MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated August 15, 2016, for the three months ended June 30, 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 three months ended June 30, 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 period ended June 30, 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 Canadian registered oil and gas producer and explorer with extensive operations and production infrastructure in the Taranaki Basin of New Zealand. As of the date of this MD&A, the Company controls a land holding consisting of eight onshore oil and gas permits amounting to 67,000 net acres of land.

During a period of ongoing economic uncertainty in the oil and gas industry, TAG's management has been able to remain disciplined and adapt where necessary to changing commodity prices and shareholder appetite for risk. TAG's focus on preserving its capital and reducing production and administrative costs wherever possible has not affected its vision of being a profitable production and exploration company in New Zealand and Australia. By focusing on its core producing operations, TAG has deferred the majority of its exploration focused capital program, and has relinquished several existing permits that had either large commitments or were no longer key to the Company's strategy.

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:

- Focus on planning and execution of key projects in its shallow Taranaki drilling program to grow reserves and production;
- Deploy enhanced oil recovery techniques in the Cheal field to optimize production and lower per barrel production costs to maximize the value of its operations;
- Enhance development of its exploration program and workover prospects;
- Review potential acquisitions of overlooked/undervalued opportunities in New Zealand;
- Assess acreage growth via the New Zealand Government's blocks offer programs;
- Consider select opportunities for international expansion in onshore Australia; and
- Manage its operating cash flows and balance sheet as effectively as possible to minimize costs while focusing on shareholder returns.

TAG is one of New Zealand's leading operators and is positioned for reserve-based growth with high impact exploration upside in the lightly explored Taranaki discovery fairway. 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 a financially strong entity that is well positioned for the future. Further, the Company is preparing to begin growing its production and reserves base again through exploration drilling.

FIRST QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At June 30, 2016, the Company had $15.0 million (March 31, 2016: $16.8 million; June 30, 2015: $20.5 million) in cash and cash equivalents and $20.9 million (March 31, 2016: $22.1 million; June 30, 2015: $26.1 million) in working capital.
- Average net daily production decreased by 2% for the quarter ended June 30, 2016 to 1,222 BOE/d (76% oil) from 1,251 BOE/d (77% oil) for the quarter ended March 31, 2016. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 4% to 933 bbl/d compared with 968 bbl/d for the quarter ended March 31, 2016. The decrease is primarily due to the Cheal-B8 and Cheal-E4 well being shut-in to allow for well stimulation projects and minor plant outages at the Cheal site.
  - Average net daily gas production increased by 2% to 1.73 MMSCFD compared with 1.70 MMSCFD for the quarter ended March 31, 2016. The increase is primarily due to higher gas volumes from the Sidewinder mining permit (PMP 53803) with the Sidewinder facility operating for 44 days during Q1 2017, compared to 36 days in Q4 2016.
- Average net daily production decreased by 28% for the quarter ended June 30, 2016 to 1,222 BOE/d (76% oil) from 1,689 BOE/d (73% oil) for the quarter ended June 30, 2015. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 24% to 933 bbl/d compared with 1,234 bbl/d for the quarter ended June 30, 2015. The decrease is primarily due to Cheal-B8 and Cheal-E4 being shut-in to allow for well stimulation projects and minor plant outages at the Cheal site.
  - Average net daily gas production decreased by 36% to 1.73 MMSCFD compared with 2.73 MMSCFD for the quarter ended June 30, 2015. The decrease is primarily due to lower gas volumes from the Sidewinder mining permit (PMP 53803) due to the Sidewinder facility operating for 44 days during Q1 2017, compared to 100 days in Q1 2016.
- Revenue from oil and gas sales increased by 16% for the quarter ended June 30, 2016 to $5.8 million from $5.0 million for the quarter ended March 31, 2016. The 16% increase is due to a 27% increase in average Brent oil prices. Revenues generated from oil and gas sales decreased by 35% for the quarter ended June 30, 2016 to $5.8 million from $9.0 million for the quarter ended June 30, 2015. The decrease is attributable to a 16% decrease in average Brent oil prices and total oil sold decreased by 320 bbl/d or 26% and total gas sold decreased by 64 BOE/d or 25%.
- Operating netback increased by 59% for the quarter ended June 30, 2016 to $29.17 per BOE compared with $18.33 per BOE for the quarter ended March 31, 2016. The increase is attributable to a 27% increase in average Brent oil prices and a 4% decrease in production costs per BOE, which was due to further power usage optimisation through power generation on the two megawatt gas-fired generators and no landowner payments made in Q1 2017 for Cheal E site as this was captured in Q4 2016. Operating netback decreased by 18% for the quarter ended June 30, 2016 to $29.17 per BOE compared with $35.61 per BOE for the for the quarter ended June 30, 2015. The decrease is attributable to the 16% decrease average Brent oil prices and a 4% increase in production costs per BOE.
- Capital expenditures totalled $2.8 million for the quarter ended June 30, 2016 compared to $2.9 million for the quarter ended March 31, 2016. The majority of the expenditure in Q1 2017 related to Cheal-B3 water flood and Cheal-G STOS 3D seismic.
- On June 6, 2016, the Company announced it had acquired a 70% working interest and operatorship of the PEP 51153 ("Puka") onshore permit in the Taranaki Basin of New Zealand. TAG's joint venture partner in the Puka permit is MEO Australia Limited ("MEO", 30%). The Puka permit covers an area of approximately 85 square kilometers (21,000 acres) and is located to the east of TAG's producing Cheal field. Three wells have been drilled since the Puka oil field was discovered in 2012, with the Puka-1 and Puka-2 wells producing 100 bbl/d from the Mt. Messenger formation before being shut-in due to low oil prices and down hole mechanical issues. The joint venture is committed to drilling one well on the Puka permit by Q4 2018 at a location and depth to be determined.

