MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated July 2, 2019, for the year ended March 31, 2019 and should be read in conjunction with the audited consolidated financial statements for the years ended March 31, 2019 and 2018.

The audited consolidated financial statements for the year ended March 31, 2019, 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 year ended March 31, 2019, 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 a development-stage international oil and gas producer with established production, development and exploration assets, including production infrastructure in New Zealand and Australia. As of the date of this MD&A, the Company controls holdings consisting of ten onshore oil and gas permits amounting to 326,903 net acres of land.

TAG had announced the signing of a definitive share and asset purchase agreement with Malaysian-based Tamarind Resources Pte. Ltd. ("Tamarind") and certain of its subsidiaries. This arm's length transaction is for the sale of substantially all of TAG's Taranaki Basin assets and operations in New Zealand (the "Transaction"), which consists of seven permits amounting to 37,439 net acres of land. TAG's shareholders voted in favour of the Transaction on January 3, 2019.

In light of the Transaction, management will continue to employ its disciplined approach and remain focused on production, appraisal and exploration opportunities. TAG will continue to work towards achieving the following goals:

- Maximizing the value of its operations in its producing fields by focusing on lifting production through enhanced oil and gas recovery 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 additional proved reserves and commercializing its oil and gas exploration properties;
- Reviewing potential acquisitions of overlooked/undervalued opportunities; and
- Managing its operating cash flows and balance sheet effectively to minimize costs while focusing on shareholder returns.

FINANCIAL SNAPSHOT

	For the year ended March 31, 2019	For the year ended March 31, 2018	For the year ended March 31, 2017
Proven & Probable "2P" Reserves (Mboe)	**3,988**	**4,079**	**4,143**
Oil production (bbl/d)	930	861	948
Gas production (MMcf/d)	1,430	1,551	1,510
Combined boe/d	**1,168**	**1,120**	**1,200**
Oil & gas revenue per boe	$84.15	$70.50	$60.48
Production and transportation and storage costs per boe	($35.30)	($32.35)	($29.49)
Royalties per boe	($7.95)	($7.49)	($6.11)
Operating netback per boe(1)	**$40.90**	**$30.66**	**$24.88**
Revenue	$33,236,667	$23,669,850	$23,340,949
Cashflow from operating activities	$12,066,555	$8,741,865	$1,462,514
Net (loss) income before tax	($60,921,615)	$3,832,417	$24,686,719
Income tax	$639,197	$0	$0
Net (loss) income for the year	($60,282,418)	$3,832,417	24,686,719
(Loss) earnings per share – basic	($0.71)	$0.04	$0.39
(Loss) earnings per share – diluted	($0.71)	$0.04	$0.38
Total assets	$82,165,801	$144,283,364	$145,864,625
Asset retirement obligation	$140,056	$13,793,714	$14,963,715
Deferred tax liability	$0	$0	$0
Shareholders equity	$61,120,231	$124,897,603	$122,810,467

(1) Operating netback is a non-GAAP measure. Operating netback is the operating margin the company receives from each boe sold. See non-GAAP measures for further explanation.

ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2019, the Company had $1.9 million (March 31, 2018: $1.8 million) in cash and cash equivalents and $0.06 million (March 31, 2018: $3.4 million) in working capital.
- Total Proven + Probable ("2P") reserves at March 31, 2019 reflecting the Company's 100% interest in PMP 38156 (Cheal), 70% interest in PMP 60291 (Cheal East) and 100% interest in PMP 53803 (Sidewinder), are estimated at 3,988 Mboe (91% oil) compared with 4,079 Mboe (92% oil) at March 31, 2018. The approximate 2% reserves reduction is due to:
  - An approximate 9% decrease due to 391 Mboe produced over the 12-month period in fiscal year 2019.
  - An approximate 7% increase in annual 2P reserves revisions of 300 Mboe, which is primarily due to technical revisions:
    - The technical volumes increased as a result of improvements after an artificial lift optimization campaign in the wells Cheal-A11, Cheal-B8, Cheal-BH1 and Sidewinder-1. Perforations on Cheal-E1 are performing better than predicting, therefore improving expected recovery.
    - The technical volumes decreased due to perforations performing less than expected on Cheal-B5 and Cheal-B10. The infill location for the Cheal-BT well has also been removed from development.
- Average net daily production increased by 4% to 1,168 boe/d compared with 1,120 boe/d in fiscal year 2018. A breakdown of net production is as follows:
  - Average net daily oil production increased by 8% to 930 bbl/d compared with 861 bbl/d in fiscal year 2018. The increase is primarily a result of Cheal-A11 returning to production in September 2018 for part of the year following a planned workover to add perforations and installation of an artifical lift system. Perforations were also added to the Urenui formation in the Cheal-B7 and B10 wells, and the Cheal-B5 well that was previously offline. All three wells have been installed with rod pump systems to produce from both the Urenui and Mt. Messenger formations and came online throughout December 2018. Cheal-A12 has been online for the entire year after returning to production in March 2018 following a workover to repair a parted down hole pump and additonal production from Cheal-E6 being online for the entire year following a rod pump installation. This is partly offset by reduced production on Cheal-E1 due to pump efficiency issues and the well coming offline in December 2018 due to wax in tubing. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system and reduced production on Cheal-E8 due to a reduction in production after the well was initially drilled in 2018.
  - Average net daily gas production decreased by 8% to 1.4 MMcf/d compared with 1.6 MMcf/d in fiscal year 2018. Reduced gas production is predominately due to Cheal-E1 pump efficiency issues and the well coming offline in December 2018 due to wax in tubing. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system, reduced production on Cheal-E8 due to a reduction in production after the well was initially drilled in 2018 and reduced gas uplift on Sidewinder 5/6. This is partly offset by Cheal-B5 coming back online after a rod pump installation in December 2018, Cheal-A12 being online for the entire year after returning to production in March 2018 following a workover to repair a parted down hole pump and additonal production from Cheal-E6 being online for the entire year following a rod pump installation.
- Revenue increased 40% to $33.2 million compared with $23.7 million in fiscal year 2018. A breakdown of revenue is as follows:
  - Revenue from oil sales increased 40% to $31.9 million compared with $22.7 million due to a 21% increase in average oil prices and a 17% increase in oil sales volumes.
  - Revenue from gas sales increased 40% to $1.4 million compared with $1.0 million due to a 26% increase in gas sales volumes and a 11% increase in gas sales price.
- Operating netbacks increased by 33% for fiscal year 2019 to $40.90 per boe compared with $30.66 per boe for the fiscal year 2018. The increase is attributable to a 21% increase in average oil prices. This is partly offset by an 11% increase in production costs per boe, resulting from additional well workover costs during fiscal year 2019.
- Capital expenditures totaled $9.2 million compared to $24.2 million for the fiscal year 2018. The majority of the expenditure related to the following:
  - Taranaki development workovers and facility improvements ($7.9 million).
  - Taranaki exploration seismic acquisition and other exploration activities ($1.1 million).
  - Australian PL17 exploration activities ($0.1 million).
  - Other Assets ($0.1 million).
- The Company had impairment losses of $63.1 million for losses relating to the remeasurement of the disposal group to the lower of its carrying amount and its fair value less costs to sell have been included in net loss for the year ended March 31, 2019. The impairment losses have reflected a reduction in the carrying amount of property and equipment within the disposal group. During the fiscal year 2018, the Company had an asset impairment reversal of $15.2 million as a result of the Company's increased reserve position after production and improved current economic conditions with $12.0 million relating to PMP 38156 / PMP 60291 and $3.2 million to PMP 53803.
- The Company acquired the following permits:
  - 100% interest in the 1,851 acre onshore PMP 60454 (Supplejack) in October 2018, carved out of the existing exploration permit PEP 57065 (Waitoriki).
  - 100% interest in the 120,340 acre onshore ATO 2037 (Rocky Dam) effective January 2019.
  - 100% interest in the 138,132 acre onshore ATO 2038 (Kingston) effective January 2019.

