FORM 51-102F3

MATERIAL CHANGE REPORT

Item 1: Name and Address of Company

TAG Oil Ltd. (the "**Company**" or "**TAG Oil**")
1710 - 1050 West Pender Street
Vancouver, British Columbia, Canada, V6E 3S7

Item 2: Date of Material Change

November 22, 2022

Item 3: News Release

The news release was disseminated on November 22, 2022 through Cision and filed on SEDAR. A copy of the news release is attached hereto as Schedule "A".

Item 4: Summary of Material Change

On November 22, 2022, the Company announced the results of its independent resources evaluation of the Abu Roash "F" unconventional formation ("ARF") in the Badr Oil Field ("BED-1"), Western Desert, Egypt, dated November 21, 2022 (the "BED-1 Report"), prepared by RPS Energy Canada Ltd. ("RPS").

Item 5: Full Description of Material Change

On November 22, 2022, the Company announced the results of the BED-1 Report, prepared by RPS.

BED-1 Report Highlights

- RPS estimates the ARF oil-initially-in-place ("OIIP") P50 Volumes to be 531.5 million barrels over the BED-1 concession area and Mean Volumes to be 536.6 million barrels. The discovered OIIP in the ARF is imaged by 3D seismic coverage, significant well control with over 30 penetrations, petrophysical analysis of available log and core data and production tests from the ARF.

- TAG Oil's current Field Development Plan ("FDP"), consisting of drilling 20 horizontal wells to be completed with multi-stage fracture stimulation, is focused on the east central part of the BED-1 concession area, and contains OIIP P50 Volumes of 178.3 million barrels and Mean Volumes of 179.0 million barrels.

- FDP Capital investment discounted at 10% is US$104 million for the 2C Development Pending Contingent Resources in the ARF.

- FDP Operating investment discounted at 10% is US$160 million for the 2C Development Pending Contingent Resources in the ARF.

- RPS best estimate for Contingent Resources volumes (2C Development Pending) is 27.0 million barrels gross with 16.5 million barrels net to the Company.

- RPS estimate for Contingent Resources (2C Development Pending) net present value discounted at 10% and assumed RPS Price Forecast of April 1, 2022, per barrel is US$339 million (risked at 80% chance of development) and US$423 million (un-risked).

- The Company's 2022 revised annual information form ("AIF") contains information regarding TAG Oil's reserves associated with its royalty interests in New Zealand as at March 31, 2022. Had the Company entered into the petroleum services agreement ("PSA") relating to BED-1 on or before March 31, 2022, the information presented in TAG Oil's Statement of Reserves Data and Other Oil and Gas Information on Form 51- 101F1 contained in the AIF would have been adjusted to include the resources data attributable to the oil assets in respect of the ARF reservoir in BED-1. Reference is made to the resources data in respect of the ARF reservoir in BED-1 that are set forth in Schedule "B" hereto, which sets forth TAG Oil's reasonable expectation of how the PSA, had it occurred on or before March 31, 2022, would have affected the information contained in TAG Oil's Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1 contained in the AIF.

Item 6: Reliance on subsection 7.1(2) of National Instrument 51-102

N/A.

Item 7: Omitted Information

N/A.

Item 8: Executive Officer

The following executive officer of the Company is knowledgeable about the material change disclosed in this report and may be contacted as follows:

Giuseppe (Pino) Perone, General Counsel and Corporate Secretary
Telephone: (604) 682-6496

Item 9: Date of Report

November 22, 2022

Forward Looking Statements

This material change report contains statements that are not historical facts are forward-looking statements that involve various risks and uncertainty affecting the business of TAG Oil. All estimates and statements that describe the Company's operations are forward-looking statements under applicable securities laws and necessarily involve risks and uncertainties. Actual results may vary materially from the information provided in this release, and there is no representation by TAG Oil that the actual results realized in the future will be the same in whole or in part as those presented herein. TAG Oil undertakes no obligation, except as otherwise required by law, to update these forward-looking statements if management's beliefs, estimates or opinions, or other factors change.

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:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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 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.

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.

The reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves or resources will be recovered. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Where discussed herein "NPV 10%" represents the net present value (net of capital expenditures) of net income discounted at 10%, with net income reflecting the indicated oil, liquids and natural gas prices and initial production rate, less internal estimates of operating costs and royalties. It should not be assumed that the future net revenues estimated by TAG Oil's independent reserve evaluators represent the fair market value of the reserves, nor should it be assumed that TAG Oil's internally estimated value of its undeveloped land holdings or any estimates referred to herein from third parties represent the fair market value of the lands.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources, by definition, are not classified as reserves due to several conditions including but not limited to the uncertainties of future oil prices and performance of the initial pilot wells in the first phase of the field development of the project which must be resolved to ensure commerciality. There is no certainty that it will be commercially viable to produce any portion of the resources. The Development Pending sub-set for contingent resources have reasonable potential for eventual commercial development, to the extent that further data acquisition and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame.

Exploration for hydrocarbons is a speculative venture necessarily involving substantial risk. The Company's future success in exploiting and increasing its current reserve base will depend on its ability to develop its current properties and on its ability to discover and acquire properties or prospects that are capable of commercial production. However, there is no assurance that the Company's future exploration and development efforts will result in the discovery or development of additional commercial accumulations of oil and natural gas. In addition, even if further hydrocarbons are discovered, the costs of extracting and delivering the hydrocarbons to market and variations in the market price may render uneconomic any discovered deposit. Geological conditions are variable and unpredictable. Even if production is commenced from a well, the quantity of hydrocarbons produced inevitably will decline over time, and production may be adversely affected or may have to be terminated altogether if the Company encounters unforeseen geological conditions. The Company is subject to uncertainties related to the proximity of any reserves that it may discover to pipelines and processing facilities. It expects that its operational costs will increase proportionally to the remoteness of, and any restrictions on access to, the properties on which any such reserves may be found. Adverse climatic conditions at such properties may also hinder the Company's ability to carry on exploration or production activities continuously throughout any given year.

The significant positive factors that are relevant to the resource estimates are: proven production in close proximity; proven commercial quality reservoirs in close proximity; oil and gas shows while drilling wells; and calculated hydrocarbon pay intervals from open hole logs. The significant negative factors that are relevant to the resource estimates are: tectonically complex geology could compromise seal potential; and seismic attribute mapping can be indicative but not certain in identifying proven resource.

SCHEDULE "A"

TAG OIL ANNOUNCES RESOURCES EVALUATION REPORT
Abu Roash "F", Badr Oil Field, Western Desert, Egypt
AND RESERVES EVALUATION REPORT
Royalty Interest, New Zealand

Vancouver, B.C. – November 22, 2022 – TAG Oil Ltd. (TSXV: TAO and OTCQX: TAOIF) ("**TAG Oil**" or the "**Company**") is pleased to announce the results of its independent resources evaluation of the Abu Roash "F" unconventional formation ("ARF") in the Badr Oil Field ("BED-1"), Western Desert, Egypt, dated November 21, 2022 (the "BED-1 Report"), prepared by RPS Energy Canada Ltd. ("RPS") and its previously announced independent reserves report associated with its royalty interests within Petroleum Mining Permit ("PMP") 38156 (Cheal A/B), PMP 60291 (Cheal E) and PMP 53803 (Sidewinder) (collectively the "Permits"), onshore New Zealand, dated November 7, 2022 (the "Royalty Report"), prepared by ERC Equipoise Ltd. ("ERCE").

A) BED-1 REPORT HIGHLIGHTS

- RPS estimates the ARF oil-initially-in-place ("OIIP") P50 Volumes to be 531.5 million barrels over the BED-1 concession area and Mean Volumes to be 536.6 million barrels. The discovered OIIP in the ARF is imaged by 3D seismic coverage, significant well control with over 30 penetrations, petrophysical analysis of available log and core data and production tests from the ARF.
- TAG Oil's current Field Development Plan ("FDP"), consisting of drilling 20 horizontal wells to be completed with multi-stage fracture stimulation, is focused on the east central part of the BED-1 concession area, and contains OIIP P50 Volumes of 178.3 million barrels and Mean Volumes of 179.0 million barrels.
- FDP Capital investment discounted at 10% is US$104 million for the 2C Development Pending Contingent Resources in the ARF.
- FDP Operating investment discounted at 10% is US$160 million for the 2C Development Pending Contingent Resources in the ARF.
- RPS best estimate for Contingent Resources volumes (2C Development Pending) is 27.0 million barrels gross with 16.5 million barrels net to the Company.
- RPS estimate for Contingent Resources (2C Development Pending) net present value discounted at 10% and assumed RPS Price Forecast of April 1, 2022, per barrel is US$339 million (risked at 80% chance of development) and US$423 million (un-risked).
- ***Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources, by definition, are not classified as reserves due to several conditions including but not limited to the uncertainties of future oil prices and performance of the initial pilot wells in the first phase of the field development of the project which must be resolved to ensure commerciality. There is no certainty that it will be commercially viable to produce any portion of the resources. The***

