

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated August 28, 2020, for the three months ended June 30, 2020 and should be read in conjunction with the condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2020.

The condensed consolidated interim financial statements for the three months ended June 30, 2020, have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), and its interpretations. Results for the period ended June 30, 2020, are not necessarily indicative of future results. All figures are expressed in Canadian dollars unless otherwise stated.

ABOUT TAG OIL LTD.

TAG Oil Ltd. ("TAG" or the "Company") is an international oil and gas exploration, development and production company with assets that are situated in Australia. As of the date of this MD&A, the Company controls holdings consisting of three onshore oil and gas permits amounting to 284,172 net acres of land.

During the year ended March 31, 2020, the Company, and certain of its subsidiaries, completed the definitive share and asset purchase agreement with Tamarind Resources Pte. Ltd. ("Tamarind"), and certain of its subsidiaries (collectively, "Transaction").

On March 16, 2020, the Company has conducted a return of capital to its shareholders in the amount of \$0.30 per common share (approximately \$25.6 million in cash), in accordance with Canadian income tax law.

The return of capital was paid on April 14, 2020 to all shareholders of record of the common shares of the Company on March 27, 2020 (record date).

Following the return of capital, the Company retained approximately \$15 million in cash along with the 2.5% gross overriding royalty on all future production from the New Zealand assets sold and up to US\$5 million in future event specific payments payable on Tamarind achieving certain milestones. TAG has enough capital to continue its business operations as currently operated for the foreseeable future.

On June 15, 2020, TAG confirmed that its common shares would be voluntarily delisted from the Toronto Stock Exchange immediately following the close of trading on June 26, 2020 and would begin trading on the TSX Venture Exchange (the "TSX-V") at market open on June 29, 2020. TAG's trading symbol will continue to be "TAO" on the TSX-V. TAG continues to maintain its listing on the premier tier of the OTC market in the United States, the OTCQX International (the "OTCQX"), under the trading symbol "TAOIF".

On having completed the Transaction, management has been reviewing operations and will focus production, and new appraisal and exploration opportunities. TAG will continue to work towards achieving the following goals:

- Maximizing the value of operations by leveraging expertise in producing fields by focusing on lifting production through enhanced oil techniques and lower per barrel production costs;
- Enhancing the development of its exploration program through careful evaluation of its exploration prospects and leads inventory;
- Establishing reserves and commercializing oil and gas exploration properties; and
- Managing its operating cash flows and balance sheet effectively to minimize costs while focusing on shareholder returns.

FIRST QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At June 30, 2020, the Company had \$15.0 million (March 31, 2020: \$41.5 million) in cash and cash equivalents and \$17.4 million (March 31, 2020: \$43.7 million) in working capital.
- Average net daily production decreased to nil boe/d for the quarter ended June 30, 2020 from 2 boe/d (100% oil) for the quarter ended March 31, 2020.
- The decrease in production is due to well shut downs mainly due to Covid-19 concerns.
- Capital expenditures totaled \$0.1 million for the quarter ended June 30, 2020, compared to \$0.1 million for the quarter ended March 31, 2020. The majority of the expenditures in Q1 2021 relate to ATP 2037/2038 seismic acquisition program for 2021.