FOURTH QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2019, the Company had $1.9 million (December 31, 2018: $2.8 million) in cash and cash equivalents and $0.06 million (December 31, 2018: $3.1 million) in working capital.
- Average net daily production increased by 1% for the quarter ended March 31, 2019, to 1,218 boe/d (80% oil) from 1,211 boe/d (80% oil) for the quarter ended December 31, 2018. A breakdown of net production is as follows:
  - Average net daily oil production increased by 1% to 972 bbl/d compared with 965 bbl/d for the quarter ended December 31, 2018. The increase is primarily a result of Cheal-E1 returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing. Added perforations to the Urenui formation in the Cheal-B7 and B10 wells, and the Cheal-B5 well that was previously offline have also increased production. All three wells have been installed with rod pump systems to produce from both the Urenui and Mt. Messenger formations and have been online for the entire quarter after returning to production in December 2018. This is partly offset by reduced production on Cheal-A11 after coming offline in December 2018. The well has since returned to production in late March 2019.
  - Average net daily gas production has remained unchanged at 1.5 MMcf/d. Additional gas production at Cheal A/E sites were offset by reduced gas production at Sidewinder site.
- Operating netbacks decreased by 32% for the quarter ended March 31, 2019, to $29.18 per boe compared with $43.14 per boe for the quarter ended December 31, 2018. The decrease is attributable to a 7% decrease in average oil prices and a 29% increase in production costs per boe, resulting from a 17% increase production costs due to workovers on Cheal-A7 and Cheal-A11 during the quarter. Operating netbacks increased by 10% for the quarter ended March 31, 2019, to $29.18 per boe compared with $26.42 per boe for the quarter ended March 31, 2018. The increase is attributable to a 21% decrease in production costs per boe, resulting from a 37% increase in total sales volumes due to utilisation of high oil inventory levels for the quarter. This is partly offset by a 14% decrease in average oil prices.
- Capital expenditures totaled $1.4 million for the quarter ended March 31, 2019, compared to $3.8 million for the quarter ended December 31, 2018. The majority of the expenditures in Q4 2019 relate to Cheal-E1 additional perforations, Cheal E-2 rod pump installation and shifting the pump depth of Cheal-E6.
- On March 5, 2019, Tamarind received approval from the New Zealand Overseas Investment Office in relation to the Transaction. More specifically, consent has been granted under New Zealand's Overseas Investment Act 2005 for the transfer of ownership of TAG's Taranaki Basin assets to Tamarind NZ Onshore Limited, a wholly-owned subsidiary of Tamarind. TAG is currently waiting for final approval from New Zealand Petroleum and Minerals ("NZP&M") for the sale and transfer of operatorship to Tamarind of its New Zealand operations.
- The Cheal A and E planned workover campaign was successfully completed in March. Perforations were completed on Cheal-E1 in February and was back online early March. Cheal-E6 came back online mid-March following rig operations to shift the pump depth. Cheal-E2 rod installation was completed in the last week of March and the rod pump units arrived early April and installed early May. Cheal-A7 and A11 workovers were completed in March, with Cheal-A11 returning to production early April. With all wells online, gross production rates reached over 1,700 boe/d.

RECENT DEVELOPMENTS

Operations

TAG is nearing completion of stage three of the PEP 57065 (Waitoriki) work commitments. AVO inversion volumes of the Waitoriki 2D seismic were received late September 2018, with encouraging AVO anomalies identified. Subsequently, an amendment was made to the stage three work program to defer the drill commitment and allow for further AVO inversion work over the 2018 merged 3D data set. The 3D inversion volumes over the 2018 KIN 3D seismic merge were received early March 2019. Interpretation is ongoing in preparation for the 51 month, Stage 4 commitment decision.

There has been a continued positive response from the Cheal E waterflood program, with both production and pressure increases having been observed. The Cheal E waterflood program was expanded to include the conversion of the Cheal-E4 well to a water injector in two Mt. Messenger formation intervals, which is anticipated to sweep oil towards the Cheal-E1 producing well from the southern area of the field resulting in additional oil recovery and extending the Cheal-E site's field life.

RESERVES UPDATE

NEW ZEALAND

		FY2019	FY2018	FY2017
Opening 2P reserves	Mboe	4,079	4,143	3,619
Production	Mboe	(391)	(351)	(422)
2P Reserves net additions	Mboe	300	287	946
Closing 2P reserves	Mboe	**3,988**	**4,079**	**4,143**
2P year end valuation (NPV 10% before tax)	mmCdn$	$98.2	$96.8	$82.1
2P year end valuation (NPV 10% after tax)	mmCdn$	$97.8	$96.1	$78.3
Future capital expenditure included in 2P valuation	mmCdn$	$25.0	$33.9	$49.7

The Company's year-end independent reserves assessment on its interests within the Cheal, Cheal East and Sidewinder mining permits, within the onshore Taranaki Basin, New Zealand, dated March 31, 2019, assigned a pre-tax net present value of $98.2 million (2018: $96.8 million), using a 10% discount rate to net 2P reserves.

Net 2P reserves estimates within the Taranaki Basin at March 31, 2019, were 3,988 Mboe compared to fiscal year 2018 2P reserves of 4,079 Mboe. Taking into account the 391 Mboe that the Company produced over the 12-month period and the 300 Mboe increase for technical revisions and economic factors, the Company's reserves decreased by approximately 2%.

TAG has a drilling inventory of over 20 infill locations within the defined producing Cheal pool boundaries at 160 acre spacing. This leaves TAG considerable low risk development potential within the existing pool and the potential for down spacing in the future. There is additional recoverable potential associated with water flood expansion projects at both the Cheal A and E sites; and TAG has also identified future exploration targets to potentially add new resources and expand the play area.

AUSTRALIA

ERCE provided TAG with its first NI 51-101 compliant independent reserves assessment on the Company's Bennett oil field held in the PL17 permit of the Surat Basin, Queensland and is effective as at March 31, 2019. Current production from Bennett is approximately 10 bbl/d of light, sweet crude that is sold at the wellhead.

ERCE has assigned a pre-tax net present value of $0.6 million, using a 10% discount rate to the Company's 100% working interest 2P reserves.

TAG has a number of potential lower risk options to increase production on the PL17 licence and will look at pursuing these later in the year.

The primary focus in Australia for TAG at present is the farm-out and/or sales process of its coal seam gas rights that lie across a portion of the PL17 acreage.

