MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated February 14, 2019, for the nine months ended December 31, 2018 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, 2018.

The condensed consolidated interim financial statements for the nine months ended December 31, 2018, 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 December 31, 2018, 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 a land holding consisting of ten onshore oil and gas permits amounting to 323,444 net acres of land.

TAG has announced the signing of a definitive share and asset purchase agreement with Malaysian-based Tamarind Resources Pte. Ltd. ("Tamarind") and certain of its subsidiaries (the "SPA").

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.

THIRD QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At December 31, 2018, the Company had $2.8 million (September 30, 2018: $3.2 million) in cash and cash equivalents and $3.1 million (September 30, 2018: $2.4 million) in working capital.
- Average net daily production increased by 1% for the quarter ended December 31, 2018, to 1,211 boe/d (80% oil) from 1,195 boe/d (80% oil) for the quarter ended September 30, 2018. A breakdown of net production is as follows:
  - Average net daily oil production increased by 2% to 965 bbl/d compared with 950 bbl/d for the quarter ended September 30, 2018. The increase is primarily a result of Cheal-A11 being online for the entire quarter after returning to production in September 2018 following a planned workover to add perforations and installation of an artifical lift system. Perforations have also been 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. 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 and inability to rotate the rod string. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system.
  - Average net daily gas production remained unchanged at 1.5 MMcf/d compared with the quarter ended September 30, 2018. Additional gas production at Cheal A site was offset by reduced gas production at Cheal E site.
- Operating netbacks decreased by 8% for the quarter ended December 31, 2018, to $43.14 per boe compared with $47.08 per boe for the quarter ended September 30, 2018. The decrease is attributable to a 9% decrease in average oil prices and a 43% increase in royalty costs per boe. This is partly offset by a 6% decrease in production costs per boe, resulting from a 16% increase in total sales volumes due to utilisation of high oil inventory levels for the quarter. Royalty costs per boe returned to a more normal level this quarter compared to an unusally low level in the prior quarter due to an adjustment to Q4 2018 royalties paid in Q2 2019. Operating netbacks remained consistent for the quarter ended December 31, 2018, at $43.14 per boe compared with $43.21 per boe for the quarter ended December 31, 2017.
- Capital expenditures totalled $3.8 million for the quarter ended December 31, 2018, compared to $3.0 million for the quarter ended September 30, 2018. The majority of the expenditures in Q3 2019 relate to the Cheal-A7 well conversion to a water injector and added perforations with rod pump installation at the Cheal-B7, B10 and B5 wells.

- The second phase of the planned workover program at Cheal commenced in October 2018. The Cheal-A7 well was converted to a water injector in the Cheal A pool, to target the Urenui and Mt. Messenger intervals. This was completed in November 2018, however plugs became stuck in the hole on commisioning and a planned workover in February 2019 is required to recover these. Perforations were sucessfully 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. Full production rates have been monitored and optimized throughout January 2019.
- On October 11, 2018, an application to extend the duration of PEP 51153 (Puka) to September 22, 2022 was approved by New Zealand Petroleum and Minerals ("NZP&M").
- On October 16, 2018, a mining permit referred to as PMP 60454 (Supplejack) was granted by NZP&M (covering 1,851 acres) and has been carved out of the existing exploration permit (PEP 57065).
- On October 17, 2018, TAG, through its subsidiary CX Oil Limited ("CX"), and MEO New Zealand Pty Limited ("MEO") entered into a conditional agreement where MEO will transfer its 30% interest in PEP 51153 (Puka) to CX. Accordingly, CX has agreed to use its commercially reasonably efforts to satisfy the remaining conditions and acquire MEO's 30% interest.
- On November 9, 2018, TAG, and certain of its subsidiaries, and Tamarind, and certain of its subsidiaries, entered into the SPA. The Transaction is at arm's length and will include TAG's 100% working interests in: PMP 38156 (Cheal and Cardiff), PMP 53803 (Sidewinder), PMP 60454 (Supplejack), PEP 51153 (Puka), PEP 57065 (Waitoriki) and TAG's 70% interest in PMP 60291 (Cheal East) and PEP 54877 (Cheal East) (collectively, the "NZ Assets"). Formal closing of the Transaction is expected in Q4 2019, depending on timing of regulatory approvals.
- On January 3, 2019, TAG's shareholders approved the Transaction. A total of 46.74% of TAG's 85,282,252 outstanding shares were voted by TAG's shareholders, of which 38,853,531 shares (97.47%) were voted "for" the Transaction.

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. Results from this 3D AVO inversion are expected late February 2019.

