MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated February 16, 2015, for the three and nine months ended December 31, 2014 and should be read in conjunction with the Company's accompanying condensed consolidated interim financial statements for the same period as well as the audited consolidated financial statements for the year ended March 31, 2014.

The condensed consolidated interim financial statements for the three and nine months ended December 31, 2014, 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 December 31, 2014, 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 December 31, 2014, the Company controls one of the largest land holdings of any explorer in the country, consisting of oil and gas permits amounting to 2.3 million net acres of land onshore and 0.6 million net acres offshore.

TAG believes that its leading position in New Zealand provides the backdrop for the Company to deliver a strong rate of return on capital invested. During times of low-commodity prices experienced in the quarter, TAG has taken immediate steps to focus on safe and efficient operations and maximizing production of current reserves. In addition the Company has adjusted its resources to focus on the lowest-risk/lowest-cost capital investments in Taranaki and has postponed the majority of its capital program previously budgeted for in non-core and non-producing permits. A critical strategy which the Company is taking in order to adapt to the current low-commodity price environment has been the Company's decision to seek farm-in partners on all non-core permits in order to reduce exploration and capital risk and if unsuccessful in these partnership efforts, TAG will relinquish these permits. In addition, the management team has set a goal to reduce production and administrative costs by 10-20% over the next six months, while maintaining safe operations, and continuing to build long-term value within the Company.

The Company is continuing to develop its lightly explored Cheal and Sidewinder discovery acreage through development and step out drilling in a safe, well-planned and technically diligent manner. TAG also leverages technology and expertise that is growing worldwide to advance the Company's significant resource prospects to the development stage.

TAG will continue to focus on the following goals during the 2015/16 fiscal years.

1. Grow baseline reserves, production, and cash flow in Taranaki via low-risk re-completions of by-passed zones in existing wells as well as ongoing shallow development drilling;
2. Seek partners to help unlock the major undiscovered resource potential by confirming unconventional commerciality from the fractured source rocks of the East Coast Basin;
3. Seek partners to help pursue high-impact exploration and establish production within the deep Kapuni Formation in Taranaki;
4. Seek partners to make a shallow water offshore discovery within the Kaheru Joint Venture in Taranaki; and
5. Seek partners to make a new discovery in the conventional frontier exploration drilling located in the Canterbury Basin.

The Company's long-term strategy seeks to maximize the value of its core producing operations year-over-year by increasing reserves and production, reducing risk through robust planning processes, seismic acquisition, development drilling, minimizing costs and optimizing production to lower our per barrel production costs. Further, the Company seeks to diversify exploration risk among our portfolio of opportunities thereby increasing capital investment optionality and enabling proper risk management related to the reinvestment of the Company's stable cash flow from operations in order to deliver a strong return on capital invested.

TAG management also takes a disciplined approach to all aspects of the production stream to ensure maximum revenue growth is achieved safely, while also optimizing production techniques and reducing operating costs.

TAG's leadership team has demonstrated a commitment to adapt its plans quickly when needed, yet remaining focused on conducting the Company's business plan methodically. As a result, the Company is in a position to internally fund its adjusted 2015/2016 fiscal year operations program, which will provide an opportunity for significant organic growth through drill-bit success, particularly within the Company's core asset areas. At the same time, TAG continues to focus on the future:

1. Continued prospect generation;
2. Consider strategic acceleration options of the Company's shallow Taranaki drilling program to grow production;
3. Review potential acquisitions of overlooked/undervalued opportunities; and
4. Continue acreage growth via the annual Blocks Offers from the New Zealand Government.

TAG's strategy will guide our team to realize our vision to become a leading international energy company.

FINANCIAL AND OPERATING HIGHLIGHTS

- Average net daily production increased by 8% for the quarter ended December 31, 2014 to 1,991 boe/d (77% oil) from 1,845 boe/d (78% oil) for the quarter ended September 30, 2014. Oil and Gas production increased by 7% and 10% respectively due to the succesful completion of the Cheal-B9, B10 and E6 development drilling and continued production optimization at the Cheal E production site.
- Record net oil production volumes achieved, averaging 1,543 bbl/d for the quarter ended December 31, 2014 which equates to a 44% increase over the same period last year. Average net daily production decreased by 7% for the first nine months of fiscal year 2015 to 1,862 boe/d (77% oil) from 1,992 boe/d (56% oil) for the same period last year due to lower Sidewinder gas production.
- At December 31, 2014, the Company had $31.1 million (December 31, 2013: $68.5 million) in cash and cash equivalents and $32.9 million (December 31, 2013: $71.2 million) in working capital.
- Revenue increased by 1% for the first nine months of fiscal year 2015 to $44 million from $43.5 million over the same period last year.
- Operating netback increased by 4% for the first nine months of fiscal year 2015 to $59 per boe from $56.62 per boe over the same period last year.
- Cashflow provided from operating activities increased by 9% for the first nine months of fiscal year 2015 to $23.3 million from $21.3 million over the same period last year.
- Net income before taxes decreased by 11% for the first nine months of fiscal year 2015 to $7.9 million from $8.9 million over the same period last year.
- The Company was awarded a 100% interest in the 14,725-acre PEP 57065 (Sidewinder North) offsetting the Sidewinder discoveries in the December 2014 Block Offer.
- The Company was awarded a 100% interest in the 22,054-acre PEP 57063 (Waiiti) in the December 2014 Block Offer.
- On December 8^{th} 2014, the Company announced that subject to the acceptance of the Toronto Stock Exchange (the "TSX") the Company intends to purchase and cancel up to 5,885,051 of its common shares. TAG has appointed Dundee Goodman Private Wealth to conduct the purchases through the facilities of the TSX.
- On November 5^{th} 2014 the Company announced that Dr. Douglas Ellenor has joined the board of directors of the Company, replacing Mr. Ronald Bertuzzi who is retiring.
- Capital expenditures in the nine months to date for fiscal year 2015 was $39.2 million compared to $47.8 million for the same period last year. The majority of the expenditure related to the following capital projects:
    - Exploration expenditure in PEP 38348 for Waitangi Valley-1 ($16.3 million);
    - Development and facilities expenditure in PMP 38156 related to drilling, completing, testing and tie-in of Cheal-B9, B10 and E7 ($14.3 million);
    - Exploration expenditure in PEP 54877 (TAG:70%) drilling, completing, test and tie-in Cheal E6 ($3.2 million);
    - Exploration expenditure in PEP 54876 (TAG:50%) drilling at Southern Cross permit ($1.3 million);

- Kaheru Long Lead Items ($0.7 million);
- Electricity generation and mining expenditure ($3.1 million).

