MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated June 29, 2017, for the year ended March 31, 2017 and should be read in conjunction with the Company's audited consolidated financial statements for the years ended March 31, 2017 and 2016.

The audited consolidated financial statements for the years ended March 31, 2017 and 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 year ended March 31, 2017, 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 eight onshore oil and gas permits amounting to 71,050 net acres of land.

TAG continues to remain disciplined and focused on its core producing operations. The Company has preserved capital and reduced variable production costs and administrative costs wherever possible. However, TAG is in the process of growing its production and reserves base through exploration drilling, while continuing to assess strategic acquisition and farm-in 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:

- Maintain 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;
- Continue to evalute its exploration prospects to enhance the development of its exploration program;
- Continue drilling exploration and appraisal well opportunities where appropriate;
- Continue efforts to establish additional proved reserves and to commercialize its oil and gas exploration properties;
- 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 reserve and production growth with several oil and gas fields under development in proven oil and gas fairways. As a high netback oil and gas producer, TAG is currently debt-free and reinvests its cash flow into development opportunities and exploration drilling adjacent to the Company's existing production and in close proximity to other proven fields.

FINANCIAL SNAPSHOT

	For the year ended March 31, 2017	For the year ended March 31, 2016	For the year ended March 31, 2015
Proven & Probable "2P" Reserves (Mboe)	**4,143**	**3,619**	**5,180**
Oil production (bbl/d)	948	1,019	1,425
Gas production (MMSCFD)	1,510	2,202	2,587
Combined boe/d	**1,200**	**1,386**	**1,856**
Oil & gas revenue per boe	$60.48	$52.79	$84.23
Production and transportation and storage costs per boe	($29.49)	($25.41)	($23.90)
Royalties per boe	($6.11)	($4.76)	($7.49)
Operating netback per boe(1)	**$24.88**	**$22.61**	**$52.84**
Revenue(2)	$23,340,949	$24,809,530	$49,376,797
Cashflow from operating activities	$1,462,514	$9,648,879	$28,627,532
Net income (loss) from continuing operatioms	24,686,719	($79,438,908)	($68,384,434)
Earnings (loss) per share – basic	$0.39	($1.28)	($1.08)
Earnings (loss) per share – diluted	$0.38	($1.28)	($1.08)
Net income (loss) for the year	24,686,719	($84,604,806)	($69,762,517)
Earnings (loss) per share – basic	$0.39	($1.36)	($1.10)
Earnings (loss) per share – diluted	$0.38	($1.36)	($1.10)
Total assets	$145,864,625	$95,967,162	$196,885,634
Asset retirement obligation	$14,963,715	$12,934,521	$13,247,781
Deferred tax liability	$0	$0	$0
Shareholders equity	$122,810,467	$80,009,867	$173,923,735

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

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

ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2017, the Company had $21.6 million (March 31, 2016: $16.8 million) in cash and cash equivalents and $25.9 million (March 31, 2016: $22.1 million) in working capital and no debt.
- Total Proven + Probable ("2P") reserves at March 31, 2017 reflecting the Company's 100% interest in PMP 38156 (Cheal), 70% interest in PEP 54877 (Cheal East) and 100% interest in PMP 53803 (Sidewinder), are estimated at 4.1 MMboe (92% oil) compared with 3.6 MMboe (93% oil) at March 31, 2016. The approximate reserves growth is due to:
    - An approximate 26% increase in annual reserves revisions of 946 Mboe, which is primarily due to improved recovery and reclassification from no reserves assigned ("NRA") category:
        - This is predominately from the inclusion of waterflood volumes, as TAG has commenced injection into the Cheal-B3 wellbore, and has recently converted the Cheal-A2 wellbore to an injector. These waterflood conversions will provide pressure support to the Cheal A and B-Sites, and are expected to increase the overall field recovery by 5% and 10% respectively for the proved and probable volumes. Additional behind pipe pay opportunities have also been assigned reserves that were not previously included. These include recompletions in the Urenui on the Cheal-A11, Cheal-A7 and Cheal-B7 wells.
        - The technical revisions for the gross proved volumes increased due to revisions to the production profiles and the inclusion of reserves from the Cheal-E2, Cheal-E5 and Cheal-E6 wells as these wells had previously been classified as NRA due to operational issues. The Cheal-E5 well is back on production, and TAG has development plans to bring the Cheal-E2 and E6 wells back on line in the near term.
        - Due to revisions to the production profiles and geological modelling the probable volumes decreased for the Cheal-A3X, Cheal-B3, Cheal-B6 and Cheal-B8 wells. The infill locations for the Cheal-BP, BQ and BR locations have also been reduced as lower recovered volumes have been assigned due to the depletion of the fields.
        - The workover and recompletion of the Sidewinder-1 and 2 wells, along with the planned workovers of the Sidewinder-3 and 4 wells, has added proved, probable and possible reserves up from having no reserves or resources assigned the previous fiscal year 2016.

