MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated August 14, 2015, for the three months ended June 30, 2015 and should be read in conjunction with the Company's accompaning condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2015.

The condensed consolidated interim financial statements for the three months ended June 30, 2015, have been prepared in accordance with IAS, Interim Financial Reporting Standards ("IAS 34"), as issued by the International Accounting Standards Board, and its interpretations. Results for the period ended June 30, 2015, 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 assets in the Taranaki, East Coast and Canterbury Basins of New Zealand. As of June 30, 2015, the Company controls a large land holding in the country, consisting of oil and gas permits amounting to 1.5 million net acres of land onshore and 0.6 million net acres offshore.

TAG's vision is to be a profitable production and exploration company in New Zealand and the rest of Australasia. The Company will continue to utilize its expertise to further the development of its core producing acreage and use the subsequent operating cash flows and its balance sheet to make strategic acquisitions and undertake exploration in a diligent manner where appropriate.

Over the course of the last year and during the last month, there has been a significant decrease in oil prices, which has reduced profitability and affected operating cash flows. Given the continued uncertainty in commodity prices, TAG continues to take steps to make its operations more efficient by focusing on its core operations in the Cheal field. In addition, the Company has deferred the majority of its exploration focused capital program, and is also seeking farm-in or joint venture partners on all of its non-core permits to diversify its risk. If unsuccessful in its partnership efforts, TAG may choose to relinquish several existing permits. Furthermore, management continues to focus on reducing production and administrative costs wherever possible.

TAG continues to use technology and its expertise to advance the Company's significant resource base through the development stage. TAG will focus on the following goals during the 2016 fiscal year:

1. Grow baseline reserves, production, and cash flow in the Taranaki Basin via low-risk re-completions of by-passed zones in existing wells, deploying enhanced oil recovery techniques across producing acreage, as well as performing ongoing shallow development drilling;
2. Evaluate acquisitions in New Zealand and the rest of Australasia to increase the Company's portfolio of exploration and production opportunities;
3. Seek potential joint venture or farm-in partners to help pursue high-impact exploration and establish production within the deep Kapuni Formations in the Taranaki Basin; and
4. Seek partners to joint venture or farm-out a significant portion of the Kaheru joint venture acreage in the Taranaki Basin.

The Company's long-term strategy is to maximize the value of its core producing operations year-over-year by increasing reserves and production, reducing risk through robust planning and the execution of key projects, and minimizing costs including optimizing production to lower per barrel production costs. In addition, the Company continues to apply risk management techniques to increase cash flow from existing operations while reducing its risk exposure on exploration drilling.

Going forward, TAG's management will focus more on production, and appraisal and exploitation, as well as maintaining a disciplined approach to exploration opportunities where appropriate. Management is prepared to adapt where necessary to changing commodity prices and shareholder appetite for risk.

TAG can internally fund its adjusted 2016 fiscal year capital expenditure program of CDN$23 million. The Company estimates fiscal year 2016 cash flow from operating activities of approximately CDN$22 million, with production averaging approximately 1,900 BOE/d. This guidance is based on TAG's shallow development wells and existing production; additional success associated with the Company's current and ongoing exploration programs could have a positive impact on this guidance. At the same time, TAG continues to focus on the future and will:

1. Continue to generate its development, exploration program and workover prospects;
2. Focus on its shallow Taranaki drilling program to grow production;
3. Deploy enhanced oil recovery techniques in the Cheal mining licence.
4. Review potential acquisitions of overlooked/undervalued opportunities in New Zealand;
5. Continue to assess acreage growth via the New Zealand Government's blocks offer programs;
6. Consider select opportunities for international expansion in Australasia; and
7. Manage its capital and balance sheet as effectively as possible while focusing on shareholder returns.

Despite lower oil prices and a reduced appetite for risk in global equity markets, TAG is financially strong and well positioned for the future.

FIRST QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At June 30, 2015, the Company had $20.5 million (June 30, 2014: $46.5 million) in cash and cash equivalents and $26.1 million (June 30, 2014: $50.4 million) in working capital and no debt.
- Average net daily production decreased by 8% for the quarter ended June 30, 2015 to 1,689 BOE/d (73% oil) from 1,837 BOE/d (77% oil) for the quarter ended March 31, 2015. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 13% to 1,234 bbl/d compared with 1,422 bbl/d for the quarter ended March 31, 2015. The decrease is primarily due to lower production at Cheal-B5, B7, E5 and E2 related to down hole mechanical issues. Workovers are currently planned during Q2 and Q3 to return the wells to production.
  - Average net daily gas production increased by 8% to 2.7 MMSCFD compared with 2.5 MMSCFD for the quarter ended March 31, 2015. The increase is primarily due to increased well deliverability from the Sidewinder gas wells.
- Revenue increased by 7% for the quarter ended June 30, 2015 to $10.4 million from $9.7 million for the quarter ended March 31, 2015. The 7% increase compared to 2015 Q4 is mainly due to a 5% increase in oil revenues due to a 17% increase in average Brent oil prices offset by a 12% decrease in oil sales volumes.
- Operating netback increased by 6% for the quarter ended June 30, 2015 to $35.61 per BOE compared with $33.46 per BOE for the quarter ended March 31, 2015. The increase is attributable to the 7% increase in oil and gas revenue per BOE due to the 17% increase in average Brent oil prices.
- Cash flow provided from operating activities decreased 38% for the quarter ended June 30, 2015 to $3.3 million compared to $5.3 million for the quarter ended March 31, 2015. The decrease is attributed to changes in working capital relating to the timing of oil revenue receipts and lower oil prices.
- Capital expenditures totalled $2.9 million for the quarter ended June 30, 2015 compared to $10.5 million for the quarter ended March 31, 2015. The majority of the expenditure in the current quarter related to the following capital projects:
  - Development expenditure in PMP 38156 for the construction of the Cheal E to A pipeline ($1.5 million).
  - Exploration expenditure in PEP 52181 for long lead items ($0.5 million).
  - Electricity generation on continued development of infrastructure ($0.3 million) .
  - Mining expenditure on the ongoing maintainance costs of Madison Property and consulting engineering on the Platinum Property ($0.5 million).
- On May 12, 2015, the Company announced the appointment of oil and gas executive Frank Jacobs to the post of Chief Operating Officer of TAG, replacing Drew Cadenhead.
- On May 16, 2015, the Cheal E to A pipeline was commissioned and exported gas to the market 29 days ahead of schedule. During the quarter the pipeline has moved an average of ~1.5 MMSCFD (1.1 MMSCFD net to TAG) of gas to Cheal A-Site for further processing and sales. The pipeline allows TAG to significantly reduce operating costs while generating additional revenues, giving TAG the ability to quickly monetize future oil and gas wells drilled in the Cheal E-Site development area.
- On June 1, 2015, the Company announced the appointment of Toby Pierce as Chief Executive Officer and a Director of TAG, replacing Garth Johnson.
- On June 10, 2015, the Company relinquished PEP 55770 and has written off the costs associated with this permit as at March 31, 2015
- On June 16, 2015, the Company announced the appointment of Henrik Lundin as a Director of TAG.