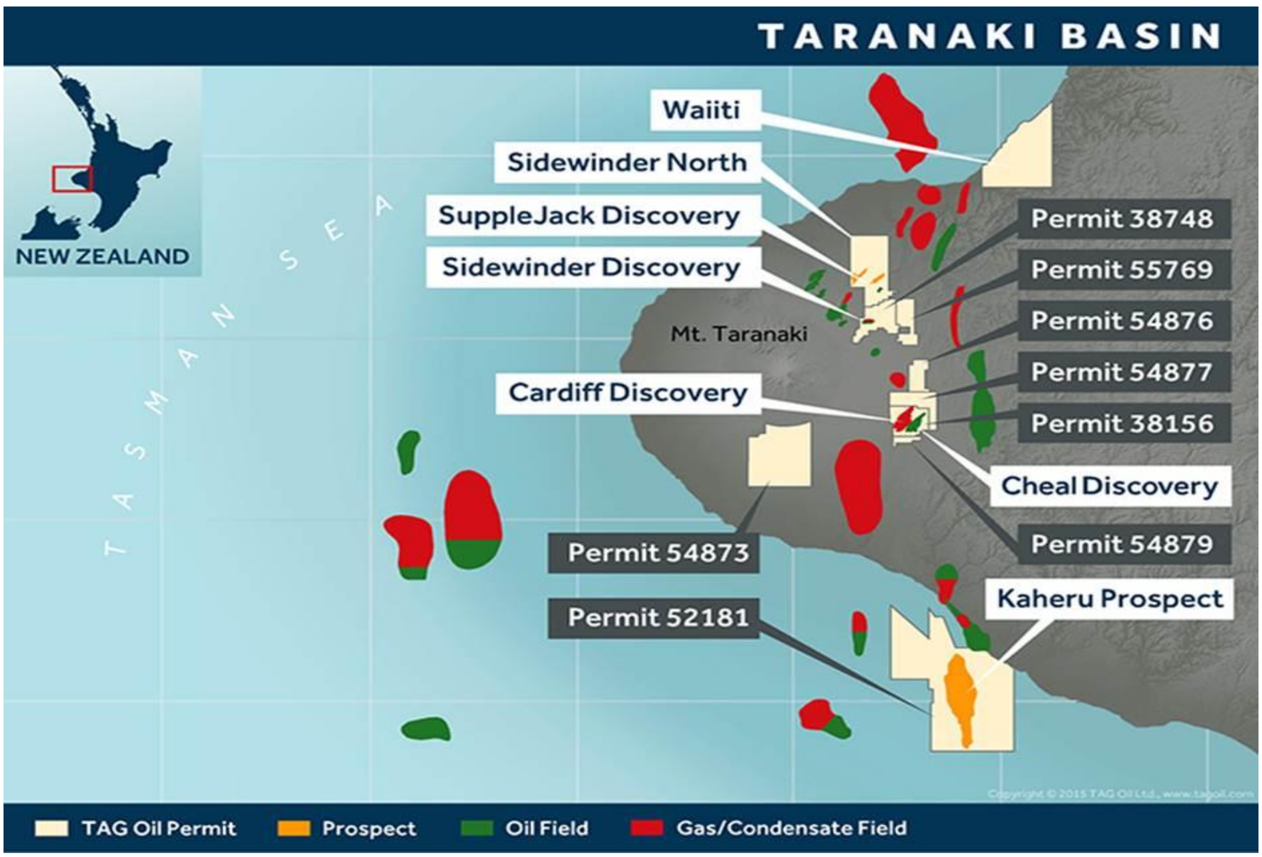
RECENT DEVELOPMENTS

- On December 15th 2014, the Company received notice from East West Petroleum (NZ) Ltd that it has elected to not participate in the Year 2 minimum work obligatgion on PEP 55770 and therefore relinquish their 40% working interest. The Company intends to farm-out the intrests in this permit or relinquish prior to incurring any futher costs.
- On January 27th 2015, the Company held the 2014 Annual General Meeting in Wellington, New Zealand. All of the five nominees listed in the Company's management information circular dated December 19, 2014 proposed by management for election to the board of directors at the Meeting were duly elected.
- In early February 2015, the workover on the Cheal B-6 well was completed, repairing a faulty packer that had caused the well to be shut in for an extended period. The well is now back on production.

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 the Heatseeker PEP 54873 exploration permit.
- 100% interest in PEP 57063 (Waiiti) exploration permit.

- 70% interest in the Cheal North East PEP 54877 exploration permit.
- 50% interest in the Southern Cross PEP 54876 and 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 thirty four 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 1,991 boe's per day (77% oil) in Q3 2015, compared to an average of 1,845 boe's per day (78% oil) in Q2 2015 and 1,527 boe's per day (70% oil) in Q3 2014. The increase in oil production is primarily due to the increased contribution from the succesful development of the Cheal North East permit (PEP 54877: TAG 70% interest).