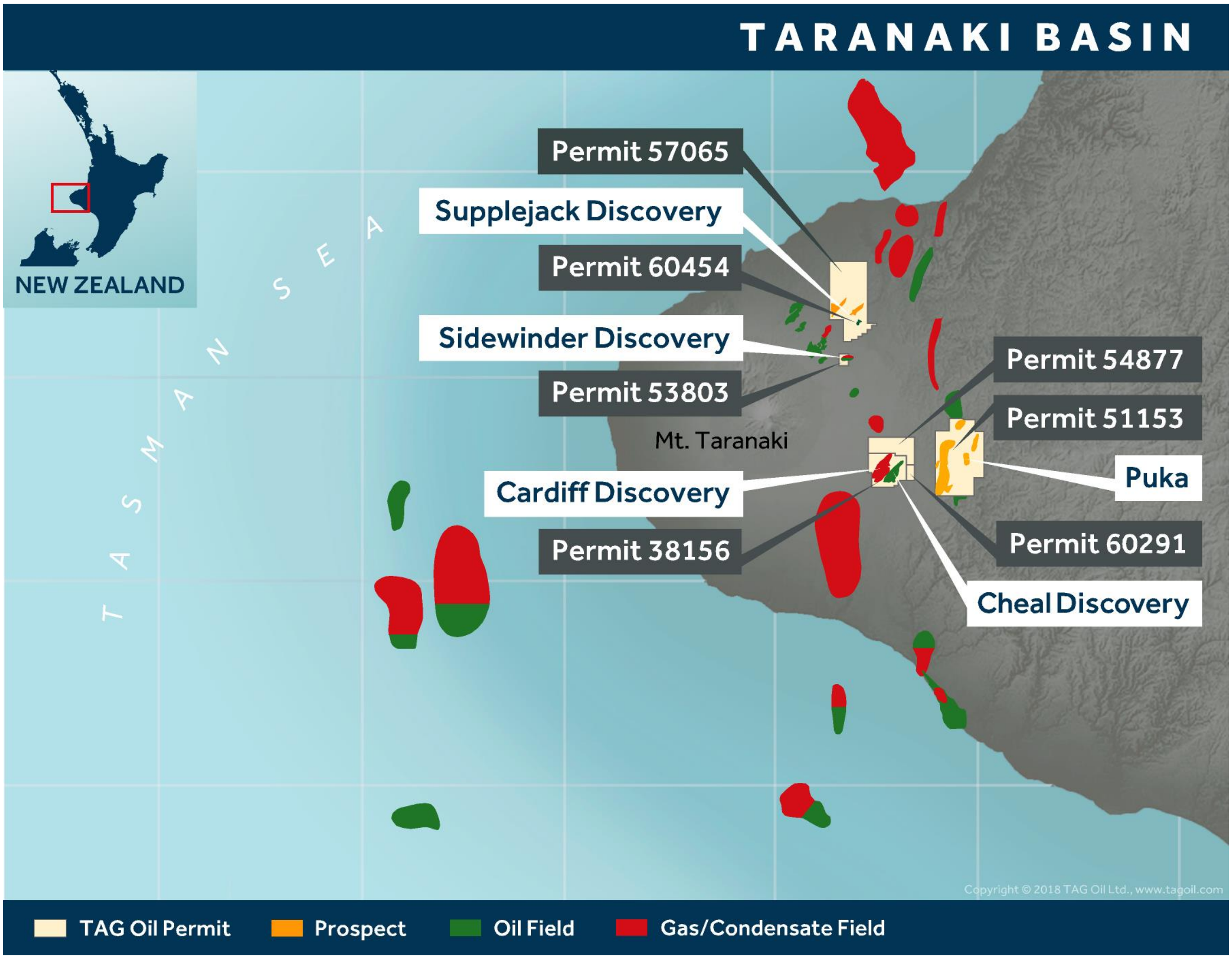
A planned workover program is scheduled for February and March 2019 at Cheal A and E sites. A workover on Cheal-A7 water injector will be completed to recover plugs and remedials on Cheal-A11 will also be completed since coming offline in December 2018. Cheal-E1 is currently offline due to wax in tubing, Cheal-E2 is also currently offline due to a downhole packer failure and Cheal-E6 tubing will also be pulled to improve the pumping efficiency of the well and allowing for additional production.

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.

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 24 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 1,211 boe/d (80% oil) in Q3 2019, compared to an average of 1,195 boe/d (80% oil) in Q2 2019 and 1,043 boe/d (79% oil) in Q3 2018. The increase is primarily a result of Cheal-A11 being online for the entire quarter after returning to production in September 2018 following a planned workover to add perforations and installation of an artifical lift system. Perforations have also been 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. 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 and inability to rotate the rod string. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system.