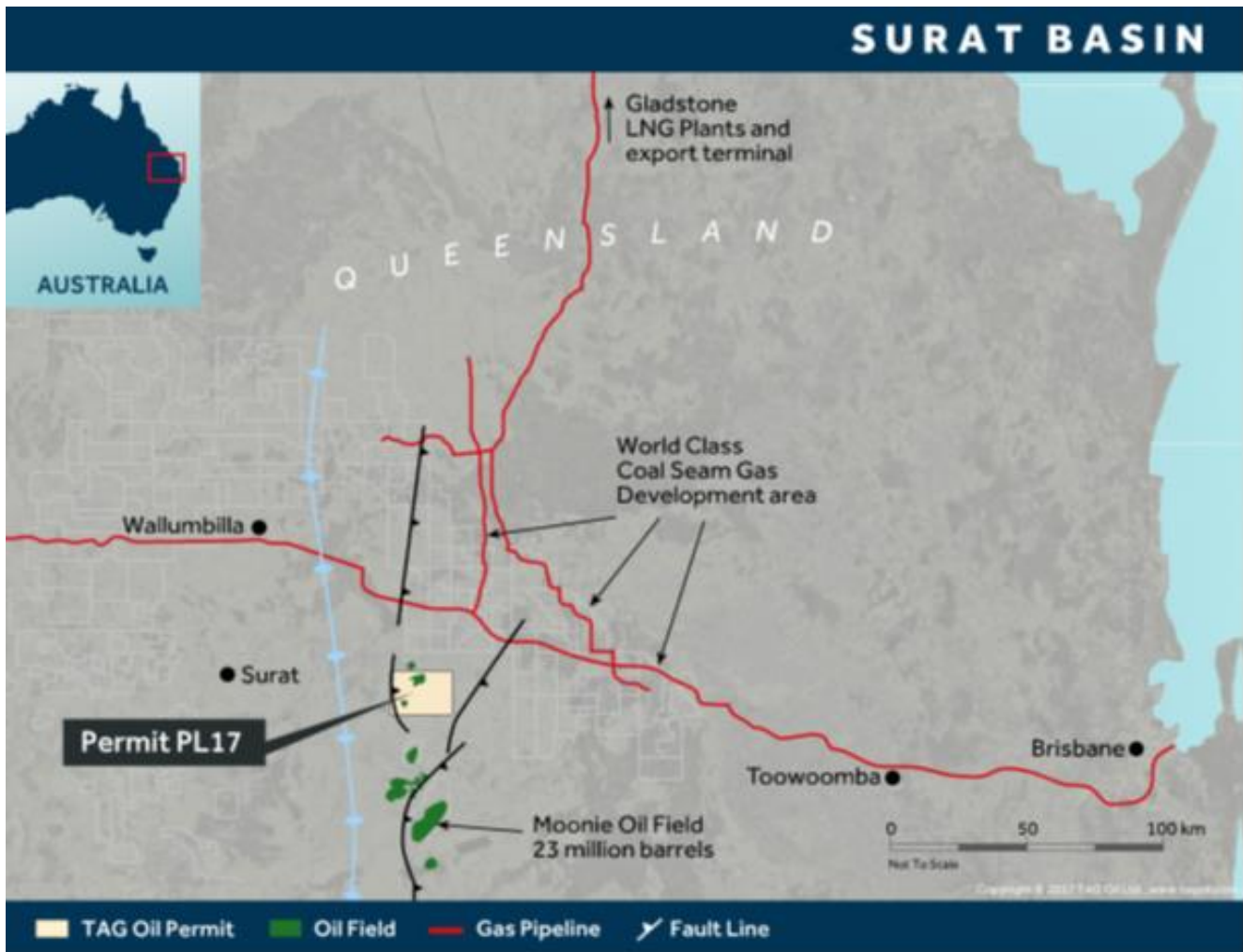
PROPERTY REVIEW

Surat Basin PL17

On January 31, 2017, the Company and its wholly owned subsidiary, Cypress Petroleum Pty Ltd. (“Cypress”), completed the purchase of 100% interest in PL17 and all related assets, which are located in Australia’s Surat Basin and subject to underlying royalties, from Southern Cross Petroleum & Exploration Pty Ltd. in exchange for AUD\$2,500,000.

The PL17 oil and gas production permit and potentially high-value exploration property covers 105km² (25,700 acres) in the Surat Basin, one of Australia’s first producing basins. PL17 is located in a light-oil discovery trend that is situated approximately 20km from the Moonie oil field, which has produced approximately 25 MMbbl of oil to date. PL17 contains two underdeveloped oil fields, the Bennett and Leichardt fields, and the production permit area is largely unexplored despite the proven and significant oil and gas potential.

To date, TAG has carried out 70km² of 3D seismic over PL17 and processing, which was followed by interpretation to identify drilling targets for a multi-target drilling campaign at a cost of approximately AUD\$3,200,000. This is the first modern 3D seismic acquired over most of the core of the PL17 acreage, which provides TAG with an enhanced subsurface understanding of the Bennett and Leichardt fields. Further processing enhancement is being evaluated in order to see if the channel system that makes up the Bennett field can be identified. TAG will continue its work on enhancing production from the existing wells on the permit.



Hutton Sand and Precipice Conventional Play

The Bennett and Leichhardt fields are both underdeveloped oil fields located within PL17. The fields have produced light oil intermittently from the Jurassic-aged Hutton Sand and Precipice formations (approximately 1,700m) since being discovered in the 1960s. Current production from the Bennett Field is currently shut in due to the impact of Covid-19. As the situation improves the company will bring personnel into the area to restart production. TAG plans to continue to develop the fields, as well as drill exploration wells to test structures identified in the Precipice and the Hutton Sand play fairway, the main producing reservoir sands in eastern Australian basins.

Deep Permian Play

PL17 also has high-impact exploration potential in the deeper Permian section; this is the primary unconventional tight gas and condensate play opportunity within PL17. The Permian formation lies immediately below the Jurassic and is up to approximately 1,000m thick. The Permian is both the source rock as well as the reservoir for potentially significant quantities of oil and gas along the erosional edge. The deep Permian tight gas potential in PL17 is being reviewed with the completion of the new 3D seismic and from a more regional contract.

Surat Basin ATPs 2037 and 2038

TAG, through its subsidiary Cypress, has been granted authority to prospect for Rocky Dam ATP 2037 and Kingston ATP 2038 in the Surat Basin, Queensland, Australia, which covers 487km² (120,340 acres) and 559km² (138,132 acres), respectively. The two ATPs are located just to the south of TAG's existing PL17 block. The ATPs have been approved for a term of six years with date of effect being January 1, 2019 and approved initial work program largely consisting of seismic reprocessing, 2D seismic acquisition and an exploration well for the period of four years from January 1, 2019, to December 31, 2022.

