MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated February 13, 2017, for the nine months ended December 31, 2016, and should be read in conjunction with the Company's condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2016.

The condensed consolidated interim financial statements for the nine months ended December 31, 2016, 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 nine months ended December 31, 2016, 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 high netback 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 nine onshore oil and gas permits amounting to 93,104 net acres of land.

TAG continues to remain disciplined and focused on its core producing operations. TAG will no longer be deferring the majority of its exploration focused capital program, and it is expecting to spud the Supplejack-A2X well in March 2017. The Company has preserved capital and reduced production and administrative costs wherever possible. However, TAG is in the process of preparing to grow its production and reserves base through exploration drilling, while continuing to assess strategic acquisition opportunities in New Zealand and Australia.

Going forward, management will continue to employ its disciplined approach and remain focused on production, appraisal, and utilization, as well as assessing exploration and acquisition opportunities in a diligent manner where appropriate. More specifically, TAG will continue to work towards achieving the following goals:

- Deploy enhanced oil and gas recovery techniques in its producing fields to optimize production and lower per barrel production costs to maximize the value of its operations;
- Diligently evalute its exploration prospects to enhance the development of its exploration program;
- Recommence drilling exploration and appraisal well opportunities;
- Review potential acquisitions of overlooked/undervalued opportunities in New Zealand and Australia; and
- Manage its operating cash flows and balance sheet as effectively as possible to minimize costs while focusing on shareholder returns.

TAG is poised for significant reserve and production growth with several oil and gas fields under development and high-impact exploration in proven oil and gas fairways. As a low cost, high netback oil and gas producer, TAG is debt-free and reinvests its cash flow into development opportunities and exploration drilling adjacent to the Company's existing production. Despite lower oil prices and a reduced appetite for risk in global equity markets, TAG is financially strong and well positioned for the future.

THIRD QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At December 31, 2016, the Company had $10.0 million (March 31, 2016: $16.8 million; December 31, 2015: $15.9 million) in cash and cash equivalents and $17.5 million (March 31, 2016: $22.1 million; December 31, 2015: $22.3 million) in working capital.
- Average net daily production increased by 1% for the quarter ended December 31, 2016, to 1,185 BOE/d (80% oil) from 1,176 BOE/d (81% oil) for the quarter ended September 30, 2016. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 1% to 944 bbl/d compared with 953 bbl/d for the quarter ended September 30, 2016. The decrease is primarily a result of Cheal-B5 remaining offline for the entire quarter due to mechanical issues and Cheal-A7, A11, B7 and B4ST being offline for part of October 2016 due to power fluid pump remedials. This has been partly offset by completion of the Cheal-E5 workover and the well returning to production in October 2016, which is currently producing over 70 BOE/d; and additional oil production at Sidewinder-1 for the entire quarter following perforations across the reservoir and temporary gas lift installation part way through Q2 2017.
  - Average net daily gas production increased by 8% to 1.45 MMSCFD compared with 1.34 MMSCFD for the quarter

ended September 30, 2016. The increase is due to completion of the Cheal-E5 workover and the well returning to production in October 2016.

- Revenue from oil and gas sales increased by 16% for the quarter ended December 31, 2016, to $6.0 million from $5.2 million for the quarter ended September 30, 2016. The 16% increase is due to a 14% increase in average Brent oil prices. Revenues generated from oil and gas sales increased by 19% for the quarter ended December 31, 2016, to $6.0 million from $5.1 million for the quarter ended December 31, 2015. The increase is attributable to a 25% increase in average Brent oil prices, partly offset by a reduction in total gas sold by 189 BOE/d or 74% due to the compressor being offline for part of October, 2016.
- Operating netbacks increased by 28% for the quarter ended December 31, 2016, to $23.86 per BOE compared with $18.61 per BOE for the quarter ended September 30, 2016. The increase is attributable to a 14% increase in average Brent oil prices, partly offset by a 7% increase in production costs per BOE. Operating netbacks increased by 76% for the quarter ended December 31, 2016 to $23.86 per BOE compared with $13.57 per BOE for the for the quarter ended December 31, 2015. The increase is attributable to 25% increase in average Brent oil prices, partly offset by a 25% increase in production costs per BOE. The increase in production costs in both instances is due to completion of the Cheal-B5 workover in October 2016.
- Capital expenditures totalled $1.5 million for the quarter ended December 31, 2016 compared to $3.2 million for the quarter ended September 30, 2016. The majority of the expenditure in Q3 2017 related to Cheal-A and Cheal-E waterflood, Sidewinder gas lift and Supplejack Upper Mt. Messenger test projects.
- At the Cheal E site, a workover was completed to install a rod pump in the Cheal-E5 well, which has been shut-in since May 2015. Start-up commenced early October 2016 and the well is currently producing approximately 70 BOE/d (gross).
- On October 31, 2016, the Company announced that it had signed a definitive agreement to acquire the PL-17 production license in the Surat Basin of Australia for AUD$2.5 million over three years. The 25,700 acre block currently has 15 bbl/d of oil production from two wells and several exploration and appraisal prospects. On January 31, 2017, TAG finalised the conditions of the agreement, obtaining all necessary government approvals and is now operator.
- On November 8, 2016, the Company announced that it had tested the Supplejack-1 well at rates of up to 7.2 MMSCFD from the Mt. Messenger formation before being limited by mechanical constraints. Initial estimates by TAG following subsequent testing operations and analysis indicate that the Supplejack-1 well is an economic discovery, which contains approximately 2.8 Bcf original gas in place as a mid-case estimate, with recovery factors approaching 90% with compression. Initial production rates are forecasted at over 2.0 MMSCFD.
- On December 6, 2016, the Company announced successful initial flow testing at the Cardiff field. The Cardiff-3 well has successfully conducted an interim flow test with gas and condensate produced to surface. Further long term testing in order to support commercialization of Cardiff production via tie back to the TAG's nearby Cheal A facility will progress in Q4 2017. During the testing period the well maintained pressure, flowing water, condensate, oil and a moderate level of gas. Options to develop the well are currently being considered.