PL17 reserves summary

Permit	Field	TAG Oil WI	1P		2P		3P	
		%	Total *Mboe*	NPV_{10} *$ mm*	Total *Mboe*	NPV_{10} *$ mm*	Total *Mboe*	NPV_{10} *$ mm*
PL17	Bennett	100%	0	$0	83.2	$0.6	145	$2.1
Total			**0**	**$0**	**83.2**	**$0.6**	**145**	**$2.1**

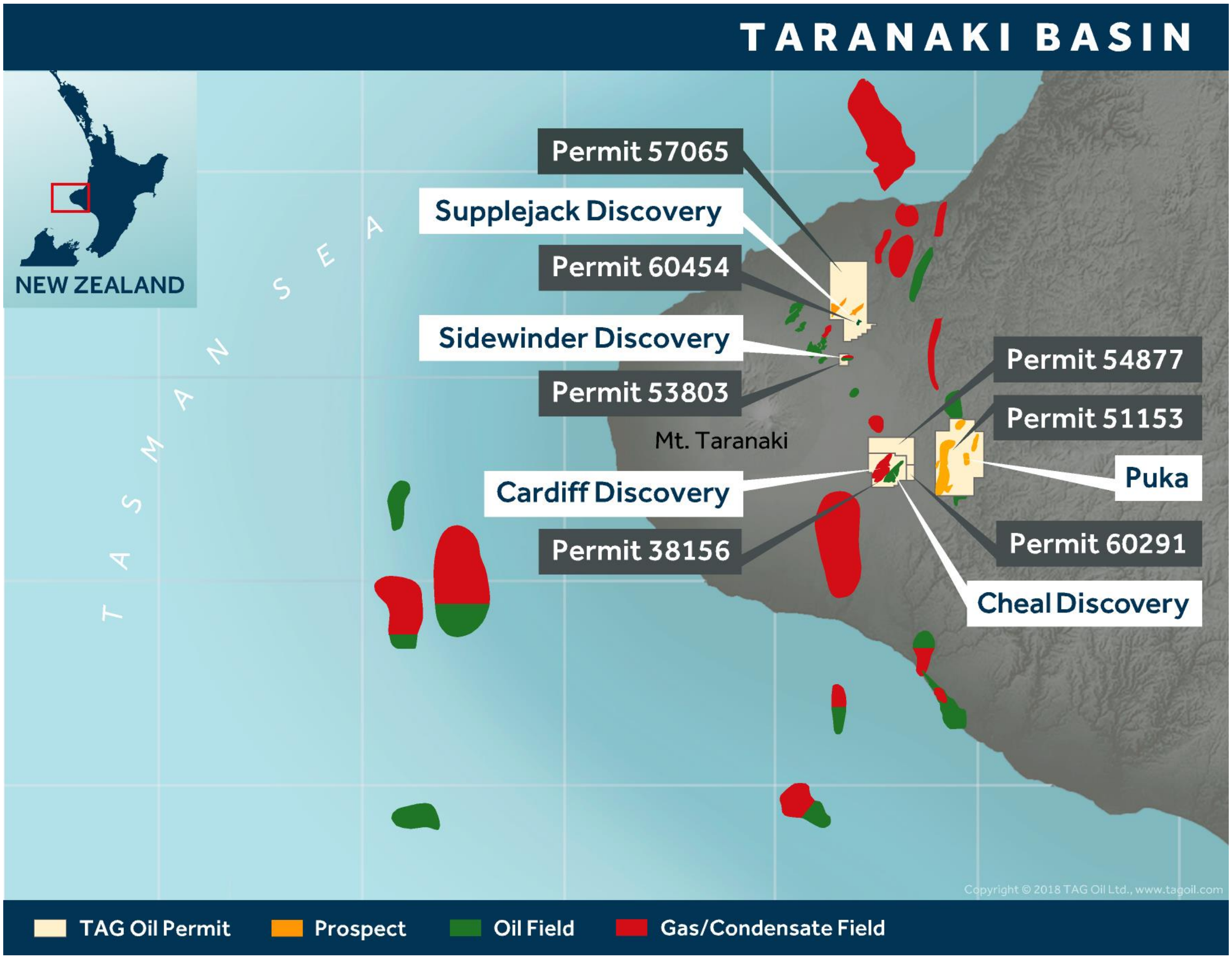
An evaluation of the contingent resources at the Bennett field was also provided by ERCE based on bypassed pay and infill drilling locations of the Bennett-1 and Bennett-4 wells. TAG will continue to evaluate further opportunities at PL-17 and will look to implement a modest capital program in 2019 in an attempt to monetize some of its resources.

	Contingent Resources (Mstb)		
	1C	*2C*	*3C*
Bennett-4 Bypassed Pay	12	41	76
Bennett-1 Area Infill	64	445	1,379
Bennett-4 Area Infill	23	249	1,039
Total	**100**	**735**	**2,494**

PROPERTY REVIEW

Taranaki Basin:

The Taranaki Basin is an oil, gas and condensate rich area located on the North Island of New Zealand. It remains under-explored compared to many comparable rift complex basins of its size and potential. Although the Taranaki Basin covers an area of about 100,000km^2, fewer than 500 exploration and development wells have been drilled since 1950. To date, proven Taranaki oil reserves of 534 million barrels, and proven gas reserves of 7.3 trillion cubic feet have been discovered.



The Taranaki Basin offers production potential from multiple formations ranging from the shallow Miocene to the deep Eocene prospects. Within the Taranaki Basin, TAG holds the following working interests:

- 100% interest in PMP 38156 (Cheal) mining permit.
- 100% interest in PMP 53803 (Sidewinder) mining permit.
- 100% interest in PEP 57065 (Waitoriki) exploration permit.
- 100% interest in PMP 60454 (Supplejack) mining permit.
- 70% interest in PEP 54877 (Cheal East) exploration permit.
- 70% interest in PMP 60291 (Cheal East) mining permit.
- 70% interest in PEP 51153 (Puka) exploration permit.

Shallow / Miocene Development and Exploration

At the time of this report, the Cheal and Sidewinder fields have 26 shallow wells on full, part-time or constrained production out of a total of 54 wells. The remaining wells are being used as water source or injection wells, currently shut-in pending work-overs and/or undergoing evaluation of economic re-completion methods and other behind pipe opportunities.

TAG's shallow Miocene net production averaged 1,218 boe/d (80% oil) in Q4 2019, compared to an average of 1,211 boe/d (80% oil) in Q3 2019 and 1,117 boe/d (75% oil) in Q4 2018. The increase is primarily a result of Cheal-E1 returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing. Added perforations to the Urenui formation in the Cheal-B7 and B10 wells, and the Cheal-B5 well that was previously offline have also increased production. All three wells have been installed with rod pump systems to produce from both the Urenui and Mt. Messenger formations and have been online for the entire quarter after returning to production in December 2018. This is partly offset by reduced production on Cheal-A11 after coming offline in December 2018. The well has since returned to production in late March 2019.

The Cheal A, B and C sites located at the Cheal mining permit (PMP 38156) produced an average of 822 boe/d (84% oil) in Q4 2019, compared to an average of 834 boe/d (85% oil) in Q3 2019 and 597 boe/d (86% oil) in Q4 2018. The decrease compared to Q3 2019 is due to Cheal-A11 being offline for most of the quarter after coming offline in December 2018. This is partly offfset by added perforations to the Urenui formation in the Cheal-B7 and B10 wells, and the Cheal-B5 well that was previously offline. All three wells have been installed with rod pump systems to produce from both the Urenui and Mt. Messenger formations and came online throughout December 2018.