Work Program

An airborne survey was flown over the entirety of ATP 2037 and ATP 2038 during March 2019, satisfying the work program commitment. The data has been processed and is being incorporated into the regional interpretation of the area. Reprocessing of available seismic data was undertaken during the first 6 months of Permit Year 1 with interpretation of the data being completed. This forms the basis of the seismic acquisition programs planned for Permit Year 2 for both ATP permits. Planning for the permit seismic acquisition is continuing.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2021	2020	
	Q1 ⁽⁴⁾	Q4 ⁽³⁾	Q1
Daily production volumes ⁽¹⁾			
Oil (bbl/d)	0	2	1,113
Natural gas (boe/d)	0	0	300
Combined (boe/d)	0	2	1,413
% of oil production	0%	100%	79%
Daily sales volumes ⁽¹⁾			
Oil (bbl/d)	0	3	1,116
Natural gas (boe/d)	0	0	149
Combined (boe/d)	0	3	1,265
Natural gas (MMcf/d)	0	0	894
Product pricing			
Oil (\$/bbl)	0.00	48.70	92.26
Natural gas (\$/Mcf)	0.00	0.00	5.02
Oil and natural gas revenues - gross (\$000s)	-	(77)	9,774
Oil and natural gas royalties ⁽²⁾	-	121	(1,015)
Oil and natural gas revenues - net (\$000s)	-	44	8,759

(1) Natural gas production converted at 6 Mcf:1 boe (for boe figures).

(2) Relates to government royalties and includes an ORR of 7.5% royalty related to the acquisition of a 69.5% interest in the Cheal field.

(3) The dollar amounts appear exaggerated due to the exchange adjustments required each period per IAS 21. Little or no cost was recorded in the quarter and very small volumes compared to Q1 and Q2 F2020.

(4) The productions had been shut in the prior quarter due to the requirement for repairs but have not been restarted due to the concern over Covid-19 and bringing in outside technical personal into the area during the process.

Average net daily production decreased to nil boe/d (100% oil) for the quarter ended June 30, 2020, from 2 boe/d (100% oil) for the quarter ended March 31, 2020. The decrease is due to PL17 not being restarted for the quarter due to concerns over Covid-19.

SUMMARY OF QUARTERLY INFORMATION

<i>Canadian \$000s, except per share or boe</i>	2021		2020				2019	
	Q1(2)	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Net production volumes (boe/d)	0	2	4	1,280	1,413	1,218	1,211	1,195
Total revenue	-	(77)	25	6,726	9,774	7,407	8,810	7,901
Operating costs	(32)	188	(57)	(3,827)	(4,654)	(4,589)	(4,246)	(3,595)
Foreign exchange	(969)	1,918	(1,177)	349	(87)	22	(134)	2
Share-based compensation	(6)	(34)	(4)	7	(17)	(60)	(70)	(80)
Other costs	(611)	(560)	(2,122)	(968)	(2,361)	(3,380)	(781)	(4,256)
Exploration recovery (impairment)	-	57	34	(7)	(30)	(4)	(9)	(19)
Recovery (write-down) to AHFS	-	-	-	3,498	(3,498)	3,590	(7,661)	(59,061)
(Loss) gain on sale of property	-	-	(102)	319	-	-	-	-
Gain on sale of PP&E	-	2,235	651	1,370	-	-	-	-
(Loss) gain on royalty valuation	(87)	155	249	-	-	-	-	-
Write-off of oil and gas property	-	-	-	(41)	-	-	-	-
Net (loss) income before tax	(1,705)	3,882	(2,503)	7,426	(873)	2,986	(4,091)	(59,108)
Income tax	-	2	-	-	-	(586)	(2)	(34)
Net (loss) income for the period	(1,705)	3,884	(2,503)	7,426	(873)	2,400	(4,093)	(59,142)
(Loss) earnings per share – basic	(0.02)	0.05	(0.03)	0.09	(0.01)	0.03	(0.05)	(0.69)
(Loss) earnings per share – diluted	(0.02)	0.05	(0.03)	0.09	(0.01)	0.03	(0.05)	(0.69)
Capital expenditures	(98)	(17)	2,629	34	992	1,354	3,817	3,019
Operating cash flow ⁽¹⁾	(902)	1,056	(2,785)	2,417	2,815	69	2,506	2,823

(1) Operating cash flow is a non-GAAP measure. It represents cash flow from operating activities before changes in working capital. See non-GAAP measures for further explanation.

(2) The productions had been shut in in the prior quarter due to the requirement for repairs but have not been restarted due to the concern over Covid-19 and bringing in outside technical personal into the area during the process.

There were no revenue generated from oil and gas sales for the quarter ended June 30, 2020 from (\$0.08) million for the quarter ended March 31, 2020. The decrease is due to operations being shut down due to Covid-19 and no foreign exchange. Revenues generated from oil and gas sales decreased to \$nil for the quarter ended June 30, 2020 from \$9.8 million for the quarter ended June 30, 2019. The decrease is due to operations being shut down in Australia due to Covid-19 and completion of the Transaction on September 25, 2019.