The Cheal A, B and C fields (PMP 38156: TAG 100% interest) produced an average of 1,238 boe's per day (86% oil) in Q3 2015, compared to an average of 1,139 boe's per day (85% oil) in Q2 2015 and 1,316 boe's per day (81% oil) in Q3 2014. The increase of 99 boe's per day from Q2 2015 is mainly due to the successful completion of Cheal-B9 and B10. Cheal-A12 remains shut in while options are evaluated to determine the optimal workover solution. Cheal B6 was successfully returned to production in Mid November, however further mechanical issues in Mid December required the well to be shut in. Cheal B6 was successfully returned to production on February 1st. The Cheal-E7 well (drilled from Cheal E Pad into the Cheal PMP) was successfully drilled and completed during December and is currently being production tested.

The Cheal North East permit (PEP 54877: TAG 70% interest) produced an average of 642 net boe's per day (74% oil) in Q3 2015 compared to an average of 598 boe's per day (77% oil) in Q2 2015 and nil boe's per day in Q3 2014. The increase of 44 boe's per day from Q2 2015 is mainly due to the successful completion and tie-in of the Cheal-E6 Joint Venture Well which averaged gross production of 334 boe's per day (81% oil) over a 15 day test period during December.

The Cheal North East area development and step out drilling continues to achieve excellent results with current stabilized production of approximately 750 bbls/d (525 bbls/d net) plus solution gas from the new "Cheal-E Area". The successful Cheal-E1 step out well, which was placed in production in November 2013, made the Cheal-E area (TAG-70%) TAG's newest producing oil site, and this success substantially extends the oil saturated area of the 100% TAG held Cheal field.

The shallow Miocene oil wells at Cheal and Greater Cheal are providing steady oil production and predictable decline rates. The majority of these shallow wells are now on production and all are utilizing good oil field practice.The Company will continue to optimize production methods and perform planned routine maintenance on wells on a regular basis, which requires certain wells to be shut-in periodically.

The Sidewinder field produced an average of 111 boe's per day (2% oil) in Q3 2015, compared to an average of 108 boe's per day (3% oil) in Q2 2015 and 211 boe's per day (1% oil) in Q3 2014. Sidewinder production has stabilized over recent quarters due to changes made to faciltiy and well operating modes resulting in improved well deliverability, however at these rates of production, Sidewinder is just moderately economic, contributes $0.1 million of cash flow per quarter and requires further drilling to continue production longer-term, otherwise the Company expects to shut-in the field within the next year.

After a re-evaluation of TAG's (100%) Sidewinder acreage where the Company discovered and produces gas from a shallow Miocene-age zone, the next exploration wells will focus on the oil potential identified within the area. In this regard, TAG is seeking a partner to contribute to funding two new exploration wells later in 2015 from the new Sidewinder-B site targeting 3D seismically defined anomalies, which are interpreted to be oil-prone prospects. With the 100% owned TAG Sidewinder Production Facility nearby, further successful Sidewinder wells can be commercialized quickly and economically utilising current available capacity.

Deep / Eocene Exploration

TAG has a number of deep, potentially high-impact onshore drilling opportunities targeting the Kapuni Formation, which is where most large onshore producing fields have been discovered in Taranaki. Most recently, TAG successfully drilled the Cardiff-3 well to total depth of 4,853m. The well intercepted 230 meters of potential oil-and-gas bearing sands in numerous zones within the Kapuni Formation. The deepest of three zones identified for further completion, the K3E zone, was perforated and hydraulically fractured. The K3E zone produced gas, oil and condensate with no formation water, but not at the commercial rates expected. As a result, TAG is now planning to move uphole and initiate testing on primary target zones, the McKee and K1A zones, while incorporating the results of the K3E zone to the overall completion strategy for the well.

The Cardiff-3 well was drilled from the Cheal-C site, which is connected by pipeline to the Cheal-A processing facilities; providing open access to the New Zealand gas sales network allowing for fast-track development of the well upon success.

Timing of conducting the uphole operations at Cardiff depends on a number of factors as discussed below that form the basis of the Company's business plan guiding operation and capital investment. At the current time after considering rig and affiliated services availability, work commitments to maintain permit tenure in core permits in Taranaki and a large inventory of low-risk shallow infill well opportnities, TAG will conduct the Cardiff-3 re-completion activities when the management team feels all planning has been completed appropriately and when the Company's balance sheet will support this investment.

The Heatseeker prospect, located in PEP 54873 (100% TAG), has been identified on 2D seismic and has similar geological features to the adjacent landmark Kapuni gas/condensate discovery field ("Kapuni"), including apparent 4-way dip closure at the crest of the feature. The permit is located in close proximity of the Kapuni gas / condensate processing facility which could allow for an efficient route to commercialization upon discovery. The Company has been awarded all consents necessary to drill Heatseeker-1 and a Change of Condition was applied for by the Company in relation to the timing of the work program commitments and the requested change was recently granted by the New Zealand Petroleum and Minerals Group extending the commitment date to drill the well until 12 June 2015. In order to carry out drilling of the Heatseeker well, the Company is seeking a suitable joint venture partner.

The Hellfire prospect, located within PMP 53803, has been identified on 3D seismic and, like Heatseeker, has similar geological features to Kapuni. Hellfire is a contingent well that will be drilled upon success of either Cardiff and/or Heatseeker and likley if a suitable joint venture partner joins TAG in the exploration drilling activities, with the Sidewinder processing facility being available to allow for commercialization of a discovery to be done efficiently.

Offshore Exploration

Planning and preparations work by the Operator, New Zealand Oil and Gas, continue on schedule to drill the shallow-water Kaheru-1 well to a total depth of 4,400 meters. The Kaheru Prospect, located in PEP 52181 (40% TAG), is a large, technically robust Miocene-age four way dip closure, situated in a discovery trend that is referred to as the "string of pearls" with Kaheru forming the "last pearl" just offshore from a number of onshore commercial discoveries. On May 31, 2011 Sproule International Limited, a qualified reserves evaluator in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook estimated the Kaheru Prospect to have potential cumulative undiscovered petroleum initially-in-place, net to TAG, of over 17.4 million barrels on a mid-range (P50) basis.