Given the current market dynamics, the Company will continue to focus its capital expenditure program towards low-risk initiatives and maintaining a strong balance sheet. TAG Oil maintains a high working interest ownership in production facilities and associated pipeline infrastructure within its operations, so successful discoveries from the majority of TAG's drilling locations can be placed efficiently into production.

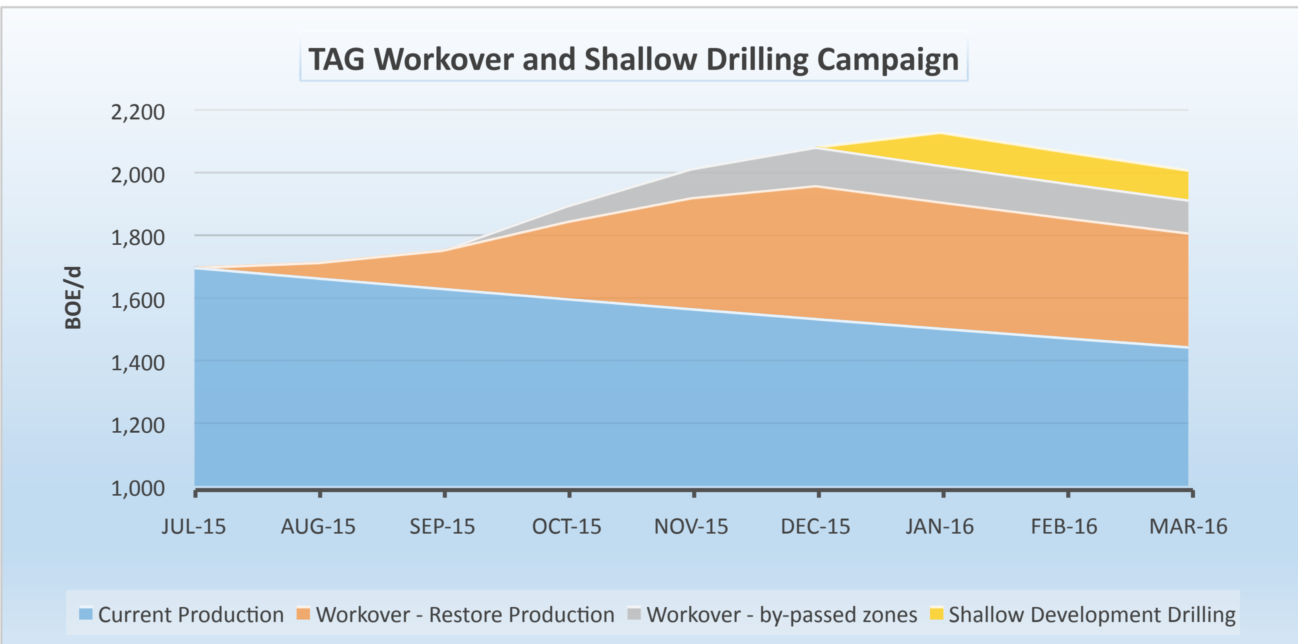
RECENT DEVELOPMENTS

TAG continues to have a near-term focus on low-risk, low-expenditure, in-field production optimization opportunities to ensure it remains financially strong and well positioned to navigate the current low oil price environment.

To meet TAG's goal for fiscal 2016 with production averaging 1,900 BOE/d (BOE/d: 77% oil), the Company has recently commenced a multi-well workover program with the Rival-1 service rig that aims to restore production and add production from low-risk recompletions of by-passed zones.

The workover program commenced on July 17, 2015 to return the Cheal-A1 rod pump well to production. The workover was successfully completed and restored approximately 50 BOE/d of production. The rig was subsequently mobilized on July 27, 2015 to commence the Cheal-E5 workover.

The chart below details the approximate timing and forecasted production expected from the workover and shallow drilling campaign.