Operating costs decreased for the quarter ended March 31, 2020, to \$0.03 million from (\$0.19) million for the quarter ended March 31, 2020. Operating costs decreased for the quarter ended June 30, 2020, to \$0.03 million from \$4.65 million when compared to the quarter ended June 30, 2019. Operating costs decreased due to the operations being shut down in Australia due to Covid-19 and completion of the Transaction on September 25, 2019.

Other costs decreased to \$0.61 million for the quarter ended June 30, 2020 from \$2.05 million for the quarter ended March 31, 2020. The decrease is due to operations being shut down in Australia due to Covid-19 and completion of the Transaction on September 25, 2019. Other costs decreased to \$0.61 million for the quarter ended June 30, 2020 from \$2.36 million for the quarter ended June 30, 2019. The decrease is due to operations being shut down in Australia due to Covid-19 and completion of the Transaction on September 25, 2019.

Net loss before tax for the quarter ended June 30, 2020, was \$1.71 million compared to net income before tax of \$3.88 million for the quarter ended March 31, 2020. Excluding impairment expense and write-offs, on a comparative basis, this equates to net loss before tax of \$1.71 million for the quarter ended June 30, 2020, compared with net income of \$1.5 million for the quarter ended March 31, 2020. The net loss compared to the net income in the prior quarter is due to operations being shut down in Australia due to Covid-19 and completion of the Transaction on September 25, 2019. Net loss before tax for the quarter ended March 31, 2020 was \$1.71 million compared to \$0.87 million for the quarter ended June 30, 2019. Excluding impairment expense and write-offs, on a comparative basis, equates to net loss before tax of \$1.71 million for the quarter ended June 30, 2020, compared to a net loss of \$2.6 million for the quarter ended June 2019. The decrease is due to operations being shut down in Australia due to Covid-19 and completion of the Transaction on September 25, 2019.

Net Production by Area (boe/d)

Area	2021		2020	
	Q1	Q4	Q1	Q1
PMP 38156 (Cheal) (1)	0	0	0	853
PMP 60291 (Cheal East) (1)	0	0	0	363
PMP 53803 (Sidewinder) (1)	0	0	0	190
PL 17 (Cypress)	0	2	2	7
Total boe/d	0	2	2	1,413

(1) All production assets in New Zealand have been sold as of September 2019.

Average net daily production decreased to nil boe/d for the quarter ended June 30, 2020 from 2 boe/d (100% oil) for the quarter ended March 31, 2020. The decrease is due to PL17-B1/B4 being shutdown due to Covid-19.

Average net daily production decreased to nil boe/d (100% oil) for the quarter ended June 30, 2020 from 1,413 boe/d (79% oil) for the quarter ended June 30, 2019. The decrease is due to the sale of the New Zealand producing assets and due to PL17-B1/B4 being shutdown due to Covid-19.

Oil and Gas Operating Netback (\$/boe)

	2021		2020	
	Q1(2)	Q4(1)	Q1	Q1
Oil and natural gas revenue	-	(247.74)	84.91	84.91
Production costs	-	127.07	(22.16)	(22.16)
Royalties	-	390.87	(8.82)	(8.82)
Transportation and storage costs	-	89.10	(9.45)	(9.45)
Operating Netback per boe (\$)	-	359.30	44.48	44.48

(1) The amounts per boe appear exaggerated due to the exchange adjustments required each period per IAS 21. Little or no cost was recorded in the quarter and very small volumes compared to Q1 and Q2 F2020.

(2) There is no calculation in the period as there was no production.

Operating netback per boe is the operating netback divided by barrels of oil equivalent sold in the applicable period. See non-GAAP measures for further explanation. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS.

General and Administrative Expenses ("G&A")

	2021		2020	
	Q1	Q4(2)	Q1	Q1
Oil and Gas G&A expenses (\$000s)	587	804	2,391	2,391
Per boe (\$) (1) (3)	N/A	4,210.00	18.59	18.59

(1) Per boe (\$) is the G&A expenses divided by barrels of oil equivalent production volume for the applicable period.

(2) The amounts per boe are significantly greater due to decreased volumes post sale.

(3) There is no calculation in the period as there was no production.

Share-based Compensation

	2021		2020	
	Q1	Q4(2)	Q1	Q1
Share-based compensation (\$000s)	6	34	17	17
Per boe (\$) (1) (3)	N/A	176.46	0.13	0.13

(1) Per boe (\$) is the share-based compensation divided by barrels of oil equivalent production volume for the applicable period.

(2) The amounts per boe are significantly greater due to decreased volumes post sale.

(3) There is no calculation in the period as there was no production.

Share-based compensation costs are non-cash charges, which reflect the theoretical estimated value of stock options granted. The Company applies the Black-Scholes option pricing model using the closing market prices on the grant dates and to date the Company has calculated option benefits using a volatility ratio and a risk-free interest rate. The theoretical fair value of the option benefit is amortized on a diminishing basis over the vesting period of the options, generally being a minimum of two years.

In the quarter ended June 30, 2020, the Company no options were granted (March 31, 2020 – 250,000) and no options were exercised (March 31, 2020: nil).

