MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated February 14, 2014, for the three and nine months ended December 31, 2013 and should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2013.

The unaudited condensed consolidated interim financial statements for the nine months ended December 31, 2013, 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, 2013, 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 consisting of approximately 2.8 million net acres of land onshore in the Taranaki, East Coast and Canterbury Basins of New Zealand and 30,816 net acres offshore in the Taranaki Basin as at December 31, 2013. TAG's business plan is designed to grow through increased cash flow provided by operating activities, strategic acquisitions and continued exploration/development drilling to grow reserves.

Maintaining 100% ownership of all facilities and associated pipeline infrastructure within TAG's operations insures the Company can commercialize all discoveries and developments expeditiously, as well as offer third party processing to joint venture partners and other companies in the Basin.

The Company's fiscal year 2012 and 2013 shallow drilling program, focused within TAG's 100% owned Cheal and Sidewinder fields, targeted the proven Urenui and Mt. Messenger formations and provides TAG with long-term stable production, predictable decline rates and significantly more subsurface knowledge that is being incorporated into future drilling programs. The 2014 fiscal year has seen a number of 100% TAG owned wells drilled as well as a number of joint ventured wells in permits generally referred to as the "Greater Cheal Area". The resulting cash flow, when combined with a strong balance sheet, has allowed TAG to embark on the most active and diverse exploration program in the Company's history for fiscal 2014 and is discussed below.

The fiscal year 2014 drilling program activity is focused substantially within the Company's four new Greater Cheal Area permits located in the Taranaki Basin that were awarded in the 2012 New Zealand Blocks Offer. A deep well (Cardiff-3) has also been drilled within TAG's 100% owned Cheal mining permit and Cardiff-3 has been logged, cased and cemented and is now ready for production testing. One unconventional well (Ngapaeruru-1) has also been drilled, logged and cased in PEP 38349 and the Company is analyzing data prior to perforating the well. Fiscal 2014's program is well underway with significant progress on the consenting, construction and drilling work required as part of such a continuous program. This is discussed in more detail below.

The Company remains in a strong financial position, with sufficient working capital to fund operations and meet all commitments for the foreseeable future.

FINANCIAL AND OPERATING HIGHLIGHTS

- At December 31, 2013, the Company had cash of $68.5 million, working capital of $71.2 million and no debt.

- Average gross daily production in the nine months to date of fiscal year 2014 increased by 26% to 2,219 BOE's per day compared with 1,765 BOE's per day for the same period last year. The largest contributor to the increase was from the Company's 100% owned Cheal field as well as the Greater Cheal Permit Area wells drilled on our Cheal-E site located on PEP 54877 (TAG: 70% interest) which increased 49% to 1,667 BOE's per day (77% oil) compared with 1,121 BOE's per day (82% oil) for the same period last year. On a net basis daily production increased by 13% to 1,992 BOE's per day in the first nine months of fiscal year 2014 compared to 1,765 BOE's per day for the same period last year. Net daily oil production increased by 20% to 1,118bbls per day while net daily gas production increased by 5% to 5.2mmscf/day compared to 934bbls/day and 5mmscf/day respectively for the same period last year.

- Average gross daily production for Q3 decreased by 16% to 1,755 BOE's per day compared with 2,100 BOE's per day for Q2. The largest contributor to the decline was from the less profitable Sidewinder field that decreased by 407 BOE's per day due to declining gas volumes. Production from the Company's 100% owned Cheal field as well as the Greater Cheal Permit Area wells drilled

TAG Oil Ltd.
www.tagoil.com

Corporate Office
885 West Georgia Street
Suite 2040
Vancouver, BC
Canada V6C 2G2
ph 604-682-6496
fx 604-682-1174

Technical Office
P.O. Box 402
New Plymouth, 4340
New Zealand
ph 64-6-759-4019
fx 64-6-759-4065

on our Cheal-E site located on PEP 54877 (TAG: 70% interest) have increased gross daily production numbers by 62 BOE's per day due to strong performance from the joint venture wells drilled on the Cheal-E site. On a net basis Cheal production decreased by 165 BOE's per day due to the arrangement with East West Petroleum where, in return for funding the first $5 million in exploration drilling costs, they receive the initial $5 million in revenue from the Cheal-E wells while paying 100% of costs related to that revenue. For clarity, any BOE's produced during the period East West is recovering their initial investment is treated as 100% production to EWP and subsequent to payback being complete, East West will return to a 30% interest. The strong performance from the E-site wells to date indicate the cost-recovery will be completed by mid-February which will result in the Company's net daily production increasing by approximately 500 BOE's per day. On a net basis daily production for Q3 decreased by 27% to 1,527 BOE's per day (70% oil) compared to 2,100 BOE's per day (58% oil) due to a combination of attributing the Company's 70% of prodcution from PEP 54877 to East West Petroleum during East West's cost recovery period as discussed above and from the decline in gas production from the less profitable Sidewinder field.

- Revenue in the nine months to date of fiscal year 2014 was $43.5 million representing a 35% increase over the same period last year (December 31, 2012; $32.3 million).

- Cash provided by operating activities in the nine months to date of fiscal year 2014 was $21.3 million representing a 41% increase over the same period last year (December 31, 2012; $15.1 million).

- Cash provided by financing activities in the nine months to date of fiscal year 2014 was $20.7 million having successfully closed the previously announced bought deal offering of common shares of the Company for aggregate gross proceeds of $25 million (net proceeds of $23.3 million).

- Capital expenditures in the first nine months to date of fiscal year 2014 were $47.8 million compared to $54.4 million for the same period ending December 31, 2012. The majority of the expenditure was invested in PMP 38156 ($20.9 million) of which $18 million related to the drilling of Cardiff-3, PEP 54877 ($7.3 million) to drill and complete the Cheal-E1 to E5 wells, PEP 38349 ($5.5 million) to drill Ngapaeruru-1, PMP 53803 ($4 million) in drilling and faciility costs at Sidewinder and PEP 54873 ($1.7 million) for long lead items and consenting for Heatseeker. The Company also invested $4.2 million in OHL during the nine months.

- The Company drilled and cased the deep gas/condensate prospect, Cardiff-3 to a total depth of 4,863m, fully penetrating and evaluating all three deep zones as planned. Condensate-rich gas shows were recorded in all three target zones within the Kapuni Formation. Evaluation will begin with perforation and, if necessary, hydraulic stimulation of the deepest targeted prospect, the Kapuni K3E zone. Following evaluation of the K3E zone, the shallower K1A and Mckee Sand zones will be evaluated and a decision will then be made on an overall production strategy. All required consents have been received for operations to be conducted.