TAG Oil 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.

RECENT DEVELOPMENTS

The Cheal B Mt. Messenger pool has been identified as the first phase of a larger water flood project within the greater Cheal area. This project has been delayed by approximately two months due to an engineering re-design. The re-design will allow TAG to inject more water at increased rates and lower costs than the original design. The water flood project will aim to improve recovery and reserves from the Cheal B Mt. Messenger pool. The project includes re-completion of Cheal-A9, hook up and consent modifications required to utilise Cheal-A9 as a water producer for Cheal water flood pumps at Cheal A site, and converting Cheal-A2 into an injection well. Planning for re-completion of Cheal-A9 is currently underway; following completion, the water injection will commence and production response will be monitored throughout Q2 2017.

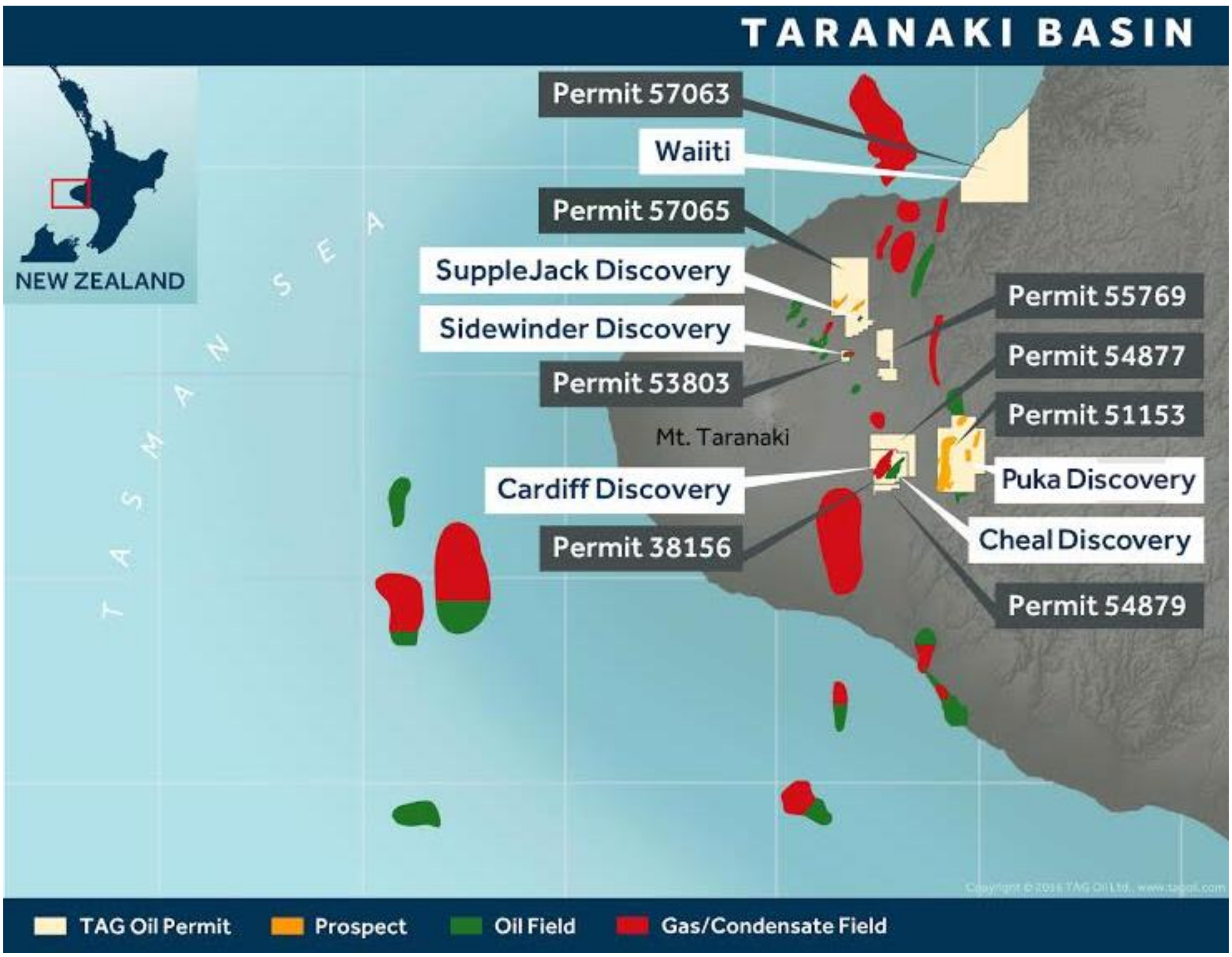
The water flood project has also been scoped at Cheal E site for implementation throughout Q2/Q3 2017. This will involve the provision of additional pumps and associated equipment, as well as converting Cheal-E7 into an injection well.

Recently, TAG successfully tested 254 bbl/d of oil and condensate from Sidewinder PMP 53803 over a 24-hour period using a temporary gas lift system. The Company has designed a permanent liquids production facility which will allow it to continually produce liquids at Sidewinder and is expected to commence production in two to three weeks' time. Further, net hydrocarbon production averaged 1,237 BOE/d for August (month to date), which excludes Sidewinder liquids production.