The Cheal A, B and C sites located at the Cheal mining permit (PMP 38156) produced an average of 834 boe/d (85% oil) in Q3 2019, compared to an average of 674 boe/d (86% oil) in Q2 2019 and 603 boe/d (84% oil) in Q3 2018. The increase compared to Q2 2019 is due to Cheal-A11 being online for the entire quarter after returning to production in September 2018 following a planned workover to add perforations and installation of an artifical lift system. Perforations have also been 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.

The Cheal E site mining permit (PMP 60291) produced an average of 180 boe/d (76% oil) in Q3 2019, compared to an average of 302 boe/d (80% oil) in Q2 2019 and 185 boe/d (73% oil) in Q3 2018. The decrease compared to Q2 2019 is due to reduced production on Cheal-E1 due to pump efficiency issues and the well coming offline in December 2018 due to wax in tubing and inability to rotate the rod string. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system.

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 194 boe/d (60% oil) in Q3 2019, compared to an average of 210 boe/d (57% oil) in Q2 2019 and 243 boe/d (68% oil) in Q3 2018. The decrease compared to Q2 2019 is due to a plug in the hole on Sidewinder-2 for part of the quarter and reduced gas uplift on Sidewinder-5/6.

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

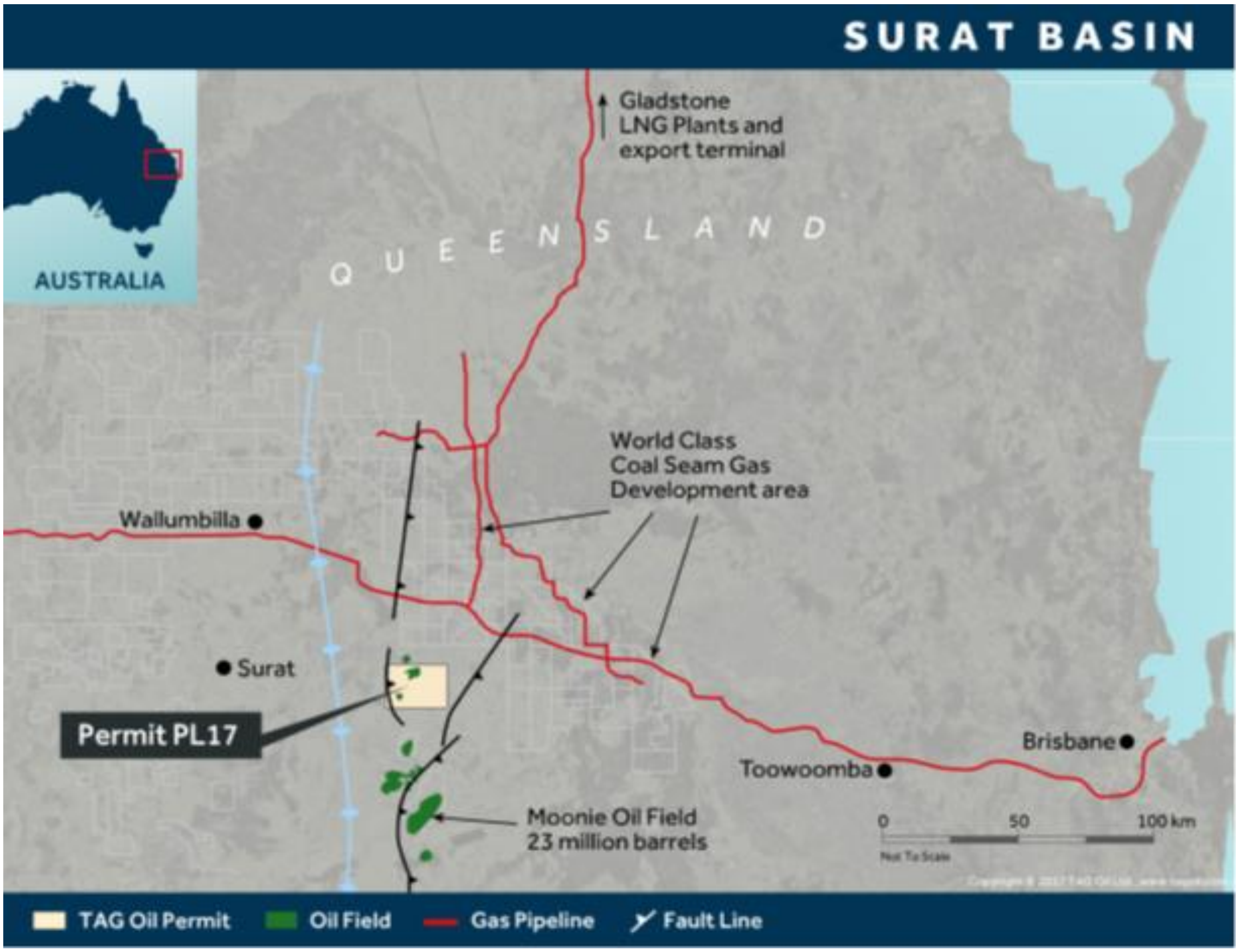
The Cheal mining permit contains the large Cardiff structure of the deeper Kapuni Group formations, which is on trend and geologically similar to the large legacy liquids rich gas condensate fields that have been discovered in the Taranaki Basin.