A budget for long lead items and well preparations was approved by the Kaheru Joint Venture and the Joint Venture has identified a rig slot in order to drill the Kaheru-1 well at the end of the jack-up rig's existing schedule anticipated to be in Q2 of fiscal year 2016 (July-Sept 2015), however at the date of this report a contract with the rig owner has yet to be executed by the Kaheru joint venture. To date, the Company has paid $1.5 million of the estimated $22.5 million net costs to TAG to participate in the drilling of the Kaheru well with the majority of costs expected to be funded in July - Sept 2015. Althought the Company has a high-level of confidence in the Kaheru prospect based on the technical data to support drilling, the Company is actively seeking joint venture partners to particiapte in funding the well, reducing the Company's interest in the Kaheru permit.

East Coast Basin:

At December, 2014, the Company controls a 100% working interest in three exploration permits totaling 1.43 million acres (PEP 38348, 38349, 53674, 55770) in the East Coast Basin of New Zealand. The Company has added a consistent focus to East Coast Basin unconventional drilling to its growth plan with a dedicated effort to unlocking the potential within the Company's tight-oil play that compares favourably to commercial tight-oil plays in North America.

Q3 2015 saw the abandonment of Waitangi Valley-1 located near Gisborne in PEP 38348. The well was spudded in July 2014; extreme drilling conditions at Waitangi Valley-1 resulted in a decision to abandon the well after approximately 900m of hole had been drilled. Further engineering is underway to design a suitable well to deliver the balance of the permit obligations that require two wells to maintain permit tenure until November 2016.

In April of 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, encouraging further drilling in the basin.

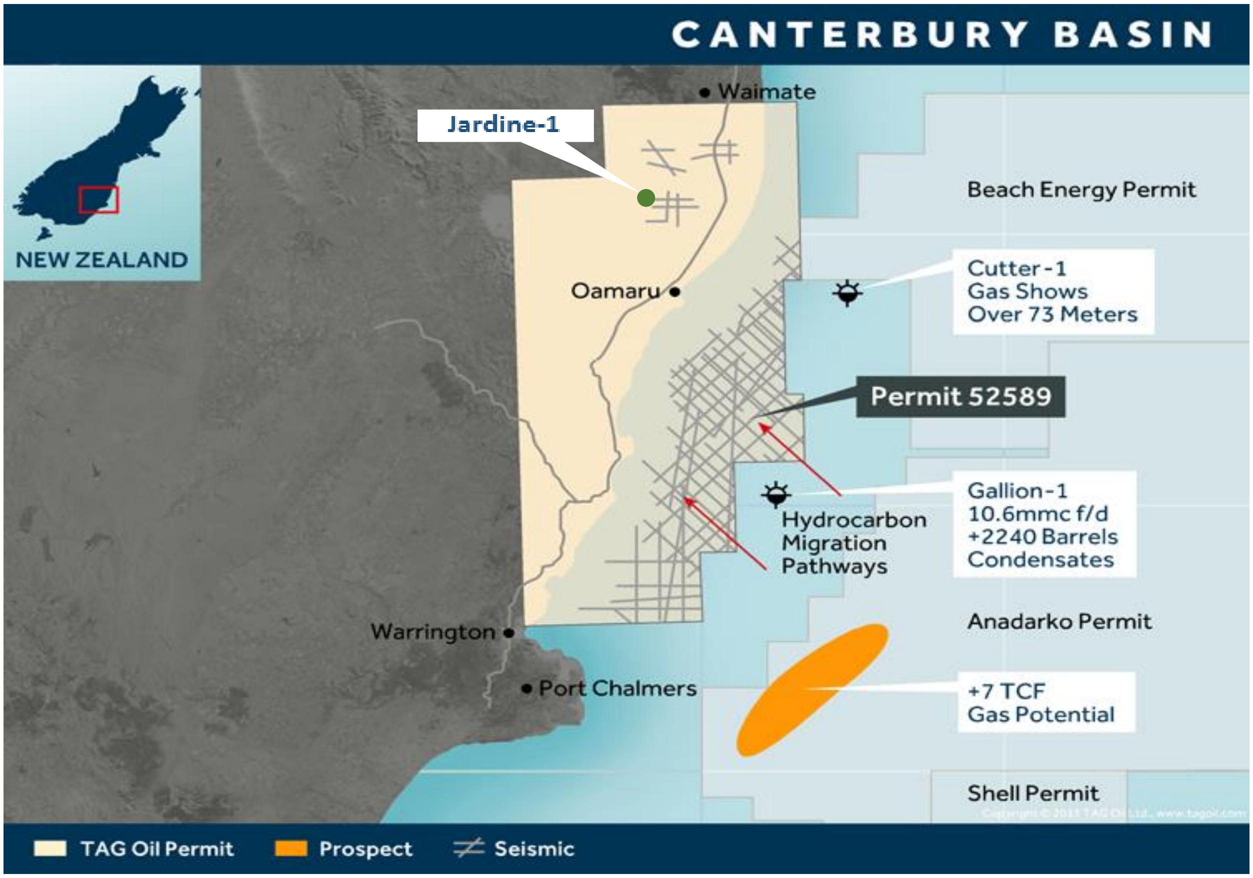
The Company is presently seeking a suitable JV partner to help further fund the East Coast program and has fielded interest from a number of suitable companies to date. Given success in finding a partner, additional drilling of one, and likely two, more unconventional stratigraphic tests are expected to occur in the coming fiscal year, over the Company's East Coast acreage holdings, in a continuation of the data building phase ("the proof of concept phase") critical to proving the play's economic viability. Should a suitable partner not be found to fund further costs within the East Coast Basin, the Company will consider relinquishing the permits. 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 and is considering opportunities to attract a suitable joint venture partner with a long-term vision similar to the Company's that would result in a consistent investment in the basin over many years to convert undiscovered resource potential to proved and producing reserves.