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 sq. km., 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, Greater Cheal, and Sidewinder fields have 20 shallow wells on full, part-time or constrained production out of a total of 40 wells. The remaining wells are shut-in pending work-overs and/or evaluation of economic re-completion methods.

TAG's shallow Miocene net production averaged 1,222 BOE/d (76% oil) in Q1 2017, compared to an average of 1,251 BOE/d (77% oil) in Q4 2016 and 1,689 BOE/d (73% oil) in Q1 2016. The decrease is primarily due to Cheal-B8 and E4 being shut-in to allow for well stimulation projects and minor plant outages at the Cheal site.

The Cheal A, B and C facilities (PMP 38156: TAG 100% interest) produced an average of 872 BOE/d (90% oil) in Q1 2017, compared to an average of 870 BOE/d (91% oil) in Q4 2016 and 997 BOE/d (85% oil) in Q1 2016.

The Cheal North East permit (PEP 54877: TAG 70% interest) produced an average of 281 net BOE/d (53% oil) in Q1 2017 versus an average of 333 BOE/d (53% oil) in Q4 2016 and 581 BOE/d (66% oil) in Q1 2016. The decrease compared to Q4 2016 is largely due to Cheal-E4 being shut-in to allow for well stimulation projects and minor plant outages at the Cheal site.

