Company Gross Reserves. However, under NI 51-101, any royalty interest share of Reserves may only be included as Company Net Reserves.

The changes to the reserves estimates can be attributed to those factors set out in the table above.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

ERCE has not evaluated the undeveloped Reserves associated with the royalty assets. The development of undeveloped reserves is not within the control of the Company as it only holds a royalty interest in such reserves and therefore does not have control or influence on the development of such reserves. The development of undeveloped reserves will be dependent on commodity prices, and it may be more than five years until they are developed.

Unlike typical oil and natural gas production companies which hold working interests, all of the Company's interests are royalties. As a result, the Company does not have any gross reserves attributed to its royalty lands and all reserves (including undeveloped reserves) are net reserves.

Significant Factors or Uncertainties

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. See "*Risk Factors*" in the Company's amended and restated annual information form for further details.

The Company does not control or have influence over the techniques used to drill and complete wells on its royalty lands nor does it generally have any control or influence over the timing of such activity.

Future Development Costs

No development costs were deducted in the estimation of the future net revenues attributable to the proved and probable reserves of the Company. No capital expenditures were anticipated for the Company's oil and gas interests, which are limited to royalty interests.

As funding for future development costs will be the responsibility of the working interest owners on the properties in which the Company owns royalty interests, and as the Company does not hold any working interests in any oil and gas properties, the Company will not be responsible for any development costs on the properties in which it owns royalty interests and cannot advise as to the sources and costs of funding future development or the impact thereof on disclosed reserves or future net revenue.

PART 6 OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

New Zealand

TAG Oil's producing properties in which the Company held a royalty interest as at December 31, 2024, are at PMP 38156, PMP 60291, and PMP 53803, located in the onshore portion of the Taranaki Basin, New Zealand. PMP 38156 and PMP 60291 are operated by Cheal Petroleum Limited, and PMP 53803 is operated by Matahio NZ Onshore Limited. ERCE has evaluated the producing fields (Cheal A/B, Cheal E, and Sidewinder), which contribute 100% of TAG's royalty revenue.

PMP 38156: Cheal A/B

The Cheal field is located within the boundaries of PMP 38156, PMP 60291 and PEP 54877. The field is separated into four pools: Cheal A, B, C, E. The Cheal A and B pools lie in PMP 38156. The Cheal A pool was discovered in 1995 and brought onstream in the same year. The Cheal A and B pools are developed from two well pads, with the Cheal B well pad operational since 2006.

Hydrocarbons are contained within the Middle to Late Miocene Mount Messenger Formation and the Late Miocene Urenui Formation. Both formations were deposited as submarine channels and fans in a deep marine environment, with reservoir intervals consisting of thinly interbedded sandstone, siltstone and shale.

The Cheal field is covered by 3D seismic data. Each pool is typically associated with an amplitude anomaly which is used to help constrain its lateral extent. It is thought that amplitude response is a weak indicator of reservoir presence and not fluid content. The drilling campaign to date in the Cheal A and B pools area has targeted areas of enhanced seismic amplitude response at each reservoir level.

The primary depletion mechanism has historically been depletion drive, but in recent years several wells have been converted to water injection in an attempt to increase reservoir pressure and sweep.

PMP 60291: Cheal E

The Cheal E pool is located within the boundaries of PMP 60291 and PEP 54877. It was discovered in 2013 and was brought onstream in the same year.

Hydrocarbons are contained within the Middle to Late Miocene Mount Messenger Formation and the Late Miocene Urenui Formation, although the majority of production has been from the former. The Cheal E pool is covered by 3D seismic data and is associated with an amplitude anomaly which is used to help constrain its lateral extent.

The primary depletion mechanism has historically been depletion drive, but in recent years several wells have been converted to water injection in an attempt to increase reservoir pressure and sweep.

PMP 53803: Sidewinder

The Sidewinder field is located within the boundaries of PMP 53803. The field was discovered in 2010 and production commenced in 2011. Initially, only the gas cap was developed, and this continues to be produced cyclically. In 2016, the oil leg was developed.

Hydrocarbons are contained in the Middle to Late Miocene Mount Messenger Formation. The field is covered by a combination of 2D and 3D seismic data. The pool is associated with an amplitude anomaly which is used to help constrain its lateral extent. The

Sidewinder field contains a gas cap and oil leg, which are developed by separate wells. The primary depletion mechanism is depletion drive.

The following table sets forth the permits in which the Company held a royalty interest as at December 31, 2024, all of which are located in New Zealand. As the Company does not hold any working interests, the net number of wells located on the Company's properties is nil.