- The Company has drilled five shallow wells in the Cheal North East permit (PEP 54877) (TAG: 70% interest) with joint venture partner East West Petroleum having a 30% interest. Permanent production facilities owned by TAG have been completed to enable testing and long term production of these wells. At the time of this report the Cheal-E1 and Cheal-E4 wells are on test with strong initial oil flows, and the Company has drilled two of the three planned shallow wells in PEP 54879 (TAG 50% interest and operator), referred to as the Cheal South permit and utilizing TAG's Cheal G-Site to drill the wells.
- The Company was granted resource consents to drill up to six wells in PEP 54876 (Southern Cross) and up to eight wells in PEP 54873 (Heatseeker).
- The Company has signed a new surface access agreement in the East Coast Basin permit for drilling the Waitangi Valley-1 well within PEP 38348.
- The Company was awarded a 100% interest in the 2,910-acre PEP 55769 offsetting the Sidewinder discoveries in the December 2013 Block Offer.
- The Company was awarded a 60% interest and operatorship in the 106,157-acre Permit 55770 within the East Coast Basin unconventional fairway in the December 2013 Block Offer. The permit is part of a Joint Venture with East West Petroleum with East West earning a 40% interest by funding up to $10 million of initial costs inclusive of seismic and one well.

PROPERTY REVIEW

Taranaki Basin:

PMP 38156 - Cheal Oil and Gas Field (TAG 100%)

At the time of this report, the Cheal field has eighteen shallow wells on full, part-time or constrained production out of a total of twenty wells that are capable of producing. The remaining wells remain shut in pending evaluation of an optimal completion method. The Cheal field produced an average of 1,317 BOE's per day in the quarter ended December 31, 2013, compared to an average of 1,148 BOE's per day for the same period in fiscal 2013, representing an increase of 15%. The Cheal and Greater Cheal Area wells are providing steady oil production and, as expected, more predictable decline rates. The majority of wells at the Cheal oil and gas field are now on production and utilizing good oil field practice, the Company will continue to optimize production methods and perform planned routine maintenance on a regular basis, which requires certain wells to be shut-in periodically.

The deep well prospect, Cardiff-3, was spudded in September and reached total depth in late December at 4,863 meters. The Company plans to perforate the well in mid-February and intends to initially production test on an unstimulated natural flow to better understand the reservoir performance. A hydraulic-fracture stimulation will be performed after considering a number of factors such as the unstimulated flow rates, total meters of net gas pay, indicative in situ permeability, and the interpreted volume of original gas in place that could be accessed with this well bore. It is anticipated that in the event of a success at Cardiff-3, a total of three wells would be needed to fully develop the undiscovered resource potential independently estimated by Sproule International Limited on July 31, 2013, at 160 BCF and 5.49 million barrels of condensate on a P50 basis.

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.

PMP 53803 - Sidewinder Oil and Gas Field (TAG 100%)

At the time of this report, the Sidewinder field has four wells on full, part-time or constrained production out of a total of seven wells that are capable of producing. The remaining three wells are awaiting the installation of production equipment or workovers however are not expected to be material producers. The Sidewinder field produced an average of 211 BOE's per day in the quarter ended December 31 2013, compared to an average of 579 BOE's per day for the same period in fiscal 2013, representing a 64% decrease. The decrease is largely due to the Sidewinder wells coming off their initial flush production rates, combined with higher than anticipated natural decline rates. The Sidewinder-A7 well bore, drilled earlier this year, has been designed to enable the Company to drill the Hellfire deep prospect at a later date.

PEP 38748 (TAG 100%)

The permit work program includes the drilling of two exploration wells prior to August 2014. During the quarter, the Company has been liasing with stakeholders and is negotiating an access agreement for a well-site lease. Resource consent documents are currently being prepared and, once granted, the Company will be approved to begin construction of the well-site lease prior to drilling.

PEP 54876, PEP 54877 and PEP 54879 (TAG 50%, 70% and 50% respectively and operator)

As stated above, the Company has embarked on the most diverse and active drilling campaign in its history with drilling, completion and facility construction operations occuring simultaneously. The drilling efforts and ability to fast-track discoveries into production through the Company's existing 100% owned facilities will enable the Company to add reserves and increase cash flow on success. The shallow exploration wells, targeting the Mt Messenger and Urenui zones, that are discussed in the following permits referred to as the Greater Cheal Area permits are expected to show similar characteristics to our existing 100% owned Cheal shallow wells which have averaged IP's of 300 BOE's per day and provide steady, long-term oil production after the initial flush production.

PEP 54876 (Southern Cross) – (TAG 50%)

The permit work program includes reprocessing 200 kilometers of 2D seismic and drilling one exploration well, which is to be funded 100% up to $2.5 million by the Company's joint venture partner East West Petroleum Limited ("EWP") with any costs in excess of $2.5 million being shared based on each companies pro-rata interest in the permit. Under the terms of the joint venture agreement EWP is entitled to recover the first $2.5 million of oil and natural gas revenue and paying 100% of all costs to do so, before all future revenue and costs are split according to each party's working interest.

During the quarter and to date, the Company has completed reprocessing of the seismic data as required and has identified a drill-ready prospect known as Southern Cross. In addition, the Company has been liasing with stakeholders and has signed an access agreement for a well-site lease. Resource consents have been granted for the site and the Company will begin construction of the well-site lease and drill Southern Cross-1 in Q4 of fiscal 2014.

PEP 54877 (Cheal North East) – (TAG 70%)

The permit work program includes the drilling of five exploration wells, two of which have been funded 100% to $5.0 million by the Company's joint venture partner EWP who holds a 30% interest in the permit. Under the terms of the joint venture agreement EWP is entitled to recover the first $5 million of oil and natural gas revenue while also paying 100% of all costs associated with that revenue, before all future revenue and costs are split according to each party's working interest.

At the time of this report, all five wells have been drilled on the Cheal-E site, and all five wells have been cased for production testing. To date all 5 wells have been perforated, initial production testing is occurring on each well individually to gather baseline production and reserve data for each well. In addition, a permanent separation facility has been built and commissioned that can process up to 1,000 bbls/d of crude oil from the E-Site while using the artificial lift infrastructure. Once the baseline initial production data has been gathered, a long-term production scheme will be implemented at the site.

A second site, Cheal D, located on PEP 54877 has also been granted all resoruce consents to drill up to twelve wells. The site will be constructed when appropriate in anticipation of further drilling on this permit. In addition the location of the Cheal-D site will enable the Company to drill wells within the Companys' 100% Cheal Mining Permit.

PEP 54879 (Cheal South)– (TAG 50%)

The permit work program includes drilling three shallow exploration wells, one of which is to be funded to a total of $2.5 million by the Company's joint venture partner EWP. Under the terms of the joint venture agreement EWP is entitled to recover the first $2.5 million oil and natural gas revenue while also paying 100% of all costs to generate that revenue, before all future revenue and costs are split according to each party's working interest.

At the time of this report, the Company has completed drilling two of the three wells planned on the Company's Cheal-G drilling site and preparations are underway for completion and testing operations in the coming months.

PEP 54873 – (TAG 100%)

The Heatseeker prospect has been identified clearly on 2D seismic and has similar geological features to the adjacent landmark Kapuni gas/condensate discovery field, 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.

During the quarter and to date, the Company has been awarded all consents necessary to drill Heatseeker-1. One party objected to the issue of consents and has lodged an appeal to the New Zealand Environment Court. At the time of this report, the Environment Court is deciding whether there is any merit in the appeal lodged, however the Company strongly believes the appeal is without merit. Once the appeal has been processed, the Company will begin construction of the well-site lease in preparation for the drilling of the Heatseeker well.