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 36 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 water-flood 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 69 BOE/d (4% oil) in Q1 2017, compared to an average of 48 BOE/d (3% oil) in Q4 2016 and 111 BOE/d (1% oil) in Q1 2016. The Sidewinder facility was operating for 44 days during Q1 2017, compared to 36 days in Q4 2016, as the Company continues to optimize the well operating mode to maximize well deliverability and economics.

The recently acquired Puka permit (PEP 51153: TAG 70% interest) covers an area of approximately 85 square kilometers (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 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 oil field, which has produced in excess of 23 MMbbl to date. The Douglas-1 well drilled in 2012 at the edge of the Shannon prospect encountered a 145m of reservoir interval and oil shows in a down-dip location, with more than 350m of up-dip potential estimated.

TAG and its joint venture partner, MEO, have agreed on a work program for the remainder of 2016 and will look to establish future plans for the acreage. The joint venture is committed to drilling one well on the Puka permit by Q4 2018 at a location and depth to be determined. 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 230m 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 the Cheal A site processing facilities and provides open access to the New Zealand gas sales network.

The Hellfire prospect, located within PMP 53803, has been identified on 3D seismic and also has similar geological features to the producing Kapuni field. Hellfire is a contingent well that could be drilled upon success of either Cardiff and/or on location of 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.

East Coast Basin

On December 4, 2015, the Company submitted notice to New Zealand Petroleum and Minerals of the surrender of PEP 38349 (Boar Hill and Ngapaeruru). Restoration of the Ngapaeruru well site is planned for Q2 2017.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2017	2016	
Daily production volumes (1)	**Q1**	Q4	Q1
Oil (bbl/d)	**933**	968	1,234
Natural gas (BOE/d)	**289**	283	455
Combined (BOE/d)	**1,222**	1,251	1,689
% of oil production	**76%**	77%	73%
Daily sales volumes (1)			
Oil (bbl/d)	**930**	991	1,250
Natural gas (BOE/d)	**190**	207	254
Combined (BOE/d)	**1,120**	1,198	1,504
Natural gas (MMcf/d)	**1,141**	1,242	1,522
Product pricing			
Oil ($/bbl)	**62.88**	49.55	74.94
Natural gas ($Mcf)	**4.82**	4.84	3.47
Oil and natural gas revenues (3) - gross *($000s)*	**5,821**	5,013	9,006
Oil & natural gas royalties (2)	**(548)**	(466)	(805)
Oil and natural gas revenues - net *($000s)*	**5,273**	4,547	8,201

(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.

Average net daily production decreased by 2% for the quarter ended June 30, 2016 to 1,222 BOE/d (76% oil) from 1,251 BOE/d (77% oil) for the quarter ended March 31, 2016. The decrease is primarily due to Cheal-B8 and E4 being shut-in to allow for well stimulation projects and minor plant outages at the Cheal site.

Oil and natural gas gross revenue increased by 16% for the quarter ended June 30, 2016 to $5.8 million from $5.0 million for the quarter ended March 31, 2016. The 16% increase is due to a 27% increase in average Brent oil prices.