Summary of TAG's Royalty Assets in New Zealand

Permit	Status	Fields / Discoveries
PMP 38156	Producing	Cheal A/B, Cardiff
PMP 60291	Producing	Cheal E
PEP 54877	Producing	Cheal E
PMP 53803	Producing	Sidewinder
PMP 60454	Shut-In	Supplejack
PEP 51153	Shut-In	Puka
PEP 57065	Exploration	Waitoriki

Egypt

The Company is focused on oil and gas exploration and development opportunities in Egypt. TAG Oil holds an interest in the Badr Oil Field ("**BED-1**"), a 26,000 acres concession located onshore in the Western Desert, Egypt, through a production services agreement (the "**PSA**") with Badr Petroleum Company ("**BPCO**"), which is dated effective October 13, 2022, for the development of the unconventional Abu Roash "F" ("**ARF**") reservoir in BED-1. Both the BED 1-7 vertical well and the BED4-T100 horizontal well ("**T100**") in Egypt that the Company held a production revenue share as at December 31, 2024, produced oil.

Properties with No Attributed Reserves

New Zealand

All of the Company's royalty lands, inclusive of those with no attributed reserves, are located in the onshore portion of the Taranaki Basin, New Zealand. As the Company does not hold any working interests, the Company relies to some extent on information from third party royalty payors. Royalty revenues payable by third parties, and the reporting provided relating to such royalty revenues, are derived from the Company's royalty lands that are producing and therefore have reserves attributed. Consistent reporting is not provided to the company for its royalty lands that are not producing (being those properties with no attributed reserves). These third parties are not always obligated to, and may not always, update the Company with respect to new information and developments relating to these properties with no attributed reserves.

As the Company does not hold any working interests in its royalty lands, the net acres associated with its royalty lands are nil. In addition, the Company is not responsible for, nor subject to, any work commitments. Similarly, the Company does not have the ability to control the expiration, surrender or continuation of rights to explore, develop, and exploit any properties with no attributed reserves.

On April 22, 2025, the Company closed the sale of its New Zealand royalty interests in PMP 38156, PMP 53803, PEP 54877, PMP 60454, PEP 51153, and PMP 60291.

Egypt

TAG Oil will maintain its primary focus on the BED-1 field and there are currently no reserves attributed to the ARF formation pertaining to the PSA. Further information regarding TAG Oil's participation in the PSA and the BED-1 field is as follows:

Location/License	**Gross Area**	**Net Area**	**Work Commitments/Expiry Date**	**Rights to Expire within One Year**
BED-1 License Area, Western Desert, Egypt	107 km^2	43 km^2 (Mineral Resources Area)	Phase 1 Evaluation Period (October 13, 2022, to October 12, 2025): Basic capital commitment of US$6 million has been completed with drilling one (1) horizontal well with multi-stage fracture stimulation (T100). Expiry date is October 12, 2025. Phase 1 Extension (October 13, 2025, to October 12, 2028): Extension discussions are under-way, and a formal PSA amendment is pending execution; additional three (3) years with additional US$6 million and two (2) vertical/horizontal wells commitment. Phase 2 Commercial Production Period: Following Phase 1 Extension the Company can at its election continue into Phase 2 Commercial Development and Production and Optional Extension Period. Commitment will be US$9 million and three (3) vertical/horizontal wells development. Expiry will be in November 2042 after the Optional Extension Period.	No

The significant economic factors and uncertainties that have affected or are reasonably expected to affect the anticipated development and/or production in Egypt are set out in the financial statements for the year ended December 31, 2024, including the notes thereto.

Forward Contracts

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

Additional Information Concerning Abandonment and Reclamation Costs

The Company is not responsible for any abandonment or reclamation costs associated with the royalty interests.

TAG Oil will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of TAG Oil's regulatory approvals and applicable legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial and, while TAG Oil accrues a reserve in its financial statements for such costs in accordance with IFRS requirements, no assurance can be given that such accruals will be sufficient. It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements and future development plans. In addition, in the future, TAG Oil may determine it prudent or be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If TAG Oil establishes a reclamation fund, its liquidity and cash flow may be adversely affected.

Tax Horizon

The Company was not required to pay income taxes for its most recently completed financial year. The Company does not anticipate paying income taxes in the fiscal year 2025 due to the immediate allowable deductions for exploration expenditure as prescribed by New Zealand tax regulations and does not anticipate being required to pay income taxes in the foreseeable future.

The fiscal structure of the PSA executed between BPCO and TAG Oil sets out terms and conditions for the payment of royalties and taxes as follows:

- TAG Oil bears the burden of all costs for the project, including all capital and operating costs on behalf of the parties for a share of revenues from the ARF development in BED-1, payable as a fee equal to a percentage of the total gross revenues generated from production.

- The royalties and taxes payable in Egypt are assumed by the Egyptian General Petroleum Corporation ("**EGPC**") on behalf of TAG Oil and payable from their share of gross revenues and TAG Oil shall be exempted from all taxes and duties imposed by the government of Egypt or municipalities.

Therefore, as TAG Oil is bearing the entire burden of financial risk on the project, the share of gross revenues attributed to BPCO (c/o EGPC) to be an effective royalty burden on the project, and no income taxes in Egypt are payable by TAG Oil.