Development Pending sub-set for contingent resources have reasonable potential for eventual commercial development.

B) ROYALTY REPORT HIGLIGHTS

- ERCE estimates the 1P Proven Reserves Volumes to be 14 thousand barrels and 2P Proven plus Probable Reserves Volumes over the Permits to be 53 thousand barrels net to the Company.
- Net present value discounted at 10% is CDN$1.47 million for Proved Reserves and CDN$4.96 million for Proven plus Probable Reserves.

Abby Badwi, Executive Chairman of TAG Oil commented "We are pleased that the RPS Report supports TAG's technical assessment of the unconventional development of the ARF and our team's plans for such large-scale development by utilizing North American proven drilling and completion technologies for the first time in Egypt. To validate these assessments, the first pilot well, a re-entry of an existing well, is scheduled for next month and will be followed by the first horizontal well with multi-stage fracture stimulation completion to be drilled in the first quarter of 2023. In New Zealand, the value of the royalty interest is attributable to the Company continuing to receive a gross overriding royalty equal to 2.5% of the gross sales revenue. In the 2022 calendar year, the Company received CDN$947,477 in royalty payments."

Further details are also available on the Company's website at www.tagoil.com.

About TAG Oil Ltd.

TAG Oil (http://www.tagoil.com/) is a Canadian based international oil and gas exploration company with a focus on opportunities in the Middle East and North Africa.

For further information:

Toby Pierce, Chief Executive Officer
Phone: 1 604 609 3355

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Email: info@tagoil.com
Website: http://www.tagoil.com/

Cautionary Note Regarding Forward-Looking Statements and Disclaimer

Statements contained in this news release that are not historical facts are forward-looking statements that involve various risks and uncertainty affecting the business of TAG. All estimates and statements that describe the Company's operations are forward-looking statements under applicable securities laws and necessarily involve risks and uncertainties. Actual results may vary materially from the information provided in this release, and there is no representation by TAG that the actual results realized in the future will be the same in whole or in part as those presented herein. TAG undertakes no obligation, except as otherwise required by law, to update these forward-looking statements if management's beliefs, estimates or opinions, or other factors change.

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.

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Where discussed herein "NPV 10%" represents the net present value (net of capital expenditures) of net income discounted at 10%, with net income reflecting the indicated oil prices and initial production rate, less internal estimates of operating costs and royalties. It should not be assumed that the future net revenues estimated by TAG Oil's independent resource evaluators represent the fair market value of the resources.

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SCHEDULE “B”

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

Part 1 Date of Statement

Item 1.1 Relevant Dates

Item 1.1 (1) This statement of reserves data and other oil and gas information is dated November 21, 2022.

Item 1.1 (2) The effective date of the information being provided in this statement is March 31, 2022.

Item 1.1 (3) The preparation date of such information is November 21, 2022.

Part 2 Disclosure of Reserves Data

TAG Oil Ltd. (“TAG” or the “Company”) has an agreement in place for the development of the Abu Roash “F” (“ARF”) formation within the Badr-1 (“BED-1”) area in the Western Desert of Egypt and has formally entered into the final Petroleum Services Agreement (“PSA”) with Badr Petroleum Company (“BPCO”), a wholly owned subsidiary company of the Egyptian General Petroleum Corporation (“EGPC”). There are currently no Company reserves attributed to the ARF formation pertaining to the PSA. Contingent Resources have been assigned and are disclosed in Part 6 and Part 7 of this document. RPS Energy Canada Ltd. (“RPS”), an independent qualified reserves evaluator appointed by the Company, compiled the report on contingent resources data entitled “Resources Evaluation of the Abu Roash “F” Formation in the Badr-1 License Area Western Desert Region, Egypt” with an effective date of March 31, 2022. All currency amounts in this Form 51-101F1 are stated in United States dollars unless otherwise indicated.