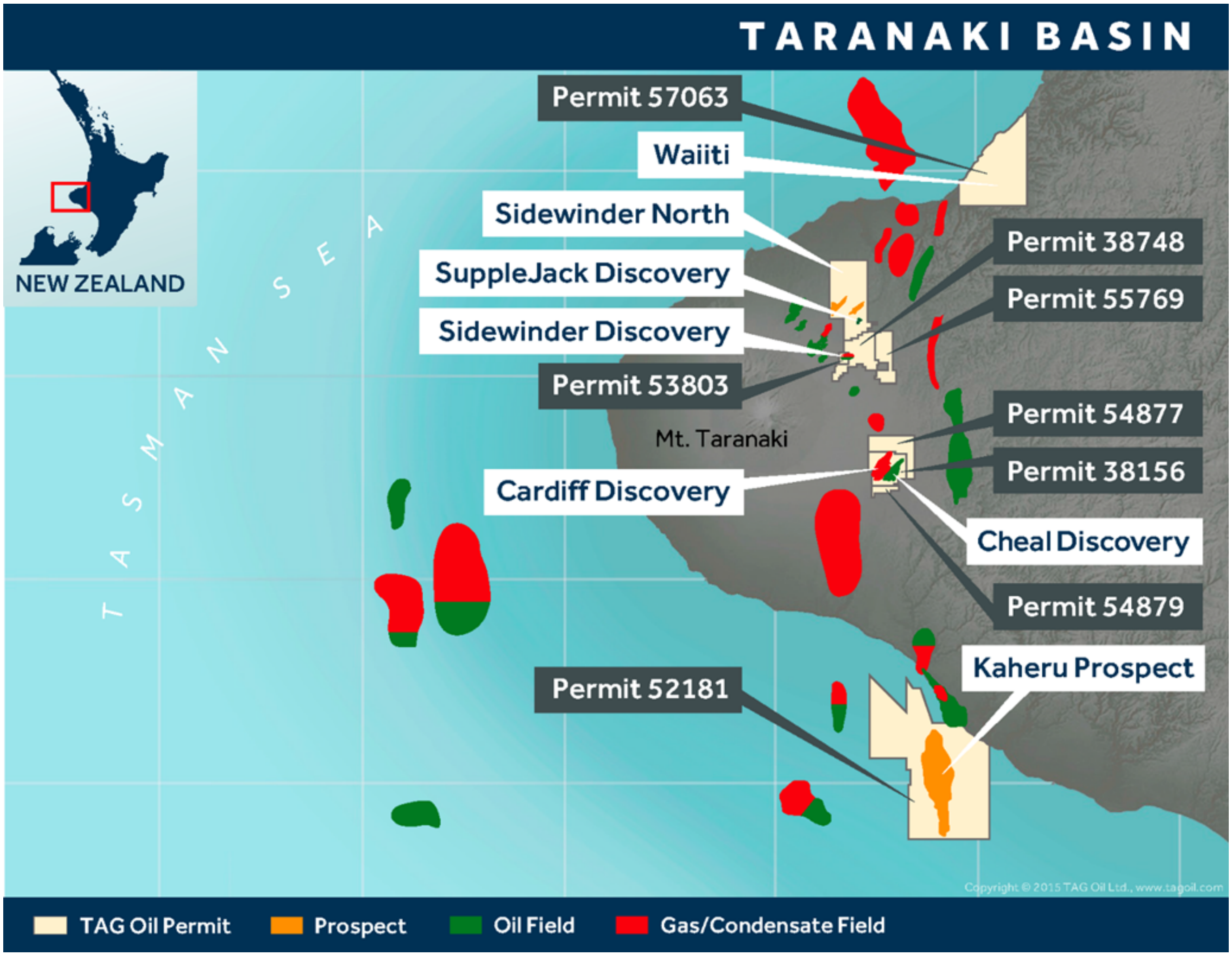


TAG believes that a properly executed development plan, combined with a moderate amount of exploration drilling will allow for an increase in daily production rates, cash flow, reserves and reserve values during fiscal 2016. Maintaining a high working interest and ownership of all facilities and associated pipeline infrastructure in the Taranaki Basin on TAG's operated Cheal, Cardiff and Sidewinder oil and gas fields ensures the Company can commercialize further discoveries and developments expeditiously, as well as potentially offer third party processing to other companies in the Taranaki Basin.

PROPERTY REVIEW

Taranaki Basin:

The Taranaki Basin is an emerging oil, gas and condensate province located on the North Island of New Zealand. The Basin 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 the Sidewinder PEP 38748, PEP 55769 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 permits.
- 40% interest in the Kaheru Offshore PEP 52181 exploration permit.

Shallow / Miocene Development and Exploration

At the time of this report, the Cheal, Greater Cheal, and Sidewinder fields have twenty two shallow wells on full, part-time or constrained production out of a total of forty four wells drilled. The remaining wells are shut in pending work-overs and/or evaluation of economic re-completion methods.

TAG's shallow Miocene net production averaged 1,689 BOE/d (73% oil) in Q1 2016, compared to an average of 1,837 BOE/d (77% oil) in Q4 2015 and 1,750 BOE/d (74% oil) in Q1 2015. The decrease compared to Q4 2015 is mainly attributable to a 128 BOE/d decrease in production from the Cheal North East permit (PEP 54877: TAG 70% interest) due to Cheal-E2 and E5 being shut because of mechanical issues.

The Cheal A, B and C facilties (PMP 38156: TAG 100% interest) produced an average of 997 BOE/d (85% oil) in Q1 2016, compared to an average of 1,084 BOE/d (84% oil) in Q4 2015 and 1,116 BOE/d (81% oil) in Q1 2015. The decrease compared to Q4 2015 is primarily due to Cheal-A1, B5 and B7 being shut in because of mechanical issues and the Cheal A production facility being offline for approximately two days during Q1 for planned maintenance and tie-in of the Cheal E to A pipeline. TAG has recently completed the Cheal-A1 workover and plans to execute further workovers on Cheal-A12, A7, B5, B7 and B1 during Q2 and Q3 which have the potential to deliver incremental production of 300 BOE/d.

The Cheal North East permit (PEP 54877: TAG 70% interest) produced an average of 581 net BOE/d (66% oil) in Q1 2016 compared to an average of 709 BOE/d (71% oil) in Q4 2015 and 504 BOE/d (77% oil) in Q1 2015. The decrease of 128 BOE/d from Q4 2015 is due to the shutting in of Cheal E5 and E2 due to mechanical issues and the Cheal E production facility being offline for approximately two days during Q1 for the tie-in of the Cheal E to A pipeline. Both these wells are scheduled for workovers during Q2 and Q3 which have the potential to deliver incremental production of 100 BOE/d.

The recently commissioned 100% owned Cheal E to A pipeline has been successfully delivering previously flared gas to the Cheal A production facility for further processing and export since May 16, 2015. Gas sales from Cheal E-Site have averaged 1.1 MMSCFD (net to TAG) since commissioning providing additonal net revenue of approximately NZ$250k for the quarter and reduced net operating costs by approximately NZ$50k through reduced trucking and electricity costs.

The Cheal oil field continues to provide TAG with a stable, high-netback production base and long-life reserves, with revenues that fund a portion of drilling costs while maintianing production and reserves. TAG plans to fully develop the 100% controlled 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 targets across the Cheal permit area. Encouraging results continue to be achieved at Cheal including in the Cheal North East area, where the naturally free flowing Cheal-E1 well (TAG: 70%) has been producing gross volumes of 500 to 600 BOE/d (82% oil) on choke for 21 months. With drilling and completion costs of under US$2.5 million per well, there is unrecognized upside and economic potential that exists within TAG's acreage.

The Cheal North East area is TAG's newest producing oil site, and this success could extend the oil potential area of the 100% TAG held Cheal field. The successful Cheal-E1 well targeted a new pool down dip from the lowest known oil contact at Cheal, and has been producing oil steadily since November 2013, with no water. The Cheal E-Site pool is being further developed and delineated with follow-up drilling, in both the Mt. Messenger and Urenui formations.
The Sidewinder field produced an average of 111 BOE/d (1% oil) in Q1 2016, compared to an average of 44 BOE/d (2% oil) in Q4 2015 and 130 BOE/d (3% oil) in Q1 2015. The Sidewinder facility was shut in for just 28 days during Q1 2016, compared to 55 days in Q4 2015, as the Company continues to optimize the well operating mode to maximize well deliverability and economics.