Share-based compensation increased for the quarter ended June 30, 2020 to \$0.006 million when compared to \$0.034 million in the quarter ended March 31, 2020. Share-based compensation costs decreased due to no options being granted in Q1 2021.

Share-based compensation decreased to \$0.006 million in the quarter ended June 30, 2020, compared with \$0.017 million for the quarter ended June 30, 2019. The decrease in total share-based compensation costs is due to declining amortization based on vesting terms on options previously granted and no new options being granted in Q1 2021.

Depletion, Depreciation and Accretion (DD&A)

	2021		2020	
	Q1	Q4 ⁽²⁾	Q1	Q1
Depletion, depreciation and accretion (\$000s)	34	(165)		142
Per boe (\$) ⁽¹⁾ ⁽³⁾	N/A	(863.55)		1.11

⁽¹⁾ Per boe (\$) is the depletion, depreciation and accretion divided by barrels of oil equivalent production volume for the applicable period.

⁽²⁾ The amounts per boe are significantly greater due to decreased volumes post sale.

⁽³⁾ There is no calculation in the period as there was no production.

DD&A expenses have increased for the quarter ended June 30, 2020 to \$0.03 million compared to (\$0.17) million the quarter ended March 31, 2020. The increase is due to the royalties being revaluated that have been held on the sale in December 2019.

DD&A expenses decreased for the quarter ended June 30, 2020 to \$0.03 million compared with \$0.14 million for the quarter ended June 30, 2019. The decrease is due to the sale of the New Zealand producing assets.

Foreign Exchange Loss (Gain)

	2021		2020	
	Q1	Q4	Q1	Q1
Foreign exchange loss (gain) (\$000s)	969	(1,918)		87

The foreign exchange loss for the quarter ended June 30, 2020 was a result of movement of the USD against the NZD, resulting in foreign exchange loss on the USD denominated royalty and ESP.

Net (Loss) Income Before Tax, Income Tax and Net (Loss) Income After Tax

(\$000s)	2021		2020	
	Q1	Q4	Q1	Q1
Net (loss) income before tax	(1,705)	3,882		(873)
Income tax	-	2		-
Net (loss) income after tax	(1,705)	3,884		(873)
(Loss) earnings per share - basic	(0.02)	0.05		(0.01)
(Loss) earnings per share - diluted	(0.02)	0.05		(0.01)

Cash Flow

(\$000s)	2021		2020	
	Q1	Q4	Q1	Q1
Operating cash flow (1)	(902)	1,056		2,815
Cash (used in) provided by operating activities	(930)	1,846		2,618
Operating cash flow per share - basic	(0.01)	0.02		0.03
Operating cash flow per share - diluted	(0.01)	0.02		0.03

(1) Operating cash flow is a non-GAAP measure. It represents cash flow from operating activities before changes in working capital. See non-GAAP measures for further explanation.

Operating cash flow decreased to (\$0.9) million for the quarter ended June 30, 2020 compared to cash outflows of \$1.1 million for the quarter ended March 31, 2020. The decrease is due to the operations being shut down in Australia due to Covid-19 and completion of the Transaction on September 25, 2019.

Operating cash flow decreased to (\$0.9) million for the quarter ended June 30, 2020 compared to \$2.8 million for the quarter ended June 30, 2019. The decrease is to the operations being shut down in Australia due to Covid-19 and completion of the Transaction on September 25, 2019.

CAPITAL EXPENDITURES

Capital expenditures were \$0.1 million for the quarter ended June 30, 2020 compared to \$0.1 million for the quarter ended March 31, 2020 and \$1.0 million for the quarter ended June 30, 2019.

The majority of the expenditures are related to the Australian exploration activities (\$0.1 million).

Taranaki Basin (\$000s)	2021		2020	
	Q1	Q4	Q1	Q1
Mining permits	-	-		503
Exploration permits	-	-		138
Total Taranaki Basin	-	-		641

Australia Surat Basin (\$000s)	2021		2020	
	Q1	Q4	Q1	Q1
Exploration permits	96	114		142
Total Surat Basin	96	114		142

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure as at June 30, 2020:

Contractual Obligations (\$000s)	Total	Less than One Year	Two to Five Years	More than Five Years
Operating leases (1)	208	139	69	-
Other long-term obligations (2)	7,726	3,530	4,196	-
Total contractual obligations (3)	7,934	3,669	4,265	-

(1) The Company has commitments related to corporate office lease signed in Vancouver, Canada.

(2) The other long term obligations that the Company has are in respect to the Company's share of expected exploration and development permit obligations and/or commitments at the date of this report. The Company may choose to alter the program, request extensions, reject development costs, relinquish certain permits or farm-out its interest in permits where practical.

(3) The Company's total commitments include those that are required to be incurred to maintain its permits in good standing during the current permit term, prior to the Company committing to the next stage of the permit term where additional expenditures would be required. In addition, costs are also included that relate to commitments the Company has made that are in addition to what is required to maintain the permit in good standing.