PEP 55769 – (TAG 100%)

The Company was awarded this 2,910-acre permit offsetting the Sidewinder discoveries in the December 2013 Block Offer. The commitments call for the acquisition of 100 km of 2-D seismic data within the first 18 months of the permit tenure. Planning is underway in order to complete the seismic program within the required timeframe.

PEP 52181 - Kaheru Offshore (TAG 40%)

Planning work by the Operator, New Zealand Oil and Gas, continues for the Kaheru-1 offshore well. The Kaheru prospect is located in 22 meters of water off the south coast of Taranaki, and is a shallow water extension of the onshore Taranaki production fairway. A large 145 km2 3D seismic survey with several reprocessing volumes covers the entire prospect and allows for four way dip closure imaging. The prospect is offset by prolific oil and gas producing fields along the entire thrust belt trend. As of May 31, 2011, this multi-zone prospect was independently evaluated by Sproule International Limited (on a 100% basis) as having an undiscovered resource potential of 43 MMbbs oil with 72 BCF of associated gas.

A budget for long lead items and well preparations was approved and the Joint Venture has secured a rig slot in order to drill the Kaheru well at the end of the jack-up rig's existing schedule at the end of calendar 2014 to early 2015.

East Coast Basin:

At December 31, 2013, the Company controls a 100% working interest in three exploration permits totaling 1.42 million acres and a 60% working interest in one joint ventured exploration permit totalling 106,111 acres in the East Coast basin of New Zealand. The Company has acquired proprietary 2D seismic data, completed extensive geological surface and sub-surface studies initially drilled a number of stratigraphic wells within three of the permits.

The Company has added 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. In April of 2013, the Company drilled and cased its first tight-oil targeted well, Ngapaeruru-1, with promising initial results that indicate on logs, a potential 155 meter gross hydrocarbon column. Additional drilling of at least three wells is expected over the next 12 to 18 months to achieve TAG's goal of converting undiscovered resource potential within the Company's permits to proved reserves. The Company recently announced the addition of two unconventional oil and gas specialists from North America contracted to the New Zealand team and the opening of an East Coast Basin office in Napier to enable the Company to plan and execute a cost-effective long-term plan to create value in the East Coast Basin.

PEP 38348 - (TAG 100%)

The Company is preparing to undertake the first phase of unconventional drilling on the northern PEP 38348 permit and is continuing extensive consultation with all stakeholders, including local iwi, landowners and local and central government. Initial construction, surface lease access and drilling consent applications for the Punawai-1 have been approved by regional and district councils. The Waitangi Valley-1 well site construction and drilling resource consent applications have been lodged, and are currently being processed by Gisborne District Council. The Company anticipates drilling a well that targets the East Coast basin tight-oil source rocks in PEP 38348 in May/June 2014.

PEP 38349 - (TAG 100%)

At the date of this report, data from logging of the Ngapaeruru-1 well continues to be studied in-house and by independent laboratories. The Company has received a detailed reservoir characterization model prepared using extensive data recovered while drilling and the interpretation to date is encouraging. Detailed petrophysical evaluation continues with a full suite of unconventional logs providing data on source rock quality, fracture identification, geochemistry, and rock moduli data. This data is critical to determining the most suitable completion method for production testing of the Ngapaeruru-1 well and to better understand the long term feasibility of TAG's East Coast Basin opportunity. Upon receipt of the final information related to completion options for Ngapaeruru-1, operations to complete the well will be planned with a goal to complete the well in calendar 2014.The Company has also commenced a 30km 2D seismic survey due to be completed in February or March 2014 and initiated landowner and stakeholder engagement for a second well to be drilled on the permit in the 2014 calendar year.

PEP 53674 - (TAG 100%)

During the quarter, and at the date of this report, the Company completed the re-processing of 30 km of 2D seismic data and a field study to combine the data with a recently completed geochemical survey to enable greater understanding of the near surface geology of the permit. The results of this work will be analyzed to provide valuable insight to building a long-term exploration plan for this permit.

PEP 55770 - (TAG 60%)

The Company (60%) and East West Petroleum (40%) were awarded an interest in this 106,157-acre Permit within the East Coast basin unconventional fairway in the December 2013 Block Offer. The commitments call for the reprocessing of existing seismic data, the acquisition of 60 km of 2-D seismic data within the first 18 months of the Permit tenure with East West paying 100% costs of the initial well for the first few years including one well to a maximum of $10 million.

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 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 drilling their Canterbury prospects in early 2014, with estimates of more than150 mmbls, or several trillion cubic feet of gas in each of their offshore Canterbury permits. Shell is also scheduled to drill nearby offshore in 2014, and Australian explorer Beach Energy entered the basin with an offshore permit awarded in October 2012 to the North of TAG's PEP 52589.

PEP 52589 (TAG 100%):

The Company evaluated the 80km of new onshore 2D seismic data the Company acquired in November 2012 over leads initially identified using geochemical surface data and has identified a number of leads and prospects within the permit. Based on the success of the initial seismic acquisition the Company has concluded that a futher 40km of 2D seismic data would be beneficial to allow better understanding of the closure and aerial extent of four newly mapped features as well as better understanding the potential resource within this frontier acreage. Based on the results and interpretation of the proprietry 2D seismic data the Company be in a position to evaluate a drilling commitment. On September 13, 2013 a change of conditions was approved by New Zealand Petroleum and Minerals to acquire, process and interpret 40km of 2D seismic data before committing to drill a well.

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

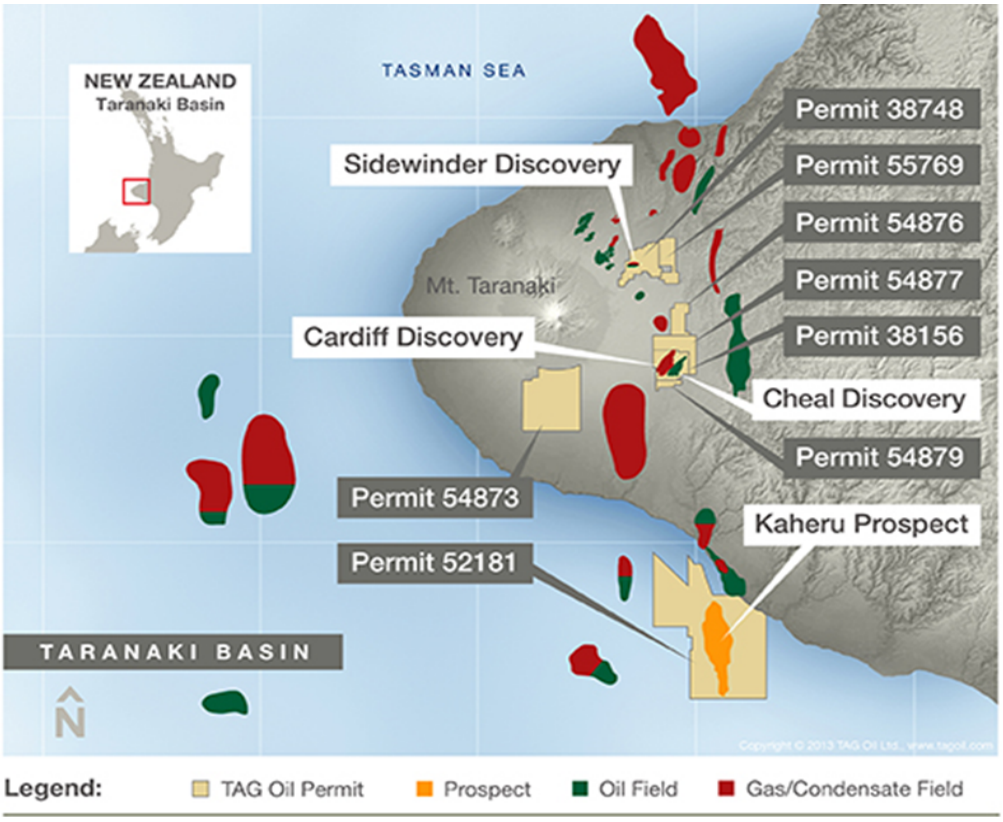
On September 28, 2013, the Company sold its 90% stake in OHL to Coronado Resources Ltd in exchange for common shares of Coronado valued at approximately $3.6 million. The common shares of Coronado that have been issued to TAG and the vendor of the remaining 10% interest represents full consideration 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 at December 31, 2013.