- An approximate 12% decrease due to 421 Mboe produced over the 12-month period in fiscal year 2017.
- Average net daily production decreased by 13% to 1,200 boe/d compared with 1,386 boe/d in fiscal year 2016. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 7% to 948 bbl/d compared with 1,019 bbl/d in fiscal year 2016. The decrease is primarily due to Cheal-B5 coming offline in September 2016 due to mechanical issues, Cheal-E6 being offline for all of fiscal year 2017 following issues with the jet pump and natural decline in production. This is partly offset by additonal oil production coming from Sidewinder as a result of workovers to Sidewinder-1 and Sidewinder-2 wells enabling access to a previously unproduced oil leg.
  - Average net daily gas production decreased by 31% to 1.5 MMcf/d compared with 2.2 MMcf/d in fiscal year 2016. The decrease is primarily due to Cheal-E6 being offline for all of fiscal year 2017 following issues with the jet pump, Cheal-E4 shut-in during Q4 2017 to conserve reservior pressure and due to declining Sidewinder gas production.
- Revenue decreased by 6% to $23.3 million compared with $24.8 million in fiscal year 2016. A breakdown of revenue is as follows:
  - Revenue from oil sales decreased 2% to $22.1 million compared with $22.5 million due to a 8% decrease in oil sales volume partly offset by 8% increase in average oil prices.
  - Revenue from gas sales decreased 48% to $1.2 million compared with $2.3 million due to a 56% decrease in gas sales volumes partly offset by a 18% increase in gas sales price.
- Operating netback increased by 10% for fiscal year 2017 to $24.88 per boe compared with $22.61 per boe for fiscal year 2016. The increase is attributable to a 15% increase in oil and gas revenue per boe due to the 8% increase in average Brent oil sales prices, partly offset by an increase in production costs per boe of 25%.
- The Company had an asset impairment reversal of $35.0 million as a result of the Company's increased reserve position and improved current economic conditions with $33.0 million relating to PMP 38156/PEP 54877 and $2.0 million to PMP 53803.
- The Company acquired the following permits:
  - 70% interest in the 20,923 acre onshore PEP 51153 (Puka) in June 2016.
  - 100% interest in the 25,700 acre onshore PL17 (Cypress) in January 2017.
- The Company relinquished the following permits:
  - 40% interest in the 21,623 acre offshore PEP 52181 (Kaheru) in April 2016.
  - 100% interest in the 4,275 acre onshore PEP 38748 (Sidewinder B) in June 2016.
  - 100% interest in the 634,047 acre onshore PEP 38349 (Boar Hill) in November 2016.
  - 100% interest in the 22,054 acre onshore PEP 57063 (Wai-iti) in April 2017.
- The Company has submitted the following permits to be relinquished that are pending approval:
  - 50% interest in the 1,102 acre onshore PEP 54879 (Cheal South) in March 2017.
- Capital expenditures totalled $15.6 million compared to $11.8 million for fiscal year 2016. The majority of the expenditure related to the following:
  - Taranaki development drilling and waterflood, workovers and facility improvements ($7.4 million).
  - Taranaki exploration activities ($5.4 million).
  - Australian PL17 acquisition and seismic planning ($2.6 million).
  - Other Assets ($0.2 million).

FORTH QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2017, the Company had $21.6 million (December 31, 2016: $10.0 million) in cash and cash equivalents and $25.9 million (December 31, 2016: $17.5 million) in working capital.
- Average net daily production increased by 3% for the quarter ended March 31, 2017, to 1,218 boe/d (79% oil) from 1,185 boe/d (80% oil) for the quarter ended December 31, 2016. A breakdown of net production is as follows:
  - Average net daily oil production increased by 2% to 964 bbl/d compared with 944 bbl/d for the quarter ended December 31, 2016. The increase is primarily a result of additional oil production at Sidewinder following a workover on Sidewinder-2 completed in Q4 2017.
  - Average net daily gas production increased by 5% to 1.5 MMcf/d compared with 1.4 MMcf/d for the quarter ended December 31, 2016. The increase is due to additional gas production at Sidewinder due to the overall uplift in production following the workover at Sidewinder-2 completed in Q4 2017.

- Revenue from oil and gas sales increased by 4% for the quarter ended March 31, 2017, to $6.3 million from $6.0 million for the quarter ended December 31, 2016. The 4% increase is due to a 5% increase in average Brent oil prices, a 44% drop in gas price and an increase in oil volume of 2% and gas volume of 5%. Revenues generated from oil and gas sales increased by 25% for the quarter ended March 31, 2017, to $6.3 million from $5.0 million for the quarter ended March 31, 2016. The increase is attributable to a 40% increase in average Brent oil prices, partly offset by a reduction in total gas sold by 111 boe/d or 54% as a result of Cheal-E4 being shut-in during Q4 2017.
- Operating netbacks increased by 15% for the quarter ended March 31, 2017, to $27.46 per boe compared with $23.86 per boe for the quarter ended December 31, 2016. The increase is attributable to a 5% increase in average Brent oil prices and an 13% decrease in production costs per boe due to Cheal-B5 work order in Q3 2017. Operating netbacks increased by 50% for the quarter ended March 31, 2017 to $27.46 per boe compared with $18.33 per boe for the for the quarter ended March 31, 2016. The increase is attributable to 40% increase in average Brent oil prices, partly offset by a 33% increase in production costs per boe. The increase in production costs are due to temporarily increased manning, repairs and maintenance at the Sidewinder production station.
- Capital expenditures totalled $8.1 million for the quarter ended March 31, 2017 compared to $1.5 million for the quarter ended December 31, 2016. The majority of the expenditure in Q4 2017, related to the Supplejack-A2X exploration well, Sidewinder-2 gas lift, Cheal-E waterflood and PL17 acqusition costs.
- On January 31, 2017, the Company's wholly owned Australian subsidiary, Cypress Petroleum Pty Ltd., closed the purchase of 100% interest in PL17 production license in the Surat Basin of Australia for AUD$2.5 million over three years. The 25,700 acre block currently has 8 bbl/d of oil production from two wells and several exploration and appraisal prospects.
- On March 20, 2017, the Company announced that it had closed a short form prospectus offering (the “Offering”) for aggregate gross proceeds of $14,995,500. The Company issued 23,070,000 units (“Units”) at a price per Unit of $0.65. Each Unit consists of one common share of the Company and one-half of one common share purchase warrant (each whole warrant a “Warrant”). Each Warrant shall be exercisable into one common share at a price of $0.90 for 24 months following the closing date of the Offering. The net proceeds of the Offering will be used for general corporate purposes, which will include appraisal and development activities at Cardiff, Cheal, Sidewinder East and Puka.
- Drilling operations have been completed at the Supplejack-A2X exploration commitment well having reached the planned total depth of 1,740 m. Well logs indicated the presence of well-developed reservoir sands; however, the sands were found to be water wet and the decision was made to plug and abandon the well. The well was targeting a potential extension of the Supplejack field, which was successfully tested late last year to flow gas at rates of up to 7.2 MMcf/d from the Mt. Messenger Formation. All current drilling commitments on the Sidewinder North permit have now been met and development of the Supplejack field is continuing.
- Following the success of a low-cost perforation of a deeper zone in the existing Sidewinder-1 wellbore, a further workover on Sidewinder-2 was completed in Q4 2017, with initial response of an additional 70 boe/d of production.
- TAG’s second water flood project in New Zealand has commenced at the Cheal East permit with water injection via the Cheal-E7 well. Water injection rates are approximately 1,200 bbl/d.
- Clean up and testing operations are continuing on the Cardiff-3 well, which continues to flow intermittently at rates of 200 boe/d. TAG is planning several upcoming interventions to improve and stabilize flow rates out of the well.
- At Cheal, the Cheal-B waterflood is continuing with injection of approximately 900 bbl/d of water. Recent production rates from wells draining the Cheal-B pool have indicated that the wells are beginning to experience a positive production rate impact from the waterflood program. This effect is expected to increase over the upcoming months as water injection continues.