The Cheal E site mining permit (PMP 60291) produced an average of 203 boe/d (76% oil) in Q4 2019, compared to an average of 180 boe/d (76% oil) in Q3 2019 and 209 boe/d (76% oil) in Q4 2018. The increase compared to Q3 2019 is due to Cheal-E1 returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing. This is partly offset by Cheal-E6 being temporarily offline during March 2019 for a planned workover to shift the pump depth.

The Cheal field continues to provide TAG with a long-life resource that generates cash flow. TAG plans to continue to develop the Cheal field, which has been substantially de-risked by the 37 wells drilled to date across the field. Permit-wide 3D seismic coverage indicates that there are additional drilling targets across the Cheal permit area and potential reserve upside from the pressure maintenance and waterflood program.

The Sidewinder mining permit (PMP 53803) produced an average of 186 boe/d (65% oil) in Q4 2019, compared to an average of 194 boe/d (60% oil) in Q3 2019 and 301 boe/d (51% oil) in Q4 2018. The decrease compared to Q3 2019 is due to natural decline.

The Puka permit (PEP 51153) covers an area of approximately 68km^2 (17,000 acres) and is located to the east of TAG's producing Cheal field. The Puka permit contains the Pukatea-1 well, which was drilled from the existing Puka production pad and completed in the Mt. Messenger formation. The permit also contains the shut-in Puka-2 oil well, which can be monetized as part of a wider field development program. With proven production and several exploration targets identified, this licence is a complimentary addition to the TAG portfolio where TAG can apply its technical and operations experience in the Taranaki Basin. TAG received approval for an appraisal extension in October 2018 and will continue to look at options to monetize the Puka field.

Deep / Eocene Exploration

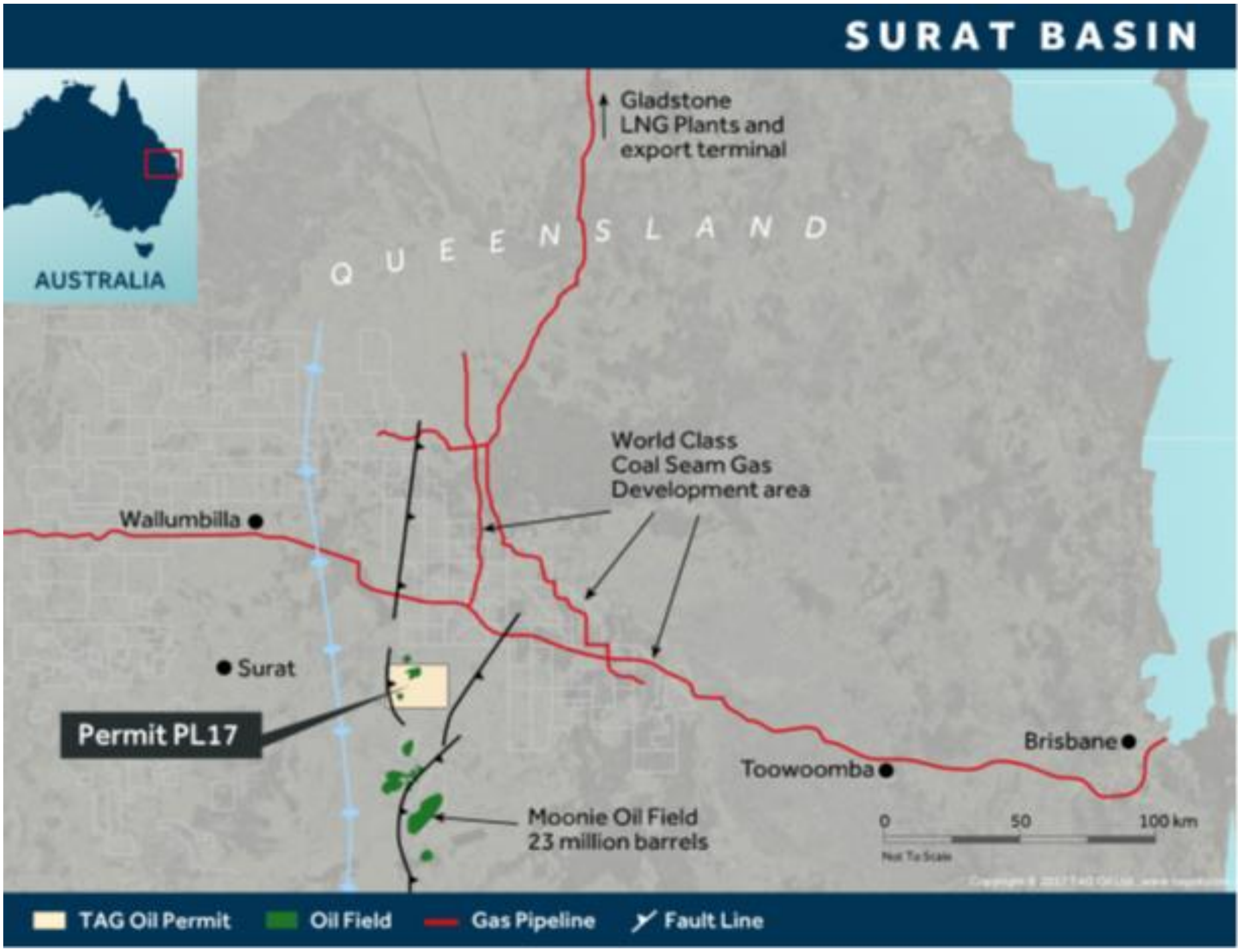
The Cheal mining permit contains the large Cardiff structure of the deeper Kapuni Group formations, which is on trend and geologically similar to the large legacy liquids rich gas condensate fields that have been discovered in the Taranaki Basin.

The Cardiff structure, identified on seismic, is an extensive linear fault bound high that is approximately 12km long and 3km wide. The Cardiff-3 well, drilled by TAG in FY2014, encountered 230m of gas and condensate bearing sands over three target zones within the Kapuni formation. The deepest zone, the "K3E" is one of the producing intervals of the Kapuni field. The Kapuni field is a legacy pool with estimated recoverable reserves of over 1.4 Tcf of gas. The upper two zones, which remain untested in the Cardiff-3 well, are the main producing intervals in the offsetting deep gas condensate fields including McKee, Mangahewa and Pohokura.

The Cardiff-3 well was drilled from the Cheal C site, which is connected by pipeline to TAG's nearby Cheal A site processing facilities and provides open access to the New Zealand gas sales network. Clean up and testing operations are continuing on the Cardiff-3 and Cardiff-2 wells. TAG is planning to continue with interventions to improve and stabilize flow rates out of these wells. Cardiff-2 has demonstrated the ability to unload fluids continuously and has been tied in to the Cheal production station via the Cheal pipeline, with ongoing water recovery at approximately 15 bbl/d and a presence of hydrocarbon and pressure response is also being observed.