TAG maintains a high working interest ownership in its production facilities and associated pipeline infrastructure within its operations allowing successful discoveries from the majority of TAG's drilling locations to be placed efficiently into production with minimal additional capital cost.

RECENT DEVELOPMENTS

The Cheal B Mt. Messenger pool has been identified as the first phase of a larger waterflood project within the greater Cheal area. TAG's enhanced recovery waterflood project commenced on September 21, 2016, and water injection continues at a rate of approximately 700 BW/d. The pressure response in the reservoir is being monitored and TAG expects to see a production response from water injection in calendar 2017.

The Cheal A Mt. Messenger pool waterflood project has progressed with the implementation of the Cheal-A2 injection conversion project that is expected to be completed during Q1 2018. Pressure support is expected to double the recovery factor, resulting in incremental production and reserves.

Execution of the waterflood project at the Cheal E site continues, with pipeline construction completed in Q3 2017. The completion target date is the end of Q4 2017. This will involve the provision of additional pumps and associated equipment, as well as converting Cheal-E7 into an injection well. In addition, the joint venture submitted an application in early November 2016 to New Zealand Petroleum and Minerals to convert Cheal E from an exploration license to a mining license. This will allow the joint venture to commence water injection into the Cheal E pool upon receipt of the mining license.

A low-cost perforation of a deeper zone in the existing Sidewinder-1 wellbore enabled access to a previously unproduced oil leg resulting in additional production. On that success, a further workover on Sidewinder-2 has been progressed and is scheduled to be completed in Q4 2017. It is expected that this will add approximately 85 BOE/d to production. Several additional gas wells at Sidewinder and Cheal continue to be reviewed as candidates for recompletions as oil producers.

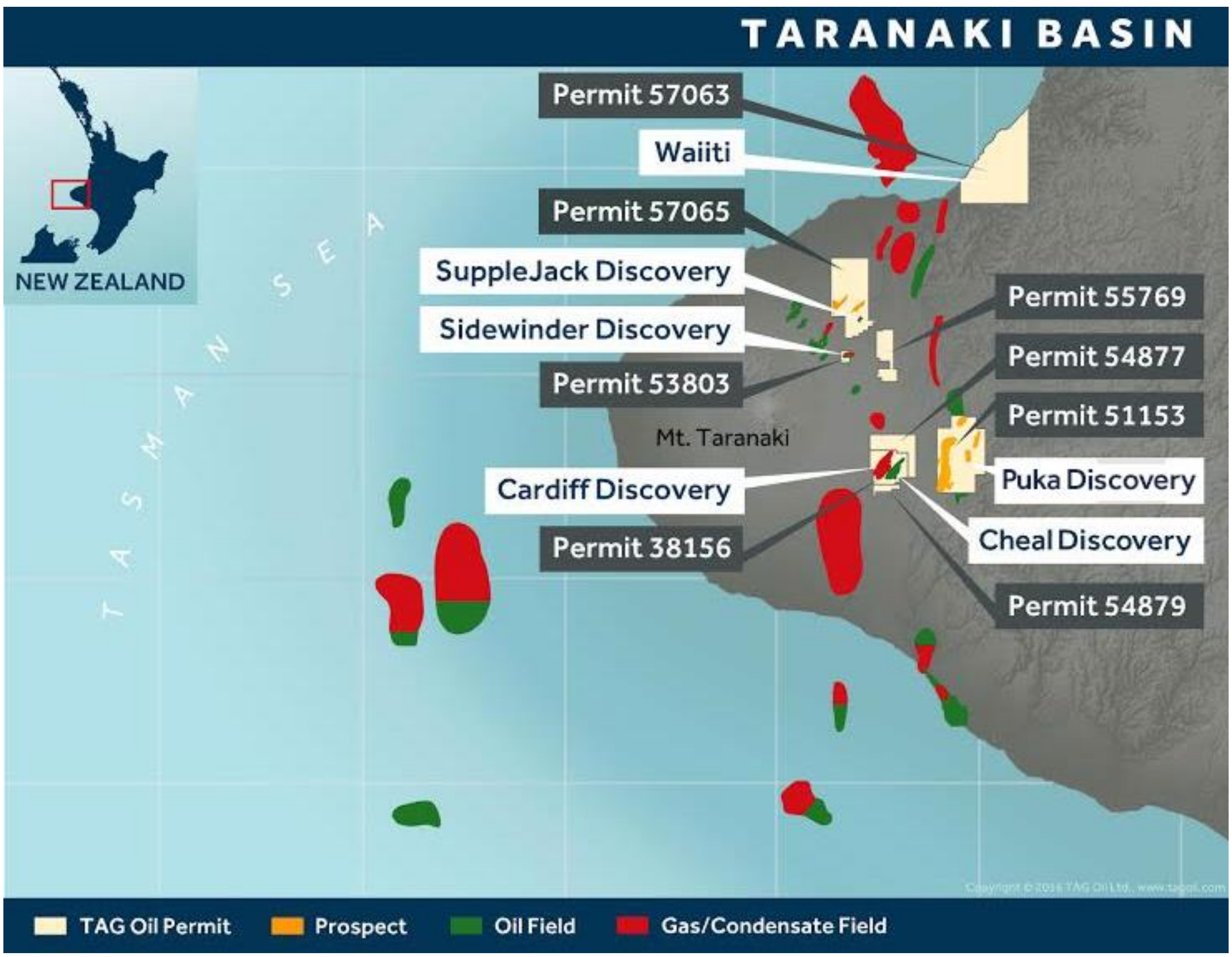
TAG and its joint venture partner, Melbana Energy Ltd. ("Melbana"), have approved drilling of the Pukatea-1 well, located onshore in New Zealand within PEP 51153 ("Puka"), which is planned to commence in Q3/Q4 2018. The Pukatea prospect is a high impact exploration opportunity, targeting a highly productive conventional reservoir. The Puka joint venture has recently upgraded the prospective resources attributable to the Pukatea prospect, which are estimated to range from 1.3 to 40 million barrels (low-high estimates) with a best estimate of 12.4 million barrels of oil equivalent. The chance of success for Pukatea has also been revised upward from 16% to 19%. The Pukatea prospect is proximal to existing infrastructure and several low-cost alternative development paths. The Pukatea-1 well is planned to be drilled from the existing Puka production pad where three wells have previously been drilled.