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

TAG and its joint venture partner, Melbana Energy Ltd. (“Melbana”), have approved drilling of the Pukatea-1 well, located onshore in New Zealand within the Puka permit (PEP 51153), 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 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.

On May 24, 2017, TAG announced that the Cheal-E8 exploration well was successfully drilled and flow tested on its 70% working interest and operated Cheal East permit (PEP 54877) in the Taranaki Basin of New Zealand. The well was drilled and completed on time and on budget to a total measured depth of over 2,000 m. The primary objective of Cheal-E8 was to test the potential of the Urenui formation, with the deeper Mt. Messenger formation as the secondary objective. Net pay of approximately 17 m of Urenui sands and 4 m of Mt. Messenger sands was recorded.

Following the completion of the Urenui zone, Cheal-E8 naturally free flowed oil and gas on choke at an average rate of 318 boe/d during a four and a half day test. No water production was observed during the test. The Cheal-E8 well will now be tied-in to TAG's existing infrastructure as a permanent producer.

The Company's next exploration well will be Cheal-D1, which will also be drilled on the Cheal East permit, and is scheduled to spud in July 2017. Construction of the Cheal-D well pad is currently underway and is proceeding on schedule. The Cheal-D well pad will be used to explore the northern portion of the Cheal East permit.

RESERVES UPDATE

		FY2017	FY2016	FY2015
Opening 2P reserves	Mboe	3,619	5,180	5,898
Production	Mboe	(421)	(507)	(677)
2P Reserves net additions	Mboe	946	(1,054)	(41)
Closing 2P reserves	Mboe	**4,143**	**3,619**	**5,180**
2P year end valuation (NPV 10% before tax)	mmCdn$	$82.12	$45.92	$114.70
2P year end valuation (NPV 10% after tax)	mmCdn$	$78.33	$45.92	$108.71
Future capital expenditure included in 2P valuation	mmCdn$	$49.67	$54.63	$65.50

The Company’s year-end independent reserves assessment on its interests within the Cheal, the Cheal East and the Sidewinder permits, within the onshore Taranaki Basin, New Zealand, dated March 31, 2017, assigned a pre-tax net present value of $82.12 million (2016: $45.92 million), using a 10% discount rate to net 2P reserves.

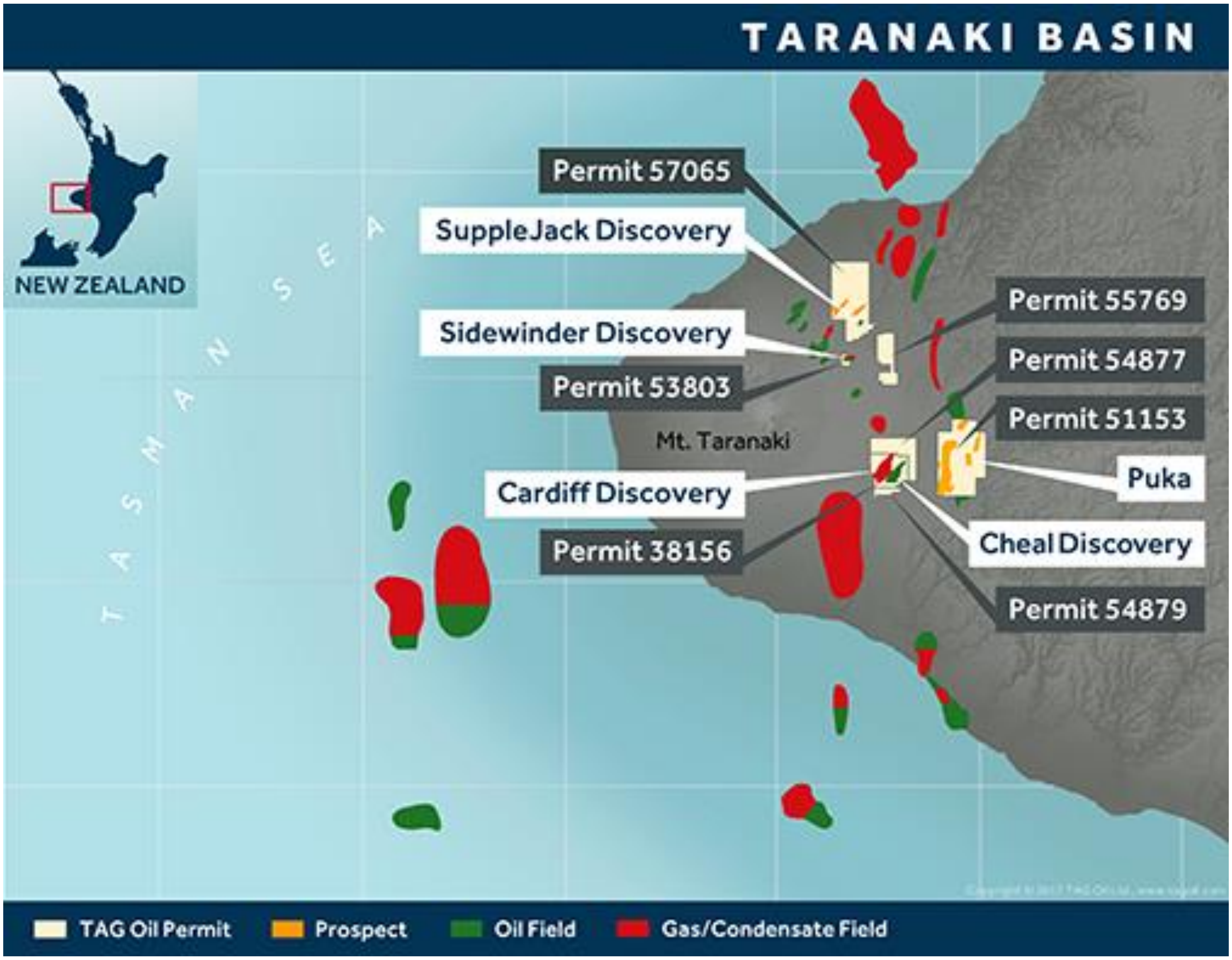
Net 2P reserves estimates within the Taranaki Basin at March 31, 2017, were 4,143 Mboe compared to fiscal year 2016 2P reserves of 3,619 Mboe. Taking into account the 421 Mboe the Company produced over the 12-month period and the 946 Mboe increase for technical revisions and economic factors, the Company’s reserves increased by 14%. The technical revisions and economic factors relate to additional reserves assigned due to improved recovery for waterflood response at the Cheal A and B-Sites; inclusion of reserves previously classified as NRA due to operational issues at the Cheal E-Site; added reserves at the Sidewinder permit following recompletions of the Sidewinder-1 and 2 wells and reserves that are now economically recoverable at the current price.