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 7 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 of 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 (559km^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.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2019		2018	Nine months ended December 31,	
Daily production volumes (1)	**Q3**	Q2	Q3	**2018**	2017
Oil (bbl/d)	**965**	950	819	**916**	870
Natural gas (boe/d)	**246**	245	224	**236**	251
Combined (boe/d)	**1,211**	1,195	1,043	**1,152**	1,121
% of oil production	**80%**	80%	79%	**80%**	78%
Daily sales volumes (1)					
Oil (bbl/d)	**1,037**	836	798	**951**	873
Natural gas (boe/d)	**113**	158	69	**133**	91
Combined (boe/d)	**1,150**	994	867	**1,084**	964
Natural gas (MMcf/d)	**678**	948	414	**800**	547
Product pricing					
Oil ($/bbl)	**88.71**	97.61	84.70	**94.65**	72.91
Natural gas ($Mcf)	**5.51**	4.49	3.60	**4.83**	4.03
Oil and natural gas revenues - gross *($000s)*	**8,810**	7,901	6,357	**25,830**	17,725
Oil and natural gas royalties (2)	**(903)**	(545)	(648)	**(2,385)**	(1,818)
Oil and natural gas revenues - net *($000s)*	**7,907**	7,356	5,709	**23,445**	15,907

(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 December 31, 2018, to 1,211 boe/d (80% oil) from 1,195 boe/d (80% oil) for the quarter ended September 30, 2018. The increase compared to Q2 2019 is primarily a result of Cheal-A11 being online for the entire quarter after returning to production in September 2018 following a planned workover to add perforations and installation of an artifical lift system. Perforations have also been 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. 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 and inability to rotate the rod string. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system.

Oil and natural gas gross revenue increased by 12% for the quarter ended December 31, 2018, to $8.8 million from $7.9 million for the quarter ended September 30, 2018. The increase is due to a 16% increase in total sales volumes due to utilisation of high oil inventory levels in the current quarter resulting in additional volumes lifted in Q3 2019 compared to Q2 2019. This is partly offset by a 9% decrease in average oil prices.

SUMMARY OF QUARTERLY INFORMATION

	2019			2018				2017
Canadian $000s, except per share or boe	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Net production volumes (boe/d)	**1,211**	1,195	1,048	1,117	1,043	1,151	1,169	1,218
Total revenue	**8,810**	7,901	9,118	5,945	6,357	5,986	5,382	6,256
Operating costs	**(4,246)**	(3,595)	(4,654)	(4,080)	(2,911)	(3,222)	(3,162)	(3,619)
Foreign exchange	**(134)**	2	150	(50)	186	35	88	(175)
Share-based compensation	**(70)**	(80)	(243)	(61)	(53)	(102)	(139)	(217)
Other costs	**(781)**	(4,256)	(5,061)	(4,705)	(3,318)	(3,906)	(4,327)	(3,845)
Exploration (impairment) recovery	**(9)**	(19)	(18)	(465)	63	(4,879)	(14)	(93)
Write-down to assets held for sale	**(7,661)**	(59,061)	-	-	-	-	-	-
Property impairment reversal	**-**	-	-	15,184	-	-	-	35,040
Net (loss) income before tax	**(4,091)**	(59,108)	(708)	11,768	324	(6,088)	(2,172)	33,347
Income tax	**(2)**	(34)	1,261	-	-	-	-	-
Net (loss) income for the period	**(4,093)**	(59,142)	553	11,768	324	(6,088)	(2,172)	33,347
(Loss) earnings per share – basic	**(0.05)**	(0.69)	0.01	0.14	0.00	(0.07)	(0.03)	0.53
(Loss) earnings per share – diluted	**(0.05)**	(0.69)	0.01	0.14	0.00	(0.07)	(0.03)	0.52
Capital expenditures	**3,817**	3,019	1,059	6,283	1,344	6,808	9,811	8,125
Operating cash flow *(1)*	**2,506**	2,823	4,286	410	2,657	1,547	440	844