The Company (60%) and East West Petroleum (40%) were awarded an interest in a 106,111-acre Permit (PEP 55770) within the East Coast basin unconventional fairway in the December 2013 Block Offer. The commitments call for the reprocessing of existing seismic data and the acquisition of 60 km of new 2-D seismic data within the first 18 months of the Permit tenure.

East West Petroleum has formally declined to continue on with the work program in this Permit therefore relinquisihing their 40% working interest. The Company will analyse the options available to move forward with this Permit in the coming quarters.

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 considerable promise and is optimally 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 has acquired a further 40km of 2D seismic data in early 2014 to allow 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. Based on the results and interpretation of the proprietary 2D seismic data the Company is considering the drilling of a well in fiscal 2016.

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 represents full consideration paid by Coronado to acquire 100% of the issued and outstanding shares of OHL. The transaction increases 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

	2015	2015	2014	Nine months ended	
Daily production volumes (1)	**Q3**	Q2	Q3	**2015**	2014
Oil (bbls/d)	**1,543**	1,437	1,069	**1,426**	1,118
Natural gas (boe/d)	**448**	408	458	**437**	874
Combined (boe/d)	**1,991**	1,845	1,527	**1,863**	1,992
% of oil production	**77%**	78%	70%	**77%**	56%
Daily sales volumes (1)					
Oil (bbls/d)	**1,536**	1,447	1,061	**1,422**	1,114
Natural gas (boe/d)	**208**	176	351	**195**	747
Combined (boe/d)	**1,744**	1,623	1,412	**1,617**	1,861
Natural gas (mmcf/d)	**1,248**	1,056	2,106	**1,172**	4,482
Product pricing					
Oil ($/bbl)	**77.29**	110.09	112.74	**100.36**	110.57
Natural gas ($mcf)	**3.60**	5.32	5.43	**4.55**	5.50
Oil and natural gas revenues (3) - gross *($000s)*	**11,333**	15,008	12,058	**40,717**	40,659
Oil & natural gas royalties (2)	**(1,070)**	(1,361)	(1,398)	**(3,706)**	(4,505)
Oil and natural gas revenues - net *($000s)*	**10,263**	13,647	10,660	**37,011**	36,154

(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 increased by 8% for the quarter ended December 31, 2014 to 1,991 boe/d (77% oil) from 1,845 boe/d (78% oil) for the quarter ended September 30, 2014, and increased by 30% from 1,527 boe/d (70% oil) for the same period last year:

a. The 8% increase compared to 2015 Q2 is due to a 7% increase in oil production primarily related to the successful completion of the Cheal-B9/B10 and Cheal-E6 development drilling and continued production optimization at the Cheal-E production site.

b. The 30% increase compared to 2014 Q3 is due to the 44% increase in oil production primarily related to the successful development of the Cheal North East area development offset partially by declining Sidewinder gas rates.

Oil and natural gas gross revenues decreased by 24% for the quarter ended December 31, 2014 to $11.3 million from $15 million for the quarter ended September 30, 2014, and decreased by 6% from $12.1 million for the same period last year:

a. The 24% decrease compared to 2015 Q2 is due to a 30% decrease in oil prices offset partially by a 6% increase in oil sales.

b. The 6% decrease compared to 2014 Q3 is due to a 31% decrease in oil prices, a 41% decrease in gas sales volumes offset partially by a 45% increase in oil sales volumes.

SUMMARY OF QUARTERLY INFORMATION

Canadian $000s, except per share or boe	**2015**			2014				2013
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Net production volumes (boe/d)	**1,991**	1,845	1,750	1,486	1,527	2,100	2,354	1,691
Total revenue	**12,282**	16,179	15,571	14,025	12,939	15,885	14,698	12,298
Operating costs	**(5,806)**	(6,213)	(5,721)	(5,706)	(4,653)	(4,800)	(4,965)	(4,056)
Foreign exchange	**(344)**	1,206	(312)	2,246	(167)	(1,012)	146	426
Stock based compensation	**(586)**	(356)	(44)	(175)	(377)	(559)	(938)	(1,276)
Other costs	**(6,490)**	(5,669)	(5,804)	(4,562)	(4,771)	(7,102)	(5,420)	(7,375)
Net income (loss) before tax	**(944)**	5,147	3,690	5,828	2,971	2,412	3,521	17
Basic income (loss) $ per share (BT)	**(0.01)**	0.08	0.06	0.09	0.05	0.04	0.06	0.00
Diluted income (loss) $ per share (BT)	**(0.01)**	0.08	0.06	0.09	0.05	0.04	0.06	0.00
Capital expenditures	**16,655**	11,126	11,370	22,767	20,959	14,466	12,349	20,032
Operating cash flow *(1)*	**3,968**	9,702	7,715	6,774	6,101	8,562	8,468	18,136

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

Total revenue decreased by 24% for the quarter ended December 31, 2014 to $12.3 million from $16.2 million for the quarter ended September 30, 2014, and decreased by 5% from $12.9 million for the same period last year. The 24% decrease compared to 2015 Q2 is mainly due to a 25% decrease in oil revenues due to a 31% decrease in oil pricing offset partially by a 6% increase in oil sales volumes:

The 5% decrease compared to 2014 Q3 is mainly due to a 61% decrease in gas revenues ($0.6 million) due to declining Sidewinder gas production and a 1% decrease in oil revenues ($0.1 million) due to a 31% decrease in oil pricing offset partially by a 45% increase in oil sales volumes.

Net loss before tax for the quarter ended December 31, 2014 was $0.9 million compared to net income of $5.2 million for the quarter ended September 30, 2014, and net income of $3 million for the same period last year. The $6.1 million decrease compared to 2015 Q2 is primarily due to the 31% decline in the oil price which equates to lower revenue of $3.8 million and combines with $1.3 million in foreign exchange movements and a $1 million increase in other costs related to staffing, administrative and share based compensation costs.