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

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 PMP 38156 (Cheal) and PMP 53803 (Sidewinder) mining permits.
- 100% interest in PEP 55769 (Sidewinder East) and PEP 57065 (Sidewinder North) exploration permits.
- 70% interest in PEP 54877 (Cheal East) exploration permit.
- 50% interest in PEP 54879 (Cheal South) 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 21 shallow wells on full, part-time or constrained production out of a total of 53 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 1,218 boe/d (79% oil) in Q4 2017, compared to an average of 1,185 boe/d (80% oil) in Q3 2017 and 1,251 boe/d (77% oil) in Q4 2016. The increase compared to Q3 2017, is primarily due to additional production at Sidewinder following a workover of the Sidewinder-2 well in Q4 2017. This was partly offset by reduced production at Cheal-E due to the Cheal-E4 well being shut-in during Q4 2017.

The Cheal A, B and C facilities (PMP 38156: TAG 100% interest) produced an average of 683 boe/d (89% oil) in Q4 2017, compared to an average of 684 boe/d (87% oil) in Q3 2017, and 870 boe/d (91% oil) in Q4 2016. The minor decrease compared to Q3 2017 is due to natural decline.

The Cheal East permit (PEP 54877: TAG 70% interest) produced an average of 266 boe/d (61% oil) in Q4 2017, versus an average of 289 boe/d (64% oil) in Q3 2017 and 333 boe/d (53% oil) in Q4 2016. The decrease compared to Q3 2017 is largely due to the Cheal-E4 well being shut-in.

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 a pressure maintenance and waterflood program.

The Sidewinder field produced an average of 269 boe/d (73% oil) in Q4 2017, compared to an average of 212 boe/d (77% oil) in Q3 2017, and 48 boe/d (3% oil) in Q4 2016. The increase is due to additional oil production at Sidewinder-2 following completion of the well workover in Q4 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 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 in 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 liquids rich gas condensate fields that have been discovered in the Taranaki Basin.

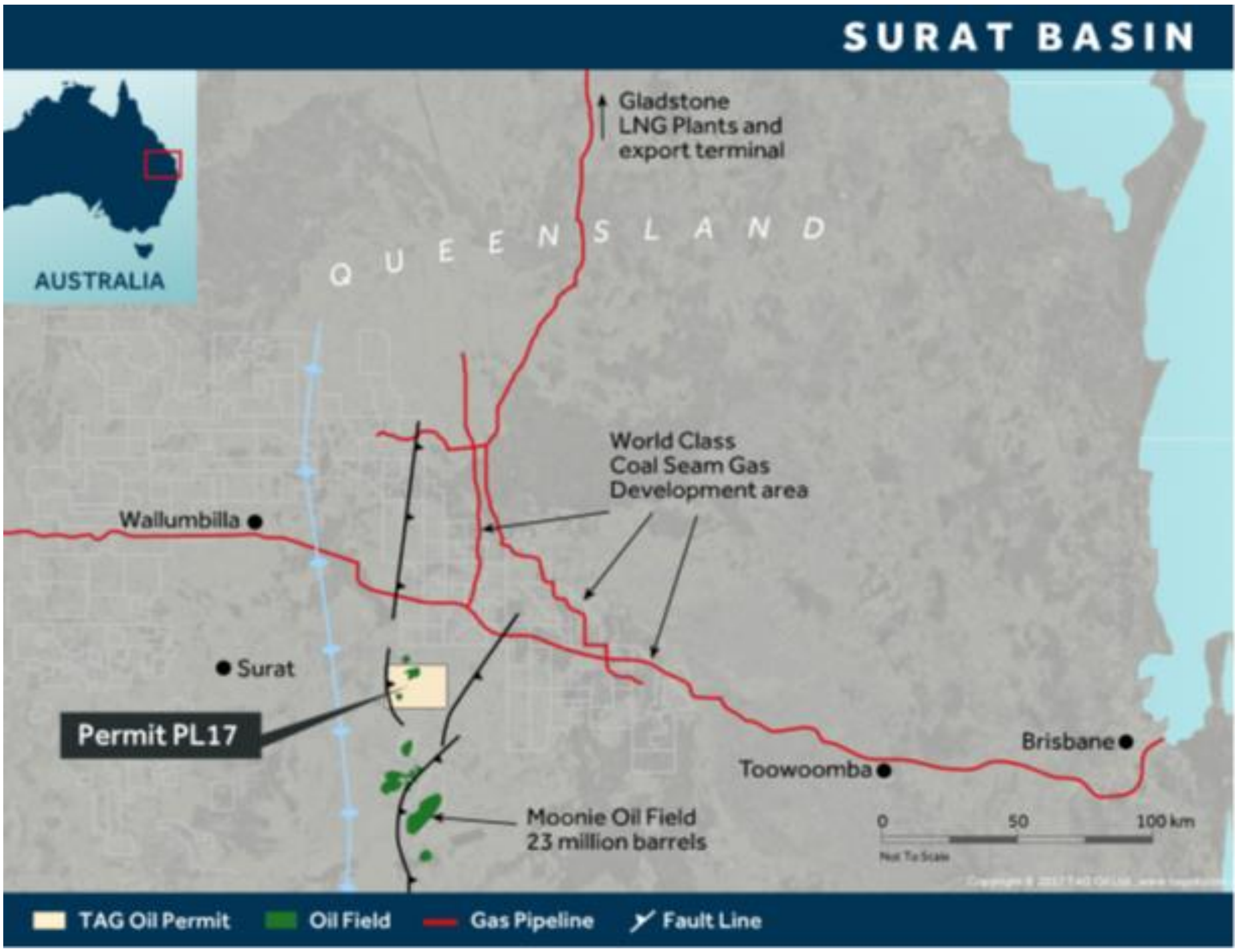
The Cardiff structure, identified on seismic, is an extensive linear fault bound high which is approximately 12 km long and 3 km wide. Cardiff-3, drilled by TAG in FY2014, encountered 230 m of gas and condensate bearing sands over three target zones within the Kapuni formation. The deepest zone, the "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-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 well, which continues to flow intermittently at rates of up to 200 boe/d. TAG is planning several upcoming interventions to improve and stabilize flow rates out of the well.