Item 2.1 Reserves Data Forecast and Costs

Item 2.1 (1) (a)	Not applicable
Item 2.1 (1) (b)	Not applicable
Item 2.1 (1) (c)	Not applicable
Item 2.1 (1) (d)	Not applicable
Item 2.1 (1) (e)	Not applicable
Item 2.1 (1) (f)	Not applicable
Item 2.1 (1) (g) (i)	Not applicable
Item 2.1 (1) (g) (ii)	Not applicable
Item 2.1 (2)	Not applicable
Item 2.1 (3) (a) (i)	Not applicable
Item 2.1 (3) (a) (ii)	Not applicable
Item 2.1 (3) (a) (iii)	Not applicable

Item 2.1 (3) (b) (i)	Not applicable
Item 2.1 (3) (b) (ii)	Not applicable
Item 2.1 (3) (b) (iii)	Not applicable
Item 2.1 (3) (b) (iv)	Not applicable
Item 2.1 (3) (b) (v)	Not applicable
Item 2.1 (3) (b) (vi)	Not applicable
Item 2.1 (3) (b) (vii)	Not applicable
Item 2.1 (3) (b) (viii)	Not applicable
Item 2.1 (3) (c)	Not applicable

Item 2.2 Supplementary Disclosure (Constant Prices and Costs)

Item 2.2 (a) (i)	Not applicable
Item 2.2 (a) (ii)	Not applicable
Item 2.2 (b)	Not applicable

Item 2.3 Repealed (July 1, 2015)

Item 2.4 Repealed (July 1, 2015)

Part 3 – Pricing Assumptions

Item 3.1 Constant Prices Used in Supplementary Estimates - Not applicable

Item 3.2 Forecast Prices Used in Estimates

Item 3.2 (1) (a) (i)	See Table 3.2 (3) - 1, The valuation has been based on the RPS Q2 2022 price forecast for Brent (forward curve between 2022 and 2031; long-term price of \$77.75 per barrel flat real at 2 per cent per annum thereafter), as shown in Table 3.2 (3). This inflation rate has also been applied to all cost estimates to adjust them from 2022 dollars to Money of the Day (“MOD”). The field gate oil pricing for ARF formation in BED-1 was estimated based on the Brent benchmark less: - Crude quality differential: \$5.00 per stb - Crude storage and handling: \$3.50 per stb
Item 3.2 (1) (a) (ii)	See Table 3.2 (3) - 1
Item 3.2 (1) (b)	See Table 3.2 (3) - 1 and Item 3.2 (1) (a) (i)
Item 3.2 (2)	See Table 3.2 (3) - 1
Item 3.2 (3)	The pricing assumptions were made by RPS, which is independent of TAG.

Table 3.2 (3) - 1: RPS Base Brent, ARF Formation in BED-1 Oil Price Forecasts (Q2 2022)

Commodity Prices, MOD		
Year	**Brent Crude (per stb)**	**ARF Formation in BED-1 Field Price (per stb)**
2022	95.52	86.98
2023	89.07	80.40
2024	80.07	71.22
2025	78.07	69.04
2026	77.06	67.86
2027	76.06	66.67
2028	75.06	65.48
2029	75.06	65.29
2030	75.06	65.10
2031	77.75	67.58
2032	+ 2% p.a.	+ 2% p.a.

Part 4 – Reconciliation of Changes in Reserves

As this is the first evaluation completed by the Company for the ARF formation development in BED-1 under National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook and no reserves are currently assigned a reserves reconciliation is not possible.