CAPITAL EXPENDITURES

For the three months ended December 31, 2013, the Company invested $20.9 million on its oil and gas assets compared to $21.1 million for the same period ending December 31, 2012. The majority of the expenditure was invested in PMP38156 ($13.1 million) for the drilling of Cardiff-3, PEP54877 ($4.5 million) to drill and complete the Cheal E1-E5 wells and PMP 53803 ($1 million) for well tie-ins and workovers.

For the nine months ended December 31, 2013, the Company invested $47.8 million on its oil and gas assets compared to $54.4 million for the same period ending December 31, 2012. The majority of the expenditure was invested in PMP 38156 ($20.9 million) for the drilling and site construction of Cardiff-3 , PEP 54877 ($7.3 million) to drill and complete the Cheal E1-E5 wells, PEP 38349 ($5.5 million) to drill Ngapaeruru-1, PMP 53803 ($4 million) in drilling and facility costs at Sidewinder and PEP 54873 ($1.7 million) for long lead items and consenting for Heatseeker. The Company also invested $4.2 million in OHL during the nine months, the proceeds of which will be used for OHL to acquire New Zealand based power generation assets.

Taranaki Basin:



Permit	Ownership Interest	2014		2013	Nine months ended	
		Q3	Q2	Q3	**2014**	2013
Mining Permits						
PMP 38156	100%	**13,125,019**	7,531,518	19,543,298	**20,951,693**	47,227,984
PMP 53803	100%	**963,424**	1,062,010	295,439	**3,903,639**	3,057,005
		14,088,443	8,593,528	19,838,737	**24,855,332**	50,284,989
Exploration Permits						
PEP 38748	100%	**207,598**	130,190	-	**1,834,456**	-
PEP 55769	100%		-	-		-
PEP 54873	100%	**182,738**	1,307,287	13,130	**1,680,347**	13,130
PEP 54876	50%	**59,783**	48,873	11,267	**109,105**	11,267
PEP 54877	70%	**4,524,538**	2,707,522	11,267	**7,305,830**	11,267
PEP 54879	50%	**237,724**	108,177	11,267	**346,350**	11,267
PEP 52181	40%	**(51,948)**	188,577	608	**344,189**	102,128
		5,160,433	4,490,626	47,539	**11,620,277**	149,059
OHL	90%	**401,743**	773,605	-	**4,176,816**	-
Total Taranaki Basin		**19,650,619**	13,857,759	19,886,276	**40,652,425**	50,434,048

Capital expenditures at PMP 38156 (Cheal A/B/C sites) for Q3 2014 were $13.1 million related primarily to drilling the deep Cardiff-3 exploration well.The Cardiff well is situated at the Cheal-C site and if succesful can be tied in to the Cheal-A production station via the exsiting pipeline infrastructure.The capital expenditure in PEP 54877 (Cheal North East) of $4.5 million relates to the Company's share of lease and drilling costs along with the purchase of materials and installation of facilities for the PEP 54877 joint venture to allow drilling, completion and testing of Cheal E1-E5 located on the Cheal-E drilling site.The Company has constructed and owns 100% of the Cheal E-site production facilities and will charge a processing fee to the PEP 54877 joint venture to use the facilities. At PMP 53803 (Sidewinder oil and gas field) the Company invested $1 million on well tie-ins and minor facilities upgrades.

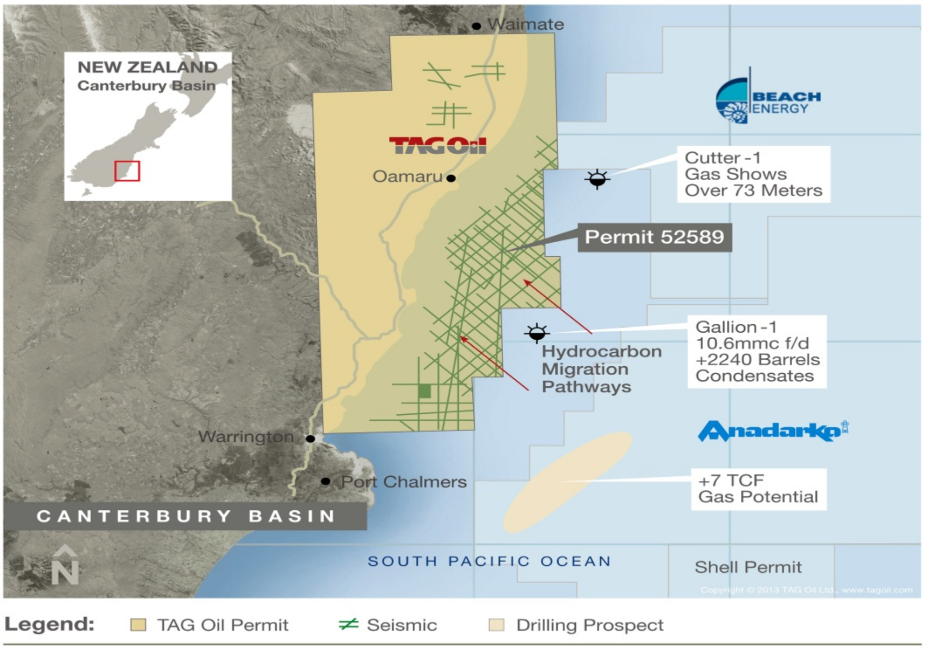
East Coast Basin:

Permit	Ownership Interest	**2014**		2013	Nine months ended	
		Q3	Q2	Q3	**2014**	2013
PEP 38348	100%	**274,019**	91,122	26,903	**425,642**	388,572
PEP 55770	60%		-	-	**-**	-
PEP 38349	100%	**386,337**	179,812	102,679	**5,508,645**	122,754
PEP 50940 (1)	100%	**2,750**	208,329	-	**211,079**	-
PEP 53674	100%	**2,276**	8,465	4,673	**91,922**	785,128
PEP 52676(1)	100%	**724**	15,348	4,673	**55,582**	785,128
		666,106	503,076	138,928	**6,292,870**	2,081,582

(1) Permits relinquished during Q2 2013.