(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 increased by 12% for the quarter ended December 31, 2018, to $8.8 million from $7.9 million for the quarter ended September 30, 2018. The 12% increase is due to a 16% increase in total sales volumes due to utilisation of high oil inventory levels in the current quarter resulting in additional volumes lifted in Q3 2019 compared to Q2 2019. This is partly offset by a 9% decrease in average oil prices. Revenues generated from oil and gas sales increased by 39% for the quarter ended December 31, 2018, to $8.8 million from $6.4 million for the quarter ended December 31, 2017. The increase is attributable to a 5% increase in average oil prices and a 33% increase in total sales volumes due to higher production and utilisation of high oil inventory levels.

Operating costs increased by 18% for the quarter ended December 31, 2018, to $4.2 million from $3.6 million for the quarter ended September 30, 2018. Operating costs increased by 18% due to oil inventory revaluation costs for oil volumes utilised as sales and increased royalty costs associated with increased revenue. Operating costs increased by 46% for the quarter ended December 31, 2018, to $4.2 million from $2.9 million for the quarter ended December 31, 2017. The increase is attributable to oil inventory revaluation costs for oil volumes utilised as sales, increased royalty costs associated with increased revenue and further Cheal-B6 wellhead repair costs in November 2018.

Other costs decreased by 82% for the quarter ended December 31, 2018 to $0.8 million from $4.3 million for the quarter ended September 30, 2018. The 82% decrease is mainly due to a gain on derivative financial instruments relating to hedged oil production and no depreciation or depletion on New Zealand producing assets that are held for sale. This is partly offset by additional professional fees relating to the Transaction. Other costs decreased by 76% for the quarter ended December 31, 2018, to $0.8 million from $3.3 million for the quarter ended December 31, 2017. The 76% decrease compared to Q3 2018 is mainly due to a gain on derivative financial instruments relating to hedged oil production and no depreciation or depletion on New Zealand producing assets that are held for sale. This is partly offset by additional professional fees relating to the Transaction.

Net loss before tax for the quarter ended December 31, 2018, was $4.1 million compared to a net loss of $59.1 million for the quarter ended September 30, 2018. Excluding impairment expense or write-offs, on a comparative basis, equates to a net gain before tax of $3.6 million for the quarter ended December 31, 2018, compared to a net gain of $0.03 million for the quarter ended September 30, 2018. The increase to a net gain, excluding impairments and write-offs, is mainly a result of a 82% decrease in other costs due to a gain on derivative financial instruments relating to hedged oil production, no depreciation or depletion on New Zealand producing assets that are held for sale and a 12% increase in revenues generated for oil and gas sales due to an increase in total sales volumes. This is partly offset by additional professional fees relating to the Transaction, an increase in operating costs due to inventory revaluation costs and increased royalty costs associated with increased revenue. Net loss before tax for the quarter ended December 31, 2018 was $4.1 million compared to net income of $0.3 million for the quarter ended December 31, 2017. Excluding impairment expense, on a comparative basis, equates to a net income before tax of $3.6 million for the quarter ended December 31, 2018, compared to net income of $0.3 million for the quarter ended December 31, 2017. The increased net gain, excluding impairments and write-offs, is mainly a result of a 76% decrease in other costs due to a gain on derivative financial instruments relating to hedged oil production, no depreciation or depletion on New Zealand producing assets that are held for sale and a 39% increase in revenues generated for oil and gas sales due to an increase in total sales volumes and average oil price.

Net Production by Area (boe/d)

Area	2019		2018	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
PMP 38156 (Cheal)	**834**	674	603	**704**	604
PMP 60291 (Cheal East) *(1)*	**180**	302	185	**227**	229
PMP 53803 (Sidewinder)	**194**	210	243	**214**	279
PL 17 (Cypress)	**3**	9	12	**7**	9
Total boe/d	**1,211**	1,195	1,043	**1,152**	1,121

(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 December 31, 2018 to 1,211 boe/d (80% oil) from 1,195 boe/d (80% oil) for the quarter ended September 30, 2018. The increase compared to Q2 2019 is primarily a result of Cheal-A11 being online for the entire quarter after returning to production in September 2018 following a planned workover to add perforations and installation of an artifical lift system. Perforations have also been 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. 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 and inability to rotate the rod string. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system.