Item 4.1 Reserves Data Forecast and Costs

Item 4.1 (1) (a) Not applicable
Item 4.1 (1) (b) Not applicable
Item 4.1 (1) (c) Not applicable
Item 4.1 (2) (a) Not applicable
Item 4.1 (3) (b) (i) Not applicable
Item 4.1 (3) (b) (ii) Not applicable
Item 4.1 (3) (b) (iii) Not applicable
Item 4.1 (3) (b) (iv) Not applicable
Item 4.1 (3) (b) (v) Not applicable
Item 4.1 (3) (b) (vi) Not applicable
Item 4.1 (3) (b) (vii) Not applicable
Item 4.1 (3) (b) (viii) Not applicable
Item 4.1 (3) (b) (ix) Not applicable
Item 4.1 (3) (b) (x) Not applicable
Item 4.1 (3) (b) (xi) Not applicable
Item 4.1 (3) (c) (i) Not applicable
Item 4.1 (3) (c) (ii) Not applicable
Item 4.1 (3) (c) (iii) Not applicable
Item 4.1 (3) (c) (iv) Not applicable
Item 4.1 (3) (c) (v) Not applicable
Item 4.1 (3) (c) (vi) Not applicable
Item 4.1 (3) (c) (vii) Not applicable

Part 5 – Additional Information Relating to Reserves Data

Item 5.1 Undeveloped Reserves

Item 5.1 (1) (a)	Not applicable
Item 5.1 (1) (b)	Not applicable
Item 5.1 (2) (a)	Not applicable
Item 5.1 (2) (b)	Not applicable

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

Item 5.2	Not applicable

Item 5.3 Future Development Costs

Item 5.3 (1) (a) (i)	Not applicable
Item 5.3 (1) (a) (ii)	Not applicable
Item 5.3 (1) (b) (i)	Not applicable
Item 5.3 (1) (b) (ii)	Not applicable
Item 5.3 (2) (a)	Not applicable
Item 5.3 (2) (b)	Not applicable
Item 5.3 (3)	Not applicable

Part 6 – Other Oil and Gas Information

Item 6.1 Oil and Gas Properties and Wells

Item 6.1 (1) (a)	The asset is located in the Western Desert petroleum province of Egypt.
Item 6.1 (1) (b)	Onshore
Item 6.1 (1) (c)	Not applicable
Item 6.1 (1) (d)	Not applicable
Item 6.1 (2)	There are no producing or non-producing wells in which the Company held a working interest as at March 31, 2022:

Table 6.1 (2) - 1: OIL AND GAS PROPERTIES AND WELLS

	OIL		**NATURAL GAS**	
	Gross	**Net**	**Gross**	**Net**
<u>ARF Formation</u>				
Producing	0	0	0	0
Non-Producing	0	0	0	0
TOTAL	0	0	0	0

Item 6.2 Properties with no Attributed Reserves

Item 6.2 (1) (a)	See table 6.2 (1) (d) - 1
Item 6.2 (1) (b)	See table 6.2 (1) (d) - 1
Item 6.2 (1) (c)	See table 6.2 (1) (d) - 1

Item 6.2 (1) (d) See table 6.2 (1) (d) - 1

Table 6.2 (1) (d) - 1: PROPERTIES WITH NO ATTRIBUTED RESERVES

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)	Basic Capital Commitment of $6 million for drilling one (1) horizontal well with multi-stage fracture stimulation / October 12, 2025 (Phase 1 expiry in 3 years if Company does not elect to continue to Phase 2 Development and Production and Optional Extension Period).	No

Item 6.2 (2) Not applicable

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

As of the effective date of March 31, 2022, there was a risk associated with the immature stage of the lease ownership and also uncertainties related to the performance of the development wells in the first phase of the ARF reservoir development of the project. Subsequently, the PSA was fully executed by BPCO and the Company on October 13, 2022.

Item 6.3 Forward Contracts

Item 6.3 (1) There are no agreements in place for future sales.

Item 6.3 (2) Not applicable

Item 6.3 (3) Not applicable

Item 6.4 Repealed (July 1, 2015)

Item 6.5 Tax Horizon

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

- TAG 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 the Arab Republic of Egypt (“ARE”) are assumed by EGPC on behalf of TAG and payable from their share of gross revenues and TAG shall be exempted from all taxes and duties imposed by the government of ARE or municipalities.

Item 6.6 Costs Incurred

Item 6.6 (a) There have been no associated property acquisition costs beyond a signature bonus of $3 million on commencement of the first phase.

Item 6.6 (b) Not applicable

Item 6.6 (c) Not applicable

Item 6.7.Exploration and Development activities

Item 6.7 (1) (a)	There have not been any wells completed by the Company in the most recent financial year.
Item 6.7 (1) (b)	Not applicable
Iteem 6.7 (2)	Not applicable

Item 6.8.Production Estimates

Item 6.8 (1)	Not applicable
Item 6.8 (2)	Not applicable

Item 6.9 Production History and Per Unit Results

There has not been Company production from the field to date.