Planning for drilling of the Supplejack-A2X well on the Waitoriki permit has commenced with drilling to begin in March 2017. If successful, the Supplejack-A2X well will be completed in Q1 2018.

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 100,000 km^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 the Cheal PMP 38156 and the Sidewinder PMP 53803 mining permits.
- 100% interest in PEP 55769 (Sidewinder East) and PEP 57065 (Sidewinder North) exploration permits.
- 100% interest in PEP 57063 (Waiiti) exploration permit.

- 70% interest in the Cheal North East PEP 54877 exploration permit.
- 50% interest in the Cheal South PEP 54879 exploration 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 19 shallow wells on full, part-time or constrained production out of a total of 42 wells. The remaining wells are being used as water source or injection wells, shut-in pending work-overs and/or evaluation of economic re-completion methods.

TAG's shallow Miocene net production averaged 1,185 BOE/d (80% oil) in Q3 2017, compared to an average of 1,176 BOE/d (81% oil) in Q2 2017 and 1,263 BOE/d (75% oil) in Q3 2016. The increase compared to Q2 2017, is primarily due to the completion of the Cheal-E5 workover and the well returning to production in October 2016, and secondly by additional production at Sidewinder-1 following additional perforations across the reservoir and temporary gas lift installation part way through Q2 2017. This is partly offset by natural declines, Cheal-B5 remaining offline for the entire quarter due to mechanical issues and Cheal-A7, A11, B7 and B4ST being offline for part of October 2016 due to power fluid pump remedials.

The Cheal A, B and C facilities (PMP 38156: TAG 100% interest) produced an average of 684 BOE/d (87% oil) in Q3 2017, compared to an average of 832 BOE/d (89% oil) in Q2 2017 and 808 BOE/d (91% oil) in Q3 2016. The decrease is due to Cheal-B5 remaining offline for the entire quarter due to mecahnical issues.

The Cheal North East permit (PEP 54877: TAG 70% interest) produced an average of 289 net BOE/d (64% oil) in Q3 2017 versus an average of 240 BOE/d (56% oil) in Q2 2017 and 380 BOE/d (56% oil) in Q3 2016. The increase compared to Q2 2017 is largely due to completion of the Cheal-E5 workover and the well returning to production in October 2016.

The Cheal oil field continues to provide TAG with a long-life resource that generates substantial cash flow. TAG plans to continue to develop the Cheal oil and gas field, which has been substantially de-risked by the 35 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 a pressure maintenance and waterflood program. With drilling and completion costs of under US$2.5 million per well, there is an unrecognized upside and economic potential that exists within TAG's acreage.

The Sidewinder field produced an average of 212 BOE/d (77% oil) in Q3 2017, compared to an average of 104 BOE/d (77% oil) in Q2 2017 and 75 BOE/d (1% oil) in Q3 2016. The increase is due to additional oil production at Sidewinder-1 for the entire quarter following perforations across the reservoir and a temporary gas lift installation part way through Q2 2017.

The Puka permit (PEP 51153: TAG 70% interest) covers an area of approximately 85 km^2 (21,000 acres) and is located to the east of TAG's producing Cheal field. In addition to the Miocene-aged Mt. Messenger drilling opportunities, the Puka permit also contains the Pukatea prospect (formerly known as Shannon prospect), a deeper Tikorangi Limestone target situated directly below the Puka oil pool. The production capability from the Tikorangi Limestone has been well proven at the adjacent Waihapa and Ngaere oil fields, which has produced in excess of 23 MMbbl to date. The Douglas-1 well drilled in 2012 at the edge of the Pukatea prospect encountered a 145 m of reservoir interval and oil shows in a down-dip location, with more than 350 m of up-dip potential estimated.

TAG and its joint venture partner, Melbana, have agreed to drill Pukatea-1 by Q3/Q4 2018 using the existing Puka production pad. With proven production and several exploration targets identified, this is a complimentary addition to the TAG portfolio where TAG can apply its extensive technical and operations experience in the Taranaki Basin.