The Sidewinder acreage provides TAG with the opportunity to potentially develop another field similar to Cheal and the adjacent Ngatoro / Kaimiro field, which is a 60 million barrel oil field. TAG has now assembled a 22,000-acre exploration play area around its existing Sidewinder gas discovery and plans to potentially drill the SW-B1 and SW-B2 wells later in the 2016 fiscal year. Both wells would target oil-prone prospects in the Miocene-aged, Mt. Messenger formation at approximately ~2000 meters depth. To date, TAG has drilled seven shallow gas wells on the Sidewinder A-Site; however, these new wells will target the oil potential identified within the Sidewinder B-Site.

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.

In December 2013, TAG completed drilling of the Cardiff-3 well, which was drilled to a total depth of 4,863 meters and intercepted 230 meters of gas and condensate bearing sands in three target zones within the Kapuni Group. The deepest of the three zones, the K3E was perforated and hydraulically fractured. It produced gas and condensate with no formation water, but at sub-commercial rates. TAG will look at completing engineering, design and associated planning to assess all viable options to re-test Cardiff which may include recompletion, a re-drill, additional sidetracks, fracture stimulation or testing of a series of other Kapuni group (deep) formations identified within the wellbore within the next 12 – 24 months.

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 Heatseeker prospect, located in PEP 54873 (100% TAG), was relinquished on June 10, 2015.

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 efficent commercialization of a discovery.

Offshore Exploration

Planning and preparation work by the Operator, New Zealand Oil and Gas, continues ahead of the shallow-water Kaheru-1 well, which is expected to be drilled to a total depth of 4,400 meters. The Kaheru permit, located in PEP 52181 (40% TAG), is a large technically robust sub-thrust anticline with mapped four way dip closure at the Miocene, Oligocene, and Cretaceous stratigraphic intervals. The Kaheru structure is situated in a discovery trend that is referred to as the "string of pearls" with Kaheru forming the "southern pearl" just offshore from a number of onshore commercial discoveries. This discovery trend proves the presence of an active hydrocarbon system.

TAG estimates the Kaheru structure has a gross mid-case undiscovered petroleum and original oil in-place volume of 257 mmboe.

A work programme and budget for the June 2015 to April 2016 permit year has been submitted to the joint venture for approval. The programme focuses on the well design, long lead inventory and required G&G work necessary for the design and execution of the Kaheru-1 exploration well. The firm budget submitted totals US$3.2 million (US$1.3 million TAG 40%) with a contingent drilling budget of US$52.2 million (US$20.9 million TAG 40%). The joint venture has decided not to use the Ensco 107 in mid-winter, when the rig is available, and continue in negotiations to secure a rig during a more favourable weather window. The joint venture has until May 2016 to elect to drill an exploration well.

Although the Company has confidence in the Kaheru prospect based on the technical data to support drilling, the Company is actively seeking joint venture partners to participate in funding the well, reducing the Company's interest in the Kaheru permit to a more suitable risk level.

East Coast Basin:

The Company controls a 100% working interest in two exploration permits totaling 0.8 million acres (PEP 38348 and PEP 38349) in the East Coast Basin of New Zealand.

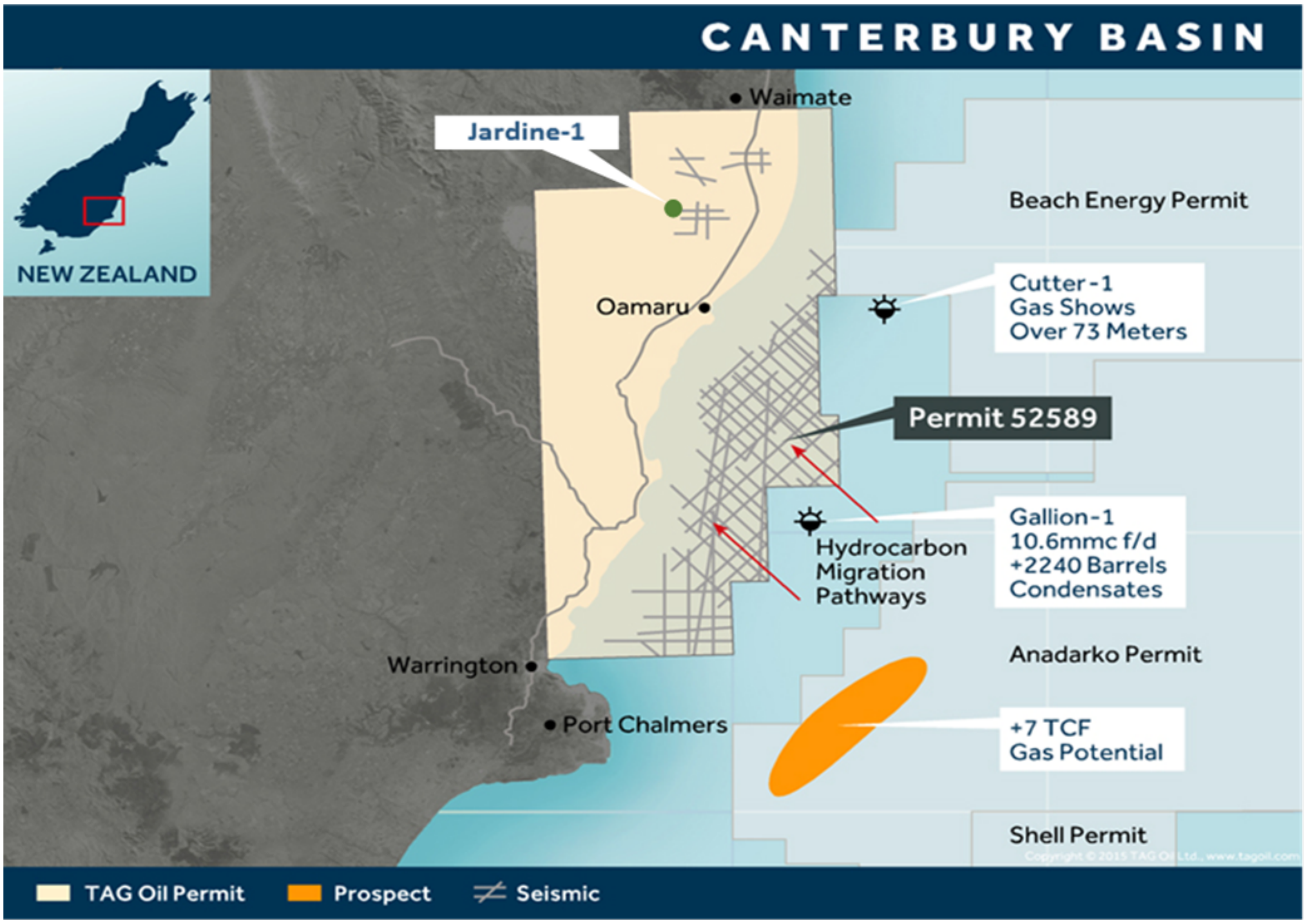
The Company is presently seeking a suitable joint venture partner to help further fund the East Coast program. On success finding a partner, additional work would be completed continuing the data building phase. Should a suitable partner not be found to fund further costs within the East Coast Basin, the Company will consider relinquishing the permits.