Surat Basin:

TAG holds a 100% working interest in PL17, which is an oil and gas production permit and potentially high-value exploration acquisition that covers 104km^2 (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 Leichhardt fields, and the production permit area is largely unexplored despite the proven and significant oil and gas potential.



Hutton Sand and Precipice Conventional Play

The Bennett and Leichhardt fields are both undeveloped oil fields located within PL17. The fields have produced light oil intermittently from the Jurassic-aged Hutton Sand and Precipice formations (approximately 2,000m) since being discovered in the 1960s, with current production from the Bennett Field of approximately 10 bbl/d of oil from dated production equipment. 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.

TAG's initial interpretation of the first modern 3D seismic recently acquired over the core of the PL17 acreage has been completed with smaller closures identified. Further processing enhancement is being evaluated in order to see if the channel system that makes up the Bennett field can be identified.

Deep Permian Play

PL17 also has high-impact exploration potential in the deeper Permian formation; this is the primary unconventional tight gas and condensate play opportunity within PL17. The Permian formation lies approximately 1,000m lower than the conventional prospects in PL17 and is both the source rock as well as the trapping mechanism 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.

Surat Basin Prospects

TAG, through its subsidiary Cypress Petroleum Pty Ltd., has been granted authority to prospect for Rocky Dam ATP 2037 (487km^2) and Kingston ATP 2038 (559 km^2) in the Surat Basin, Queensland, Australia. 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 has commenced on airborne TEM survey and 2D/3D seismic reprocessing for both ATPs.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2019		2018	Twelve months ended March 31,	
Daily production volumes (1)	**Q4**	Q3	Q4	**2019**	2018
Oil (bbl/d)	**972**	965	834	**930**	861
Natural gas (boe/d)	**246**	246	283	**238**	259
Combined (boe/d)	**1,218**	1,211	1,117	**1,168**	1,120
% of oil production	**80%**	80%	75%	**80%**	77%
Daily sales volumes (1)					
Oil (bbl/d)	**956**	1,037	648	**953**	817
Natural gas (boe/d)	**117**	113	136	**129**	103
Combined (boe/d)	**1,073**	1,150	784	**1,082**	920
Natural gas (MMcf/d)	**702**	678	816	**776**	616
Product pricing					
Oil ($/bbl)	**82.72**	88.71	95.85	**91.69**	76.08
Natural gas ($Mcf)	**4.60**	5.51	4.86	**4.79**	4.31
Oil and natural gas revenues - gross *($000s)*	**7,407**	8,810	5,945	**33,237**	23,670
Oil and natural gas royalties (2)	**(756)**	(903)	(696)	**(3,141)**	(2,514)
Oil and natural gas revenues - net *($000s)*	**6,651**	7,907	5,249	**30,096**	21,156

(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.

Average net daily production increased by 1% for the quarter ended March 31, 2019, to 1,218 boe/d (80% oil) from 1,211 boe/d (80% oil) for the quarter ended December 31, 2018. The increase compared to Q3 2019 is primarily a result of Cheal-E1 returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing. Added perforations to the Urenui formation in the Cheal-B7 and B10 wells, and the Cheal-B5 well that was previously offline have also increased production. All three wells have been installed with rod pump systems to produce from both the Urenui and Mt. Messenger formations and have been online for the entire quarter after returning to production in December 2018. This is partly offset by reduced production on Cheal-A11 after coming offline in December 2018. The well has since returned to production in late March 2019.

Oil and natural gas gross revenue decreased by 16% for the quarter ended March 31, 2019, to $7.4 million from $8.8 million for the quarter ended December 31, 2018. The decrease is due to a 7% decrease in average oil prices and a 7% decrease in total sales volumes due to utilisation of high oil inventory levels in the prior quarter resulting in reduced volumes lifted in Q4 2019 compared to Q3 2019.

SUMMARY OF QUARTERLY INFORMATION

Canadian $000s, except per share or boe		**2019**				2018		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net production volumes (boe/d)	**1,218**	1,211	1,195	1,048	1,117	1,043	1,151	1,169
Total revenue	**7,407**	8,810	7,901	9,118	5,945	6,357	5,986	5,382
Operating costs	**(4,589)**	(4,246)	(3,595)	(4,654)	(4,080)	(2,911)	(3,222)	(3,162)
Foreign exchange	**22**	(134)	2	150	(50)	186	35	88
Share-based compensation	**(60)**	(70)	(80)	(243)	(61)	(53)	(102)	(139)
Other costs	**(3,380)**	(781)	(4,256)	(5,061)	(4,705)	(3,318)	(3,906)	(4,327)
Exploration (impairment) recovery	**(4)**	(9)	(19)	(18)	(465)	63	(4,879)	(14)
Write-down to assets held for sale	**3,590**	(7,661)	(59,061)	-	-	-	-	-
Property impairment reversal	**-**	-	-	-	15,184	-	-	-
Net income (loss) before tax	**2,986**	(4,091)	(59,108)	(708)	11,768	324	(6,088)	(2,172)
Income tax	**(586)**	(2)	(34)	1,261	-	-	-	-
Net income (loss) for the period	**2,400**	(4,093)	(59,142)	553	11,768	324	(6,088)	(2,172)
Earnings (loss) per share – basic	**0.03**	(0.05)	(0.69)	0.01	0.14	0.00	(0.07)	(0.03)
Earnings (loss) per share – diluted	**0.03**	(0.05)	(0.69)	0.01	0.14	0.00	(0.07)	(0.03)
Capital expenditures	**1,354**	3,817	3,019	1,059	6,283	1,344	6,808	9,811
Operating cash flow *(1)*	**69**	2,506	2,823	4,286	410	2,657	1,547	440

(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.*

Revenues generated from oil and gas sales decreased by 16% for the quarter ended March 31, 2019, to $7.4 million from $8.8 million for the quarter ended December 31, 2018. The 16% decrease is due to a 7% decrease in average oil prices and a 7% decrease in total sales volumes due to utilisation of high oil inventory levels in the prior quarter resulting in reduced volumes lifted in Q4 2019 compared to Q3 2019. Revenues generated from oil and gas sales increased by 25% for the quarter ended March 31, 2019, to $7.4 million from $5.9 million for the quarter ended March 31, 2018. The increase is attributable to a 37% increase in total sales volumes due to higher production and utilisation of high oil inventory levels. This is partly offset by a 14% decrease in average oil prices.

Operating costs increased by 8% for the quarter ended March 31, 2019, to $4.6 million from $4.2 million for the quarter ended December 31, 2018. Operating costs increased by 8% due to a 17% increase in production costs as a result of workovers on Cheal-A7 and Cheal-A11 during the quarter. Partly offset by a 16% decrease in royalty costs associated with decreased revenue. Operating costs increased by 12% for the quarter ended March 31, 2019, to $4.6 million from $4.1 million for the quarter ended March 31, 2018. The increase is attributable to a 8% increase production costs as a result of workovers on Cheal-A7 and Cheal-A11 during the quarter and increased transportation and storage costs associated with increased oil production volumes.