Average net daily production increased by 16% for the quarter ended December 31, 2018 to 1,211 boe/d (80% oil) from 1,043 boe/d (79% oil) for the quarter ended December 31, 2017. The 16% increase is primarily due to Cheal-A11 returning to production in September 2018 following a planned workover to add perforations and installation of an artifical lift system. Cheal-A10 returned to production in August 2018 after wellhead seal failures were repaired and Cheal-A12 was offline during Q3 2019 due to a parted down hole pump. This is partly offset by Cheal-A7 being offline for injection conversion, reduced production on Cheal-E1 due to pump efficiency issues and the well coming offline in December 2018 due to wax in tubing and inability to rotate the rod string. Cheal-E2 also came offline in October 2018 as a result of a downhole packer failure following installation of an artificial lift system.

Oil and Gas Operating Netback ($/boe)

	2019		2018	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Oil and natural gas revenue	**83.27**	86.38	79.70	**86.58**	66.84
Production costs	**(23.27)**	(24.69)	(20.65)	**(25.72)**	(20.52)
Royalties	**(8.53)**	(5.96)	(8.12)	**(7.99)**	(6.85)
Transportation and storage costs	**(8.33)**	(8.65)	(7.72)	**(8.17)**	(7.67)
Operating Netback per boe ($)	**43.14**	47.08	43.21	**44.70**	31.80

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 8% for the quarter ended December 31, 2018 to $43.14 per boe compared with $47.08 per boe for the quarter ended September 30, 2018. The decrease is attributable to a 9% decrease in average oil prices and a 43% increase in royalty costs per boe. This is partly offset by a 6% decrease in production costs per boe, resulting from a 16% increase in total sales volumes due to utilisation of high oil inventory levels for the quarter. Royalty costs per boe returned to a more normal level this quarter compared to an unusally low level in the prior quarter due to an adjustment to Q4 2018 royalties paid in Q2 2019.

Operating netbacks remained consistent for the quarter ended December 31, 2018, at $43.14 per boe compared with $43.21 per boe for the quarter ended December 31, 2017. Increased revenue for the quarter ended December 31, 2018 is a result of a 5% increase in average oil prices. This is offset by a 13% increase in production costs per boe due to further Cheal-B6 wellhead repairs in Q3 2019.

General and Administrative Expenses ("G&A")

	2019		2018	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Oil and Gas G&A expenses ($000s)	**2,090**	1,571	1,068	**5,465**	3,632
Per boe ($) (1)	**18.76**	14.29	11.13	**17.25**	11.78

(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 33% for the quarter ended December 31, 2018 to $2.1 million compared with $1.6 million for the quarter ended September 30, 2018. The 33% increase is due to additional credit facility finance costs and additional professional fees relating to the Transaction. This is partly offset by reduced salaries costs in Q3 2019.

G&A expenses increased by 96% for the quarter ended December 31, 2018 to $2.1 million compared with $1.1 million for the quarter ended December 31, 2017. G&A expenses have increased 96% due primarily to increased salaries, additional credit facility finance costs and additional professional fees relating to the Transaction in Q3 2019.

Share-based Compensation

	2019		2018	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Share-based compensation ($000s)	**70**	80	53	**392**	294
Per boe ($) (1)	**0.63**	0.72	0.55	**1.24**	0.95

(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 December 31, 2018, the Company granted no options (September 30, 2018: nil) and no options were exercised (September 30, 2018: nil).

Share-based compensation decreased for the quarter ended December 31, 2018 to $0.07 million when compared to $0.08 million in the quarter ended September 30, 2018. The decrease in total share-based compensation costs is due to no new options being granted during Q3 2019 and declining amortization based on vesting terms on options previously granted.

Share-based compensation increased to $0.07 million in the quarter ended December 31, 2018, compared with $0.05 million for the quarter ended December 31, 2017. 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	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Depletion, depreciation and accretion ($000s)	**23**	2,780	2,343	**5,524**	7,666
Per boe ($) (1)	**0.21**	25.28	24.42	**17.44**	24.87

(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 decreased by 99% for the quarter ended December 31, 2018 to $0.02 million compared with $2.78 million for the quarter ended September 30, 2018. This is due to no depreciation or depletion on the New Zealand producing assets that are held for sale.

DD&A expenses decreased by 99% for the quarter ended December 31, 2018 to $0.02 million compared with $2.34 million for the quarter ended December 31, 2017. The decrease in Q3 2019 is due to no depreciation or depletion on the New Zealand producing assets that are held for sale.

Foreign Exchange Loss (Gain)

	2019		2018	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Foreign exchange loss (gain) ($000s)	134	(2)	(186)	**(18)**	(310)

The foreign exchange loss for the quarter ended December 31, 2018 was a result of movement of the USD against the NZD; resulting in foreign exchange gain on the USD denominated oil receipts.

