MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated August 14, 2013, for the three months ended June 30, 2013 and should be read in conjunction with the Company's accompaning condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2013.

The condensed consolidated interim financial statements for the three months ended June 30, 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 June 30, 2013, are not necessarily indicative of future results. 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 2.7 million acres of land onshore in the Taranaki, East Coast and Canterbury Basin's of New Zealand and 30,816 (77,039 gross acres) offshore in the Taranaki Basin as at June 30, 2013. TAG's business plan is designed to grow through increased operating cash flow, strategic acquisitions and continued exploration/development drilling to grow reserves.

Maintaining 100% ownership of all facilities and associated pipeline infrastructure in the Taranaki Basin on TAG's 100% owned and operated Cheal, Cardiff and Sidewinder oil and gas fields insures the Company can commercialize all discoveries and developments expeditiously, as well as offer third party processing to other companies in the Basin.

The Company has recently conducted an extensive Taranaki drilling campaign consisting of wells averaging approximately 2,000 meters depth, commonly referred to as TAG's shallow drilling program. This program, focused within the Company's 100% owned Cheal and Sidewinder fields, targeted the proven Urenui and Mt. Messenger formations and provides TAG with long-term stable production, low decline rates and significantly more subsurface knowledge to be incorporated into future drilling programs. The resulting cash flow will be applied to the Company's most active and diverse exploration program in the Company's history for fiscal 2014, while still allowing the Company to maintain a strong balance sheet.

The Company will apply what it has learned from the extensive new drilling data acquired during fiscal year 2012 and 2013 to the Company's fiscal year 2014 shallow program to maximize the value of the shallow Taranaki oil and gas prospects. The 2014 drilling program will focus substantially within the Company's four new Taranaki Basin permits awarded in the 2012 New Zealand Blocks Offer where the Company is progressing the consenting, construction and drilling of nine new shallow wells on three of the new permits and one deep well called Heatseeker-1 as discussed below on the fourth new permit.

The Company will also add two new drilling components to its growth plan while also conducting new operations in TAG's frontier Canterbury Basin acreage as follows:

1. The Company will drill at least two of its 100% owned deep "Kapuni" gas and condensate prospects in fiscal year 2014; Cardiff and Heatseeker. A third prospect, the Hellfire deep prospect, may be drilled contingent on the results of Cardiff and Heatseeker. Cardiff, Heatseeker and Hellfire are all located within the onshore Taranaki Basin and have the potential to contribute long-term production and reserve growth to the Company. These deep Eocene-aged targets are materially larger in reserve and deliverability potential than the historically targeted shallow Taranaki drilling programs at Cheal and Sidewinder. Drilling of TAG's deep prospects are explained in more detail below and will use TAG's knowledge of the Taranaki Basin, combined with a large seismic database to target prospect depths of approximately 3,500 to 5,000 meters, similar to successful Taranaki deep gas plays such as the Kapuni and Mangahewa fields operated by Shell and Todd Petroleum.

   A deep specialty drilling rig has been contracted to drill the two deep gas targets with TAG also having an option to drill Hellfire-1 if desired. Drilling is expected to start with Cardiff-3, in late August or September 2013. This will be followed immediately by the Heatseeker prospect to be drilled north of the landmark 1.5 TCF Kapuni gas field discovery.

2. The Company will add East Coast Basin unconventional drilling to its growth plan with a dedicated effort to unlocking the potential within the Company's 1.4 million acre 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 well, Ngapaeruru-1, with promising initial results achieved over a 155 meter gross hydrocarbon column. Additional drilling of at least three wells is expected over the next 18 to 24 months to achieve TAG's goal of converting undiscovered resource potential within the Company's permits to proven reserves.

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3. Further resource potential is being studied in fiscal year 2014 within TAG's frontier Canterbury basin permit covering 1.17 million acres. The Canterbury Basin has a proven working hydrocarbon system as evidenced by the presence of numerous oil and gas shows onshore and discoveries made offshore. TAG's new 2D seismic acquired in November 2012 over leads initially identified using geochemical surface data, has resulted in a clearly imaged subsurface, resulting in four newly mapped features within the permit. TAG is very encouraged by the latest seismic results and as a result is currently awaiting approval from New Zealand Petroleum and Minerals ("NZPM") to acquire an additional 40kms of seismic over the four newly mapped features prior to making a drilling decision.