Other costs increased by $2.6 million for the quarter ended March 31, 2019 to $3.4 million from $0.8 million for the quarter ended December 31, 2018. The increase is mainly due to a loss on derivative financial instruments relating to hedged oil production compared to a gain in the prior quarter, an inventory write down and increased salary costs. Other costs decreased by 28% for the quarter ended March 31, 2019, to $3.4 million from $4.7 million for the quarter ended March 31, 2018. The 28% decrease compared to Q4 2018 is mainly due to no depreciation or depletion on New Zealand producing assets that are held for sale. This is partly offset by a loss on derivative financial instruments relating to hedged oil production and increased salary costs.

Net income before tax for the quarter ended March 31, 2019, was $3.0 million compared to a net loss of $4.1 million for the quarter ended December 31, 2018. Excluding impairment expense and write-offs, on a comparative basis, equates to net loss before tax of $0.2 million for the quarter ended March 31, 2019, compared to $3.6 million for the quarter ended December 31, 2018. The change is mainly a result of increase in other costs due to a loss on derivative financial instruments relating to hedged oil production, an inventory write down, increased salary costs and a 16% decrease in revenues generated for oil and gas sales due to a 7% decrease in average oil prices and a 7% decrease in total sales volumes. This is partly offset by decreased royalty costs associated with decreased revenue. Net income before tax for the quarter ended March 31, 2019 was $3.0 million compared to net income of $11.8 million for the quarter ended March 31, 2018. Excluding impairment expense and write-offs, on a comparative basis, equates to a net loss before tax of $0.2 million for the quarter ended March 31, 2019, compared to a net loss of $2.4 million for the quarter ended March 31, 2018. The change is mainly a result of a 28% decrease in other costs due to no depreciation or depletion on New Zealand producing assets that are held for sale and a 25% increase in oil and gas revenue attributable to a 37% increase in total sales volumes. Partly ofset by a 12% increase in operating costs increased due to an 8% increase production costs as a result of workovers on Cheal-A7 and Cheal-A11 during the quarter.

Net Production by Area (boe/d)

Area	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
PMP 38156 (Cheal)	**822**	834	597	**733**	602
PMP 60291 (Cheal East) *(1)*	**203**	180	209	**221**	224
PMP 53803 (Sidewinder)	**186**	194	301	**207**	284
PL 17 (Cypress)	**7**	3	10	**7**	10
Total boe/d	**1,218**	1,211	1,117	**1,168**	1,120

(1) On September 7, 2017 mining permit (PMP 60291) was granted over a portion of exploration permit (PEP 54877) that included acreage surrounding the production assets. The Company was granted an extension on November 27, 2017 to the remaining acreage which will continue as exploration permit (PEP 54877).

Average net daily production increased by 1% for the quarter ended March 31, 2019 to 1,218 boe/d (80% oil) from 1,211 boe/d (80% oil) for the quarter ended December 31, 2018. The increase compared to Q3 2019 is primarily a result of Cheal-E1 returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing. Added perforations to the Urenui formation in the Cheal-B7 and B10 wells, and the Cheal-B5 well that was previously offline have also increased production. All three wells have been installed with rod pump systems to produce from both the Urenui and Mt. Messenger formations and have been online for the entire quarter after returning to production in December 2018. This is partly offset by reduced production on Cheal-A11 after coming offline in December 2018. The well has since returned to production in late March 2019.

Average net daily production increased by 4% for the fiscal year ended March 31, 2019 to 1,168 boe/d (80% oil) from 1,120 boe/d (77% oil) for the fiscal year ended March 31, 2018. The 4% increase is primarily due Cheal-A11 returning to production in September 2018 for part of the year following a planned workover to add perforations and installation of an artifical lift system. Perforations were also added to the Urenui formation in the Cheal-B7 and B10 wells, and the Cheal-B5 well that was previously offline. All three wells have been installed with rod pump systems to produce from both the Urenui and Mt. Messenger formations and came online throughout December 2018. Cheal-A12 has been online for the entire year after returning to production in March 2018 following a workover to repair a parted down hole pump and additonal production from Cheal-E6 being online for the entire year following a rod pump installation. This is partly offset by reduced production on Cheal-E1 due to pump efficiency issues and the well coming offline in December 2018 due to wax in tubing. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system and reduced production on Cheal-E8 due to flush production when drilled in 2018.

Oil and Gas Operating Netback ($/boe)

	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Oil and natural gas revenue	**76.70**	83.27	84.25	**84.15**	70.50
Production costs	**(29.94)**	(23.27)	(38.05)	**(26.75)**	(24.21)
Royalties	**(7.83)**	(8.53)	(9.87)	**(7.95)**	(7.49)
Transportation and storage costs	**(9.75)**	(8.33)	(9.91)	**(8.55)**	(8.14)
Operating Netback per boe ($)	**29.18**	43.14	26.42	**40.90**	30.66

Operating netback is a non-GAAP measure. Operating netback is the operating margin the Company receives from each barrel of oil equivalent sold. 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.

Operating netback decreased by 32% for the quarter ended March 31, 2019 to $29.18 per boe compared with $43.14 per boe for the quarter ended December 31, 2018. The decrease is attributable to a 7% decrease in average oil prices and a 29% increase in production costs per boe, resulting from a 17% increase production costs due to workovers on Cheal-A7 and Cheal-A11 during the quarter.

Operating netback increased by 33% for fiscal year ended March 31, 2019, to $40.90 per boe compared with $30.66 per boe for fiscal year ended March 31, 2018. The increase is attributable to a 21% increase in average oil prices. This is partly offset by a 11% increase in production costs per boe, resulting from additional well workover costs during fiscal year 2019.

General and Administrative Expenses ("G&A")

	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Oil and Gas G&A expenses ($000s)	**2,298**	2,090	1,511	**7,763**	5,143
Per boe ($) (1)	**20.96**	18.76	15.03	**18.21**	12.58

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

G&A expenses have increased by 10% for the quarter ended March 31, 2019 to $2.3 million compared with $2.1 million for the quarter ended December 31, 2018. The 10% increase is due to the increase in salaries in Q4 2019 and reduced credit facility finance costs and professional fees relating to the Transaction.

G&A expenses increased by 51% for the fiscal year ended March 31, 2019 to $7.8 million compared with $5.1 million for the fiscal year ended March 31, 2018. G&A expenses have increased 51% due primarily to increased salaries, credit facility finance costs and additional professional fees relating to the Transaction in fiscal year 2019.

Share-based Compensation

	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Share-based compensation ($000s)	**60**	70	61	**453**	355
Per boe ($) (1)	**0.55**	0.63	0.61	**1.06**	0.87

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

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 March 31, 2019, the Company granted no options (December 31, 2018: nil) and no options were exercised (December 31, 2018: nil).

Share-based compensation decreased for the quarter ended March 31, 2019 to $0.06 million when compared to $0.07 million in the quarter ended December 31, 2018. The decrease in total share-based compensation costs is due to no new options being granted during Q4 2019 and declining amortization based on vesting terms on options previously granted.

Share-based compensation increased to $0.5 million for the fiscal year ended March 31, 2019, compared with $0.4 million for the fiscal year ended March 31, 2018. The increase in total share-based compensation costs is due to the 2.4 million options granted during Q1 2019.