Total expenditures on the East Coast permits in Q3 2014 of $0.7 million were primarily incurred in consenting, general exploration expenditures and initial expenditure on the 32.5kms of 2-D Seismic acquisition at (PEP38348) Waitangi Hill.

Canterbury Basin:



Permit	Ownership Interest	2014		2013	Nine months ended	
		Q3	Q2	Q3	**2014**	2013
PEP 52589	100%	**630,116**	5,085	986,993	**635,201**	1,767,448
		630,116	5,085	986,993	**635,201**	1,767,448

Total expenditures on the Canterbury Basin in Q3 2014, were incurred acquiring 40 kms of 2-D seismic data.

United States:

Total expenditures relate to recording the fair value of the Madison mining assets on consolidation to the TAG accounts following the transfer of OHL to Coronado for shares.

Operation	Ownership Interest	2014		2013	Nine months ended	
		Q3	Q2	Q3	**2014**	2013
Madison mine - exploration	100%	**(451,579)**	2,684,543	-	**2,232,964**	-
Madison mine - development	100%	**(6,719)**	670,199	-	**663,480**	-
		(458,298)	3,354,742	-	**2,896,444**	-

SUMMARY OF QUARTERLY INFORMATION

,	2014 Q3 $	2014 Q2 $	2014 Q1 $	2013 Q4 $	2013 Q3 $	2013 Q2 $	2013 Q1 $	2012 Q4 $
Total revenue	**12,939,442**	15,884,584	14,698,198	12,297,777	10,851,223	9,616,276	11,825,925	16,701,663
Costs	**(4,579,360)**	(4,826,074)	(4,954,663)	(3,947,730)	(3,289,307)	(3,123,182)	(3,680,324)	(5,382,240)
Foreign exchange	**(167,122)**	(1,011,928)	145,971	426,343	(69,453)	(474,603)	280,575	181,318
Stock option compensation	**(376,599)**	(558,633)	(937,898)	(1,276,261)	(2,004,076)	(1,499,954)	(840,721)	(1,137,058)
Other (costs) / income	**(4,845,203)**	(7,046,147)	(5,430,999)	(7,483,238)	(4,849,866)	(4,819,833)	(2,866,212)	(3,475,940)
Net income (loss)	**2,971,158**	2,411,802	3,520,609	16,891	638,521	(301,296)	4,719,243	6,887,743
Basic income (loss) per share	**0.05**	0.04	0.06	0.00	0.01	(0.01)	0.09	0.12
Diluted income (loss) per share	**0.05**	0.04	0.06	0.00	0.01	(0.00)	0.08	0.12
Production (BOE/d)	**1,527**	2,100	2,354	1,691	1,727	1,848	1,721	2,157
Capital expenditures	**20,959,476**	14,466,488	12,349,082	20,032,321	21,116,096	22,203,753	11,112,181	12,924,484
Operating cash flow *(1)*	**6,100,919**	8,562,643	8,468,130	18,136,293	5,610,691	4,409,684	7,443,881	10,853,666

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

Revenue, and operating cash flow have increased by 19% and 9% respectively when compared with the same quarter last year due to higher oil production at Cheal following the commissioning of the Cheal Production Station in March 2013. Net income of $2.97 million for Q3 2014 when compared to $0.6 million for the same period last year is primarily due to an increase in oil and electricity sales of $2.3 million, a reduction of $1.6 million in stock based compensation that was partially offset with an increase of $1 million in oil and electricity production costs.

The Company continues to maintain a strong capital expenditure program based around cash provided from operating activities and a strong balance sheet. As noted above in fiscal 2014, the Company has drilled eight shallow wells and has drilled our first deep gas/condensate well. The Company will continue to develop the Taranaki Basin permits over many years and plans an active shallow drilling program as well as funding deep gas/condensate drilling and East Coast unconventional exploration wells. Successful discoveries from the majority of TAG's drillling locations can be placed efficiently into production using the existing 100% TAG owned production infrastructure. In new areas of drilling, planning is continually underway to ensure new produciton infrastrucutre can be procured and built efficiently and cost-effectively if economics support.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Daily production volumes(1)					
Oil (bbls/d)	**1,069**	1,209	942	**1,118**	934
Natural gas (BOE/d)	**458**	891	785	**874**	831
Combined (BOE/d)	**1,527**	2,100	1,727	**1,992**	1,765
Daily sales volumes(1)					
Oil (bbls/d)	**1,061**	1,227	942	**1,114**	934
Natural gas (BOE/d)	**351**	782	512	**747**	581
Combined (BOE/d)	**1,412**	2,009	1,454	**1,861**	1,515
Natural Gas (Mmcf/d)	**2,106**	4,694	3,070	**4,482**	3,487
Product pricing					
Oil ($/bbl)	**112.74**	113.30	109.57	**110.57**	108.80
Natural gas ($/Mcf)	**5.43**	5.18	4.79	**5.50**	4.55
Sales					
Total revenue – gross	**$12,939,442**	$15,884,584	$10,851,223	**$43,522,224**	$32,293,424
Less other revenue – gross	**(881,134)**	(861,603)	-	**(2,863,656)**	-
Oil and natural gas revenue – gross	**12,058,308**	15,022,981	$10,851,223	**40,658,568**	32,293,424
Oil and natural gas royalties(2)	**(1,398,536)**	(1,632,648)	(1,252,872)	**(4,505,048)**	(3,659,444)
Oil and natural gas Revenue – net	**$10,659,772**	$13,390,333	$9,598,351	**$36,153,520**	$28,633,980

(1) *Natural gas production converted at 6 Mcf:1BOE (for BOE figures)*
(2) *Includes a 7.5% royalty related to the acquisition of a 69.5% interest in the Cheal field*
(3) *Other revenue is electricity revenue related to OHL.*

Oil and natural gas gross revenue increased 11% in the quarter ended December 31, 2013, compared to the same period last year. The increase in revenue is attributable to a 13% increase in oil sales volumes and a 3% increase in oil prices, offset by a 31% decrease in gas sales due to declining gas production from Sidewinder.

Oil production was 14% higher in the quarter ended December 31, 2013 compared to the same period last year due to the Cheal facility upgrade being completed. Oil production was 13% lower in the quarter ended December 31, 2013, compared to the quarter ended September 30, 2013, due to a combination of natural decline of the existing Cheal wells, Cheal B-1 and B-2 recompletions coming off initial production rates and facility downtime related to power fluid and electricity grid outages.

Natural gas production was 41% lower and 49% lower on a BOE per day basis in the quarter ended December 31, 2013, compared to the quarter ended December 31, 2012 and the quarter ended September 30, 2013, respectively. The decrease in both cases is due to the natural decline in the Sidewinder wells in Q3, 2014.

Net Production by area (BOE/d)	**2014**		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Cheal	**1,316**	1,482	1,148	**1,440**	1,122
Sidewinder	**211**	618	579	**552**	643
	1,527	2,100	1,727	**1,992**	1,765

During the nine months ended December 31, 2013, the Cheal and Sidewinder oil and gas fields produced 307,477 (December 31, 2012: 256,879) barrels of oil and 1,443 Mmcf (December 31, 2012: 1,372 Mmcf) of natural gas and sold 306,729 (December 31, 2012: 256,745) barrels of oil and 1,234 Mmcf (December 31, 2012: 959 Mmcf) of natural gas.