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 June 30, 2013, the Company had cash of $57.2 million, working capital of $63.5 million and no debt.
- Capital expenditures in the first three months of fiscal year 2014 were $12.3 million compared to $11.1 million for the same period last year.
- Average daily production increased by 37% to 2,354 BOE's per day in the first three months of fiscal year 2014 compared to the 1,721 BOE's per day the same period last year. Average daily production increased by 39% compared to the 1,691 BOE's per day in the quarter ending March 31, 2013.
- Revenue in the first three months of fiscal year 2014 was $14.7 million representing a 24% increase over the same period last year.
- Cash flow from operations was $9.6 million compared to $9.2 million in the same period last year.
- The Company successfully drilled and cased the Ngapaeruru-1, the first of many wells to be drilled on the East Coast and is undertaking analysis of logging results and core samples from the well.
- The Company has signed a new surface access agreement in the East Coast Basin permit for drilling access on PEP 38348.
- The Company has signed three new surface access agreements in the Taranaki Basin and consenting for up to twelve wells per well site is underway.
- During FY 2013 the Company acquired 40% in Coronado Resources Ltd ("Coronado"). At the date of this report, TAG is in the process of acquiring an additional 10% of Coronado common shares as a result of selling Opunake Hydro Limited to Coronado. The deal is subject to the terms and conditions of the Share Purchase Agreement that has been executed by all parties involved.

PROPERTY REVIEW

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

At the time of this report, the Cheal field has eighteen wells on full, part-time or constrained production out of a total of twenty wells that are capable of producing. The remaining two wells are awaiting the installation of production equipment or workovers. The Cheal field produced an average of 1,523 BOE's per day in the quarter ended June 30, 2013, compared to an average of 1,320 BOE's per day for the same period in fiscal 2013, representing a 15% increase due to new wells coming on stream.

The Cheal wells are providing steady oil production and, as expected, low 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.

During the quarter, the Company undertook well and facility work including production testing, pressure and temperature testing, jet-pump throat and nozzle combination optimization. The Company will use this data to maximize long-term production using oilfield production best practices. The Company also undertook a number of work-over operations in the quarter to optimize wells in its existing well inventory as an effort to maximize production efficiency.

At the time of this report, the Company has started preparations at the Cheal-C site to allow the mobilization of the deep drilling rig onto site to drill the Cardiff-3 deep gas well. Gas and condensate had previously been produced from three separate zones in these historic wells, but economics, in particular, gas and condensate prices at that time did not dictate an economic development at that time. New completion techniques as well as higher gas and condensate prices in New Zealand now create the opportunity to exploit the existing resource. The question of deliverability is the primary risk to all Taranaki deep plays, but with Cardiff the reservoir, hydrocarbon saturations and depths have all been de-risked to a certain extent from past drilling activities by other operators in the Basin.

The Cardiff-3 well will be drilled from the Cheal-C site, which is now connected by a 4" pipeline to the Cheal-A processing facilities and a 6" gas export line to the open access 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 five wells on full, part-time or constrained production out of a total of seven wells that are capable of producing. The remaining two wells are awaiting the installation of production equipment or workovers. The Sidewinder field produced an average of 831 BOE's per day in the quarter ended June 30, 2013, compared to an average of 401 BOE's per day for the same period in fiscal 2013, representing a 107% increase due to new wells coming on stream. The Sidewinder wells are now coming off their initial flush production and the Company continues to optimize production facilities to offset declines that are proving to be significantly higher than shallow oil wells at Cheal.

During the quarter, Sidewinder-A5 and Sidewinder-A6 have been tied-in to the Sidewinder production facilities for testing and at the time of this report pipework construction is being undertaken to permanantly tie-in these wells. The Sidewinder-A7 well was drilled and completed during the quarter and is currently suspended. The Sidewinder-A7 well bore was designed to enable the Company to drill the Hellfire deep prospect contingent on the results of Cardiff and Heatseeker.

PEP 38748 (TAG 100%)

Drilling of a new well from the Sidewinder site commenced during the quarter as part of the commitment on PEP 38748, but was suspended during the period. The Company is reviewing options to either re commence the drilling operations at the current well location or to drill the target from a new location. The well has been deferred until calendar 2014 to focus on drilling the commitment wells in its newly acquired Taranaki permits as discussed in this MD&A.