The details of the Company's material commitments shown previously are as follows:

Permit	Commitment	Less than One Year (\$000s)	Two to Five Years	More than Five Years
ATP 2037	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	1,514	2,098	-
ATP 2038	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	2,016	2,098	-
	TOTAL COMMITMENTS	3,530	4,196	-

The Company expects to manage its working capital on hand as well as cash flow from oil and gas sales to meet commitments that best allow it to continue with its core operations while allowing selective development and exploration. Commitments and work programs are subject to change as dictated by cashflow, which in turn is affected by oil and gas prices and production levels.

LIQUIDITY AND CAPITAL RESOURCES

(\$000s)	2021		2020	
	Q1	Q4	Q1	Q1
Cash and cash equivalents	14,960	41,540	7,175	7,175
Working capital	17,419	43,662	6,445	6,445
Contractual obligations, next twelve months	3,669	3,669	6,926	6,926
Revenue	-	16,449	9,774	9,774
Cashflow from operating activities	(930)	1,846	2,618	2,618

As of the date of this report, the Company is monitoring its funding requirements and may adjust its current exploration and development programs to ensure anticipated cash flow from the Cheal and Sidewinder oil and gas fields allow the Company to meet its commitments for the next twelve months. TAG's management continues to adjust to changes in the price of oil and will reduce and relinquish obligations as necessary to provide more certainty and liquidity for the Company as needed. The Company has cash available and it continues to monitor commodity prices and cash flow. TAG will react to up or down movements in commodity prices and cash flow, which may result in future reductions in commitments or taking on additional projects and obligations to improve productions and reserves.

Additional material commitments, changes to production estimates, continued low oil prices, or any acquisitions by the Company may require a source of financing or an alteration to the Company's drilling program. Alternatively, certain permits may be farmed-out, sold, relinquished, or the Company can request changes to the work commitments included in the permit terms.

NON-GAAP MEASURES

The Company uses certain terms for measurement within this MD&A that do not have standardized meanings prescribed by generally accepted accounting principles ("GAAP"), including IFRS, and these measurements may differ from other companies and accordingly may not be comparable to measures used by other companies. The terms "operating cash flow", "operating netback" and "operating margin" are not recognized measures under the applicable IFRS. Management of the Company believes that these terms are useful to provide shareholders and potential investors with additional information, in addition to profit and loss and cash flow from operating activities as defined by IFRS, for evaluating the Company's operating performance and leverage. References to operating cash flow are to cash revenue less direct operating expenses, which includes operations and maintenance expenses and taxes (other than income and capital taxes) but excludes the effect of changes in non-cash working capital accounts. Operating netback denotes oil and gas revenue, less royalty expenses, operating expenses and transportation and storage expenses.

Operating Margin (\$000s)	2021		2020	
	Q1(2)	Q4(1)	Q1	Q1
Total revenue	0	(77)	9,774	9,774
Less production costs	(32)	39	(2,551)	(2,551)
Less royalties	0	121	(1,015)	(1,015)
Less transportation and storage	0	28	(1,088)	(1,088)
Operating margin	(32)	111	5,120	5,120

- (1) The amounts appear exaggerated due to the exchange adjustments required each period per IAS 21. Little or no cost was recorded in the quarter and very small volumes compared to Q1 and Q2 F2020.
- (2) The productions had been shut in in the prior quarter due to the requirement for repairs but have not been restarted due to the concern over Covid-19 and bringing in outside technical personal into the area during the process.

OFF-BALANCE SHEET ARRANGEMENTS AND PROPOSED TRANSACTIONS

The Company has no off-balance sheet arrangements or proposed transactions.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments on the Company's balance sheet include cash, accounts receivable and accounts payable. The carrying value of these instruments approximates their fair value due to the short term nature of the instruments. The Company manages its risk through its policies and procedures, but other than as described above has not generally used derivative financial instruments to manage risks.

RELATED PARTY TRANSACTIONS

As required under IAS 24, related party transactions include compensation paid to the Company's CEO, COO, Chairman and CFO as well as to the remaining board as part of the ordinary course of the Company's business. The Company reports that no related party transactions have occurred during the reporting period other than ongoing compensation as disclosed in the table below.

The Company is of the view that the amounts incurred for services provided by related parties approximates what the Company would incur to arms-length parties for the same services. Compensation paid to key management is as follows:

(\$000s)	2021		2020	
	Q1	Q4	Q4	Q1
Share-based compensation	6	8	8	8
Management wages and director fees	147	147	147	457
Total management compensation	153	155	155	465

SHARE CAPITAL

- At June 30, 2020, there were 85,416,252 common shares, 3,525,000 stock options outstanding and no warrants outstanding.
- At August 28, 2020, there were 85,416,252 common shares, 3,525,000 stock options outstanding and no warrants outstanding.

The Company has one class of common shares. No class A or class B preference shares have been issued.

SUBSEQUENT EVENTS

None noted.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of the condensed consolidated interim financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the condensed consolidated interim financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these condensed consolidated interim financial statements.

Areas of judgment that have the most significant effect on the amounts recognized in these condensed consolidated interim financial statements are recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities and functional currency.

Key sources of estimation uncertainty that have the most significant effect on the amounts recognized in these condensed consolidated interim financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities, determination of the fair values of share-based compensation and assessment of contingencies.