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.

Surat Basin:

TAG holds 100% working interest in PL17, which is an oil and gas production permit and potentially high-value exploration acquisition that covers 104 km^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 issituated approximately 20 km from the Moonie oil field, which has produced approximately 25 MMbbl to date. PL17 contains two undeveloped 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 2,000 m) since being discovered in the 1960s, with current production from the Bennett Field of approximately 8 bbl/d of oil from dated production equipment. TAG plans 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 work plans at PL17 include mechanical enhancements to the existing dated production equipment and the acquisition of 70 km^2 of 3D seismic over the most prospective area of the block. This 3D seismic program will better define structures and prospects that exist in the Hutton Sand and Precipice oil fairways, and give TAG a better understanding of the deeper Permian tight gas/condensate potential. This work program is expected to commence in mid-2017 and is anticipated to be followed with a multi-target drilling campaign.

Deep Permian Play

PL17 also has high-impact exploration potential in the deeper Permian formation, and is the primary unconventional tight gas and condensate play opportunity within PL17. The Permian formation lies approximately 1,000 m 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.

OUTLOOK FOR FISCAL YEAR 2018

TAG's capital budget for fiscal year 2018 is $27.4 million, which we project to be funded entirely by forecasted cash flow and working capital on hand. A further $8.4 million of incremental capital expenditures are contingent mainly on the results of the activities outlined below, the status of locating suitable joint venture or farm-in partners and notable improvements in oil prices. Farm-out discussions have commenced and more information will be provided as it becomes available in due course. TAG intends to diligently manage its balance sheet.

As TAG enters the next phase of its reserve and production growth, the FY2018 capital budget of $27.4 million will re-introduce an exploration focused capital program for the Company and continue with other necessary activities that are core to its business. These opportunities have been identified through an extensive ongoing geological and engineering review of the Company's development and exploration acreage, and namely include the following:

- Drilling of one further exploration well at PEP 54877 (Cheal East);
- Drilling of one exploration well at PEP 51135 (Puka);
- Drilling of up to two exploration wells at PEP 55769 (Sidewinder East);
- Commencement of the Cheal A-Site waterflood program;
- Continued appraisal of the Cardiff field; and
- Meeting various permit obligations, including the acquisition and reprocessing of seismic data on PEP 57065 (Sidewinder North) and PL17, which will allow TAG to properly select exploration drilling opportunities.

Guidance

TAG is estimating that FY2018 revenue from operations will be $28 million, with production averaging approximately 1,400 boe/d (75% oil). TAG expects to exit FY2018 with production of approximately 1,900 boe/d. This guidance is based on TAG's optimization of in-field opportunities and existing production, and assumes a Brent oil price for the year of US$55 per bbl. An increase in oil prices or success from any of the five planned exploration wells to be drilled in the next 12 months would have a positive impact on this guidance. Should oil prices remain significantly below US$55 per bbl for any length of time, TAG may reduce its capital program and/or activities to protect its balance sheet.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2017		2016	Twelve months ended March 31,	
Daily production volumes (1)	**Q4**	Q3	Q4	**2017**	2016
Oil (bbl/d)	**964**	944	968	**948**	1,019
Natural gas (boe/d)	**254**	241	283	**252**	367
Combined (boe/d)	**1,218**	1,185	1,251	**1,200**	1,386
% of oil production	**79%**	80%	77%	**79%**	74%
Daily sales volumes (1)					
Oil (bbl/d)	**971**	954	991	**944**	1,030
Natural gas (boe/d)	**96**	67	207	**113**	254
Combined (boe/d)	**1,067**	1,021	1,198	**1,057**	1,284
Natural gas (MMcf/d)	**576**	401	1,242	**677**	1,526
Product pricing					
Oil ($/bbl)	**69.47**	66.12	49.55	**64.21**	59.69
Natural gas ($Mcf)	**3.55**	6.36	4.84	**4.89**	4.14
Oil and natural gas revenues (3) - gross *($000s)*	**6,256**	6,038	5,013	**23,341**	24,810
Oil & natural gas royalties (2)	**(648)**	(649)	(466)	**(2,359)**	(2,239)
Oil and natural gas revenues - net *($000s)*	**5,608**	5,389	4,547	**20,982**	22,571

(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 3% for the quarter ended March 31, 2017 to 1,218 boe/d (79% oil) from 1,185 boe/d (80% oil) for the quarter ended December 31, 2016. The increase is primarily due to additional production at Sidewinder following a workover of the Sidewinder-2 well in Q4 2017. This was partly offset by reduced production at the Cheal East permit due to Cheal-E4 beind shut-in during Q4 2017.

Oil and natural gas gross revenue increased by 4% for the quarter ended March 31, 2017, to $6.3 million from $6.0 million for the quarter ended December 31, 2016. The 4% increase is due to a 5% increase in average Brent oil prices, a 44% drop in gas price and a increase in oil volume of 2% and gas volume of 5%.