During the three months ended December 31, 2013, the Cheal and Sidewinder oil and gas fields produced 98,347 (December 31, 2012: 86,632) barrels of oil and 253 Mmcf (December 31, 2012: 434 Mmcf) of natural gas and sold 97,616 (December 31, 2012: 86,687) barrels of oil and 194 Mmcf (December 31, 2012: 282 Mmcf) of natural gas.

Royalties

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Royalties	**1,398,536**	1,632,648	1,252,872	**4,505,048**	3,659,444
As a percentage of revenue	**12%**	10%	12%	**11%**	11%

Royalties increased in the three and nine months ended December 31, 2013 when compared to the same periods ended December 31, 2012 due to higher oil and gas revenues being generated in the 2014 fiscal year. The Royalty, as a percentage of revenue, has remained consistent with the same periods ended December 31, 2012.

Royalty costs incurred relate to crown royalty payments of 5% on net oil and gas proceeds received in the first nine months of fiscal year 2014 and an overriding 7.5% royalty paid on net oil proceeds from Cheal to a previous owner of a 69.5% interest in the Cheal oil and gas field. The Sidewinder overriding royalty agreement requires TAG to pay a 5% royalty on net sales revenue. Sidewinder royalties also include a 3.33% royalty on net oil and gas proceeds payable to a previous partner.

Production, Transportation and Storage

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Total production costs	**2,231,767**	2,270,017	1,341,219	**7,083,804**	4,167,506
Electricity production costs	**(618,115)**	(633,886)	-	**(1,995,758)**	-
Oil and gas production costs*	**1,613,652**	1,636,131	1,341,219	**5,088,046**	4,167,506
Per BOE ($)	**11.48**	8.47	8.44	**9.29**	8.58
Transportation and storage costs	**949,057**	923,409	695,216	**2,771,245**	2,265,863
Per BOE ($)	**6.75**	4.78	4.38	**5.06**	4.67

* Production costs are oil and gas costs only. Electricity produciton costs related to OHL are excluded from the production numbers above

Total oil and gas production costs decreased 1% from Q2, 2014 to Q3, 2014 reflecting the predominately fixed operating cost portion to operate the Cheal and Sidewinder processing plants. Oil and gas production costs per BOE increased by 36% as a result of the lower Q3 production volumes relating mainly to Sidewinder gas.

Electricity production costs to December 31, 2013 were lower than the costs for the quarter ended September 30, 2013 as there was less demand due to the seasonal nature of the business operations.

Transportation and storage costs have increased 3% in the quarter ended December 31, 2013, compared to the same period last year. Lower transportation costs associated with lower oil production volumes have been offset by higher storage costs associated with increased water disposal and crude quality testing at the Omata Tank Farm Storage Facility. The per BOE cost has increased by 54% due to the increased testing and disposal costs and the increase in ratio of oil production as compared with gas production as natural gas does not incur transportation or storage costs.

Oil and Gas Operating Netback ($/BOE)

	2014		2013	Nine months ended	
($/BOE)	**Q3**	Q2	Q3	**2014**	2013
Oil and gas revenue	**92.81**	81.28	68.29	**79.34**	66.51
Royalties	**(9.95)**	(8.45)	(7.88)	**(8.22)**	(7.54)
Transportation and storage costs	**(6.75)**	(4.78)	(4.38)	**(5.06)**	(4.67)
Production costs	**(11.48)**	(8.47)	(8.44)	**(9.29)**	(8.58)
Netback per BOE ($)	**64.63**	59.58	47.59	**56.77**	45.72

Operating netback is the operating margin the company receives from each barrel of oil equivalent sold. The netback on a BOE basis for the current quarter is 36% higher when compared to the netback in the same period last year and 9% higher than the netback for the quarter ended September 30, 2013 due to decreasing lower-net back gas production and increasing, higher-netback oil production. The higher per BOE are due to a higher proportion of oil produced from Cheal and Sidewinder oil and gas fields as natural gas has a lower price per BOE and does not incur transportation charges.

Insurance

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Directors and officers insurance	**11,580**	11,578	11,577	**34,735**	39,195
Insurance	**48,491**	159,143	110,189	**312,316**	294,356
	60,071	170,721	121,766	**347,051**	333,551
Per BOE ($)	**0.43**	0.88	0.77	**0.63**	0.69

Insurance expense decreased in Q3 2014 by 65% from Q2 2014 due to the allocation of 6 monthly premiums to capital related drilling activities. Insurance expense increased 4% during the nine months ending December 31, 2013 due to generally higher premiums for the Cheal facilities and the addition of the Sidewinder facilities and pipeline insurance costs.

Equity Loss in Associated Companies

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Loss in Associate ($)	-	164,329	14,607	**221,641**	32,069

On September 28, 2013, the Company sold its share of OHL to Coronado Resources Limited ("Coronado") increasing its shareholding in Coronado from 40% to 49% and gaining a controlling interest. Coronado was fully consolidated at December 31, 2013 and the share of loss incurred under equity accounting for the Coronado investment before acquiring control is recorded in the compresensive statement of profit and loss.

General and Administrative Expenses ("G&A")

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Consulting fees	**224,239**	126,047	188,382	**416,120**	399,569
Directors fees	**152,157**	77,297	97,167	**306,250**	227,667
Filing, listing and transfer agent	**74,644**	11,891	42,386	**152,431**	210,340
Reports	**1,856**	128,173	62,090	**142,427**	526,552
Office and administration	**204,117**	140,618	151,867	**508,776**	374,506
Professional fees	**141,846**	64,553	199,865	**374,705**	462,831
Rent	**82,992**	65,501	49,047	**210,528**	169,237
Shareholder relations and communications	**112,870**	91,266	86,958	**348,753**	244,004
Travel	**98,353**	119,783	129,611	**328,799**	319,829
Wages and salaries	**1,157,184**	707,113	1,137,670	**2,470,389**	1,930,408
Overhead recoveries	**(103,093)**	(4,216)	-	**(107,309)**	-
	2,147,165	1,528,026	2,145,043	**5,151,869**	4,864,943
Per BOE ($)	**15.28**	7.91	13.50	**9.40**	10.02

G&A costs have increased by less than 1% in Q3 2014 when compared with the same quarter last year and have increased by 6% for the nine months ended December 31 compared to the same period last year.

G&A costs for Q3 were 41% higher than Q2 due to annual performance bonus payments being awarded in December, the move of several staff from consulting to permanent employment contracts and the hiring of additional staff to support expanded activities related to drilling, operations, acquisitions and financing.

Share-based Compensation

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Share-based compensation	**376,599**	558,633	2,004,076	**1,873,130**	4,344,751
Per BOE ($)	**2.68**	2.89	12.61	**3.42**	8.95

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 75% and a risk free interest rate of 2.5% to calculate option benefits. The fair value of the option benefit is amortized over the vesting period of the options, generally being eighteen months.