Depletion, Depreciation and Accretion (DD&A)

	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Depletion, depreciation and accretion ($000s)	**344**	23	2,267	**5,868**	9,934
Per boe ($) (1)	**3.14**	0.21	22.55	**13.76**	24.30

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

DD&A expenses have increased for the quarter ended March 31, 2019 to $0.3 million compared with $0.02 million for the quarter ended December 31, 2018. This is due to increased accretion charges on asset restoration obligations.

DD&A expenses decreased by 41% for the fiscal year ended March 31, 2019 to $5.9 million compared with $9.9 million for the fiscal year ended March 31, 2018. The decrease is due to no depreciation or depletion on the New Zealand producing assets that have been held for sale since October 2019.

Foreign Exchange (Gain) Loss

	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Foreign exchange (gain) loss ($000s)	(22)	134	50	**(40)**	(260)

The foreign exchange gain for the quarter ended March 31, 2019 was a result of movement of the USD against the NZD; resulting in foreign exchange gain on the USD denominated oil receipts.

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

($000s)	**2019**		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Net income (loss) before tax	**2,986**	(4,091)	11,768	**(60,922)**	3,832
Income tax	**(586)**	(2)	-	**639**	-
Net income (loss) after tax	**2,400**	(4,093)	11,768	**(60,282)**	3,832
Earnings (loss) per share - basic	**0.03**	(0.05)	0.14	**(0.71)**	0.04
Earnings (loss) per share - diluted	**0.03**	(0.05)	0.14	**(0.71)**	0.04

Net income before tax for the quarter ended March 31, 2019, was $3.0 million compared to a net loss of $4.1 million for the quarter ended December 31, 2018. Excluding impairment expense and write-offs, on a comparative basis, equates to a net loss before tax of $0.2 million for the quarter ended March 31, 2019, compared to $3.6 million for the quarter ended December 31, 2018. The change is mainly a result of an increase in other costs due to a loss on derivative financial instruments relating to hedged oil production, increased salary costs and a 16% decrease in revenues generated for oil and gas sales due to a 7% decrease in average oil prices and a 7% decrease in total sales volumes. This is partly offset by decreased royalty costs associated with decreased revenue.

Net loss before tax for the fiscal year ended March 31, 2019 was $61.0 million compared to net income of $3.8 million for the fiscal year ended March 31, 2018. Excluding impairment expense and write-offs, on a comparative basis, equates to a net income before tax of $2.7 million for the fiscal year ended March 31, 2019, compared to net loss of $10.3 million for the fiscal year ended March 31, 2018. The change is mainly a result of a 40% increase in oil and gas revenue, resulting from a 17% increase in average oil prices and a 17% increase in oil sales volumes. There has also been a 21% decrease in other costs due to reduced inventory write down and no depreciation or depletion on New Zealand producing assets that are held for sale. This is partly offset by increased salaries, credit facility finance costs and additional professional fees relating to the Transaction in fiscal year 2019. There has also been a 28% increase in operating costs resulting from additional well workover costs during fiscal year 2019, increased royalties due to increased revenue and increased transportation and storage costs due to increased oil production volumes.

Cash Flow

($000s)	**2019**		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Operating cash flow ***(1)***	**69**	2,506	410	**9,684**	5,054
Cash provided by operating activities	**943**	3,205	2,354	**12,067**	8,742
Operating cash flow per share - basic	**0.01**	0.04	0.03	**0.14**	0.10
Operating cash flow per share - diluted	**0.01**	0.04	0.03	**0.14**	0.10

(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 $0.7 million for the quarter ended March 31, 2019 compared to $2.5 million for the quarter ended December 31, 2018. The decrease is attributable to a 16% decrease in oil and gas revenue, resulting from a 7% decrease in average oil prices and a 7% decrease in total sales volumes. Operating costs have also increased by 8% due to a 17% increase production costs as a result of workovers on Cheal-A7 and Cheal-A11 during the quarter. Partly offset by a 16% decrease in royalty costs associated with decreased revenue.

Operating cash flow increased to $9.7 million for the fiscal year ended March 31, 2019 compared to $5.1 million for the fiscal year ended March 31, 2018. The increase is attributable to a 40% increase in oil and gas revenue, resulting from a 21% increase in average oil prices and a 17% increase in oil sales volumes. This is partly offset by increased salaries, credit facility finance costs and additional professional fees relating to the Transaction in fiscal year 2019. There has also been a 28% increase in operating costs resulting from additional well workover costs during fiscal year 2019, increased royalties due to increased revenue and increased transportation and storage costs due to increased oil production volumes.

CAPITAL EXPENDITURES

Capital expenditures were $9.2 million for the fiscal year ended March 31, 2019 compared to $24.2 million for the fiscal year ended March 31, 2018.

The majority of the expenditures related to the following:

- Taranaki development workovers and facility improvements ($7.9 million).
- Taranaki exploration seismic acquisition and other exploration activities ($1.1 million).
- Australian PL17 exploration activities ($0.1 million).
- Other Assets ($0.1 million).

Taranaki Basin ($000s)	**2019**		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Mining permits	**1,158**	3,580	753	**7,930**	9,010
Exploration permits	**172**	189	5,311	**1,165**	11,690
Total Taranaki Basin	**1,330**	3,769	6,064	**9,095**	20,700

Australia Surat Basin ($000s)	**2019**		2018	Twelve months ended March 31,	
	Q4	**Q3**	Q4	**2019**	2018
Exploration permits	**25**	**22**	114	**103**	3,430
Total Surat Basin	**25**	**22**	114	**103**	3,430

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at March 31, 2019:

Contractual Obligations ($000s)	**Total**	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases ***(1)***	**620**	324	296	-
Other long-term obligations ***(2)***	**18,725**	7,323	11,402	-
Total contractual obligations ***(3)***	**19,345**	7,647	11,698	-

(1) The Company has commitments relating to office leases situated in New Plymouth, New Zealand and 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 required to be incurred to maintain its permits in good standing during the current permit term at the date of this report and those that are required prior to the Company committing to the next stage of the permit term where additional expenditures would be required. 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 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
PMP 38156	G&G studies and Cheal Petrophysics (VPPS)	606	-	-
PMP 53803	G&G studies	118	-	-
PMP 60291	G&G studies, Water flood monitoring and Cheal E Petrophysics (VPPS)	162	-	-
PMP 60454	Supplejack-1 Tie-in, production development plan and evaluation of Supplejack South-1A	4,186	-	-
PEP 54879	Regulatory maintenance	45	-	-
PEP 54877	Eocene petrophysical study, consenting, pad and one exploration well (2021)	102	3,025	-
PEP 51153	G&G studies, Seismic Acquisition and merge of existing Puka 3D and newly acquired 3D	259	2,384	-
PEP 57065	G&G studies and 2D AVO	143	**-**	**-**
PL17	Permit settlement	1,296	-	-
ATP 2037	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	175	2,854	**-**
ATP 2038	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	231	3,139	-
	TOTAL COMMITMENTS	**7,323**	**11,402**	**-**

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)	**For the year ended March 31, 2019**	For the year ended March 31, 2018	For the year ended March 31, 2017
Cash and cash equivalents	**1,892**	**1,778**	21,565
Working capital	**58**	**3,418**	25,907
Contractual obligations, next twelve months	**7,647**	**3,324**	28,851
Revenue	**33,237**	**23,670**	23,341
Cashflow from operating activities	**12,067**	**8,742**	1,463

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 has secured a revolving credit facility 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 additional 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 marketing expenses.