SUMMARY OF QUARTERLY INFORMATION

	2017	2016				2015		
Canadian $000s, except per share or BOE	**Q1**	Q4 *(2)*	Q3 *(2)*	Q2 *(2)*	Q1 *(2)*	Q4 *(2)*	Q3 *(2)*	Q2 *(2)*
Net production volumes (BOE/d)	**1,222**	1,251	1,263	1,341	1,689	1,837	1,991	1,845
Total revenue	**5,821**	5,013	5,078	5,713	9,006	8,660	11,333	15,008
Operating costs	**(2,848)**	(3,014)	(3,607)	(3,428)	(4,133)	(3,928)	(4,790)	(5,222)
Foreign exchange	**(195)**	(307)	(279)	810	553	757	(344)	1,206
Share-based compensation	**(223)**	(487)	(218)	(403)	(896)	(380)	(586)	(356)
Other costs	**(4,180)**	(5,555)	(4,668)	(4,495)	(5,600)	(6,654)	(6,276)	(5,605)
Exploration impairment	**(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)	(281)	16
Net (loss) income before tax	**(1,725)**	(65,259)	(12,270)	(4,675)	(2,400)	(83,216)	(944)	5,147
Basic (loss) income $ per share	(0.03)	(1.05)	(0.20)	(0.08)	(0.04)	(1.30)	(0.01)	0.08
Diluted (loss) income $ per share	(0.03)	(1.05)	(0.20)	(0.08)	(0.04)	(1.30)	(0.01)	0.08
Capital expenditures	**2,773**	2,859	3,266	2,755	2,916	10,465	16,655	11,126
Operating cash flow *(1)*	**1,625**	1,695	(1,540)	1,263	3,071	2,826	3,968	9,702

(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 16% for the quarter ended June 30, 2016 to $5.8 million from $5.0 million for the quarter ended March 31, 2016. The increase is attributable to a 27% increase in average Brent oil prices. Revenues generated from oil and gas sales decreased by 35% for the quarter ended June 30, 2016 to $5.8 million from $9.0 million for the quarter ended June 30, 2015. The decrease is attributable to a 16% decrease in average Brent oil prices and total oil sold decreased by 320 bbl/d or 26% and total gas sold decreased by 64 BOE/d or 25%

Operating costs decreased by 6% for the quarter ended June 30, 2016 to $2.8 million from $3.0 million for the quarter ended March 31, 2016 and decreased by 31% for the quarter ended June 30, 2016 to $2.8 million from $4.1 million for the quarter ended June 30, 2015. Operating costs related to oil and gas activities decreased by 6% and 31% due to further power usage optimisation through power generation on the two megawatt gas-fired generators and no landowner payments made in Q1 2017 for Cheal E site, as this was captured in 2016. This was partly offset by higher repairs and maintenance work required due to an overhaul on one of the power generators and Cheal-A2 well investigation costs.

Other costs decreased by 25% for the quarter ended June 30, 2016 to $4.2 million from $5.6 million for the quarters ended March 31, 2016 and June 30, 2015. The 25% decrease compared to Q4 2016 is mainly due to a 39% 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. The 25% decrease compared to Q1 2016 is mainly due to a 40% 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. Oil and gas general and administrative costs have also decreased by 23% compared to Q4 2016 due to a further increase in timewriting allocations to capital projects; a reduction in professional fees due to audit costs captured in Q4 2016 and a reduction in report costs due to reserves reporting costs were captured in Q4 2016. Oil and gas general and administrative costs have also decreased by 32% compared to Q1 2016 due to a further increase in timewriting allocations to capital projects; a reduction in professional fees due to audit costs captured in Q1 2016.

Net loss before tax for the quarter ended June 30, 2016 was $1.7 million compared to a net loss of $65.3 million for the quarter ended March 31, 2016. Excluding impairment expense 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 June 30, 2016 compared to a net loss of $4.5 million for the quarter ended March 31, 2016. Net loss before tax for the quarter ended June 30, 2016 was $1.7 million compared to a net loss of $2.4 million for the quarter ended June 30, 2016. Excluding impairment of investments in the Q1 2017 and net loss from discontinued operations, on a comparative basis, equates to a net loss before tax of $1.0 million for the quarter ended June 30, 2016 compared to a net loss of $1.8 million for the quarter ended June 30, 2015.

Net Production by Area (BOE/d)

Area	2017	2016	
	Q1	Q4	Q1
PMP 38156 (Cheal)	**872**	870	997
PEP 54877 (Cheal North East)	**281**	333	581
PMP 53803 (Sidewinder)	**69**	48	111
Total BOE/d	**1,222**	1,251	1,689

Average net daily production decreased by 2% for the quarter ended June 30, 2016 to 1,222 BOE/d (76% oil) from 1,251 BOE/d (77% oil) for the quarter ended March 31, 2016. The decrease compared to Q4 2016 is primarily due to Cheal-B8 and E4 being shut-in to allow for well stimulation projects and minor plant outages at the Cheal site.