SUMMARY OF QUARTERLY INFORMATION

	2017				2016			
Canadian $000s, except per share or boe	**Q4**	Q3	Q2	Q1	Q4 *(2)*	Q3 *(2)*	Q2 *(2)*	Q1 *(2)*
Net production volumes (boe/d)	**1,218**	1,185	1,176	1,222	1,251	1,263	1,341	1,689
Total revenue	**6,256**	6,038	5,226	5,821	5,013	5,078	5,713	9,006
Operating costs	**(3,619)**	(3,796)	(3,477)	(2,848)	(3,014)	(3,607)	(3,428)	(4,133)
Foreign exchange	**(175)**	178	(13)	(195)	(307)	(279)	810	553
Share-based compensation	**(217)**	(355)	(149)	(223)	(487)	(218)	(403)	(896)
Other costs	**(3,845)**	(4,224)	(6,260)	(4,180)	(5,555)	(4,668)	(4,495)	(5,600)
Exploration impairment	**(93)**	(86)	(17)	(100)	(3,676)	(2,104)	(2,740)	(715)
Property reversal (impairment)	**35,040**	-	-	-	(59,287)	-	-	-
Net income (loss) from discontinued operations	**-**	-	-	-	2,054	(6,472)	(132)	(615)
Net income (loss) before tax	**33,347**	(2,245)	(4,690)	(1,725)	(65,259)	(12,270)	(4,675)	(2,400)
Earnings (loss) per share – basic	0.53	(0.04)	(0.08)	(0.03)	(1.05)	(0.20)	(0.08)	(0.04)
Earnings (loss) per share – diluted	0.52	(0.04)	(0.07)	(0.03)	(1.05)	(0.20)	(0.08)	(0.04)
Capital expenditures	**8,125**	1,513	3,161	2,773	2,859	3,266	2,755	2,916
Operating cash flow *(1)*	**844**	822	407	1,625	1,695	(1,540)	1,263	3,071

(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 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 4% for the quarter ended March 31, 2017, to $6.3 million from $6.0 million for the quarter ended December 31, 2016. The 4% increase is due to a 5% increase in average Brent oil prices, a 44% drop in gas price and a increase in oil volume of 2% and gas volume of 5%. Revenues generated from oil and gas sales increased by 25% for the quarter ended March 31, 2017, to $6.3 million from $5.0 million for the quarter ended March 31, 2016. The increase is attributable to a 40% increase in average Brent oil prices, partly offset by a reduction in total gas sold by 111 boe/d or 54% as a result of Cheal-E4 being shut-in during Q4 2017.

Operating costs decreased by 5% for the quarter ended March 31, 2017, to $3.6 million from $3.8 million for the quarter ended December 31, 2016. Operating costs decreased by 5% as a result of the Cheal-B5 work order having been completed during Q3 2017, partly offset by increased repairs and maintenance at the Sidewinder production station for wireline services and gas compressor repairs in Q4 2017. Operating costs increased by 20% for the quarter ended March 31, 2017, to $3.6 million from $3.0 million for the quarter ended March 31, 2016. The increase is attributable to increased temporary manning, repairs and maintenance at the Sidewinder production station for wireline services and gas compressor maintenance; and additional royalty costs associated with increased revenue.

Other costs decreased by 9.9% for the quarter ended March 31, 2017, to $3.8 million from $4.2 million for the quarter ended December 31, 2016. The 9.9% decrease is mainly due to a loss on sale of Coronado assets of $0.5 million in Q3 2017. Other costs decreased by 31% for the quarter ended March 31, 2017 to $3.8 million from $5.6 million for the quarter ended March 31, 2016. The 31% decrease compared to Q4 2016, is mainly due to a 44% 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 income before tax for the quarter ended March 31, 2017, was $33.3 million compared to a net loss of $2.2 million for the quarter ended December 31, 2016. Excluding impairment expense or write back, on a comparative basis, equates to a net loss before tax of $1.6 million for the quarter ended March 31, 2017, compared to a net loss of $2.1 million for the quarter ended December 31, 2016. Net income before tax for the quarter ended March 31, 2017, was $33.3 million compared to a net loss of $65.3 million for the quarter ended March 31, 2016. Excluding impairment expense or write back and net loss from discontinued operations, on a comparative basis, equates to a net loss before tax of $1.6 million for the quarter ended March 31, 2017, compared to a net loss of $4.5 million for the quarter ended March 31, 2016.

Exploration and property impairment reversal for the quarter totalled $35.0 million following a comprehensive impairment review of the carrying value of its exploration and evaluation (E&E) and property, plant and equipment (PP&E) assets. The Company has booked the impairment write back as a result of the increase in the Company's reserve position and an increase to commodity prices.

Net Production by Area (boe/d)

Area	2017		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
PMP 38156 (Cheal)	**683**	684	870	**768**	840
PEP 54877 (Cheal East)	**266**	289	333	**269**	454
PMP 53803 (Sidewinder)	**269**	212	48	**163**	92
Total boe/d	**1,218**	1,185	1,251	**1,200**	1,386

Average net daily production increased by 3% for the quarter ended March 31, 2017, to 1,218 boe/d (79% oil) from 1,185 boe/d (80% oil) for the quarter ended December 31, 2016. The increase is primarily due to additional production at Sidewinder following a workover of the Sidewinder-2 well in Q4 2017. This was partly offset by reduced production at the Cheal East permit due to Cheal-E4 being shut-in during Q4 2017.

Average net daily production decreased by 13% for the fiscal year ended March 31, 2017, to 1,200 boe/d (79% oil) from 1,386 boe/d (74% oil) for the fiscal year ended March 31, 2016. The 13% decrease is primarily due to Cheal-B5 coming offline in September 2016 due to mechanical issues, Cheal-E6 being offline for all of fiscal year 2017 following issues with the jet pump and natural decline in production. This is partly offset by additonal production at Sidewinder as a result of work overs to Sidewinder-1 and Sidewinder-2 wells enabling access to a previously unproduced oil leg.

Oil and Gas Operating Netback ($/boe)

	2017		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Oil and natural gas revenue	**65.15**	64.29	45.98	**60.48**	52.79
Royalties	**(6.75)**	(6.91)	(4.27)	**(6.11)**	(4.76)
Transportation and storage costs	**(8.73)**	(7.85)	(6.68)	**(7.64)**	(7.89)
Production costs	**(22.21)**	(25.67)	(16.70)	**(21.85)**	(17.53)
Operating Netback per boe ($)	**27.46**	23.86	18.33	**24.88**	22.61

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 15% for the quarter ended March 31, 2017, to $27.46 per boe compared with $23.86 per boe for the quarter ended December 31, 2016. The increase is attributable to a 5% increase in average Brent oil prices and an 13% decrease in production costs per boe due to the Cheal-B5 work order in Q3 2017.