Operating Cash Flow ($000s)	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Cash provided by operating activities	**943**	3,205	2,354	**12,067**	8,742
Changes for non-cash working capital accounts	**(874)**	(699)	(1,944)	**(2,383)**	(3,688)
Operating cash flow	**69**	2,506	410	**9,684**	5,054

Operating Margin ($000s)	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Total revenue	**7,407**	8,810	5,945	**33,237**	23,670
Less production costs	**(2,891)**	(2,462)	(696)	**(10,565)**	(8,128)
Less royalties	**(755)**	(903)	(699)	**(3,141)**	(2,514)
Less transportation and storage	**(942)**	(881)	(2,685)	**(3,378)**	(2,734)
Operating margin	**2,819**	4,564	1,865	**16,153**	10,294

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)	2019		2018	Twelve months ended March 31,	
	Q4	Q3	Q4	**2019**	2018
Share-based compensation	**30**	41	29	**219**	237
Management wages and director fees	**212**	235	201	**838**	904
Total Management Compensation	**242**	276	230	**1,057**	1,141

SHARE CAPITAL

a. At March 31, 2019, there were 85,282,252 common shares, 4,585,000 stock options outstanding and no warrants outstanding.
b. At July 2, 2019, there were 85,282,252 common shares, 4,585,000 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

The Company extended secured revolving credit facility to July 2019 with the ability to extend it further if required.

On April 3, 2019, the Company announced that Ocean Reach Advisory has been appointed as financial advisor to TAG with a mandate to secure a farm-in partner for TAG's Australian assets.

On May 28, 2019, the Company announced that TAG and Tamarind have mutually agreed to extend the Transaction to July 15, 2019.

In accordance with the anticipated closing of the Transaction in July 2019, Mr. Henrik Lundin concluded his position as Chief Operating Officer of the Corporation, along with Mr. Max Murray as its New Zealand Country Manager, to purse other opportunities.

On June 26, 2019, an application to extend the duration of PEP 57065 (Waitoriki) to March 31, 2025 was approved by NZP&M.

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 1.52% and a risk-free discount rate ranging from 1.70% to 3.05%, 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 involve estimating the outcome of future events.

Future changes in accounting policies

Certain pronouncements were issued by the IASB or the International Financial Reporting Interpretations Committee, but not yet effective as at March 31, 2019. The Company intends to adopt these standards and interpretations when they become effective. Pronouncements that are not applicable to the Company have been excluded from those described below.

IFRS 9, Financial Instruments (effective on or after January 1, 2018)

The Company has adopted the new IFRS pronouncements as at April 1, 2018 in accordance with the transitional provisions of the standard and as described below. The adoption of these new pronouncements has not resulted in any adjustments to previously reported figures as outlined below.

The Company elected not to adopt the hedging requirements of IFRS 9, but may adopt them in a future period. IFRS 9 addresses the classification, measurement and recognition of financial assets and financial liabilities and supersedes the guidance relating to the classification and measurement of financial instruments in IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 requires financial assets to be classified into three measurement categories on initial recognition: those measured at fair value through profit and loss (FVTPL), those measured at fair value through other comprehensive income (FVOCI) and those measured at amortized cost. Investments in equity instruments are required to be measured by default at FVTPL. However, there is an irrevocable option for each equity instrument to present fair value changes in other comprehensive income. Measurement and classification of financial assets is dependent on the entity's business model for managing the financial assets and the contractual cash flow characteristics of the financial asset. For financial liabilities, the standard retains most of the IAS 39 requirements. The main change is that, in cases where the fair value option is taken for financial liabilities, the part of a fair value change relating to an entity's own credit risk is recorded in other comprehensive income rather than the income statements, unless this creates an accounting mismatch.

IFRS 9 introduces a new three-stage expected credit loss model for calculating impairment for financial assets. IFRS 9 no longer requires a triggering event to have occurred before credit losses are recognized. An entity is required to recognize expected credit losses when financial instruments are initially recognized and to update the amount of expected credit losses recognized at each reporting date to reflect changes in the credit risk of the financial instruments. In addition, IFRS 9 requires additional disclosure requirements about expected credit losses and credit risk.

The new hedge accounting model in IFRS 9 aligns hedge accounting with risk management activities undertaken by an entity.

Classification and Measurement Changes

The Company has assessed the classification and measurement of its financial assets and financial liabilities under IFRS 9 and has summarized the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 in the following table:

	Measurement Category	
	Original (IA S 39)	**New (IFRS 9)**
Financial Assets:		
Cash and cash equivalents	Fair value through profit and loss	Fair value through profit and loss
Amounts receivable	Amortized cost	Amortized cost
Restricted cash	Amortized cost	Amortized cost
Investments	Fair value through profit and loss	Fair value through profit and loss
Financial Liabilities:		
Accounts payable and accrued liabilities	Amortized cost	Amortized cost
Asset retirement obligations	Amortized cost	Amortized cost

New accounting standards issued but not yet effective

Certain pronouncements were issued by the IASB or the IFRS Interpretations Committee (“IFRIC”) but not yet effective as at February 28, 2019. The Company intends to adopt these standards and interpretations when they become effective. The Company does not expect these standards to have an impact on its financial statements. Pronouncements that are not applicable to the Company have been excluded from those described below.

The following standards or amendments are effective for annual periods beginning on or after January 1, 2019:

IFRS 16, Leases (effective on or after January 1, 2019)

Under IFRS 16, the Company is required to review all of its contracts to determine if they contain leases or lease-type arrangements. Virtually all leases are required to be accounted for as finance leases rather than operating leases, where the required lease payments are disclosed as a commitment in the notes to the consolidated financial statements. As a result, the Company will be required to recognize leased assets (“right-of-use” assets) and the related lease liability on the consolidated statement of financial position when applicable.

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

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 year ended March 31, 2019. 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 year ended March 31, 2019, 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 year ended March 31, 2019, 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 March 31, 2019. 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 March 31, 2019, 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; resource potential of unconventional plays; plans to grow baseline reserves, production, and cash flow in Taranaki; pursuing high-impact exploration on deep Kapuni Formation prospects in Taranaki; and other statements set out herein. Also included in this MD&A are forward-looking statements regarding TAG's expectations regarding the ability to complete, and the anticipated results of, the Transaction, the funds that will be available to TAG upon completion of the Transaction, the achievement of any of the event specific payments, the anticipated closing date of the Transaction, the benefits to TAG of the gross overriding royalty, and the anticipated timing of the Meeting. 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 TAG will be able to complete the Transaction on the timelines expected, or at all, 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 Transaciton include the risk that the Transaction does not close on the anticipated timeline, or at all, 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 March 31, 2019 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

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The Annual General Meeting was held on September 4, 2018 at 11:00 am in Vancouver, B.C, Canada.

SHARE LISTING
Toronto Stock Exchange (TSX)
Trading Symbol: TAO
OTCQX Trading Symbol: TAOIF

SHAREHOLDER RELATIONS
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SHARE CAPITAL
At July 2, 2019, there were 85,282,252 shares issued and outstanding.
Fully diluted: 89,867,252 shares.

WEBSITE
www.tagoil.com

SUBSIDIARIES

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