Costs Incurred

There were no acquisition, development or exploration costs incurred in respect of the Company's royalty lands for the year ended December 31, 2024.

For further information regarding the acquisition, development or exploration costs incurred in respect of the Company's participation in the PSA and the BED-1 field, please refer to the Company's financial statements for the year ended December 31, 2024.

Exploration and Development Activities

As the Company does not hold any working interests in the royalty lands, the net number of wells drilled and completed by the Company in the royalty lands is nil.

The phase 1 evaluation period at BED-1 of the ARF reservoir commenced with the re-entry of an existing vertical well, BED 1-7, which was completed in May 2023. Cumulative gross production from the BED 1-7 well to the end of 2024 is in excess of 10,000 bbl of oil (produced by TAG Oil and measured as field estimates prior to adjustment for sales volumes). The positive response confirming reservoir model and performance, and the data collected, along with geo-mechanical and 3D seismic reviews, informed the drilling of the T100 horizontal well.

The drilling phase of the T100 well was completed in March 2024 in the ARF reservoir followed by a successful multi-stage fracture stimulation treatment on the well with twelve (12) stages pumped according to design. Cumulative gross production of the T100 horizontal well to the end of 2024 is in excess of 20,000 bbl of oil. Both T100 and BED 1-7 wells have been temporarily shut-in at various stages to analyze reservoir pressure build-up characteristics and adjust lift system.

Planning of the Company's next vertical/horizontal well is in progress and will incorporate learnings and information that were obtained in drilling, completing, and producing the T100 and BED 1-7 wells.

Production Estimates

The following table sets out the first-year production forecast of volumes of the Company's royalty interests (Company net). Estimated production volumes are derived from gross proved reserves and gross probable reserves associated with New Zealand. Figures quoted are net to the Company.

New Zealand

	Proved		Probable		Proved + Probable	
	Oil	Gas	Oil	Gas	Oil	Gas

	bbl	MMcf	bbl	MMcf	bbl	MMcf
Property Gross	221,579	221	125,480	321.2	347,058	542
Company Gross	0	0	0	0	0	0
Company Net	5,539	5.5	3,137	8	8,676	13.6

Notes:

1. Company net values are Company net due to Company gross being zero.
2. Forecast of production volumes recoverable between January 1, 2025 and December 31, 2025.

Production History

New Zealand

The Company's historical production and royalty price received data for the period ended December 31, 2024, is presented below in CDN$:

	Q1	Q2	Q3	Q4
New Zealand				
Light Crude Oil and Medium Crude Oil Combined				
PMP 38156 (Cheal Permit) (bbl/d)	24	15	10	18
PMP 60291 (Cheal East Permit) (bbl/d)	5	4	3	6
PMP 53803 (Sidewinder Permit) (bbl/d)	3	2	2	3
Company share of daily production (bbl/d)	32	21	15	27
Conventional Natural Gas				
PMP 38156 (Cheal Permit) (Mcf/d)	29	21	22	20
PMP 60291 (Cheal East Permit) (Mcf/d)	4	4	3	5
PMP 53803 (Sidewinder Permit) (Mcf/d)	5	7	4	4
Company share of daily production (Mcf/d)	38	31	29	29
Royalty price received (C$/boe)	93.3	106.2	104.4	82.2

Notes:

1. Represents the Company's royalty share of production.
2. Unlike typical oil and natural gas production companies which hold working interests, all of the Company's interests are royalties. As a result, (a) no royalties are payable with respect to the Company's share of royalty

production, (b) the Company does not incur production or operating costs, and (c) the Company's "netback" as that term is defined in NI 51-101 is equivalent to its price received.

Egypt

The Company produced oil from two (2) wells in 2024: T100 and BED 1-7. The BED 1-7 vertical well was shut down for the majority of the year with a faulty down-hole electric submersible pump. After extended pressure build-up, the well began flowing at surface through natural flow and was equipped with a sucker rod pumping system to resume stable production in December 2024. The gross producing day average rate was 85 barrels of oil per day in the fourth quarter, which is based on field measured production prior to adjustment to sales delivered volumes. The cumulative production under TAG Oil operations from the well at the end of 2024 was 10,670 bbl of oil (field gross production estimates).

After drilling and fracture stimulation were completed on the T100 well, production was initiated from the well in April 2024 with flow-back of the fracture fluid and oil production from the well. Following flow-back, the well was evaluated with a jet pump system but was unable to attain a stable long term run due to sand plugging of the pump nozzle. The well is currently set up with a sucker rod pumping system, which has been effective for a stabilized run from September to end of the year. The gross producing day average in the fourth quarter of 2024 was 102 bbl/d of oil and cumulative oil of 9,370 bbl. For the full year 2024, the cumulative production from T100 is 23,297 bbl of oil (field gross production estimates prior to adjustments for sales volumes).

The combined field production from T100 and BED 1-7 is 33,967 bbl of oil at the end of 2024 and achieved over 40,000 bbl of oil within the first quarter of 2025.