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

The Company is embarking on the most diverse and active drilling campaign in its history with up to four rigs undertaking drilling and completion operations 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 Messanger and Urenui zones, that are discussed in the following permits are expected to show similar characteristics to our existing Cheal wells which have averaged EUR of 300 BOE's per day and provide steady oil production after the initial flush production.

PEP 54876 – (TAG 50% and operator)

The permit work program includes reprocessing 200 kilometers of 2D sesmic and drilling two exploration wells, one of 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 net oil and natural gas revenue before all future revenue is split according to each party's working interest.

During the quarter and to date, the Company has been liasing with stakeholders and has negotiated and signed an access agreement for a well-site lease. Resource consent is currently being prepared for submission to the local council and once granted the Company will begin construction of the well-site lease. Once the well-site has been constructed a contracted rig will be mobilised to site to begin drilling.

PEP 54877 – (TAG 70%)

The permit work program includes the drilling five exploration wells, two of which are to be funded 100% up to $5.0 million by the Company's joint venture partner EWP with any costs in excess of $5.0 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 $5.0 million of net oil and natural gas revenue before all future revenue is split according to each party's working interest.

At the time of this report, the Company has signed two land access agreements, securing two well-site locations to drill up to five commitment wells. Resource consent applications allowing the Company to drill up to twelve wells on each site have been granted by the local council. Construction has been completed for the first site and the rig is being readied to mobilize to site with the first of five wells anticipated to commence drilling in August. The second site will be constructed early next year in anticipation of further drilling on this permit and the Cheal mining permit.

PEP 54879 – (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 net oil and natural gas revenue before all future revenue is split according to each party's working interest.

At the time of this report, the Company has identified a well-site location and has signed a land access agreement. A resource consent application to drill up to twelve wells has been submitted to the local council and once granted construction of the well-site lease will commence.

PEP 54873 – (TAG 100%)

PEP 54873 provides several shallow drilling leads along with significant exploration upside via a drill-ready deep gas and condensate prospect. 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 liasing with stakeholders and has signed a land access agreement for a well-site lease. Resource consent to drill the Heatseeker well is currently being prepared for submission to the local council and once granted the Company will begin construction of the well-site lease in preparation for the drilling of the Heatseeker well, scheduled to follow directly after the Cardiff-C3.

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 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 fields along the entire thrust belt trend. The multi-zone prospect Kaheru has been independently evaluated as having a resource potential of 45 MMbbs oil with 72 BCF (oil case) or 266 BCF with 13 MMbbls condensate (gas case).

A budget for long lead items and well preparations was approved and the Joint Venture is now seeking to secure a rig slot in order to drill the well. Discussions are on going with the Joint Venture of offshore drillers that are mobilizing a jack-up rig to New Zealand late in 2013 for a multi-well offshore program for other operators. A slot has been agreed for the drilling of the Kaheru prospect at the end of the jack-up rig's existing schedule.

East Coast Basin:

At June 30, 2013, the Company controlled a 100% working interest in five (one permit is on the South Island) exploration permits totaling 1.74 million acres on the East Coast of the North Island of New Zealand. At the date of this report the Company surrenderd PEP 50940 and PEP 52676 as described below. The Company's exploration permits now total approximately 1.42 million acres on the East Coast of the North Island of New Zealand. The Company has acquired proprietry 2D seismic data, completed extensive geological surface and sub-surface studies and has drilled a number of stratigraphic wells within three of the permits.

The Company applied for a change of conditions to extend the date for drilling a well on each of the PEP 38348 and 38349 permits to December 2013 and July 2013, respectively. On April 9, 2013 the Company received approval of the change of conditions by New Zealand Petroleum and Minerals.

PEP 38348 - (TAG 100%)

The Company continues to progress in preparation to undertake the first phase of the drilling on the northern PEP 38348 permit and has continued with extensive consultation with all stakeholders, including local iwi, landowners, local and central government. Initial construction, surface lease access and drilling consent applications for the Punawai-1 well have been submitted to the various regional and district councils and the Company is awaiting confirmation of approval of the consents prior to commencing any activity. At the same time the Company has now secured a new surface access agreement to drill a well, referred to as Waitangi

Station-1 on the permit and is currently preparing the consent applications for submission to the regional and district councils. The Company anticipates a well targeting the East Coast basin tight-oil source rocks in PEP 38348 will be drilled by December 2013.