The Company recorded a 81% decrease in total share–based compensation costs in the quarter ended December 31, 2013 when compared with the same period last year. The decrease in total share-based compensation costs was due to higher exercise prices compared to the current share value resulting in a lower compensation cost.

In the quarter ended December 31, 2013, the Company granted 75,000 (December 31, 2012: nil) options and no options were exercised (December 31, 2012: 12,500 options exercised at a price of $2.60 per share).

In the nine months ended December 31, 2013, the Company granted 75,000 (December 31, 2012: 1,395,000) options and 71,429 (December 31, 2012: 193,332) options were exercised at a weighted average price of $3.00 (December 31, 2013: $3.54) per share.

Depletion, Depreciation and Accretion

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Depletion, depreciation and accretion	**2,737,580**	3,608,171	2,955,980	**10,257,201**	8,039,790
Per BOE ($)	**19.48**	18.68	18.60	**18.72**	16.56

Depletion, depreciation and accretion increased 28% in the first nine months of fiscal year 2014, compared to the same period in fiscal year 2013 due to a 13% increase in production volumes and an increase cost base due to additional development drilling at Sidewinder and Cheal facility construction. D,D&A decreased 24% in Q3 2014 compared to Q2 2014 due to lower production primarily associated with Sidewinder gas.

Foreign Exchange (Gains) / Losses

	2013		2012	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Foreign exchange (gain) / loss ($)	**167,122**	1,011,928	69,453	**1,033,079**	263,481

The foreign exchange loss for the current quarter and year to date was caused by fluctuations of both the U.S. dollar and New Zealand dollar in comparison to the Canadian dollar.

Interest Income

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Interest income	**188,484**	188,792	246,036	**558,877**	829,991

Decreased interest income for fiscal year 2014 to date reflects the lower cash balances held when compared to comparative quarters in fiscal year 2013.

Net Income and Operating Margin

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Net income ($)	**2,971,158**	2,411,802	638,521	**8,903,569**	5,056,468
Per share, basic ($)	**0.05**	0.04	0.01	**0.15**	0.08
Per share, diluted ($)	**0.05**	0.04	0.01	**0.15**	0.08

Operating margin increased by $2.3 million in Q3, 2014, compared to Q3, 2013 due to a $2.1 million increase in revenue due to increased oil sales (13%) and oil prices (3%), a $1.5 million decrease in operating expenses primarily due to lower stock based compensation costs, offset by a $1.3 million increase in production, transportation and storage and royalty costs associated with increased revenue and oil production.

For the nine months ended December 31, 2014, the Company generated a $3.8 million increase in net income compared to the same period last year due to a $11.2 million increase in revenue as a result of higher production (23%) at both Cheal and Sidewinder offset by a $4.3 million increase in production, storage, handling and royalty costs related to increased production volumes and a $3.1 million increase in operating costs relating to higher depletion and written down oil & gas property values.

Cash Flow

	Nine months ended	
	2014	2013
Operating cash flow ($) *(1)*	**23,131,692**	17,464,256
Cash provided by operating activities ($)	**21,261,093**	15,121,384
Per share, basic ($)	**0.33**	0.25
Per share, diluted ($)	**0.31**	0.24

(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 32% from $17.5 million in the nine months to December 31, 2012 to $23.1 million in the nine months to December 31, 2013 as a result of increased oil & gas production (23%) and an increase in non-cash operating expenses being mainly depletion and depreciation charges and valuation write-offs.

Cash provided by operating activities increased 41% from $15.1 million in the nine months ended December 31, 2012 to $21.2 million in the nine months to December 31, 2013 primarily due to the activity explained above with a minor adjustment for movements in non-cash related capital accounts such as accounts receivable and Inventory.

The Company had the following commitments for Capital Expenditure at December 31 2013**:**

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases *(1)*	838,322	362,786	475,536
Other long-term obligations *(2)*	70,585,000	51,481,000	19,104,000
Total Contractual Obligations *(3)*	**71,423,322**	**51,843,786**	**19,579,536**

(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 $	More than One Year $
PMP 38156	Workovers, optimisations and lease improvements	3,013,000	
	Drill 1 deep gas well in Cardiff structure	2,682,000	
PMP 53803	Workovers, optimisations and lease improvements	390,000	
PEP 54873	Drilling of one deep exploration well and reprocess 2D seismic	17,115,000	
PEP 54876 (1)	Drilling of one shallow exploration well and reprocess 2D seismic	2,001,000	
PEP 54877 (1)	Drilling of three shallow exploration wells	2,242,000	
PEP 54879 (1)	Drilling of two shallow exploration wells	3,522,000	
PEP 38748	Drilling of two shallow exploration wells and lease improvements	24,000	4,376,000
PEP 50940	Nil	-	
PEP 52181	Drilling Kaheru-1	2,332,000	14,728,000
PEP 52589	Permit costs and 2D seismic	258,000	
PEP 55769	Technical Study	88,000	
PEP 55770	2-D Seismic reprocessing	82,000	
PEP 53674	Permit costs and geochemical sampling	77,000	
PEP 38348	Drilling of two shallow exploration wells and 2D seismic acquisition	11,465,000	
PEP 38349	Drilling of one shallow exploration well and 2D seismic acquisition	6,190,000	
TOTAL COMMITMENTS		**51,481,000**	**19,104,000**

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

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.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2013, the Company had $68.5 million (December 31, 2012: $62.7 million) in cash and cash equivalents and $71.2 million (December 31, 2012: $67.8 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 from the Cheal and Sidewinder oil and gas fields.

Additional material commitments, changes to production estimates or any acquisitions by the Company may require a source of additional financing. 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 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

	Nine months ended	
	2014	2013
Cash provided by operating activities	**21,261,093**	15,121,384
Changes for non cash working capital accounts	**1,870,598**	2,342,872
Operating cash flow	**23,131,692**	17,464,256

Operating netback

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Total revenue	**$12,939,442**	$15,884,584	$10,851,223	**$43,522,224**	$32,293,424
Less electricity revenue	**(881,134)**	(861,603)	-	**(2,863,656)**	-
Oil and natural gas revenue	**12,058,308**	15,022,981	10,851,223	**40,658,568**	32,293,424
Less oil and natural gas royalties	**(1,398,536)**	(1,632,648)	(1,252,872)	**(4,505,048)**	(3,659,444)
Less transportation and storage costs	**(949,057)**	(923,409)	(695,216)	**(2,771,245)**	(2,265,863)
Less total production costs	**(1,613,652)**	(2,270,017)	(1,341,219)	**(5,088,046)**	(4,167,506)
Add back electricity production costs	**618,115**	633,886	-	**1,995,758**	-
Operating Netback	**8,715,178**	10,830,793	7,561,916	**30,289,987**	22,200,611

Operating margin

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Revenue	**$12,939,442**	$15,884,584	$10,851,223	**$43,522,224**	$32,293,424
Less oil and natural gas royalties	**(1,398,536)**	(1,632,648)	(1,252,872)	**(4,505,048)**	(3,659,444)
Less production costs	**(1,613,652)**	(2,270,017)	(1,341,219)	**(5,088,046)**	(4,167,506)
Less transportation and storage costs	**(949,057)**	(923,409)	(695,216)	**(2,771,245)**	(2,265,863)
Operating Margin	**8,978,197**	11,058,510	7,561,916	**31,157,885**	22,200,611