Deep / Eocene Exploration

TAG's 100% controlled mining permit, PMP 38156, where the Company's Cheal oil field is located, also contains the large Cardiff structure of the deeper Kapuni Group formations, which is on trend and geologically similar to the large legacy deep gas condensate fields that have been discovered in the Taranaki Basin.

The Cardiff structure, identified on seismic, is an extensive linear fault bound high which is approximately 12 km long and 3 km wide. Cardiff-3, drilled by TAG in FY2014, encountered 230 m of gas and condensate bearing sands over three target zones within the Kapuni Group. The deepest zone, the "K3E" is one of the producing intervals of the Kapuni Field, a legacy pool with estimated recoverable reserves of over 1.4 Tcf of gas. The upper two zones which remain untested in the Cardiff 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. The Cardiff-3 well has successfully conducted an interim flow test with gas and condensate produced to surface. Further long term testing in order to support commercialization of Cardiff production via tie back to the Cheal A facility will be ongoing in Q4 2017. During the testing period the well maintained pressure, flowing water, oil, condensate and a moderate level of gas. Options to develop the well are currently being considered.

The Hellfire prospect, located within PMP 53803, has been identified on 3D seismic and has similar geological features to the producing Kapuni field. Hellfire is a contingent well that could be drilled upon the success of Cardiff and/or on finding a suitable joint venture partner to join TAG in its exploration drilling activities. The Sidewinder processing facility is currently available to allow for efficient commercialization of a discovery.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2017		2016	Nine months ended December 31,	
Daily production volumes (1)	**Q3**	Q2	Q3	**2016**	2015
Oil (bbl/d)	**944**	953	945	**943**	1,036
Natural gas (BOE/d)	**241**	223	318	**251**	395
Combined (BOE/d)	**1,185**	1,176	1,263	**1,194**	1,431
% of oil production	**80%**	81%	75%	**79%**	72%
Daily sales volumes (1)					
Oil (bbl/d)	**954**	923	922	**936**	1,043
Natural gas (BOE/d)	**67**	99	256	**118**	270
Combined (BOE/d)	**1,021**	1,022	1,178	**1,054**	1,313
Natural gas (MMcf/d)	**401**	594	1,536	**710**	1,619
Product pricing					
Oil ($/bbl)	**66.12**	58.12	52.94	**62.42**	62.84
Natural gas ($Mcf)	**6.36**	5.34	4.16	**5.25**	3.97
Oil and natural gas revenues (3) - gross *($000s)*	**6,038**	5,226	5,078	**17,085**	19,797
Oil & natural gas royalties (2)	**(649)**	(515)	(485)	**(1,711)**	(1,773)
Oil and natural gas revenues - net *($000s)*	**5,389**	4,711	4,593	**15,374**	18,024

(1) Natural gas production converted at 6 Mcf:1BOE (for BOE figures).
(2) Relates to government royalties and includes an ORR of 7.5% royalty related to the acquisition of a 69.5% interest in the Cheal field.
(3) Oil and Gas Revenue excludes electricity revenue related to Coronado Resources Ltd. ("Coronado").

Average net daily production increased by 1% for the quarter ended December 31, 2016 to 1,185 BOE/d (80% oil) from 1,176 BOE/d (81% oil) for the quarter ended September 30, 2016. The increase is primarily due to completion of the Cheal-E5 workover and the well returning to production in October 2016 and additional oil production at Sidewinder-1 for the entire quarter following additional perforations across the reservoir and temporary gas lift installation part way through Q2 2017. This is partly offset by Cheal-B5 remaining offline for the entire quarter due to mechanical issues and Cheal-A7, A11, B7 and B4ST being offline for part of October 2016 due to power fluid pump remedials.

Oil and natural gas gross revenue increased by 16% for the quarter ended December 31, 2016 to $6.0 million from $5.2 million for the quarter ended September 30, 2016. The 16% increase is primarily attributable to a 14% increase in average Brent oil prices.

SUMMARY OF QUARTERLY INFORMATION

	2017			2016				2015
Canadian $000s, except per share or BOE	**Q3**	Q2	Q1	Q4 *(2)*	Q3 *(2)*	Q2 *(2)*	Q1 *(2)*	Q4 *(2)*
Net production volumes (BOE/d)	**1,185**	1,176	1,222	1,251	1,263	1,341	1,689	1,837
Total revenue	**6,038**	5,226	5,821	5,013	5,078	5,713	9,006	8,660
Operating costs	**(3,796)**	(3,477)	(2,848)	(3,014)	(3,607)	(3,428)	(4,133)	(3,928)
Foreign exchange	**178**	(13)	(195)	(307)	(279)	810	553	757
Share-based compensation	**(355)**	(149)	(223)	(487)	(218)	(403)	(896)	(380)
Other costs	**(4,224)**	(6,260)	(4,180)	(5,555)	(4,668)	(4,495)	(5,600)	(6,654)
Exploration impairment	**(86)**	(17)	(100)	(3,676)	(2,104)	(2,740)	(715)	(71,714)
Property impairment	**-**	-	-	(59,287)	-	-	-	(9,182)
Net gain / (loss) income from discontinued operations	**-**	-	-	2,054	(6,472)	(132)	(615)	(775)
Net (loss) income before tax	**(2,245)**	(4,690)	(1,725)	(65,259)	(12,270)	(4,675)	(2,400)	(83,216)
Basic (loss) income $ per share	(0.04)	(0.08)	(0.03)	(1.05)	(0.20)	(0.08)	(0.04)	(1.30)
Diluted (loss) income $ per share	(0.04)	(0.07)	(0.03)	(1.05)	(0.20)	(0.08)	(0.04)	(1.30)
Capital expenditures	**1,513**	3,161	2,773	2,859	3,266	2,755	2,916	10,465
Operating cash flow *(1)*	**822**	407	1,625	1,695	(1,540)	1,263	3,071	2,826

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

(2) Due to the sale of the Opunake Hydro Limited ("OHL") business in 2016 the operations were considered discontinued and results exclude the related electrical generation operating segments, which are included in net (loss) income from discontinued operations.