Recoverability, impairment and fair value of oil and gas properties

Fair values of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves, oil and gas prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the condensed consolidated interim financial statements of future periods could be material. The fair value of properties is determined based on cost and supported by the discounted cash flow of reserves based on anticipated work program. The net present value uses a discount rate of 10% and costs are determined on the anticipated exploration program, forecast oil prices and contractual price of natural gas along with forecast operating and decommissioned costs. A discount rate of 10% has been used in determining the net present value of oil and gas properties.

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing unless the recoverable amount based on value in use can be estimated for an individual asset. The determination of the Company's CGUs is based on separate business units for retail and producing oil and gas fields with petroleum mining permits granted including associated infrastructure on the basis that field investment decisions are made based on expected field production and all wells are dependent on the field infrastructure.

Each CGU or asset is evaluated for impairment to ensure the carrying value is recoverable. Management looks at the discounted cash flows of capital development, income, production, reserves, and field life and asset retirement obligations of the CGU or asset in assessing the recoverable amount of the CGU or asset. A discount rate of 10% is applied to the assessment of the recoverable amount.

The decision to transfer exploration and evaluation assets to property, plant and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves. The calculation of decommissioning liabilities includes estimates of the future costs to settle the liability, the timing of the cash flows to settle the liability, the risk-free rate and the future inflation rates. The rates used to calculate decommissioning liabilities are an inflation rate of 1.62% and a risk-free discount rate ranging from 0.33% to 1.56%, which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing, and inflation on the condensed consolidated interim financial statements of future periods may be material.

Income taxes

The calculation of income taxes requires judgment in applying tax laws and regulations, estimating the timing of the reversals of temporary differences, and estimating the reliability of deferred tax assets. These estimates impact current and deferred income tax assets and liabilities, and current and deferred income tax expense (recovery).

Share-based compensation

The calculation of share-based compensation requires estimates of volatility, forfeiture rates and market prices surrounding the issuance of share options. These estimates impact share-based compensation expense and share-based payment reserve.

Functional currency

The determination of a subsidiary's functional currency often requires significant judgment where the primary economic environment in which they operate may not be clear. This can have a significant impact on the consolidated results of the Company based on the foreign currency translation methods used.

Contingencies

Contingencies are resolved only when one or more events transpire. As a result, the assessment of contingencies inherently involves estimating the outcome of future events.

Future changes in accounting policies

None noted.

CHANGES IN ACCOUNTING POLICIES

None noted.

BUSINESS RISKS AND UNCERTAINTIES

The Company, like all companies in the international oil and gas sector, is exposed to a variety of risks which include title to oil and gas interests, the uncertainty of finding and acquiring reserves, funding and developing those reserves and finding storage and markets for them. In addition there are commodity price fluctuations, interest and exchange rate changes and changes in government regulations. The oil and gas industry is intensely competitive and the Company must compete against companies that have larger technical and financial resources. The Company works to mitigate these risks by evaluating opportunities for acceptable funding, considering farm-out opportunities that are available to the Company, operating in politically stable countries, aligning itself with joint venture partners with significant international experience and by employing highly skilled personnel. The Company also maintains a corporate insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts and other operating accidents and disruptions. The oil and gas industry is subject to extensive and varying environmental regulations imposed by governments relating to the protection of the environment and the Company is committed to operate safely and in an environmentally sensitive manner in all operations.

There have been no significant changes in these risks and uncertainties in the three month period ended June 30, 2020.

Please also refer to Forward Looking Statements.

Management's Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting. Any system of internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

There have been no changes in the Company's internal control over financial reporting during the period ended June 30, 2020, that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

The following pertains to the Company's MD&A for the period ended June 30, 2020, confirming that the Company is in compliance with disclosure controls and procedures and internal controls over the financial reporting period:

The Company's management, with the participation of its CEO and CFO, have evaluated the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the Company's CEO and CFO have concluded that, as of the end of the year covered by this report, the Company's disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed by the Company in reports it files is recorded, processed, summarized and reported, within the appropriate time periods. Required information is accumulated and communicated to management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

The Company's management, including the CEO and the CFO, are responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's CEO and CFO and effected by the board, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of condensed consolidated interim financial statements for external purposes in accordance with IFRS. The Company's internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets and liabilities of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the condensed consolidated interim financial statements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of June 30, 2020. In making the assessment, it used the criteria set forth in the Internal Controls Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on their assessment, management has concluded that, as of June 30, 2020, the Company's internal control over financial reporting was effective based on those criteria.

Additional information relating to the Company is available on Sedar at www.sedar.com.

FORWARD LOOKING STATEMENTS

The MD&A contains forward-looking statements within the meaning of securities laws, including the “safe harbour” provisions of Canadian securities legislation. Forward-looking statements and information concerning anticipated financial performance are based on management’s assumptions using information currently available. Material factors or assumptions used to develop forward-looking information include drilling programs and results, facility and pipeline construction operations and enhancements, potential business prospects, growth strategies, the ability to add production and reserves through development and exploration activities, the ability to reduce costs and extend commitments, projected capital costs, government legislation, well performance, the ability to market production, the commodity price environment and quality differentials and exchange rates. Management also assumes that the Company will continue to be able to maintain permit tenures in good standing, that the Company will be able to access equity capital when required and that the Company will maintain access to necessary oil and gas industry services and equipment to conduct its operations. Although management considers its assumptions to be reasonable based on these factors, they may prove to be incorrect.