Item 6.9 (1) (a)	Not applicable
Item 6.9 (1) (b) (i)	Not applicable
Item 6.9 (1) (b) (ii)	Not applicable
Item 6.9 (1) (b) (iii)	Not applicable
Item 6.9 (1) (b) (iv)	Not applicable
Item 6.9 (2)	Not applicable

Part 7 – Optional Disclosure of Contingent Resources Data and Prospective Resources Data

An estimate of risked net present value of future net revenue of Contingent Resources and prospective resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the required investment. It includes Contingent Resources that are considered too uncertain with respect to the chance of development and chance of discovery to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized. The ARF formation in the BED-1 area is classified as Contingent Resources (Development Pending).

Item 7.1 Contingent Resources Data

Item 7.1 (1)(a) See Table 7.1 (1) (a) - 1.

Table 7.1 (1)(a) - 1: Summary of Risked Contingent Resources in the ARF Formation in BED-1 as of March 31, 2022
(Forecast Prices and Costs)

CONTINGENT	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL	
Development Pending[1,4]	Gross[2] (Mstb)	Net[3] (Mstb)
2C (ARF Formation)	27,000	16,500
Totals	**27,000**	**16,500**

Notes:
1 Chance of Development, Pd of 80%.

2 Gross field Resources (100% basis) after economic limit test.
3 Company's Net Entitlement after economic limit test.
4 There is uncertainty that it will be commercially viable to produce any portion of the resources.

Item 7.1 (1) (b) See Table 7.1 (1) (b) - 1.

Table 7.1 (1) (b) - 1: Summary of Risked Oil Contingent Resources in the ARF Formation in BED-1 as of March 31, 2022
(Forecast Prices and Costs)

RISKED NET PRESENT VALUE OF FUTURE NET REVENUE ($MM)										
CONTINGENT RESOURCES Development Pending[1]	BEFORE INCOME TAXES DISCOUNTED AT					AFTER INCOME TAXES DISCOUNTED AT				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
1C	494	340	241	176	132	494	340	241	176	132
2C	686	474	339	250	190	686	474	339	250	190
3C	1,003	687	490	363	277	1,003	687	490	363	277

Note:
1 There is uncertainty that it will be commercially viable to produce any portion of the resources.

Item 7.1 (2) (a) For the ARF formation within the BED-1 field project area, the main contingencies impacting the COD relate to the immature stage of the lease ownership, and the uncertainties of performance of the development wells in the pilot phase of the field development of the project. RPS has estimated a 10% development risk for each of these factors:

- Lease ownership development risk (10%): As of the effective date March 31, 2022, a proposal for project lease terms and conditions was submitted in a letter of intent, a draft PSA document was prepared and a letter of approval of the proposal was pending for the project. As of this statement date of November 21, 2022, final execution of the PSA between TAG and BPCO was completed.
- Pilot field confirmation of performance development risk (10%): The first phase of the project will see two development wells drilled, completed, stimulated, produced and extensively evaluated. Data from these wells will allow confirmation of the expected full field development performance. Based on the current data set available, RPS expects the first phase of the project will confirm the existing assumptions and therefore assesses the development risk to be relatively low.

Therefore, the estimate of the current overall COD is 80%.

Item 7.1 (2) (b) RPS was appointed to forecast the performance of the field. RPS has evaluated the resource recovery potential from the ARF formation based on the petrophysical well data from multiple vertical penetrations, a few selected well tests within these vertical wells and used its local knowledge of the analogue fields to generate notional forecasts. The notional production profiles were generated based on the conceptual development plan provided by TAG, and subsequently the chance of development and risk were applied.

Item 7.2 Prospective Resources Data

Item 7.2 (1) Not applicable

Item 7.2 (2) (a) Not applicable

Item 7.2 (2) (b) Not applicable

Item 7.3 Forecast Prices Used in Estimates

Item 7.3 (1) The valuation has been based on the RPS Q2 2022 price forecast for Crude Oil at Sullom Voe,“Brent” (forward curve between 2022 and 2031; long-term price of 77.75 per barrel flat real at 2 per cent per annum thereafter), as shown in Table 7.3 (1). This inflation rate has also been applied to all cost estimates to adjust them from 2022 dollars to MOD.