Revenues generated from oil and gas sales increased by 16% for the quarter ended December 31, 2016, to $6.0 million from $5.2 million for the quarter ended September 30, 2016. The 16% increase is primarily attributable to a 14% increase in average Brent oil prices. Revenues generated from oil and gas sales increased by 19% for the quarter ended December 31, 2016, to $6.0 million from $5.1 million for the quarter ended December 31, 2015. The increase is attributable to a 25% increase in average Brent oil prices, partly offset by a reduction in total gas sold by 189 BOE/d or 74% due to the compressor being offline in October 2016.

Operating costs increased by 9% for the quarter ended December 31, 2016, to $3.8 million from $3.5 million for the quarter ended September 30, 2016. Operating costs increased by 9% due completion of the Cheal-B5 workover and additional royalty costs associated with increased revenue for the quarter. Operating costs increased by 5% for the quarter ended December 31, 2016, to $3.8 million from $3.6 million for the quarter ended December 31, 2015. The increase is attributable to the completion of the Cheal-B5 workover and additional royalty costs associated with increased revenue.

Other costs increased by 18% for the quarter ended December 31, 2016, to $4.2 million from $3.6 million for the quarter ended September 30, 2016. The 18% increase compared to September 30, 2016, is mainly due to a loss on sale of Coronado assets of $0.5 million. Other costs decreased by 10% for the quarter ended December 31, 2016 to $4.2 million from $4.7 million for the quarter ended December 31, 2015. The 10% decrease compared to Q3 2016 is mainly due to a 26% decrease in depreciation and depletion, which was driven by a significant reduction in the depletable base as a result of the $59.3 million property impairment following the reserves review at March 31, 2016.

Net loss before tax for the quarter ended December 31, 2016, was $2.2 million compared to a net loss of $4.7 million for the quarter ended September 30, 2016. Excluding impairment expense, on a comparative basis, equates to a net loss before tax of $2.1 million for the quarter ended December 31, 2016, compared to a net loss of $2.0 million for the quarter ended September 30, 2016. Net loss before tax for the quarter ended December 31, 2016, was $2.2 million compared to a net loss of $12.3 million for the quarter ended December 31, 2015. Excluding impairment expense and net loss from discontinued operations, on a comparative basis, equates to a net loss before tax of $2.1 million for the quarter ended December 31, 2016, compared to a net loss of $3.7 million for the quarter ended December 31, 2015.

Net Production by Area (BOE/d)

Area	2017		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
PMP 38156 (Cheal)	**684**	832	808	**796**	829
PEP 54877 (Cheal North East)	**289**	240	380	**270**	494
PMP 53803 (Sidewinder)	**212**	104	75	**128**	107
Total BOE/d	**1,185**	1,176	1,263	**1,194**	1,431

Average net daily production increased by 1% for the quarter ended December 31, 2016, to 1,185 BOE/d (80% oil) from 1,176 BOE/d (81% oil) for the quarter ended September 30, 2016. The increase is primarily due to completion of the Cheal-E5 workover and the well returning to production in October 2016, and additional oil production at Sidewinder-1 for the entire quarter following additional perforations across the reservoir and temporary gas lift installation part way through Q2 2017. This is partly offset by Cheal-B5 remaining offline for the entire quarter due to mechanical issues and Cheal-A7, A11, B7 and B4ST being offline for part of October 2016 due to power fluid pump remedials.

Average net daily production decreased by 6% for the quarter ended December 31, 2016, to 1,185 BOE/d (80% oil) from 1,263 BOE/d (75% oil) for the quarter ended December 31, 2015. The 6% decrease compared to Q3 2016 is due to a combination of natural decline rates and well downtime related to the above-mentioned wells.

Oil and Gas Operating Netback ($/BOE)

	2017		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Oil and natural gas revenue	**64.29**	55.60	46.85	**58.94**	54.82
Royalties	**(6.91)**	(5.48)	(4.47)	**(5.90)**	(4.91)
Transportation and storage costs	**(7.85)**	(7.59)	(8.32)	**(7.29)**	(8.25)
Production costs	**(25.67)**	(23.92)	(20.49)	**(21.73)**	(17.77)
Operating Netback per BOE ($)	**23.86**	18.61	13.57	**24.02**	23.89

Operating netback is a non-GAAP measure. Operating netback is the operating margin the Company receives from each barrel of oil equivalent sold. *See non-GAAP measures for further explanation*.

Operating netback increased by 28% for the quarter ended December 31, 2016, to $23.86 per BOE compared with $18.61 per BOE for the quarter ended September 30, 2016. The increase is attributable to a 14% increase in average Brent oil prices, partly offset by a 7% increase in production costs per BOE. The increase in production costs is due to completion of the Cheal-B5 workover in October 2016.