In April 2013, the Company drilled it's first unconventional tight-oil well called "Ngapaeruru-1" in PEP 38349. The Company has also acquired proprietary 2D seismic data, completed extensive geological surface and sub-surface studies and initially drilled a number of shallow stratigraphic wells within three of the permits. Ngapaeruru-1 reached total depth with promising initial results that indicate on logs, a potential 155 meter gross hydrocarbon column.

As part of the planning for continued drilling in the East Coast Basin, the Company has also submitted applications for consents needed to drill the Boar-Hill-1 well located in PEP 38349 in the event TAG attracts a suitable joint venture partner.

Canterbury Basin:

The Canterbury Basin is a frontier basin on New Zealand's South Island, with a proven onshore and offshore hydrocarbon system as evidenced by the presence of numerous oil and gas shows onshore and discoveries made offshore. The Company controls 1.17 million acres of conventional and unconventional targets in a permit (PEP 52589) that spans onshore as well as shallow offshore, with water less than 100 meters deep. The onshore / offshore permit holds promise and is thought to be located within the migration pathway of a proven working hydrocarbon system.



The Company has evaluated 80km of new onshore 2D seismic data acquired by the Company in November 2012 over a number of leads initially identified using geochemical surface data, and the Company has identified a number of subsurface leads and prospects within the permit. Based on the success of the initial seismic acquisition, the Company acquired a further 40km of 2D seismic data in early 2014 to allow for a better understanding of the closure and aerial extent of four newly mapped features, as well as a better understanding of the potential resource within this frontier acreage.

The Company is presently seeking a suitable joint venture partner to help further fund the Canterbury Basin program. Should a suitable partner not be found to fund further costs within the Canterbury Basin, the Company will consider relinquishing the permit.

Opunake Hydro Limited ("OHL") and Coronado Resources Limited ("Coronado"):

On September 28, 2013, the Company sold its 90% stake in OHL to Coronado Resources Ltd., in exchange for common shares of Coronado valued at approximately $3.6 million. The common shares of Coronado that have been issued to TAG and the vendor of the remaining 10% interest represent full consideration paid by Coronado to acquire 100% of the issued and outstanding shares of OHL. The transaction increased TAG's shareholding in Coronado from 40% to 49% and accordingly Coronado is consolidated into the TAG group accounts from September 28, 2013 and to date.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2016 Q1	2015 Q4	2015 Q1
Daily production volumes (1)			
Oil (bbl/d)	**1,234**	1,422	1,296
Natural gas (BOE/d)	**455**	415	454
Combined (BOE/d)	**1,689**	1,837	1,750
% of oil production	**73%**	77%	74%
Daily sales volumes (1)			
Oil (bbl/d)	**1,250**	1,415	1,282
Natural gas (BOE/d)	**254**	157	202
Combined (BOE/d)	**1,504**	1,572	1,484
Natural gas (Mcf/d)	**1,522**	942	1,213
Product pricing			
Oil ($/bbl)	**74.94**	63.94	118.57
Natural gas ($/Mcf)	**3.47**	6.14	4.93
Oil and natural gas revenues (3) - gross *($000s)*	**9,006**	8,660	14,375
Oil & natural gas royalties (2)	**(805)**	(687)	(1,275)
Oil and natural gas revenues - net *($000s)*	**8,201**	7,973	13,100

(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

Average net daily production decreased by 8% for the quarter ended June 30, 2015 to 1,689 BOE/d (73% oil) from 1,837 BOE/d (77% oil) for the quarter ended March 31, 2015. The 8% decrease compared to 2015 Q4 is due to a combination of well reliability issues related with Cheal-A1, B5, B7, E2 and E5 and increased downtime at the Cheal A-Site and Cheal E-Site production facilities for maintenance and tie-in of the Cheal E to A pipeline. The 215 BOE/d decrease in production from the Cheal A, B, C and E-Sites has been partially offset by increased well deliverability at Sidewinder of 67 BOE/d due to optimizing the cycling of the wells.

TAG has recently completed the Cheal-A1 workover and plans to execute further workovers during Q2 and Q3 which have the potential to deliver incremental production of approximately 400 BOE/d.

Natural gas sales increased by 62% for the quarter ended June 30, 2015 to 1,522 Mcf/d from 942 Mcf/d for the quarter ended March 31, 2015. The increase is due to the commissioning of the Cheal E to A pipeline which delivers previously flared gas to the market via the Cheal A production station.

Oil and natural gas gross revenue increased by 4% for the quarter ended June 30, 2015 to $9 million compared with $8.7 million for the quarter ended March 31, 2015. The increase is attributable to a 17% increase in average Brent oil prices offset by a 12% decrease in oil sales volumes.

SUMMARY OF QUARTERLY INFORMATION

	2016	2015				2014		
Canadian $000s, except per share or BOE	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Net production volumes (BOE/d)	**1,689**	1,837	1,991	1,845	1,750	1,486	1,527	2,100
Total revenue	**10,385**	9,705	12,282	16,179	15,571	14,025	12,939	15,885
Operating costs	**(5,562)**	(5,281)	(5,806)	(6,213)	(5,721)	(5,706)	(4,579)	(4,826)
Foreign exchange	**553**	757	(344)	1,206	(312)	2,246	(167)	(1,012)
Share-based compensation	**(896)**	(380)	(586)	(356)	(44)	(175)	(377)	(559)
Other costs	**(6,165)**	(7,120)	(6,490)	(5,669)	(5,804)	(4,663)	(4,830)	(5,914)
Exploration impairment	**(715)**	(71,714)	-	-	-	101	(15)	(1,132)
Property impairment	**-**	(9,182)	-	-	-	-	-	-
Net (loss) income before tax	**(2,400)**	(83,216)	(944)	5,147	3,690	5,828	2,971	2,412
Basic (loss) income $ per share (BT)	**(0.04)**	(1.30)	(0.01)	0.08	0.06	0.09	0.05	0.04
Diluted (loss) income $ per share (BT)	**(0.04)**	(1.30)	(0.01)	0.08	0.06	0.09	0.05	0.04
Capital expenditures	**2,916**	10,465	16,655	11,126	11,370	22,767	20,959	14,466
Operating cash flow *(1)*	**3,066**	2,826	3,968	9,702	7,715	6,774	6,101	8,562

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

Total revenue increased by 7% for the quarter ended June 30, 2015 to $10.4 million from $9.7 million for the quarter ended March 31, 2015. The 7% increase compared to 2015 Q4 is mainly due to a 5% increase in oil revenues ($0.4 million) and a 32% increase in electricity revenue ($0.3 million). The increase in oil revenues is related to a 17% increase in average Brent oil prices offset by a 12% decrease in oil sales volumes. The increase in electricity revenue is related to the continued sales effects of Utilise brand.