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

	2019		2018	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2018**	2017
Net (loss) income before tax	**(4,091)**	(59,108)	324	**(63,908)**	(7,935)
Income tax	**(2)**	(34)	-	**1,226**	-
Net (loss) income after tax	**(4,093)**	(59,142)	324	**(62,682)**	(7,935)
(Loss) earnings per share, basic ($)	**(0.05)**	(0.69)	0.00	**(0.73)**	(0.09)
(Loss) earnings per share, diluted ($)	**(0.05)**	(0.69)	0.00	**(0.73)**	(0.09)

Net loss before tax for the quarter ended December 31, 2018 was $4.1 million compared to a net loss of $59.1 million for the quarter ended September 30, 2018. Excluding impairment expense or write-offs, on a comparative basis, equates to a net gain before tax of $3.6 million for the quarter ended December 31, 2018, compared to a net loss of $0.03 million for the quarter ended September 30, 2018. The increase to a net gain, excluding impairments and write-offs, is mainly a result of a 82% decrease in other costs due to a gain on derivative financial instruments relating to hedged oil production, no depreciation or depletion on New Zealand producing assets that are held for sale and a 12% increase in revenues generated for oil and gas sales due to an increase in total sales volumes. This is partly offset by additional professional fees relating to the Transaction, an increase in operating costs due to inventory revaluation costs and increased royalty costs associated with increased revenue.

Net loss before tax for the quarter ended December 31, 2018 was $4.1 million compared to net income of $0.3 million for the quarter ended December 31, 2017. Excluding impairment expense, on a comparative basis, equates to a net income before tax of $3.6 million for the quarter ended December 31, 2018, compared to net income of $0.3 million for the quarter ended December 31, 2017. The increased net gain, excluding impairments and write-offs, is mainly a result of a 76% decrease in other costs due to a gain on derivative financial instruments relating to hedged oil production, no depreciation or depletion on New Zealand producing assets that are held for sale and a 39% increase in revenues generated for oil and gas sales due to an increase in total sales volumes and average oil price.

Cash Flow

	2019		2018	Nine months ended December 31,	
($000s)	**Q2**	Q2	Q3	**2018**	2017
Operating cash flow ***(1)***	**2,506**	2,823	2,657	**9,616**	4,644
Cash provided by operating activities	**3,205**	2,771	3,866	**11,123**	6,388
Operating cash flow per share, basic ($)	**0.04**	0.03	0.05	**0.13**	0.07
Operating cash flow per share, diluted ($)	**0.04**	0.03	0.05	**0.13**	0.07

(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 $2.5 million for the quarter ended December 31, 2018 compared to $2.8 million for the quarter ended September 30, 2018. The decrease is attributable to an 18% increase in operating costs due to oil inventory revaluation costs for oil volumes utilised as sales and increased royalty costs associated with increased revenue. There has also been additional credit facility finance costs and additional professional fees relating to the Transaction. This is offset 12% increase in revenues generated for oil and gas sales due to an increase in total sales volumes.

Operating cash flow decreased to $2.5 million for the quarter ended December 31, 2018 compared to $2.7 million for the quarter ended December 31, 2017. The decrease is attributable to a 46% increase in operating costs due to oil inventory revaluation costs for oil volumes utilised as sales, increased royalty costs associated with increased revenue and further Cheal-B6 wellhead repair costs in November 2018. There have also been additional credit facility finance costs and additional professional fees relating to the Transaction. This is offset 39% increase in revenues generated for oil and gas sales due to a 33% increase in total sales volumes and 5% increase in average oil price.

CAPITAL EXPENDITURES

Capital expenditures were $3.8 million for the quarter ended December 31, 2018 compared to $3.0 million for the quarter ended September 30, 2018 and $1.3 million for the quarter ended December 31, 2017.

The majority of the expenditures related to the following:

- Taranaki development workovers, waterflood and facility improvements ($3.6 million).
- Taranaki exploration activities ($0.2 million).
- Australian PL17 exploration activities ($0.02 million).