PEP 38349 - (TAG 100%)

At the date of this report, data from logging of the Ngapaeruru-1well has now been forwarded to independent laboratories for expert analysis and initial data recovered and interpreted to date is encouraging. Detailed petrophysical evaluation continues with a full suite of unconventional logs to ascertain source rock quality, fracture identification, geochemistry, and rock moduli data. This data is critical to determining the most suitable completion method for production testing the Ngapaeruru-1 well, as well as to better understand the long term feasibility of TAG's East Coast Basin opportunity. The Company also began planning for a 20km 2D seismic survey to be completed by May 2014 and initiated landowner and stakeholder engagement for a second well to be drilled on the permit.

PEP 50940 - (TAG 100%)

On July 19, 2013, the Company submitted to New Zealand Petroleum and Minerals a notice to surrender the permit, which was granted on July 23, 2013. The Company intends to focus exploration efforts on the most prospective East Coast permits.

PEP 53674 - (TAG 100%)

During the quarter and at the date of this report the Company undertook the re-processing of 30 km of 2D seismic data and a field study to combine with the 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 the development of the permit.

PEP 52676 - (TAG 100%)

During the quarter, the Company analyzed the results of the geochemical study in conjunction with a geological and seismic review. Based on the results of the survey the Company provided notice to New Zealand Petroleum and Minerals of its intention to surrender the permt on July 1, 2013 and the surrender was granted on July 12, 2013.

Canterbury Basin:

The Canterbury Basin is a frontier basin on New Zealand's South Island, with a proven onshore and offshore hydrocarbon system. The Company controls more than a 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 working hydrocarbon system. Anadarko Petroleum, which is slated to bring a jack-up rig to New Zealand in early 2014, estimates +150 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 award in October 2012 to the North of TAG's PEP 52589.

PEP 52589 (TAG 100%):

During the quarter the Company evaluated the recently acquired 80km of onshore 2D seismic 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 more seismic data would be beneficial to allow TAG to better understand the closure and aerial extent of the four mapped features as well as understanding the potential resource within this frontier acreage that would enable a drilling commitment to be made.

On June 14, 2013, a change of conditions application was made to New Zealand Petroleum and Minerals seeking to acquire further seismic data before drilling a well. At the time of this report, the Company is waiting to receive approval of the change of conditions by New Zealand Petroleum and Minerals.

Opunake Hydro Limited ("OHL")

During the quarter the Company completed the acquisition of 90% of the equity of OHL at a price of approximately $5 million. The acquisition cost consisted of cash paid to OHL to secure new generation equipment as well as TAG transferring ownership of two new gas fired gensets to OHL after they were successfully commissioned at TAG's Cheal A site. The gensets are currently in operation and provide electricity to the expanded Cheal site with excess power being sold to the national grid. OHL purchased a further one megawatt generator and commenced the planning for installing the genset and associated switchgear to bring the total gas fired generation capacity to three megawatts. The additional genset is scheduled to be installed by the end of the year.

OHL has also successfully integrated the new customers acquired from the purchase of Hampton Electric and is currently advanced in developing a strategy to grow the existing customer base including review of upgraded systems and resourcing.
On May 15, 2013, the Company announced it has agreed to sell its 90% stake in OHL to Coronado Resources Ltd in exchange for common shares of Coronado valued at approximately $5 million. The common shares of Coronado that are being 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.

CAPITAL EXPENDITURES

In the first three months of fiscal year 2014, the Company invested $12,267,735 in capital expenditures compared to $11,085,979 for the same period last year. Details of capital expenditure are included below:

Taranaki Basin:

Permit	Ownership Interest	**2014 Q1**	2013 Q4	2013 Q1
Mining Permits				
PMP 38156	100%	**295,156**	11,317,883	9,045,340
PMP 53803	100%	**1,878,205**	7,554,678	1,259,133
		2,173,361	18,872,561	10,304,473
Exploration Permits				
PEP 38748	100%	**1,496,668**	-	-
PEP 54873	100%	**190,322**	141	-
PEP 54876	50%	**449**	10,229	-
PEP 54877	70%	**73,770**	10,229	-
PEP 54879	50%	**449**	10,229	-
PEP 52181	40%	**207,560**	1,089	92,520
		1,969,218	31,917	92,520
OHL		**3,001,468**	-	-
Total Taranaki basin		**7,144,047**	18,904,478	10,396,993