Operating costs increased by 5% for the quarter ended June 30, 2015 to $5.6 million from $5.3 million for the quarter ended March 31, 2015. The 5% increase when compared to 2015 Q4 is mainly due to increased oil, gas and electricity production costs related to planned maintenance ($0.3 million), an increase in royalties associated with higher revenue ($0.1 million) offset partially by lower transport and storage costs due to lower oil production and trucking cost savings relating to the Cheal E to A pipeline ($0.1 million).

Other costs decreased by 13% for the quarter ended June 30, 2015 to $6.2 million from $7.1 million for the quarter ended March 31, 2015. The 13% decrease compared to 2015 Q4 is mainly due to a 17% decrease in DD&A expense due to lower production ($0.8 million) and an 18% decrease in G&A costs due to additional costs recorded in 2015 Q4 relating to annual reserve reporting, upgrades to the TAG corporate website, and the IT infrastructure build associated with the branding and launch of Utilise Limited, a wholly owned subsidiary of OHL.

Net loss before tax for the quarter ended June 30, 2015 was $2.4 million compared to a net loss of $83.2 million for the quarter ended March 31, 2015. Excluding impairment expense, on a comparative basis, equates to a net loss before tax of $1.7 million for the quarter ended June 30, 2015 compared to a net loss of $2.3 million for the quarter ended March 31, 2015. The decrease in net loss is primarily due to the $0.7 million increase in revenue.

Net Production by Area (BOE/d)

Area	2016	2015	
	Q1	Q4	Q1
PMP38156 (Cheal)	**997**	1,084	1,116
PEP54877 (Cheal North East)	**581**	709	504
PMP53803 (Sidewinder)	**111**	44	130
Total BOE/d	**1,689**	1,837	1,750

Average net daily production decreased by 8% for the quarter ended June 30, 2015 to 1,689 BOE/d (73% oil) from 1,837 BOE/d (77% oil) for the quarter ended March 31, 2015. The 8% decrease compared to 2015 Q4 is due to a combination of well reliability issues related with Cheal-A1, B5, B7, E2 and E5 and increased downtime at the Cheal A-Site and E-Site production facilities for maintenance and tie-in of the Cheal E to A pipeline. The 215 BOE/d decrease in production from the Cheal A,B,C and E-Sites has been partially offset by increased well deliverability at Sidewinder of 67 BOE/d due to optimizing the cycling of the wells.

Average net daily production decreased by 3% for the quarter ended June 30, 2015 to 1,689 BOE/d (73% oil) from 1,750 BOE/d (74% oil) for the quarter ended June 30, 2014. The 3% decrease compared to 2015 Q1 is due to a combination of natural decline rates, the well reliability issues related to the above-mentioned wells, and additional production from Cheal-B9, B10, E7 and the Cheal North East joint venture wells Cheal-E4, E5 and E6.

Oil and Gas Operating Netback ($/BOE)

	2016	2015	
	Q1	Q4	Q1
Oil and natural gas revenue	**65.81**	61.24	106.45
Royalties	**(5.88)**	(4.86)	(9.44)
Transportation and storage costs	**(8.83)**	(9.57)	(10.50)
Production costs	**(15.49)**	(13.35)	(14.35)
Netback per BOE ($)	**35.61**	33.46	72.16

Operating netback is the operating margin the company receives from each barrel of oil equivalent sold.

Operating netback increased by 6% for the quarter ended June 30, 2015 to $35.61 per BOE compared with $33.46 per BOE for the quarter ended March 31, 2015. The increase is attributable to the 7% increase in oil and gas revenue per BOE due to the 17% increase in average Brent oil prices.

Operating netback decreased by 51% for the quarter ended June 30, 2015 to $35.61 per BOE compared with $72.16 per BOE for the quarter ended June 30, 2014. The decrease is attributable to the 38% decrease in oil and gas revenue per BOE due to the 37% decrease in average brent oil sales prices.

General and Administrative Expenses (“G&A”)

	2016	2015	
	Q1	Q4	Q1
Oil and Gas G&A expenses ($000s)	**1,612**	1,968	1,713
Oil and Gas G&A per BOE ($)	**10.49**	11.91	10.76
Electricity/Mining G&A expenses ($000s)	**381**	450	244
Total G&A Expenses	**1,993**	2,418	1,957

Total G&A expenses decreased by 18% for the quarter ended June 30, 2015 to $1.99 million compared with $2.42 million for the quarter ended March 31, 2015. The decrease is primarily related to additional costs recorded in 2015 Q4 relating to annual reserve reporting, upgrades to the TAG corporate website, and the IT infrastructure build associated with the branding and launch of Utilise Limited, a wholly owned subsidiary of OHL.

Total G&A expenses increased by 2% for the quarter ended June 30, 2015 to $1.99 million compared with $1.96 million for the quarter ended June 30, 2014. The 2% increase is primarily related to a 56% increase in costs associated with the electricity retail activities relating to the IT infrastructure build, branding and launch of Utilise Limited, a wholly owned subsidiary of OHL. These costs have been partially offset by a 6% decrease in G&A costs relating to oil and gas production activities.

Share-based Compensation

	2016	2015	
	Q1	Q4	Q1
Share-based compensation ($000s)	**896**	380	44
Per BOE ($)	**5.83**	2.30	0.27

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 over the vesting period of the options, generally being a minimum of two years.

In the quarter ended June 30, 2015, the Company granted 2.8 million options (March 31, 2015: nil) and no options were exercised (March 31, 2015: nil).

Share-based compensation increased by 136% in the quarter ended June 30, 2015 to $0.896 million when compared with $0.380 million for the quarter ended March 31, 2015. The increase in total share-based compensation costs was due to a higher amount of options granted and the change in the vesting period required a larger portion of the expense to be recorded on the grant date.

Share-based compensation increased to $0.896 million in the quarter ended June 30, 2015 compared with $0.04 million for the quarter ended June 30, 2014. The increase in total share-based compensation costs was due to a higher amount of options granted in the last 12 months and the change in the vesting period required a larger portion of the expense to be recorded on the grant date.