The $3.9 million decrease in net income when comparing 2015 Q3 results to 2014 Q3 is primarily due to lower oil and gas revenue of $0.7 million due to a combination lower oil prices and lower gas sales, higher operating costs ($1.2 million) related primarily to the 45% increase in oil production and higher other costs of $1.6 million related to an increase in DD&A due to a 30% increase in total daily production as oil production increased and gas production decreased.

Capital expenditures totalled $16.7 million for the quarter ended December 31, 2014 compared to $11.1 million for the quarter ended September 30, 2014. The majority of the expenditure in the current quarter related to the following capital projects:

- Exploration expenditure in PEP 38348 for Waitangi Valley-1 ($6.4 million)
- Exploration expenditure in PEP 54877 drilling and completing Cheal E6 ($2.6 million)
- Development expenditure in PMP 38156 drilling and completing Cheal-B10 and Cheal E7 ($5.9 million)
- Electricity generation expenditure ($0.6 million);

Given the current market dynamics, the Company will focus its capital expenditure program towards low-risk initiatives based around cash provided from operating activities to maintain a strong balance sheet. Successful discoveries from the majority of TAG's drilling locations can be placed efficiently into production using the existing 100% TAG owned production infrastructure.

Net Production by Area (BOE/d)

Area	2015		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
PMP38156 (Cheal)	**1,238**	1,139	1,316	**1,165**	1,440
PEP54877 (Cheal North East)	**642**	598	-	**582**	-
PMP53803 (Sidewinder)	**111**	108	211	**116**	552
Total boe/d	**1,991**	1,845	1,527	**1,863**	1,992

Daily net production volumes increased by 8% for the quarter ended December 31, 2014 to 1,991 boe/d compared with 1,845 boe/d for the quarter ended September 30, 2014. PMP38156 (Cheal) production increased 9% due to a 9% increase in oil production provided by new production brought on-stream from the addition of the Cheal-B9/B10 wells. PEP54877 (Cheal North East) net production increased 7% due to continued production optimization and the successful drilling, completion and hookup of the Cheal E6 well in December. Production at PMP53803 (Sidewinder) increased 3% due to changes made to facility and well operating modes resulting in improved well deliverability.

Daily net production volumes increased by 30% for the quarter ended December 31, 2014 to 1,991 boe/d compared with 1,527 boe/d for the same period last year. The increase of 464 boe/d is due to the discovery and commercialization of the Cheal North East (TAG: 70%) area contributing new production of 642 boe/d offset by declining gas rates at Sidewinder and Cheal.

Oil and Gas Operating Netback ($/BOE)

$BOE	2015		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Oil and natural gas revenue	**70.65**	100.51	92.81	**91.54**	79.34
Royalties	**(6.67)**	(9.11)	(9.95)	**(8.33)**	(8.22)
Transportation and storage costs	**(9.85)**	(9.63)	(6.75)	**(9.97)**	(5.06)
Production costs	**(13.35)**	(15.09)	(12.01)	**(14.24)**	(9.44)
Netback per boe ($)	**40.78**	66.68	64.10	**59.00**	56.62

Operating netback is the operating margin the company receives from each barrel of oil equivalent sold. Netback per boe decreased by 39% for the quarter ended December 31, 2014 to $40.78 per boe from $66.68 per boe for the quarter ended September 30, 2014, and decreased by 36% from $64.10 per boe for the same period last year.

The 39% decrease in netback per boe when compared to 2015 Q2 is mainly due to the 30% decline in average oil sales prices from $110.09 per bbl in Q2 to $77.29 in Q3. The remainder of the decrease comes as a result of increased costs to produce, transport, and sell Cheal oil, compared to the low cost of gas production and transportation from comparative quarters.

The 36% decrease in netback per boe compared to 2014 Q3 is mainly due to the 31% decline in average oil sales prices from $112.74 per bbl in 2014 Q3 to $77.29 in 2015 Q3.

General and Administrative Expenses ("G&A")

	2015		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
General and administrative expenses ($000s)	**2,214**	1,558	2,147	**5,729**	5,152
Per boe ($)	**12.09**	9.18	15.28	**11.19**	9.40

G&A expenses increased by 42% for the quarter ended December 31, 2014 compared to the quarter ended September 30, 2014, and increased by 3% when compared to the same period last year.

The 42% increase compared to 2015 Q2 is mainly due to the successful recruitment of key vacant positions (NZ Country Manager and HSE Manager) and higher staffing costs in December 2014 related to annual performance reviews.

The 3% increase compared to 2014 Q3 is mainly due to increased shareholder relations, inclusive of New Zealand Community and stakeholder outreach efforts, as well as office and administration costs.

Share-based Compensation

	2015		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Share-based compensation ($000s)	**586**	356	377	**986**	1,873
Per boe ($)	**3.20**	2.12	2.68	**1.93**	3.42

Share-based compensation costs are non-cash charges which reflect the estimated value of stock options granted and 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 71% and a risk free interest rate of 1.91% to calculate option benefits. The fair value of the option benefit is amortized over the vesting period of the options, generally being eighteen months.

In the quarter ended December 31, 2014, the Company did not grant any options (December 31, 2013: 75,000), no options were exercised (December 31, 2013: 71,429) and 440,000 options were cancelled (December 31, 2013: nil).

Depletion, Depreciation and Accretion (DD&A)

	2015		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	**2014**
Depletion, depreciation and accretion ($000s)	**4,335**	4,326	2,738	**12,297**	10,257
Per boe ($)	**23.67**	25.49	19.48	**24.01**	18.72

DD&A expenses were constant for the quarter ended December 31, 2014 when compared to the quarter ended September 30, 2014, and increased by 58% when compared to the same quarter last year.

The 58% increase compared to 2014 Q3 is mainly due to the inclusion of the Cheal-E permit (PEP 54877 TAG: 70%) oil & gas properties balance transferred from exploration and evaluation assets.

Foreign Exchange Loss / (Gains)

	2015		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Foreign exchange loss / (gains) ($000s)	**344**	(1,206)	167	**(550)**	1,033

The foreign exchange loss for the quarter ended December 31, 2014 was caused by fluctuations of both the US Dollar and NZ Dollar in comparison to the Canadian Dollar.