Forward-looking information is often, but not always, identified by the use of words such as “anticipate”, “assume”, “believe”, “estimate”, “expect”, “forecast”, “guidance”, “may”, “plan”, “predict”, “project”, “should”, “will”, or similar words suggesting future outcomes. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: oil and natural gas production estimates and targets; statements regarding boe/d production capabilities; anticipated revenue from oil and gas fields; completing announced exploration acquisitions and other activities; capital expenditure programs and estimates; plans to drill additional wells; ; and other statements set out herein. Also included in this MD&A are forward-looking statements regarding the achievement of any of the event specific payments, the benefits to TAG of the gross overriding royalty. In making the forward-looking statements in this release, TAG has applied certain factors and assumptions that are based on information currently available to TAG as well as TAG’s current beliefs and assumptions made by TAG, including that the Transaction will benefit TAG, that TAG’s New Zealand business will continue to be operated by Tamarind in a way that is beneficial to TAG and results in the achievement of the event specific payments and payment pursuant to the gross overriding royalty.

Because forward-looking information addresses future events and conditions, it involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the forward-looking information. These risks and uncertainties include, but are not limited to: access to capital, commodity price volatility; well performance and marketability of production; transportation and refining availability and costs; exploration and development costs; infrastructure costs; the recoverability of reserves; reserves estimates and valuations; the Company’s ability to add reserves through development and exploration activities; accessibility of services and equipment; fluctuations in currency exchange rates; and changes in government legislation and regulations. Risks with respect to the Transaction include the risk that TAG’s New Zealand business will not be operated in a way that is beneficial to TAG or results in the achievement of the event specific payments pursuant to the gross overriding royalty.

The forward-looking statements contained herein are as of June 30, 2020 and are subject to change after this date. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive and as such undue reliance should not be placed on forward-looking statements. Except as required by applicable securities laws, with the exception of events or circumstances that occurred during the period to which the MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking information for a period that is not yet complete that was previously disclosed to the public, the Company disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

Certain information in this MD&A may constitute “analogous information” as defined in NI 51-101, including, but not limited to, information relating to areas with similar geological characteristics to the lands held by the Company. Such information is derived from a variety of publicly available information from government sources, regulatory agencies, public databases, or other industry participants (as at the date stated therein) that the Company believes are predominantly independent in nature. The Company believes this information is relevant as it helps to define the reservoir characteristics in which the Company may hold an interest. The Company is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor and in accordance with the COGE Handbook. Such information is not an estimate of the reserves or resources attributable to lands held or to be held by the Company and there is no certainty that the reservoir data and economics information for the lands held by the Company will be similar to the information presented therein. The reader is cautioned that the data relied upon by the Company may be in error and/or may not be analogous to the Company’s land holdings.

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.

CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Toby Pierce,
CEO and Director
Vancouver, British Columbia

Keith Hill, Director
Key Largo, Florida

Ken Vidalin, Director
Vancouver, British Columbia

Peter Loretto, Director
Vancouver, British Columbia

Brad Holland, Director
Calgary, Alberta

David Bennett, Director
Wellington, New Zealand

Gavin Wilson, Director
Zurich, Switzerland

Barry MacNeil, CFO
Surrey, British Columbia

Giuseppe (Pino) Perone,
General Counsel and Corporate Secretary
Vancouver, British Columbia

CORPORATE OFFICE

885 W. Georgia Street
Suite 2040
Vancouver, British Columbia
Canada V6C 3E8
Telephone: 1-604-682-6496
Facsimile: 1-604-682-1174

BANKER

Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Vancouver, British Columbia
Bell Gully
Wellington, New Zealand

AUDITORS

De Visser Gray LLP
Chartered Professional Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT

Computershare Investor Services Inc.
100 University Avenue, 9th Floor
Toronto, Ontario
Canada M5J 2Y1
Telephone: 1-800-564-6253
Facsimile: 1-866-249-7775

The Annual General Meeting was held on
September 26, 2019 at 11:00 am in Vancouver,
B.C, Canada.

SHARE LISTING

TSX Venture Exchange (TSX-V)
Trading Symbol: TAO
OTCQX Trading Symbol: TAOIF

SHAREHOLDER RELATIONS

Telephone: 604-682-6496
Email: ir@tagoil.com

SHARE CAPITAL

At August 28, 2020, there were 85,416,252 shares
issued and outstanding.
Fully diluted: 88,941,252 shares.

WEBSITE

www.tagoil.com

SUBSIDIARIES

Cypress Petroleum Pty Ltd.
TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Trans-Orient Petroleum Ltd.

Orient Petroleum (NZ) Limited
CX Oil Limited
Stone Oil Limited