Operating netback increased by 10% for the fiscal year ended March 31, 2017, to $24.88 per boe compared with $22.61 per boe for the for the fiscal year ended March 31, 2016. The increase is attributable to an 8% increase in average Brent oil prices, partly offset by a 25% increase in production costs per boe. The increase in production costs is a result of additional production costs at Sidewinder for increased plant uptime and reduced overall production volumes.

General and Administrative Expenses ("G&A")

	2017		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Oil and Gas G&A expenses ($000s)	**1,552**	1,517	1,483	**5,586**	5,913
Oil and Gas G&A per boe ($)	**14.16**	13.91	13.03	**12.75**	11.66
Mining G&A expenses ($000s)	**30**	58	13	**209**	613
Total G&A Expenses	**1,582**	1,575	1,496	**5,795**	6,526

Total G&A expenses remained flat for the quarter ended March 31, 2017 and the quarter ended December 31, 2017, at $1.6 million. Oil and Gas G&A expenses have increased by 2% due to external reserves reporting fees in Q4 2017.

Total G&A expenses decreased by 11% for the fiscal year ended March 31, 2017, to $5.8 million compared with $6.5 million for the fiscal year ended March 31, 2016. Oil and Gas G&A expenses have decreased 5% due primarily to lower wages and salaries cost. Electricity/Mining G&A expenses have also decreased 66% due to G&A relating to the electricity business being sold.

Share-based Compensation

	2017		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Share-based compensation ($000s)	**217**	355	487	**944**	2,004
Per boe ($)	**1.98**	3.26	4.28	**2.16**	3.95

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 63.28% and a risk-free interest rate of 1.24%. 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 March 31, 2017, the Company granted no options (December 31, 2016: 1,585,000) and no options were exercised (December 31, 2016: nil).

Share-based compensation decreased by 39% for the quarter ended March 31, 2017, to $0.2 million compared with $0.4 million for the quarter ended December 31, 2016. The decrease in total share-based compensation costs is due to no new options being granted during Q4 2017 and declining amortization based on vesting terms on options previously granted. During Q3 2017, 1.6 million options were granted.

Share-based compensation decreased to $0.9 million in the fiscal year ended March 31, 2017, compared with $2.0 million for the fiscal year ended March 31, 2016. The decrease in total share-based compensation costs is due to the reduced amortization of estimated charge for the 1.6 million options granted during the fiscal year ended March 31, 2017, compared to the amortization of estimated charge for the 4.7 million options granted during the fiscal year ended March 31, 2016.

Depletion, Depreciation and Accretion (DD&A)

	2017		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Depletion, depreciation and accretion ($000s)	**2,149**	2,088	3,816	**8,734**	13,677
Per boe ($)	**19.60**	19.15	33.52	**19.94**	26.96

DD&A expenses increased by 3% for the quarter ended March 31, 2017, to $2.15 million compared with $2.1 million for the quarter ended December 31, 2016. The increase in Q4 2017 is attributable to lower gas sales during Q3 2017, as a result of a compressor outage at the Cheal plant. Oil production used to calculate the depletion rate on the depletable base has also increased for the quarter ended March 31, 2017.

DD&A expenses decreased by 36% for the fiscal year ended March 31, 2017, to $8.7 million compared with $13.7 million for the fiscal year ended March 31, 2016. 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	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Foreign exchange loss / (gains) ($000s)	**175**	(178)	307	**206**	(777)

The foreign exchange loss for the quarter ended March 31, 2017, was a result movement in USD against the NZD resulting in foreign exchange loss on the USD denominated oil receipts.

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

	2017		**2016**	Twelve months ended March 31,	
($000s)	**Q4**	Q3	Q4	**2017**	2016
Net income (loss) before tax	**33,347**	(2,245)	(65,259)	**24,687**	(84,604)
Income tax recovery (expense) - deferred	**-**	-	-	**-**	-
Net income (loss) after tax	**33,347**	(2,245)	(65,259)	**24,687**	(84,604)
Earnings (loss) per share, basic ($)	**0.53**	(0.04)	(1.05)	**0.39**	(1.36)
Earnings (loss) per share, diluted ($)	**0.52**	(0.04)	(1.05)	**0.38**	(1.36)

Net income before tax for the quarter ended March 31, 2017, was $33.3 million compared to a net loss of $2.2 million for the quarter ended December 31, 2016. Excluding impairment expense or write back, on a comparative basis, equates to a net loss before tax of $1.6 million for the quarter ended March 31, 2017, compared to a net loss of $2.1 million for the quarter ended December 31, 2016. The decreased loss is due to a combination of increased revenue as a result of a 5% increase in average Brent oil prices, a loss on sale of Coronado assets of $0.5 million in Q3 2017 and a 13% decrease in production costs per boe due to completion of the Cheal-B5 work order in Q3 2017.

Net income before tax for the fiscal year ended March 31, 2017, was $24.7 million compared to a net loss of $84.6 million for the fiscal year ended March 31, 2016. Excluding impairment expense or write back and net loss from discontinued operations, on a comparative basis, equates to a net loss before tax of $10.0 million for the fiscal year ended March 31, 2017, compared to a net loss of $11.5 million for the fiscal year ended March 31, 2016. The reduced loss is predominately attributable to a 8% increase in average Brent oil prices, reduced salary and wages costs 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**	Twelve months ended March 31,	
($000s)	**Q4**	Q3	Q4	**2017**	2016
Operating cash flow *(1)*	**844**	820	1,695	**3,695**	**4,489**
Cash provided by operating activities	**318**	66	6,174	**1,463**	**9,649**
Earnings (loss) per share, basic ($)	**0.01**	0.00	0.10	**0.02**	**0.15**
Earnings (loss) per share, diluted ($)	**0.00**	0.00	0.10	**0.02**	**0.15**

(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 3% for the quarter ended March 31, 2017, to $0.8 million versus operating cash flow of $0.8 million for the quarter ended December 31, 2016. The increase is a result of increased revenue due to a 5% increase in average Brent oil prices and reduced operating costs relating to workover activities completed in Q3 2017.