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

($000s)	2015		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Net income / (loss) before tax	**(944)**	5,147	2,971	**7,893**	8,904
Income tax expense - current	**-**	-	-	**-**	-
Income tax expense - deferred	**-**	-	-	**-**	-
Net income / (loss) after tax	**(944)**	5,147	2,971	**7,893**	8,903
Per share, basic ($)	**(0.01)**	0.08	0.05	**0.12**	0.15
Per share, diluted ($)	**(0.01)**	0.08	0.05	**0.12**	0.15

Net loss before tax was $0.9 million for the quarter ended December 31, 2014 when compared to net income of $5.2 million for the quarter ended September 30, 2014, and $3 million when compared to the same quarter last year.

The net loss of $0.9 million in 2015 Q3 compared to net income of $5.2 million in 2015 Q2 is primarily due to a $3.8 million decrease in oil & gas revenues due to the oil price decline, a movement of $1.5 million in foreign exchange gains/(losses) and a $0.8 million increase in other costs related to staffing, administrative and share based compensation costs.

The net loss of $0.9 million in 2015 Q3 compared to net income of $3 million in 2014 Q3 is primarily due to a $0.7 million decrease in oil & gas revenues due to the oil price decline and lower gas sales volumes higher operating costs ($1.2 million) related primarily to the 45% increase in oil production and higher other costs of $1.6 million related to an increase in DD&A due to a 30% increase in production.

Cash Flow

($000s)	**2015**		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Operating cash flow *(1)*	**3,968**	9,702	6,101	**21,385**	23,132
Cash provided by operating activities	**8,342**	7,785	7,105	**23,293**	21,261
Per share, basic ($)	**0.13**	0.12	0.12	**0.37**	0.33
Per share, diluted ($)	**0.13**	0.12	0.12	**0.37**	0.31

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

Operating cash flow decreased by 59% for the quarter ended December 31, 2014 when compared to the quarter ended September 30, 2014, and decreased by 35% when compared to the same quarter last year.

The 59% decrease compared to 2015 Q2 is mainly due to the $3.7 million decrease in oil & gas revenue due to the decline in oil prices.

The 35% decrease compared to 2014 Q3 is primarily due to the decrease in oil revenue due to the decline in oil prices and an increase in oil related transportation and storage costs due to the 44% increase in oil production volumes.

CAPITAL EXPENDITURES

Capital expenditures totaled $16.7 million for the quarter ended December 31, 2014 compared to $11.1 million for the quarter ended September 30, 2014, and $21 million for the same period last year.

Details of capital expenditure are included below:

Taranaki Basin ($000s)	**2015**		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Mining permits	**5,959**	1,231	14,088	**13,783**	24,855
Exploration permits	**3,282**	(14)	5,160	**5,110**	11,620
Opunake Hydro Limited	**589**	981	402	**2,560**	4,178
Total Taranaki Basin	**9,830**	2,198	19,651	**21,453**	40,653

East Coast Basin ($000s)	**2015**		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Exploration permits	**6,602**	8,540	666	**16,786**	6,293
Total East Coast Basin	**6,602**	8,540	666	**16,786**	6,293

Canterbury Basin ($000s)	**2015**		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Exploration permits	**6**	43	630	**55**	635
Total Canterbury Basin	**6**	43	630	**55**	635

United States ($000s)	2015	2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Madison mine - exploration	**113**	327	(452)	**537**	2,233
Madison mine - development	**-**	-	(7)	**-**	663
Total United States	**113**	327	(459)	**537**	2,896

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at December 31 2014:

Contractual Obligations ($000s)	Total	Less than One Year	More than One Year
Long term debt	**-**	-	-
Operating leases *(1)*	**566**	340	226
Other long-term obligations *(2)*	**78,572**	75,516	3,056
Total contractual obligations *(3)*	**79,138**	75,856	3,282

(1) The Company has commitments relating to office leases situated in New Plymouth and Napier,New Zealand and Vancouver.

(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, optimisations and lease improvements	4,641	
PMP 53803	Sidewinder B-site consenting	9	
PEP 54873	Drilling of one deep exploration well and reprocess 2D seismic	16,243	
PEP 54876 (1)	Site remediation works	78	
PEP 54877 (1)	Drilling of one shallow exploration well	3,232	2,152
PEP 54879 (1)	Production testing of one well	181	
PEP 38748	Drilling of two shallow wells and lease improvements	4,521	
PEP 52181	Drilling Kaheru-1	22,426	
PEP 52589	Drilling of one shallow exploration well	90	904
PEP 55769	Technical study	2,170	
PEP 55770	2-D seismic reprocessing	2,351	
PEP 57065	2-D seismic reprocessing	90	
PEP 57063	2-D seismic reprocessing	90	
PEP 38348	Drilling of one shallow exploration well and 2D seismic acquisition	11,752	
PEP 38349	Drilling of one shallow exploration well and 2D seismic acquisition	7,640	
	TOTAL COMMITMENTS	**75,514**	**3,056**

(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 $48 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 previoulsy 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.