Capital expenditures for the quarter at Cheal of $0.3 million related to workover and field optimization and were lower than the March 31, 2013 quarter and the comparable quarter last year when the Company invested in the Cheal facilities upgrade and drilling activities. At the Sidewinder oil and gas field the Company invested $1.9 million drilling the Sidewinder-A7 well which is lower than Q4, 2013 where expenditures were invested in the Sidewinder-A6 and Sidewinder-A7 wells.

The Company's costs incurred on exploration permits in the Taranaki basin during the current quarter related to drilling the Sidewinder-A8 well on PEP38748 and on lease consenting and design for the four permits awarded in the 2012 New Zealand blocks offer to enable the drilling of nine Miocene wells and two deep gas wells. OHL's investments in the current quarter consisted of the acquisition costs of two gas fired gensets from Cheal and the purchase of a third gas fired generator for installation at the Cheal-A site.

East Coast Basin:

Permit	Ownership Interest	**2014 Q1**	2013 Q4	2013 Q1
PEP 38348	100%	**60,501**	247,800	314,728
PEP 38349	100%	**4,942,496**	423,359	119,302
PEP 50940	100%	**-**	391,719	-
PEP 53674	100%	**39,510**	8,372	84,985
PEP 52676	100%	**81,181**	8,372	84,985
		5,123,688	1,079,622	604,000

Total expenditures on the East Coast permits in the first three months of fiscal year 2014 were primarily incurred on drilling the Ngapaeruru-1 well, costs associated with managing the consenting process in preparation for construction of lease and general exploration costs.

Canterbury Basin:

Permit	Ownership Interest	2014 Q1	2013 Q4	2013 Q1
PEP 52589	100%	**-**	78,898	84,986
		-	78,898	84,986

SUMMARY OF QUARTERLY INFORMATION

	2014	2013				2012		
	Q1 **$**	**Q4** **$**	**Q3** **$**	**Q2** **$**	**Q1** **$**	**Q4** **$**	**Q3** **$**	**Q2** **$**
Total revenue	**14,698,198**	12,297,777	10,851,223	9,616,276	11,825,925	16,701,663	12,976,714	7,377,177
Costs	**(4,954,663)**	(3,947,730)	(3,289,307)	(3,123,182)	(3,680,324)	(5,382,240)	(4,280,725)	(3,353,417)
Foreign exchange	**145,971**	426,343	(69,453)	(474,603)	280,575	181,318	(129,433)	699,797
Stock option compensation	**(937,898)**	(1,276,261)	(2,004,076)	(1,499,954)	(840,721)	(1,137,058)	(1,590,387)	(1,905,267)
Other (costs) / income	**(5,430,999)**	(7,483,238)	(4,849,866)	(4,819,833)	(2,866,212)	(3,475,940)	(2,650,559)	(1,924,123)
Net income (loss)	**3,520,609**	16,891	638,521	(301,296)	4,719,243	6,887,743	4,325,610	894,167
Basic income (loss) per share	**0.06**	0.00	0.01	(0.01)	0.09	0.12	0.08	0.02
Diluted income (loss) per share	**0.06**	0.00	0.01	(0.00)	0.08	0.12	0.08	0.02
Production (BOE/d)	**2,354**	1,691	1,727	1,848	1,721	2,157	2,032	824
Capital expenditures	**12,349,082**	20,032,321	21,116,096	22,203,753	11,112,181	12,924,484	12,164,822	6,302,996
Cash flow from operations *(1)*	**8,468,130**	18,136,293	5,610,691	4,409,684	7,443,881	10,853,666	7,169,637	3,532,581

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

Revenue, cash flow from operations and daily production have increased by 24%, 14% and 37% respectively when compared with the same quarter last year due to higher oil and gas production at Sidewinder and Cheal after the commissioning of the Cheal gas plant and from production from the Sidewinder-A5 and Sidewinder-A6 wells. The difference in the current quarters net income of $3,520,609 and net income of $4,719,243 for the same period last year is primarily due to an increase in depletion due to higher production rates for the current quarter with G&A increasing by $399,675 for the quarter as a result of more resources required to manage the expanding operations of the business and interest income decreasing due to lower cash balances on hand.