Operating netback increased by 76% for the quarter ended December 31, 2016, to $23.86 per BOE compared with $13.57 per BOE for the for the quarter ended December 31, 2015. The increase is attributable to 25% increase in average Brent oil prices, partly offset by a 25% increase in production costs per BOE. The increase in production costs is due to completion of the Cheal-B5 workover in October 2016.

General and Administrative Expenses (“G&A”)

	2017		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Oil and Gas G&A expenses ($000s)	**1,517**	1,407	1,711	**4,034**	4,728
Oil and Gas G&A per BOE ($)	**13.91**	13.00	14.72	**12.83**	12.78
Mining G&A expenses ($000s)	**58**	72	144	**179**	302
Total G&A Expenses	**1,575**	1,479	1,855	**4,213**	5,030

Total G&A expenses increased by 6% for the quarter ended December 31, 2016, to $1.6 million compared with $1.5 million for the quarter ended December 31, 2016. Oil and Gas G&A expenses have increased by 8% due to timing of annual fees for a number of IT licenses.

Total G&A expenses decreased by 15% for the quarter ended December 31, 2016, to $1.6 million compared with $1.9 million for the quarter ended December 31, 2015. Oil and Gas G&A expenses have decreased 11% due primarily to lower wages and salaries cost. Electricity/Mining G&A expenses have also decreased 60% due to G&A relating to the electricity business being sold.

Share-based Compensation

	2017		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Share-based compensation ($000s)	**355**	149	218	**727**	1,517
Per BOE ($)	**3.26**	1.38	1.87	**2.21**	3.85

Share-based compensation costs are non-cash charges, which reflect the 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 of 60.61% to 61.62% and a risk-free interest rate of 1.66% to 1.69%. The 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, 2016, the Company granted 1,585,000 options (September 30, 2016: nil) and no options were exercised (September 30, 2016: nil).

Share-based compensation increased by 138% for the quarter ended December 31, 2016, to $0.4 million compared with $0.1 million for the quarter ended September 30, 2016. The increase in total share-based compensation costs is due to the 1.6 million options granted during Q3 2017.

Share-based compensation increased to $0.4 million in the quarter ended December 31, 2016, compared with $0.2 million for the quarter ended December 31, 2015. The increase in total share-based compensation costs is due to the 1.6 million options granted during Q3 2017.

Depletion, Depreciation and Accretion (DD&A)

	2017		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Depletion, depreciation and accretion ($000s)	**2,088**	2,161	2,819	**6,585**	9,861
Per BOE ($)	**19.15**	19.97	24.26	**20.05**	25.06

DD&A expenses decreased by 3% for the quarter ended December 31, 2016, to $2.1 million compared with $2.2 million for the quarter ended September 30, 2016. The decrease is attributable to a reduction in gas sales resulting from gas flared during the compressor outage at the Cheal plant which continued into October 2016 and oil production is used to calculate the depletion rate on the depletable base.

DD&A expenses decreased by 26% for the quarter ended December 31, 2016, to $2.1 million compared with $2.8 million for the quarter ended December 31, 2015. The decrease is attributable to a significant reduction in the depletable base as a result of the $59.3 million property impairment following the reserves review at March 31, 2016, and lower production volume.

Foreign Exchange Loss (Gains)

	2017		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Foreign exchange loss / (gains) ($000s)	**(178)**	13	279	**31**	(1,084)

The foreign exchange gain for the quarter ended December 31, 2016, was a result movement in USD against the NZD resulting in foreign exchange gain on the USD denominated oil receipts.

Net Income Before Tax, Tax Expense and Net Income After Tax

	2017		2016	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2016**	2015
Net (loss) income before tax	**(2,245)**	(4,690)	(12,270)	**(8,661)**	(19,345)
Income tax recovery (expense) - deferred	**-**	-	-	**-**	-
Net (loss) income after tax	**(2,245)**	(4,690)	(12,270)	**(8,661)**	(19,345)
Per share, basic ($)	**(0.04)**	(0.08)	(0.20)	**(0.14)**	(0.31)
Per share, diluted ($)	**(0.04)**	(0.07)	(0.20)	**(0.14)**	(0.31)

Net loss before tax for the quarter ended December 31, 2016, was $2.2 million compared to a net loss of $4.7 million for the quarter ended September 30, 2016. Excluding impairment expense, on a comparative basis, equates to a net loss before tax of $2.1 million for the quarter ended December 31, 2016, compared to a net loss of $2.0 million for the quarter ended September 30, 2016. The increased loss is due to a combination of a loss on sale of Coronado assets of $0.5 million and a 7% increase in production costs per BOE due to completion of the Cheal-B5 workover in October 2016. This is partly offset by increased revenue due to a 14% increase in average Brent oil prices.

Net loss before tax for the quarter ended December 31, 2016, was $2.2 million compared to a net loss of $12.3 million for the quarter ended December 31, 2015. Excluding impairment expense and net loss from discontinued operations, on a comparative basis, equates to a net loss before tax of $2.1 million for the quarter ended December 31, 2016, compared to a net loss of $3.7 million for the quarter ended December 30, 2015. The reduced loss is predominately attributable to a 25% increase in average Brent oil prices and reduced DD&A expense due to a reduction in the depletable base as a result of the $59.3 million property impairment following the reserves review at March 31, 2016.