The field gate oil pricing for ARF formation in BED-1 was estimated based on the Brent benchmark less:

- Crude quality differential: $5.00 per stb
- Crude storage and handling: $3.50 per stb

Table Error! No text of specified style in document..3 (1): RPS Base Brent, ARF Formation in BED-1 Oil Price Forecasts (Q2 2022)

Commodity Prices, MOD		
Year	**Brent Crude (per stb)**	**BED1 Abu-Roash “F” Field Price (per stb)**
2022	95.52	86.98
2023	89.07	80.40
2024	80.07	71.22
2025	78.07	69.04
2026	77.06	67.86
2027	76.06	66.67
2028	75.06	65.48
2029	75.06	65.29
2030	75.06	65.10
2031	77.75	67.58
2032	+ 2% p.a.	+ 2% p.a.

Item 7.3 (2) Egypt See table 7.3 (1) – A 2% inflation rate has also been applied to all cost estimates to adjust them from 2022 dollars to MOD.

Item 7.3 (3) The pricing assumption is the same as the pricing assumption used in Part 3.

7.4 Supplementary Contingent Resources Data

TAG’s development plan is to drill twenty (20) horizontal wells beginning in January 2023 and ending in January 2030. The drilling campaign is scheduled to start with one (1) well in January 2023 followed by another in July 2023 then ramp up to three (3) wells in 2026 and 2027, concluding with four (4) wells in 2028, 2029 and 2030. The development schedule is detailed in Table 7.4 (1). The first two (2) horizontal wells will be drilled as part of Phase 1 of the development program. This three (3) year period, considered the unconventional resource evaluation period, is deemed necessary to properly access the commerciality of the ARF formation in the BED-1 concession area. Once this three (3) year period is complete, the development will move into the commercial phase in which the remaining 18 wells will be drilled. The current field development plan for the AR-F is focused on the region of the concession where historic vertical well development occurred. Upon completion of the unconventional resource evaluation, development potential in the other areas of the ARF formation in the BED-1 concession area may be evaluated.

Table Error! No text of specified style in document..4 (1): Conceptual Development Well Schedule

Development Well Schedule				
	Month	ARF - 1C	ARF - 2C	ARF - 3C
Eval. P1 (year 0)	2022-06-30			
Eval. P1 (year 1)	2023-01-31	1	1	1
Eval. P1 (year 2)	2023-07-31	1	1	1
Eval. P1 (year 2)	2024-01-31	0	0	0
Eval. P1 (year 3)	2025-01-31	0	0	0
Dev. P2 (year 4)	2026-01-31	3	3	3
Dev. P2 (year 5)	2027-01-31	3	3	3
Dev. P2 (year 6)	2028-01-31	4	4	4
Dev. P2 (year 7)	2029-01-31	4	4	4
Dev. P2 (year 8)	2030-01-31	4	4	4
Dev. P2 (year 9)	2031-01-31			
		20	20	20

All capital costs are estimated in US$, and then escalated by the appropriate cost escalation factors used in the economic model. The capital cost estimates used are:

- Drill costs for vertical data wells during first phase: $3.7 million
- Drill, complete, tie-in (D, C, T) horizontal oil production well: $4.8 million
- Fracture stimulation for oil production well: $2.0 million
- Temporary production facilities (first phase): $3.0 million
- Field infrastructure facilities (development phase): $15.0 million

Based on operations data available in the public domain for Egyptian western desert area, and general RPS knowledge in the area, RPS has estimated the field operating costs. These costs will be refined once operations commence, and a more definitive field specific cost base is available:

- Field fixed operating costs: $5.5 million per year
- Variable field operating costs: $4.80 per bbl oil produced

RPS has included an estimate for field and well abandonment costs in the economic evaluation. The estimate is based on estimates provided by TAG and is deemed to be reasonable based on RPS general knowledge of onshore project abandonment costs for analogous projects. The abandonment cost estimate includes costs for abandonment of all production wells, field facilities, and site reclamation.

- Abandonment and reclamation costs: $15.0 million