Average net daily production decreased by 28% for the quarter ended June 30, 2016 to 1,222 BOE/d (76% oil) from 1,689 BOE/d (73% oil) for the quarter ended June 30, 2015. The 28% decrease compared to Q1 2016 is due to a combination of natural decline rates, the well downtime related to the above-mentioned wells and Cheal-A10 not currently being in production due to wellhead seal failures.

Oil and Gas Operating Netback ($/BOE)

	2017	2016	
	Q1	Q4	Q1
Oil and natural gas revenue	**57.11**	45.98	65.81
Royalties	**(5.36)**	(4.27)	(5.88)
Transportation and storage costs	**(6.49)**	(6.68)	(8.83)
Production costs	**(16.09)**	(16.70)	(15.49)
Operating netback per BOE ($)	**29.17**	18.33	35.61

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 59% for the quarter ended June 30, 2016 to $29.17 per BOE compared with $18.33 per BOE for the quarter ended March 31, 2016. The increase is attributable to the 27% increase in average Brent oil prices and a 4% decrease in production costs per BOE due to to further power usage optimisation through power generation on the two megawatt gas-fired generators and no landowner payments made in Q1 2017 for Cheal E site, as this was captured in Q4 2016.

Operating netback decreased by 18% for the quarter ended June 30, 2016 to $29.17 per BOE compared with $35.61 per BOE for the quarter ended June 30, 2015. The decrease is attributable to the 13% decrease in oil and gas revenue per BOE driven by the 16% decrease in average Brent oil sales prices.

General and Administrative Expenses ("G&A")

	2017	2016	
	Q1	Q4	Q1
Oil and Gas G&A expenses ($000s)	**1,110**	1,483	1,314
Oil and Gas G&A per BOE ($)	**9.98**	13.03	8.55
Mining G&A expenses ($000s)	**48**	13	381
Total G&A Expenses	**1,158**	1,496	1,695

Total G&A expenses decreased by 23% for the quarter ended June 30, 2016 to $1.2 million compared with $1.5 million for the quarter ended March 31, 2016. Oil and Gas G&A expenses have decreased by 23% due to an increase in timewriting allocations to capital projects; a reduction in professional fees due to audit costs captured in Q4 2016 and a reduction in report costs due to reserves reporting costs that were captured in Q4 2016.

Total G&A expenses decreased by 32% for the quarter ended June 30, 2016 to $1.2 million compared with $1.7 million for the quarter ended June 30, 2015. Oil and Gas G&A expenses have decreased 32% due primarily to lower wages and salaries costs. Electricity/Mining G&A expenses have decreased 87% due to G&A relating to the electricity business being sold.

Share-based Compensation

	2017	2016	
	Q1	Q4	Q1
Share-based compensation ($000s)	**223**	487	896
Per BOE ($)	**2.01**	4.28	5.83

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 June 30, 2016, the Company granted no options (March 31, 2016: 1.9 million) and no options were exercised (March 31, 2016: nil).

Share-based compensation decreased by 54% for the quarter ended June 30, 2016 to $0.2 million compared with $0.5 million for the quarter ended March 31, 2016. The decrease in total share-based compensation costs is due to the amortization of estimated charge for 1.9 million options granted during the previous quarter.

Share-based compensation decreased to $0.2 million in the quarter ended June 30, 2016 compared with $0.9 million for the quarter ended June 30, 2015. The decrease in total share-based compensation costs is due to the amortization of estimated charge for 2.3 million options granted during the quarter ended June 30, 2015.

Depletion, Depreciation and Accretion (DD&A)

	2017	2016	
	Q1	Q4	Q1
Depletion, depreciation and accretion ($000s)	**2,337**	3,816	3,875
Per BOE ($)	**21.01**	33.52	25.21

DD&A expenses decreased by 39% for the quarter ended June 30, 2016 to $2.3 million compared with $3.8 million for the quarter 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.