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,	Current anticipated use of actual proceeds received	Status of operation
Taranaki Basin: PMP 38156	Drill one deep exploration well	$17,200,000	$10,200,000	Pending
	Contribute to deep exploration well	-	7,000,000	Completed
	Drill one Cheal or Greater Cheal shallow well	$2,000,000	$2,000,000	Completed
East Coast Basin:				
PEP 38348, PEP 38349, PEP 55770 & PEP 53674	Unconventional project team build	$500,000	$500,000	Commenced
	Seismic acquisition	$2,500,000	$2,500,000	Commenced
Canterbury Basin: PEP 52589	Seismic acquisition	$1,000,000	$630,000	Completed
New business opportunities:	Identify and pursue new business opportunities including future land acquisitions in the Taranaki Basin and East Coast Basin	$326,000	$326,000	Completed
Working capital		-	370,000	Completed
Total		**$23,526,000**	**$23,526,000**	

(1) The drilling of the Heatseeker exploration well is subject to satisfactory resolution of consenting operations and The Company's ability to meet exploration objectives.
(2) The Company used approximately $7 million to date to fund costs related to the successful drilling of the Cardiff-3 well.
(3) The Company has completed the drilling of the Cheal-G1 well (the first of three planned Greater Cheal Shallow Wells) in PEP54879, targeting Miocene-aged prospects.
(4) The Company recently announced the addition of two unconventional oil and gas specialists from North America contracted to the New Zealand team and the opening of an East Coast Basin office in Napier to enable the Company to plan and execute a cost-effective long-term plan to create value in the East Coast Basin.
(5) The Company has commenced a 30km 2D seismic survey in PEP 38349 which is due to be completed in Q4 fiscal 2014 and commenced a 32.5km 2D seismic survey in PEP 38348.
(6) The Company has completed the acquisition of 40 kms of 2-D Seismic Data in the Canterbury Permit PEP52589
(7) The Company was awarded a 100% interest in the 2,910-acre PEP 55769 offsetting the Sidewinder discoveries in the December 2013 Block Offer and was also awarded a 60% interest and operatorship in the 106,157-acre Permit 55770 within the East Coast Basin unconventional fairway in the December 2013 Block Offer. Further evaluation of business opportunities is ongoing.

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 nine months ended December 31:

	2014		2013	Nine months ended	
	Q3	Q2	Q3	**2014**	2013
Share-based compensation	**209,911**	321,823	1,388,462	**1,100,354**	3,087,490
Management wages and director fees	**663,165**	254,396	926,929	**1,163,190**	1,425,145
Total management compensation	**873,076**	576,219	2,315,391	**2,263,544**	4,512,635

SHARE CAPITAL

a. At December 31 2013, there were 64,487,052 common shares outstanding
b. At February 14, 2014, there were 64,402,052 common shares outstanding and there are 3,683,334 stock options outstanding, of which 3,043,334 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 10 of the accompanying condensed consolidated interim financial statements.

SUBSEQUENT EVENTS

Subsequent to December 31, 2013, the Company purchased and cancelled 85,000 common shares under its normal course issuer bids at an average weighted price of $3.29 per common share.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of the condensed consolidated interim financial statements requires management to make estmates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the condensed consolidated interim financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these condensed consolidated interim financial statements. Further information on the Company's critical accounting estimates can be found in the notes to the consolidated annual financial statements and the annual MD&A for the year ended March 31, 2013. There have been no changes to the Company's critical accounting estimates as of December 31, 2013.

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 first nine months of the 2014 fiscal

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

New Accounting Pronouncements

The Company adopted the following new IFRS standards effective April 1, 2013

(a) IFRS 10, *Consolidated Financial Statements,* IFRS 11, *Joint Arrangements,* IFRS 12, *Disclosure of Interests in Other Entities,* and amendments to IAS 27, *Separate Financial Statements* and IAS 28, *Investments in Associated and Joint Ventures:*

These five new standards establish control as the basis for consolidation and provide enhanced disclosure requirements for the Company's interests in other entities and the effects of those interests on the Company's financial statements. IFRS 10 requires consolidation of an investee only if the investor possesses power over the investee, has exposure to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. Detailed guidance is provided on applying the definition of control. The accounting requirements for consolidation have remained largely consistent with IAS 27. The Company assessed its consolidation conclusions on April 1, 2013, and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of any of its subsidiaries or investees. IFRS 11 also had no impact as the Company had classified its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements. The Company will continue to include herein its proportionate share of the relevant assets and liabilities.

(b) IFRS 7*, Financial Instruments Disclosures*

This standard contains amendments relating to disclosure requirements for the offsetting of financial assets and liabilities when offsetting is permitted under IFRS. Amendments to IFRS 7 required minimal disclosure changes in the Company's financial statements as of March 31, 2013.

(c) IFRS 13, *Fair Value Measurement*:

This new standard provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. The Company adopted IFRS 13 on April 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at April 1, 2013.

(d) IFRS 19, *Employee benefits*

This standard includes fundamental changes such as removing the corridor mechanism and the concept of expected returns on plan assets to simple clarifications and re-wording. Amendments to IFRS 19 required minimal disclosure changes in the Company's financial statements as of March 31, 2013.

(e) IAS 1, *Presentation of Financial Statements*

The Company has adopted the amendments to IAS 1, Presentation of Financial Statements, effective April 1, 2013. These amendments require the Company to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

Accounting standards issued but not yet applied

In May 2013, the IASB released an amendment to IAS 36, "*Impairment of Assets"* . This amendment requires entities to disclose the recoverable amount of impaired Cash Generating Units ("CGU"). The amendment is effective January 1, 2014. Early adoption is permitted.

Please refer to Note 2 of the March 31, 2013 audited consolidated 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 nine months ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

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, including those at Cheal and Sidewinder, including, without limitation, statements regarding BOE/d production capabilities, an increase in cash flow, reserves and reserve values through a properly executed development plan at Cheal and Sidewinder, including maximizing the value at Cheal through the implementation of further optimization operations, successful completion of infrastructure enhancements at Cheal and Sidewinder and additional successful drilling; anticipated revenue from the Cheal and Sidewinder oil and gas fields; converting the undiscovered resource potential to proved reserves within the East Coast Basin, completing announced exploration acquisitions; capital expenditure programs and estimates including those set out herein under “Use of Proceeds”; and the impact of the transition to International Financial Reporting Standards (“IFRS”) on the Company’s financial statements.

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 February 14, 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.

TAG Oil

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

Ronald Bertuzzi, Director
Vancouver, British Columbia

Chris Ferguson, CFO
New Plymouth, New Zealand

Drew Cadenhead, COO
New Plymouth, New Zealand

Randy Toone, 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

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

WEBSITE
www.tagoil.com

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 December 12, 2013 at 10:00am at the offices of Blake, Cassels & Graydon located at Suite 2600, 595 Burrard Street Vancouver, B.C. V7X 1L3

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 14, 2013, there were 64,402,052, shares issued and outstanding. Fully diluted: 68,085,386 shares.