Taranaki Basin ($000s)	**2019**		2018	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Mining permits	**3,580**	2,783	486	**6,772**	8,257
Exploration permits	**189**	223	683	**993**	6,379
Total Taranaki Basin	**3,769**	3,006	1,169	**7,765**	14,636

Australia Surat Basin ($000s)	**2019**		2018	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Exploration permits	**22**	11	175	**77**	3,316
Total Surat Basin	**22**	11	175	**77**	3,316

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at December 31, 2018:

Contractual Obligations ($000s)	**Total**	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases ***(1)***	**724**	330	394	-
Other long-term obligations ***(2)***	**17,379**	2,028	15,351	-
Total contractual obligations ***(3)***	**18,103**	2,358	15,745	-

(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)	200	-	-
PMP 53803	G&G studies	25	-	-
PMP 60291	G&G studies, Water flood monitoring and Cheal E Petrophysics (VPPS)	217	-	-
PMP 60454	Supplejack-1 Tie-in, production development plan and evaluation of Supplejack South-1A	-	3,796	-
PEP 54879	Regulatory maintenance	46	-	-
PEP 54877	Eocene petrophysical study, consenting, pad and one exploration well (2021)	137	3,041	-
PEP 51153	G&G studies, Seismic Acquisition and merge of existing Puka 3D and newly acquired 3D	93	1,678	-
PEP 57065	G&G studies and 2D AVO	47	**-**	**-**
PL17	Permit settlement	603	759	-
ATO2037	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	293	2,894	
ATO2038	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	367	3,183	
	TOTAL COMMITMENTS	**2,028**	**15,351**	**-**

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)	**2019**		2018
	Q3	Q2	Q3
Cash and cash equivalents	**2,766**	3,179	3,310
Working capital	**3,131**	2,363	9,753
Contractual obligations, next twelve months	**2,358**	4,346	15,390
Revenue	**8,810**	7,901	6,357
Cashflow from operating activities	**3,205**	2,771	3,866

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	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Cash provided by operating activities	**3,205**	2,771	3,866	**11,123**	6,388
Changes for non-cash working capital accounts	**(699)**	52	(1,209)	**(1,507)**	(1,744)
Operating cash flow	**2,506**	2,823	2,657	**9,616**	4,644

Operating Margin ($000s)	2019		2018	Nine months ended December 31,	
	Q3	Q2	Q3	**2018**	2017
Total revenue	**8,810**	7,901	6,357	**25,829**	17,725
Less production costs	**(2,462)**	(2,259)	(1,647)	**(7,674)**	(5,442)
Less royalties	**(903)**	(545)	(648)	**(2,385)**	(1,818)
Less transportation and storage	**(881)**	(791)	(616)	**(2,436)**	(2,035)
Operating margin	**4,564**	4,306	3,446	**13,334**	8,430

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:

	2019		2018	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2018**	2017
Share-based compensation	**41**	39	46	**189**	208
Management wages and director fees	**235**	192	204	**626**	703
Total Management Compensation	**276**	231	250	**815**	911

SHARE CAPITAL

a. At December 31, 2018, there were 85,282,252 common shares, 11,535,000 warrants and 8,370,000 stock options outstanding.
b. At February 14, 2018, there were 85,282,252 common shares, 11,535,000 warrants and 8,370,000 stock options outstanding.

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

SUBSEQUENT EVENTS

On January 29, 2019, TAG announced that the Toronto Stock Exchange ("TSX") approved TAG's request to commence a normal course issuer bid to purchase and cancel up to 6,441,258 of its common shares through the facilities of the TSX. Under TSX policies, these purchases can commence on February 1, 2019, and will terminate on January 31, 2020.

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 1.77% and a risk-free discount rate ranging from 2.42% to 4.02%, 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 December 31, 2018. 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 16 Leases (effective January 1, 2019)

The Company has not early adopted these new and amended standards and is currently assessing the impact that these standards will have on the Company's financial statements.

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 period ended December 31, 2018. 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 December 31, 2018, 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 December 31, 2018, 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 December 31, 2018. 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 December 31, 2018, 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 December 31, 2018 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.

CORPORATE INFORMATION

DIRECTORS AND OFFICERS
Toby Pierce,
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Vancouver, British Columbia

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Key Largo, Florida

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Vancouver, British Columbia

Peter Loretto, Director
Vancouver, British Columbia

Brad Holland, Director
Calgary, Alberta

David Bennett, Director
Wellington, New Zealand

Barry MacNeil, CFO
Surrey, British Columbia

Max Murray, NZ Country Manager
New Plymouth, New Zealand

Henrik Lundin, COO
New Plymouth, New Zealand

Giuseppe (Pino) Perone,
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AUDITORS
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Chartered Professional Accountants
Vancouver, British Columbia

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100 University Avenue, 9th Floor
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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
Telephone: 604-682-6496
Email: ir@tagoil.com

SHARE CAPITAL
At February 14, 2019, there were 85,282,252 shares issued and outstanding.
Fully diluted: 105,187,252 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.