Cash Flow

	2017		2016	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2016**	2015
Operating cash flow *(1)*	**822**	407	(1,540)	**2,854**	2,794
Cash provided by operating activities	**69**	236	(3,052)	**1,147**	3,475
Per share, basic ($)	**0.00**	0.00	(0.05)	**0.02**	0.06
Per share, diluted ($)	**0.00**	0.00	(0.05)	**0.02**	0.06

(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 increased by 102% for the quarter ended December 31, 2016, to $0.8 million versus operating cash flow of $0.4 million for the quarter ended September 30, 2016. The increase is a result of increased revenue due to a 14% increase in average Brent oil prices.

Operating cash flow increased positively by 153% for the quarter ended December 31, 2016, to $0.8 million versus negative operating cash flow of $1.5 million for the quarter ended December 31, 2015. The increase is a result of higher revenue due to a 25% increase in average Brent oil prices, partly offset by a reduction in total gas sold by 189 BOE/d or 74% due to the compressor being offline for part of October 2016.

CAPITAL EXPENDITURES

Capital expenditures were $1.5 million for the quarter ended December 31, 2016, compared to $3.2 million for the quarter ended September 30, 2016, and $3.2 million for the quarter ended December 31, 2015.

The majority of the expenditure related to the following:

- Taranaki development drilling and waterflood, workovers and facility improvements ($1.1 million).
- Taranaki exploration activities ($0.3 million).
- Australia exploration activities ($0.1 million).

Taranaki Basin ($000s)	**2017**		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Mining permits	**1,073**	2,731	3,025	**5,519**	6,843
Exploration permits	**364**	266	103	**1,634**	890
Opunake Hydro Limited	**-**	-	139	**-**	661
Total Taranaki Basin	**1,437**	2,997	3,267	**7,153**	8,394

Australia Surat Basin ($000s)	**2017**		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Exploration permits	**60**	**-**	-	**60**	-
Total Surat Basin	**60**	**-**	-	**60**	-

United States ($000s)	**2017**		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Madison mine - exploration	**-**	139	**-**	**167**	483
Madison mine - development	**-**	-	**-**	**-**	-
Total United States	**-**	139	**-**	**167**	483

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at December 31, 2016:

Contractual Obligations ($000s)	**Total**	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases *(1)*	**878**	233	645	-
Other long-term obligations *(2)*	**30,609**	13,372	17,237	-
Total contractual obligations *(3)*	**31,487**	13,605	17,882	-

(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 at the date of this report that relate to operations and infrastructure. 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	Waterflood, optimizations and lease improvements	3,804	282	-
PEP 53803	Permanent gas lift & minor capital works	467	-	-
PEP 54877	Drilling of one shallow exploration well and waterflood	2,713	-	-
PEP 54879	3D seismic and G&G studies	147	-	-
PEP 51153	Facilities preservation, gravity survey and G&G studies	508	4,505	-
PEP 55769	G&G studies and two exploration wells (2018)	10	7,930	-
PEP 57065	2-D seismic, upper MM test and one exploration well (2017)	3,644	3,285	-
PEP 57063	2-D seismic reprocessing and 60km of seismic reprocessing	24	-	-
PEP 38349	*Relinquished (site reinstatement)*	79	-	-
PL 17	Permit settlement and seismic acquisition	1,976	1,235	-
	TOTAL COMMITMENTS	**13,372**	**17,237**	**-**

The Company expects to use working capital on hand as well as cash flow from oil and gas sales to meet these commitments. Commitments and work programs are subject to change.

LIQUIDITY AND CAPITAL RESOURCES

(000s)	2017		2016
	Q3	Q2	Q3
Cash and cash equivalents	**$10,008**	$13,644	$15,918
Working capital	**$17,471**	$18,987	$22,255
Contractual obligations, next twelve months	**$13,372**	$13,825	$29,727
Revenue(1)	**$6,038**	$5,226	$5,078
Cashflow from operating activities	**$69**	$236	($3,052)

(1) Due to the sale of the OHL business in Q4 FY2016 the operations are considered discontinued. Reported results from the related electricity generation segment are now included in net (loss) income from discontinued operations.

As of the date of this report, the Company has sufficient funds to meet its planned operations and ongoing requirements for the next twelve months based on the current exploration and development programs and anticipated cash flow from the Cheal and Sidewinder oil and gas fields. TAG's management has adjusted to the change in the commodity price of oil and reduced and relinquished obligations as necessary to provide more certainty and liquidity for the Company. The Company is in a strong cash position with no debt and is continually monitoring commodity prices and cash flow and will react to movements up or down 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 general and administrative expenses. Operating netback is exclusive of electricity revenue and costs and denotes oil and gas revenue and realized gain (loss) on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses.

Operating Cash Flow ($000s)	2017		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Cash provided by operating activities	**69**	236	(3,052)	**1,147**	3,475
Changes for non-cash working capital accounts	**753**	171	1,512	**1,707**	(681)
Operating cash flow	**822**	407	(1,540)	**2,854**	2,794

Operating Margin ($000s)	2017		2016	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Total revenue	**6,038**	5,226	5,078	**17,085**	19,796
Less royalties	**(649)**	(515)	(485)	**(1,711)**	(1,773)
Less transportation and storage	**(737)**	(713)	(902)	**(2,112)**	(2,977)
Less total production costs	**(2,411)**	(2,249)	(2,221)	**(6,298)**	(6,418)
Operating margin	**2,241**	1,749	1,470	**6,964**	8,628

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 generally has not used derivative financial instruments to manage risks other than managing electricity pricing risk through hedges that approximate electricity consumption for third parties.