Depletion, Depreciation and Accretion (DD&A)

	2016	2015	
	Q1	Q4	Q1
Depletion, depreciation and accretion ($000s)	**3,929**	4,726	3,635
Per BOE ($)	**25.56**	28.59	22.83

DD&A expenses decreased by 17% for the quarter ended June 30, 2015 to $3.9 million compared with $4.7 million for the quarter ended March 31, 2015. The decrease is a result of lower production and combining Cheal A-Site and Cheal E-Site as one cash-generating unit due to the interconnecting pipeline.

DD&A expenses increased by 8% for the quarter ended June 30, 2015 to $3.9 million compared with $3.6 million for the quarter ended June 30, 2015. The increase is a result of a higher depletable base due to the Cheal E-Site exploration costs being transferred to the property, plant and equipment balance from exploration expense.

Foreign Exchange Loss / (Gains)

	2016	2015	
	Q1	Q4	Q1
Foreign exchange loss / (gains) ($000s)	**(553)**	(757)	312

The foreign exchange gain for the quarter ended June 30, 2015 was a result of the strengthening of the USD against the NZD resulting in foreign exchange gains on the USD denominated oil receipts.

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

	2016	2015	
($000s)	**Q1**	Q4	Q1
Net (loss) / income before tax	**(2,400)**	(83,216)	3,690
Income tax recovery (expense) - deferred	**-**	5,561	-
Net (loss) / income after tax	**(2,400)**	(77,655)	3,690
Per share, basic ($)	**(0.04)**	(1.23)	0.06
Per share, diluted ($)	**(0.04)**	(1.23)	0.06

Net loss before tax for the quarter ended June 30, 2015 was $2.4 million compared to a net loss of $83.2 million for the quarter ended March 31, 2015. Excluding impairment expense, on a comparative basis, equates to a net loss before tax of $1.7 million for the quarter ended June 30, 2015 compared to a net loss of $2.3 million for the quarter ended March 31, 2015. The decrease in net loss is primarily due to the $0.7 million increase in revenue.

Net loss before tax for the quarter ended June 30, 2015 was $2.4 million compared to a net income of $3.7 million for the quarter ended June 30, 2015. The decrease is primarily related to the decrease in oil revenue related to the 37% decrease in average brent oil sales prices.

Cash Flow

	2016	2015	
($000s)	**Q1**	Q4	Q1
Operating cash flow *(1)*	**3,071**	2,826	7,715
Cash provided by operating activities	**3,318**	5,334	7,166
Per share, basic ($)	**0.05**	0.09	0.11
Per share, diluted ($)	**0.05**	0.09	0.11

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

Operating cash flow increased by 9% for the quarter ended June 30, 2015 to $3.1 million from $2.8 million for the quarter ended March 31, 2015, and decreased by 60% from $7.7 million for the same period last year.

The 9% increase compared to 2015 Q4 is primarily due to the 5% increase in oil revenue due to the 17% increase in average brent oil sales prices.

The 60% decrease compared to 2015 Q1 is primarily due to the 38% decrease in oil revenue due to the 37% decrease in average brent oil sales prices.

CAPITAL EXPENDITURES

Capital expenditures totaled $2.9 million for the quarter ended June 30, 2015 compared to $10.5 million for the quarter ended March 31, 2015, and $11.4 million for the same period last year.

Taranaki Basin ($000s)	**2016**	2015	
	Q1	Q4	Q1
Mining permits	**1,484**	4,142	6,592
Exploration permits	**639**	1,831	1,842
Opunake Hydro Limited	**320**	493	991
Total Taranaki Basin	**2,443**	6,466	9,425

East Coast Basin ($000s)	**2016**	2015	
	Q1	Q4	Q1
Exploration permits	**-**	3,827	1,644
Total East Coast Basin	**-**	3,827	1,644

Canterbury Basin ($000s)	2016	**2015**	
	Q1	Q4	Q1
Exploration permits	**38**	8	41
Total Canterbury Basin	**38**	8	41

United States ($000s)	**2016**	2015	
	Q1	Q4	Q1
Madison mine - exploration	**152**	103	97
Madison mine - development	**-**	-	-
Total United States	**152**	103	97

At March 31, 2015, the Company assessed and concluded that the carrying value of PEP 53674, PEP 54873, PEP 54876, PEP 38348, PEP 38349 and Cardiff exceeded recoverable amounts and has written off the costs associated with the permits. The write-off reflects the assessment that existing exploration wells are unlikely to access proved and probable reserves in the near term. In PEP 38748 (Sidewinder) the partial write-off reduced the carrying amount to $2,141,234 reflecting seismic data that the Company expects to obtain additional value from.

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at June 30 2015:

Contractual Obligations ($000s)	Total	Less than One Year	More than One Year
Long term debt	**-**	-	-
Operating leases *(1)*	**377**	283	94
Other long-term obligations *(2)*	**54,876**	52,864	2,012
Total contractual obligations *(3)*	**55,253**	53,147	2,106

(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 above are as follows:

Permit	Commitment	Less than One Year ($000s) (2)	More than One Year
PMP 38156	Drilling, workovers, optimizations and lease improvements	1,881	
PMP 53803	Minor capital projects	-	
PEP 54873	*Relinquished*	-	
PEP 54876 (1)	*Relinquished*	19	
PEP 54877 (1)	Workovers and drilling of one shallow exploration well	2,656	2,012
PEP 54879 (1)	Technical study	169	
PEP 38748	Drilling of two shallow wells including pad construction	6,762	
PEP 52181	Drilling Kaheru-1 (40% Working Interest)	20,962	
PEP 52589	Drilling of one shallow exploration well	930	
PEP 55769	Technical study	2,029	
PEP 55770	*Relinquished*	-	
PEP 57065	2-D seismic reprocessing	85	
PEP 57063	2-D seismic reprocessing	85	
PEP 38348	Drilling of one shallow exploration well	10,144	
PEP 38349	Drilling of one shallow exploration well	7,143	
	TOTAL COMMITMENTS	**52,865**	**2,012**

(1) The commitment does not include the cost of wells funded by the Company's joint venture partner.

(2) Included in the less than one year commitments, a total of $38 million is included in regard to permit obligations that will only be carried out if these commitments are funded by a suitable joint venture partner. Otherwise the permits associated with these commitments will be relinquished prior to the Company incurring these costs.

The Company may also have an obligation to pay its joint venture interest share of costs to plug and abandon the SuppleJack wells previously drilled. 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.