A controlled subsidiary ot 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 December 31, 2014, the Company had $31.1 million (December 31, 2013: $68.5 million) in cash and cash equivalents and $33 million (December 31, 2013: $71.2 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

	2015		2014	Nine months ended	
($000s)	**Q3**	Q2	Q3	**2015**	2014
Cash provided by operating activities	**8,342**	7,785	7,105	**23,293**	21,261
Changes for non-cash working capital accounts	**(4,374)**	1,917	(1,004)	**(1,908)**	1,871
Operating cash flow	**3,968**	9,702	6,101	**21,385**	23,132

Operating Netback ($000s)	**2015**		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Total revenue	**12,282**	16,179	12,939	**44,032**	43,522
Less electricity revenue	**(949)**	(1,171)	(881)	**(3,315)**	(2,864)
Oil and gas revenue	**11,333**	15,008	12,058	**40,717**	40,659
Less royalties	**(1,070)**	(1,361)	(1,399)	**(3,706)**	(4,505)
Less transportation and storage	**(1,579)**	(1,439)	(949)	**(4,435)**	(2,771)
Less total production costs	**(3,157)**	(3,413)	(2,306)	**(9,599)**	(7,142)
Add back electricity production costs	**1,015**	1,160	618	**3,266**	1,996
Operating Netback	**6,542**	9,955	8,022	**26,243**	28,237

Operating Margin ($000s)

	2015		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Total revenue	**12,282**	16,179	12,939	**44,032**	43,522
Less royalties	**(1,070)**	(1,361)	(1,399)	**(3,706)**	(4,505)
Less transportation and storage	**(1,579)**	(1,439)	(949)	**(4,435)**	(2,771)
Less total production costs	**(3,157)**	(3,413)	(2,306)	**(9,599)**	(7,142)
Operating margin	**6,476**	9,966	8,285	**26,292**	29,104

Use Of Proceeds

On November 13, 2013, the Company closed a bought deal offering of common shares at a price of $4.40 per common share for gross proceeds of $25,080,000 and net proceeds of $23,526,000. The Company filed a final short form prospectus in each of the provinces of Canada except Quebec on November 5, 2013.

Property	**Operation**	**Anticipated use of proceeds in Short Form Prospectus ($000s)**	**Current anticipated use of actual proceeds received ($000s)**	**Status of operation**
Taranaki Basin:				
PMP 38156	Drill one deep exploration well	17,200	17,200	Completed
	Drill one Cheal or Greater Cheal shallow well	2,000	2,000	Completed
East Coast Basin:				
	Unconventional project team build	500	500	Completed
PEP38348, 38349	Seismic acquisition	2,500	2,500	Completed
Canterbury Basin:				
PEP52589	Seismic acquisition	1,326	956	Completed
Working Capital			370	Completed
		23,526	**23,526**	

Please refer to the Company's final short-form prospectus filed on November 5, 2013.

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 party's.

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 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 personnel for the three months ended December 31:

($000s)	**2015**		2014	Nine months ended	
	Q3	Q2	Q3	**2015**	2014
Share-based compensation	**279**	**193**	210	**499**	1.100
Management wages and director fees	**873**	**265**	663	**1,348**	1,164
Total Management Compensation	**1,112**	**458**	873	**1,847**	2,264

SHARE CAPITAL

a. At December 31 2014, there were 63,445,852 common shares outstanding.

b. At February 16, 2015, there were 62,376,252 common shares outstanding and there are 4,595,334 stock options outstanding, of which 3,623,667 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 9 of the accompanying condensed consolidated interim financial statements.

SUBSEQUENT EVENTS

Corporate

On February 11, 2015, the Company announced that Chief Executive Officer and Director, Garth Johnson, and Chief Operating Officer, Drew Cadenhead, have submitted their resignations, but will continue in their respective roles during a transition period to support the appointment of new executives.

Share Capital

Subsequent to December 31, 2014, the Company purchased and cancelled 69,600 common shares under its normal course issuer bids at an average price of $1.34 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 and 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, 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 2015 fiscal year. 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

New and amended standards adopted by the Company

Effective April 1, 2014, the Company adopted the following new and revised IFRS that were issued by the IASB:

- Amendments to IAS 32, Offsetting Financial Assets and Financial Liabilities

- Amendments to IFRS 10, IFRS 12 and IAS 27, Investment Entities
- Amendments to IAS 36, Recoverable Amount Disclosures for Non-Financial Assets
- Amendments to IAS 39, Novation of Derivatives and Continuation of Hedge Accounting
- IFRIC 21, Levies

The application of these new and revised IFRS has not had any material impact on the amounts reported for the current and prior periods but may affect the accounting for future transactions or arrangements.

New standards, amendments and interpretations to existing standards not yet effective

Effective for annual reporting periods beginning on or after January 1, 2016:
- Amendments to IAS 16 and IAS 38, Clarification of Acceptable Methods of Depreciation and Amortization

Effective for annual reporting periods beginning on or after January 1, 2018 (tentative date):
- 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.

Managements Report on Internal Control over Financial Reporting

Disclosure controls and 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 three months ended June 30, 2014 that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

The following pertains to the Company's Annual Management Discussion and Analysis for the year ended March 31, 2014, 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 Company's Board of Directors, 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 March 31, 2014. 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 March 31, 2014, 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 within the East Coast Basin, 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 under “Outlook for Fiscal Year 2015”.

Because forward-looking information addresses future events and conditions, it involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the forward-looking information. These risks and uncertainties include, but are not limited to: access to capital, commodity price volatility; well performance and marketability of production; transportation and refining availability and costs; exploration and development costs; infrastructure costs, the recoverability of reserves; reserves estimates and valuations; the Company’s ability to add reserves through development and exploration activities; accessibility of services and equipment, fluctuations in currency exchange rates; and changes in government legislation and regulations.

The forward-looking statements contained herein are as of December 31, 2014, 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.

Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) 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.

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
Garth Johnson
President, CEO, and Director
Vancouver, British Columbia

Alex Guidi, Director
Vancouver, British Columbia

Keith Hill, Director
Vancouver, British Columbia

Ken Vidalin, Director
Vancouver, British Columbia

Douglas Ellenor, Director
Vancouver, British Columbia

Chris Ferguson, CFO
New Plymouth, New Zealand

Drew Cadenhead, COO
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

SUBSIDIARIES
TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Cheal Petroleum Limited
Trans-Orient Petroleum Limited
Orient Petroleum (NZ) Limited
Eastern Petroleum (NZ) Limited
DLJ Management Corp.

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%)

BANKER
Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL
Blake, Cassels & Graydon
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 February 16, 2015, there were 62,376,252
shares issued and outstanding.
Fully diluted: 66,971,586 shares.

WEBSITE
www.tagoil.com