DD&A expenses decreased by 40% for the quarter ended June 30, 2016 to $2.3 million compared with $3.9 million for the quarter ended June 30, 2015. The decrease is attributable to the reduction in the depletable base and lower production volume.

Foreign Exchange Loss (Gains)

	2017	2016	
	Q1	Q4	Q1
Foreign exchange loss (gains) ($000s)	**195**	307	**(553)**

The foreign exchange loss for the quarter ended June 30, 2016 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	
($000s)	**Q1**	Q4	Q1
Net (loss) income before tax	**(1,725)**	(65,259)	(2,400)
Income tax recovery (expense) - deferred	**-**	-	-
Net (loss) income after tax	**(1,725)**	(65,259)	(2,400)
Per share, basic ($)	**(0.03)**	(1.05)	(0.04)
Per share, diluted ($)	**(0.03)**	(1.05)	(0.04)

Net loss before tax for the quarter ended June 30, 2016 was $1.7 million compared to a net loss of $65.3 million for the quarter ended March 31, 2016. Excluding impairment expense 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 June 30, 2016 compared to a net loss of $4.5 million for the quarter ended March 31, 2016. The reduced loss is primarily related to higher revenue due to the 27% increase in average Brent oil sales prices, partly offset by 2% decrease in production.

Net loss before tax for the quarter ended June 30, 2016 was $1.7 million compared to a net loss of $2.4 million for the quarter ended June 30, 2015. The reduced loss is primarily related to the loss on discontinued operations of $0.6 million in Q1 2016, a impairment of investments of $0.6 million in Q1 2017, a 32% decrease in general and administrative costs, partly offset by a 4% increase in production costs and lower revenue due to the 16% decrease in average Brent oil sales prices and 28% decrease in production.

Cash Flow

	2017	2016	
($000s)	**Q1**	Q4	Q1
Operating cash flow *(1)*	**1,625**	1,695	3,071
Cash provided by operating activities	**842**	6,174	3,318
Per share, basic ($)	**0.01**	0.10	0.05
Per share, diluted ($)	**0.01**	0.10	0.05

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

Operating cash flow decreased by 4% for the quarter ended June 30, 2016, to $1.6 million versus operating cash flow of $1.7 million for the quarter ended March 31, 2016. The decrease is a result of positive cashflow from discontinued operations in the quarter ended March 31, 2016.

Operating cash flow decreased by 47% for the quarter ended June 30, 2016, to $1.6 million versus operating cash flow of $3.1 million for the quarter ended June 30, 2015. The decrease is a result of lower revenue due to a 11% decrease in oil and gas sales volumes and a 16% decrease in average Brent oil sales prices.

CAPITAL EXPENDITURES

Capital expenditures were $2.8 million for the quarter ended June 30, 2016, compared to $2.9 million for the quarter ended March 31, 2016 and $2.9 million for the quarter ended June 30, 2015.

The majority of the expenditure related to the following:

- Taranaki development drilling, workovers and facility improvements ($1.7 million).
- Taranaki exploration activities ($1.0 million).
- Mining expenditure ($0.1 million).

Taranaki Basin ($000s)	2017	2016	
	Q1	Q4	Q1
Mining permits	**1,715**	2,405	1,484
Exploration permits	**1,004**	493	639
Opunake Hydro Limited	**-**	-	320
Total Taranaki Basin	**2,719**	2,898	2,443

East Coast Basin ($000s)	2017	2016	
	Q1	Q4	Q1
Exploration permits	**-**	**-**	**-**
Total East Coast Basin	**-**	**-**	**-**

Canterbury Basin ($000s)	2017	2016	
	Q1	Q4	Q1
Exploration permits	**-**	**-**	38
Total Canterbury Basin	**-**	**-**	38

United States ($000s)	2017	2016	
	Q1	Q4	Q1
Madison mine - exploration	**28**	**-**	152
Madison mine - development	**-**	**-**	-
Total United States	**28**	**-**	152

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at June 30, 2016:

Contractual Obligations ($000s)	Total	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases *(1)*	**959**	221	645	93
Other long-term obligations *(2)*	**16,829**	10,346	6,483	-
Total contractual obligations *(3)*	**17,788**	10,567	7,128	93

(1) The Company has commitments relating to office leases situated in New Plymouth and Napier, 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) (1)	Two to Five Years	More than Five Years
PMP 38156	Water flood, optimizations and lease improvements	689	276	-
PEP 53803	Sidewinder Perforation	50	-	-
PEP 54877	Drilling of one shallow exploration well	2,551	-	-
PEP 54879	3D Seismic and G&G Studies	88	-	-
PEP 51153	Lease Preparation & Acquire & Process 2D Seismic	167	-	-
PEP 55769	Cuttings study and two exploration wells (2018)	14	6,207	-
PEP 57065	2-D seismic reprocessing and one exploration well (2017)	3,878	-	-
PEP 57063	2-D seismic reprocessing and 60km of seismic reprocessing	2,442	-	-
PEP 38348	*Relinquished (site reinstatement)*	77	-	-
PEP 38349	*Relinquished (site reinstatement)*	390	-	-
	TOTAL COMMITMENTS	**10,346**	**6,483**	**-**

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**	
	Q1	Q4	Q1
Cash and cash equivalents	**$15,025**	$16,846	$20,545
Working capital	**$20,906**	$22,110	$26,065
Contractual obligations, next twelve months	**$10,346**	$9,230	$53,147
Revenue(1)	**$5,821**	$5,013	$9,006
Cashflow from operating activities	**$842**	6,174	3,318

(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	
	Q1	Q4	Q1
Cash provided by operating activities	842	6,174	3,318
Changes for non-cash working capital accounts	783	(4,479)	(247)
Operating cash flow	1,625	1,695	3,071

Operating Margin ($000s)	2017	2016	
	Q1	Q4	Q1
Total revenue	**5,821**	5,013	9,006
Less royalties	**(548)**	(466)	(805)
Less transportation and storage	**(661)**	(728)	(1,209)
Less total production costs	**(1,639)**	(1,820)	(2,119)
Operating Margin	**2,973**	1,999	4,873

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	
($000s)	Q1	Q4	Q1
Share-based compensation	**150**	299	732
Management wages and director fees	**222**	211	231
Total Management Compensation	**372**	510	963

SHARE CAPITAL

a. At June 30, 2016, there were 62,212,252 common shares outstanding.
b. At August 15, 2016, there were 62,212,252 common shares outstanding and there are 4,935,000 stock options outstanding.

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

Please refer to Note 8 of the accompanying condensed consolidated interim financial statements.

SUBSEQUENT EVENTS

On July 21, 2016, Coronado and its wholly owned subsidiary, Coronado Resources USA LLC ("Coronado USA"), entered into a definitive asset purchase agreement with Carolina Capital Corp. ("Carolina"), pursuant to which Coronado USA would sell its copper and gold mining property located in Silverstar, Montana and related assets to Carolina, in exchange for the following:

1) $250,000 (less a US$25,000 non-refundable deposit) on the closing date;

2) 1,000,000 common shares of Carolina as follows:
   i. 500,000 shares upon the first anniversary of the closing date; and
   ii. 500,000 shares upon the second anniversary of the closing date; and

3) the sum of $100,000, within 30 days of the commencement of commercial production as described in the definitive asset purchase agreement payable.

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 involves 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 June 30, 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 June 30, 2016. The Company intends to adopt these standards and interpretations when they become effective. The Company does not expect these standards to have an impact on its financial statements. Pronouncements that are not applicable to the Company have been excluded from those described below.

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 June 30, 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 June 30, 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, is 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 June 30, 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 June 30, 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 June 30, 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.

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

Henrick Lundin, COO
New Plymouth, New Zealand

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

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The Annual General Meeting was held on December 18, 2015 at 11:00 am in Vancouver, B.C, Canada.

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

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

SHARE CAPITAL
At August 15, 2016, there were 62,212,252 shares issued and outstanding.
Fully diluted: 67,147,252 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
Lynx 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%)