The Company has provided a guarantee of NZ$900,000 on a credit facility that provides security to the New Zealand electrical clearing manager.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2015, the Company had $20.5 million (June 30, 2014: $46.5 million) in cash and cash equivalents and $26.1 million (June 30, 2014: $50.4 million) in working capital. As of the date of this report, the Company is adequately funded 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.

Additional material commitments, changes to production estimates, 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 Corporation 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 Corporation 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 Corporation'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)	**2016**	2015	
	Q1	Q4	Q1
Cash provided by operating activities	**3,318**	5,334	7,166
Changes for non-cash working capital accounts	**(247)**	(2,508)	549
Operating cash flow	**3,071**	2,826	7,715

Operating Netback ($000s)	**2016**	2015	
	Q1	Q4	Q1
Total revenue	**10,385**	9,705	15,571
Less electricity revenue	**(1,379)**	(1,045)	(1,196)
Oil and gas revenue	**9,006**	8,660	14,375
Less royalties	**(805)**	(687)	(1,275)
Less transportation and storage	**(1,209)**	(1,353)	(1,417)
Less total production costs	**(3,548)**	(3,241)	(3,029)
Add back electricity production costs	**1,429**	1,353	1,090
Operating Netback	**4,873**	4,732	9,744

Operating Margin ($000s)	**2016**	2015	
	Q1	Q4	Q1
Total revenue	**10,385**	9,705	15,571
Less royalties	**(805)**	(687)	(1,276)
Less transportation and storage	**(1,209)**	(1,353)	(1,417)
Less total production costs	**(3,548)**	(3,241)	(3,029)
Operating margin	**4,823**	4,424	9,849

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 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:

	2016	2015	
($000s)	**Q1**	Q4	Q1
Share-based compensation	**732**	176	27
Management wages and director fees	**231**	317	250
Total Management Compensation	**963**	493	277

SHARE CAPITAL

a. At June 30, 2015, there were 62,314,052 common shares outstanding.

b. At August 14, 2015, there were 62,301,252 common shares outstanding and there are 5,160,000 stock options outstanding, of which 2,965,001 have vested.

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 consolidated financial statements.

SUBSEQUENT EVENTS

Share capital

Subsequent to June 30, 2015, the Company purchased and cancelled 12,800 common shares under its normal course issuer bids at an average price of $1.31 per common share.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of the consolidated 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 consolidated financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these consolidated financial statements.

Areas of judgment that have the most significant effect on the amounts recognized in these consolidated 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 consolidated 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 consolidated 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 asset or CGU. 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 1.6% and a risk free discount rate of 2.75%, which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing and inflation on the consolidated 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 quarter ended June 30, 2015. Please also refer to Forward Looking Statements.

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

New accounting standards and recent pronouncements

The Company has evaluated the following new and revised IFRS standards and has determined there to be no material impact on the financial statements upon adoption:

- IAS 1 – Presentation of Financial Statements
- IFRIC 21 – Levies
- IAS 32 – Financial instruments - Presentation

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, 2015. The Company intends to adopt these standards and interpretations when they become effective. The Company does not expect these standards to have an impact on its financial statements. Pronouncements that are not applicable to the Company have been excluded from those described below.

The following standards or amendments are effective for annual periods beginning on or after January 1, 2015:

- IFRS 9 – Financial Instruments (annual periods beginning January 1, 2018)

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 quarter ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

The following pertains to the Company's Management Discussion and Analysis for the quarter ended June 30, 2015, confirming that the Company is in compliance with disclosure controls and procedures and internal controls over financial reporting:

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 and 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 ("ICFR") 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 consolidated 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 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 consolidated financial statements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of June 30, 2015. 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 ("COSO"). Based on their assessment, management has concluded that, as of June 30, 2015, 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, unitization, 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; converting the undiscovered resource potential to proved reserves; 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 and Offshore prospects in Taranaki; the potential results of conventional frontier exploration drilling in the Canterbury Basin; 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, 2015, 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.

The resource estimate in this document is a best case estimate prepared by TAG professionals, a non-independent qualified reserves evaluator in accordance with NI 51-101 and the COGE Handbook, with an effective date of March 31, 2015.

Undiscovered Petroleum Initially-In-Place is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially-in-place is referred to as "prospective resources, the remainder as "unrecoverable. Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

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

The significant positive factors that are relevant to the estimate contained in the independent resource assessment are:
- proven production in close proximity;
- proven commercial quality reservoirs in close proximity; and
- oil and gas shows while drilling wells nearby.

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

Certain information in this website 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.

Readers are further cautioned that disclosure provided herein in respect of well flow test results may be misleading, as the test results are not necessarily indicative of long-term performance or of ultimate recovery.

CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Toby Pierce
CEO and Director
Vancouver, British Columbia

Alex Guidi
Chairman and Director
Vancouver, British Columbia

Keith Hill, Director
Vancouver, British Columbia

Ken Vidalin, Director
Vancouver, British Columbia

Brad Holland, Director
Vancouver, British Columbia

Henrik Lundin, Director
Oslo, Norway

Chris Ferguson, CFO
New Plymouth, New Zealand

Frank Jacobs, COO
Vancouver, British Columbia

Max Murray, NZ Country Manager
New Plymouth, New Zealand

Giuseppe (Pino) Perone, Corporate Secretary
Vancouver, British Columbia

CORPORATE OFFICE

885 W. Georgia Street
Suite 2040
Vancouver, British Columbia
Canada V6C 3E8
Telephone: 1-604-682-6496

Facsimile: 1-604-682-1174

REGIONAL OFFICE

New Plymouth, New Zealand

BANKER

Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Vancouver, British Columbia
Bell Gully
Wellington, New Zealand

AUDITORS

De Visser Gray LLP
Chartered Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT

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

ANNUAL GENERAL MEETING

The Annual General Meeting was held on January 27, 2015 at 3:00 pm in Wellington, New Zealand

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 14, 2015, there were 62,301,252 shares issued and outstanding.
Fully diluted: 67,461,252 shares.

WEBSITE

www.tagoil.com

SUBSIDIARIES

TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Cheal Petroleum Limited
Trans-Orient Petroleum Limited
Orient Petroleum (NZ) Limited
Eastern Petroleum (NZ) Limited

Coronado Resources Limited (49%)
Opunake Hydro Limited (49%)
Lynx Clean Power Corp. (49%)
Lynx Gold Corp. (49%)
Lynx Petroleum Ltd. (49%)
Coronado Resources USA LLC (49%)
Lynx Gold (NZ) Limited (49%)
Lynx Platinum Limited (49%)
Lynx Oil & Gas Limited (49%)
Utilise Limited (49%)