Operating cash flow decreased by 18% for the fiscal year ended March 31, 2017, to $3.7 million versus operating cash flow of $4.5 million for the fiscal year ended March 31, 2016. The decrease is due to lower revenue as a result of a 13% decrease in average net daily production, primarily due Cheal-B5 coming offline in September 2016 due to mechanical issues, Cheal-E6 being offline for all of fiscal year 2017 following issues with the jet pump and natural decline in production.

CAPITAL EXPENDITURES

Capital expenditures were $15.6 million for the fiscal year ended March 31, 2017, compared to $11.8 million for the fiscal year ended March 31, 2016.

The majority of the expenditure related to the following:

- Taranaki development drilling and waterflood, workovers and facility improvements ($7.4 million).
- Taranaki exploration activities ($5.4 million).
- Australian PL17 acquisition and siesmic planning ($2.6 million).
- Other Assets ($0.2 million).

Taranaki Basin ($000s)	**2017**		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Mining permits	**1,877**	1,073	2,405	**7,396**	9,248
Exploration permits	**3,733**	364	493	**5,367**	1,382
Opunake Hydro Limited	**-**	-	0	**-**	661
Total Taranaki Basin	**5,610**	1,437	2,898	**12,763**	11,291

Australia Surat Basin ($000s)	**2017**		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Exploration permits	**2,539**	60	-	**2,599**	-
Total Surat Basin	**2,539**	60	-	**2,599**	-

United States ($000s)	**2017**		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Madison mine - exploration	**-**	-	**-**	**167**	483
Madison mine - development	**-**	-	**-**	**-**	-
Total United States	**-**	-	**-**	**167**	483

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at March 31, 2017:

Contractual Obligations ($000s)	**Total**	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases *(1)*	**808**	197	611	-
Other long-term obligations *(2)*	**30,172**	28,851	1,321	-
Total contractual obligations *(3)*	**30,980**	29,048	1,932	-

(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 statutory inspections	3,584	93	-
PMP 53803	Permanent gas lift completion	81	-	-
PEP 54877	Drilling of two shallow exploration wells, pad construction and E1 rod pump	5,902	-	-
PEP 54879	Annual lease and G&G studies	144	-	-
PEP 51153	Facilities preservation, one exploration well and G&G studies	4,802	-	-
PEP 55769	G&G studies and two exploration wells (2018)	7,874	-	-
PEP 57065	2-D seismic acquisition	3,459	-	-
PEP 38349	*Relinquished (site reinstatement)*	66	-	-
PL 17	Permit settlement and seismic acquisition	2,939	1,228	-
	TOTAL COMMITMENTS	**28,851**	**1,321**	**-**

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)	For the year ended March 31, 2017	For the year ended March 31, 2016	For the year ended March 31, 2015
Cash and cash equivalents	**$21,565**	**$16,846**	**$27,055**
Working capital	$25,907	$22,110	$27,793
Contractual obligations, next twelve months	$28,851	$9,230	$71,775
Revenue(1)	$23,341	$24,810	$49,377
Cashflow from operating activities	$1,463	$9,649	$28,628

(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	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Cash provided by operating activities	**318**	66	6,174	**1,463**	9,649
Changes for non-cash working capital accounts	**526**	754	(4,479)	**2,233**	(5,160)
Operating cash flow	**844**	820	1,695	**3,695**	4,489

Operating Margin ($000s)	2017		2016	Twelve months ended March 31,	
	Q4	Q3	Q4	**2017**	2016
Total revenue	**6,256**	6,038	5,013	**23,341**	24,810
Less royalties	**(648)**	(649)	(466)	**(2,359)**	(2,239)
Less transportation and storage	**(838)**	(737)	(728)	**(2,950)**	(3,706)
Less total production costs	**(2,133)**	(2,411)	(1,820)	**(8,431)**	(8,238)
Operating margin	**2,637**	2,241	1,999	**9,601**	10,627

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	Twelve months ended March 31,	
($000s)	**Q4**	Q3	Q4	**2017**	2016
Share-based compensation	**131**	233	299	**616**	1,210
Management wages and director fees	**252**	251	211	**992**	913
Total Management Compensation	**383**	484	510	**1,608**	2,123

SHARE CAPITAL

a. At March 31, 2017, there were 85,282,252 common shares, 11,535,000 Warrants and 6,220,000 stock options outstanding.
b. At June 29, 2017, there were 85,282,252 common shares, 11,535,000 Warrants 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 twelve months ended March 31, 2017, 23,070,000 common shares were issued and none were purchased or cancelled.

SUBSEQUENT EVENTS

On May 25, 2017, the Company completed the distribution of approximately 2,785,029 common shares of Coronado (the "Coronado Shares") to its shareholders of record at the close of business on May 9, 2017 (the "Record Date"), and ceased to be a control person of Coronado. The Company's shareholders received approximately 0.0326 of a Coronado Share for each common share of the Company held as of the Record 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 1.74% and a risk free discount rate ranging from 3.00% to 4.36%, 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 year ended March 31, 2017. 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, but not yet effective as at March 31, 2017. 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, 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

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

There have been no changes in the Company's internal control over financial reporting during the year ended March 31, 2017, 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 March 31, 2017, 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 March 31, 2017. In making the assessment, it used the criteria set forth in the Internal Controls Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on their assessment, management has concluded that, as of March 31, 2017, 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 March 31, 2017, and are subject to change after this date. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive and as such undue reliance should not be placed on forward-looking statements. Except as required by applicable securities laws, with the exception of events or circumstances that occurred during the period to which the MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking information for a period that is not yet complete that was previously disclosed to the public, the Company disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

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

Disclosure provided herein in respect of boe (barrels of oil equivalent) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities", which refers to the lowest level at which reserves calculations are performed, and to "reported reserves", which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

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

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

CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Toby Pierce
CEO and Director
Vancouver, British Columbia

Alex Guidi
Chairman and Director
Vancouver, British Columbia

Keith Hill, Director
Key Largo, Florida

Ken Vidalin, 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, Corporate Secretary
Vancouver, British Columbia

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Vancouver, British Columbia

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Bell Gully
Wellington, New Zealand

AUDITORS

De Visser Gray LLP
Chartered Professional Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT

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100 University Avenue, 9th Floor
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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 June 29, 2017, there were 85,282,252 shares issued and outstanding.
Fully diluted: 103,037,252 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%)