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 of directors (the "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:

	2017		2016	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2016**	2015
Share-based compensation	**233**	102	(59)	**485**	911
Management wages and director fees	**251**	267	226	**740**	702
Total Management Compensation	**484**	369	167	**1,225**	1,613

SHARE CAPITAL

a. At December 31, 2016, there were 62,212,252 common shares and 6,220,000 stock options outstanding.
b. At February 13, 2017, there were 62,212,252 common shares and 6,220,000 stock options outstanding.

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

During the nine months ended December 31, 2016, no common shares were issued or purchased and cancelled.

On November 23, 2016, the Company granted 1,475,000 incentive stock options to various directors, executive officers, employees and consultants. These options are exercisable until November 23, 2021, at a price of $1.05 per share subject to one-third of the total options vested on grant date, one-third of the total options one year from the date of the grant and one-third of the total options two years from the date of the grant.

On November 23, 2016, the Company granted 60,000 incentive stock options to a New Zealand executive officer. These options are exercisable until November 23, 2021, at a price of $1.05 per share subject to one-third of the total options vest one year from the date of the grant, one-third of the total options vest two years from the date of the grant and one-third of the total options vest three years from the date of the grant.

On November 23, 2016, the Company granted 50,000 incentive stock options to a New Zealand consultant. These options are exercisable until November 23, 2021 at a price of $0.90 per share subject to one-third of the total options vest six months from the date of the grant, one-third of the total options vest one year from the date of the grant and one-third of the total options vest eighteen months from the date of the grant.

SUBSEQUENT EVENTS

On January 31, 2017, the Company and its wholly owned subsidiary, Cypress Petroleum Pty Ltd. ("Cypress"), completed the purchase of 100% interest in Petroleum Lease 17 and all related assets, which are located in Australia's Surat Basin and subject to underlying royalties, from Southern Cross Petroleum & Exploration Pty Ltd. ("Southern Cross") in exchange for AUD$2,500,000, payable to Southern Cross as follows:

1) AUD$750,000 (less the AUD$40,000 non-refundable deposit already paid) payable in cash on the closing date;

2) AUD$500,000 payable in cash on July 20, 2017;

3) AUD$500,000 payable, at the sole discretion of Cypress, in cash or satisfied by shares of the Company, on the second anniversary of the closing date; and

4) AUD$750,000 payable, at the sole discretion of Cypress, in cash or satisfied by shares of the Company, on the third anniversary of the closing date.

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 stock-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 electricity generation, retail, and producing oil and gas fields with petroleum mining permits granted including associated infrastructure on the basis that field investment decisions are made based on expected field production and all wells are dependent on the field infrastructure.

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

The decision to transfer exploration and evaluation assets to property, plant and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves. The calculation of decommissioning liabilities includes estimates of the future costs to settle the liability, the timing of the cash flows to settle the liability, the risk-free rate and the future inflation rates. The rates used to calculate decommissioning liabilities are an inflation rate of 1.62% and a risk free discount rate ranging from 2.94% to 4.15%, 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.

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, 2016. Please also refer to Forward Looking Statements.

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

Future changes in accounting policies

Certain pronouncements were issued by the IASB or the International Financial Reporting Interpretations Committee ("IFRIC") but not yet effective as at December 31, 2016. 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.

Effective for annual reporting periods beginning on or after January 1, 2017:
- IFRS 15 – Revenue from Contracts with Customers Issued

Effective for annual reporting periods beginning on or after January 1, 2018:
- IFRS 9, Financial Instruments, Classification and Measurement

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.

Management's Report on Internal Control over Financial Reporting

Disclosure controls, procedures, and internal controls 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, 2016 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, 2016, 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 Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period 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 Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

The Company's management, including the Chief Executive Officer and the Chief Financial Officer, 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 principal executive and principal financial officers 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, 2016. 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, 2016, 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 cashflow in Taranaki; pursuing high-impact exploration on deep Kapuni Formation prospects in Taranaki; and other statements set out herein.

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.

The forward-looking statements contained herein are as of December 31, 2016, 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.

The resource estimates in this document are by TAG professionals, a non-independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, with effective dates of November 30, 2016, and December 1, 2016.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

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

The significant positive factors that are relevant to the resource estimate are: proven production in close proximity; proven commercial quality reservoirs in close proximity; oil and gas shows while drilling wells; and calculated hydrocarbon pay intervals from open hole logs.

The significant negative factors that are relevant to the resource estimate are: tectonically complex geology could compromise seal potential; and seismic attribute mapping can be indicative but not certain in identifying proven resource.

CORPORATE INFORMATION

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Vancouver, British Columbia
Bell Gully
Wellington, New Zealand

AUDITORS
De Visser Gray LLP
Chartered Professional Accountants
Vancouver, British Columbia

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

The Annual General Meeting was held on October 31, 2016 at 2:00 pm 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 13, 2017, there were 62,212,252 shares issued and outstanding.
Fully diluted: 68,432,252 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 (formerly Eastern Petroleum Limited)
Stone Oil Limited
Cypress Petroleum Pty Ltd.

Coronado Resources Ltd. (49%)
Lynx Clean Power Corp. (49%)
Lynx Gold Corp. (49%)
Lynx Petroleum Ltd. (49%)
Coronado Resources USA LLC (49%)
Lynx Platinum Limited (49%)