The Company continues to have a strong capital expenditure program based around operating cash-flows from current production and a strong balance sheet. The Company will continue to leverage its Cheal and Sidewinder permits over many years combined with nine shallow wells and a deep gas well to be drilled in four new highly prospective onshore Taranaki permits. The Company will also undertake drilling of the Cardiff deep gas and condensate well. Successful discoveries from the drillling campaign can be placed efficiently into production using the existing 100% TAG owned Cheal and Sidewinder facilities.

RESULTS FROM OPERATIONS

Oil and Natural Gas Production, Pricing and Revenue

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Daily production volumes(1)			
Oil (bbls/d)	**1,075**	1,013	1,125
Natural gas (BOE/d)	**1,279**	678	596
Combined (BOE/d)	**2,354**	1,691	1,721
Daily sales volumes(1)			
Oil (bbls/d)	**1,058**	1,007	1,120
Natural gas (BOE/d)	**1,115**	436	353
Combined (BOE/d)	**2,173**	1,443	1,473
Natural Gas (Mmcf/d)	**6,690**	2,618	2,118
Product pricing			
Oil ($/bbl)	**104.87**	116.59	107.36
Natural gas ($/Mmcf)	**5.72**	4.94	4.61
Sales			
Total revenue – gross	**14,698,198**	11,993,143	11,825,925
Less other revenue – gross	**(1,120,919)**	304,634	-
Oil and natural gas revenue – gross	**$ 13,577,279**	$ 12,297,777	$11,825,925
Oil and natural gas royalties(2)	**(1,473,864)**	(1,376,561)	(1,329,541)
Oil and natural gas Revenue – net	**$ 12,103,415**	$ 10,921,216	$10,496,384

(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 15% in the quarter ended June 30, 2013, compared to the same period last year. The increase in revenue is attributable to a 48% increase in sales volume (on a BOE basis), a 24% increase in natural gas prices and a 2% decrease in oil prices.

Oil production was 4% lower in the quarter ended June 30, 2013 compared to the same period last year due to flush production from the Cheal-B5 and Cheal-B7 wells in the first quarter last year. Oil production was 6% higher in the quarter ended June 30, 2013 compared to the quarter ended March 31, 2013, as new wells were brought on after the Cheal infrastructure expansion.

Natural gas production was 115% higher and 89% higher in the quarter ended June 30, 2013 compared to the same period in fiscal 2013 and the quarter ended March 31, 2013, respectively. The increase in both cases is due to the new Sidewinder wells coming on stream in the current quarter.

Production by Area (BOE/d)

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Cheal	**1,523**	1,236	1,320
Sidewinder	**831**	455	401
	2,354	1,691	1,721

For the quarter ended June 30, 2013, daily production increased 37% when compared with the same period last year. Cheal production increased 23% in Q1 2014 compared to Q4 2013 and Sidewinder production increased 83% for the same period. The increase in production is due to the completion of the infrastructure upgrade at Cheal in March 2013 allowing all wells from the field to be on production along with the addition of the new Sidewinder wells brought into production in the current quarter.

During the period ended June 30, 2013, the Cheal and Sidewinder oil and gas fields produced 97,862 (2012: 102,390) gross barrels of oil and 698 Mcf (2012: 325 Mcf) of natural gas and sold 96,261 (2012: 101,880) gross barrels of oil and 609 Mcf (2012: 193 Mcf) of natural gas.

Royalties

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Royalties	**1,473,864**	1,376,561	1,329,541
As a percentage of revenue	**10%**	11%	11%

Royalties increased 11% in the three months ended June 30, 2013 when compared to the three months ended June 30, 2012 due to higher revenues being generated in the current period.

Royalty costs incurred relate to crown royalty payments of 5% on net oil and gas proceeds received in the first three months of fiscal year 2014 and a 7.5% royalty paid on net oil proceeds from Cheal as part of the Company's agreement to acquire 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 on the first 200,000 barrels of oil produced from the date of acquisition and then dropping to a 2.5% royalty on net oil sales revenue thereafter. At June 30, 2013, 11,245 barrels of oil (June 30, 2012: 4,372) had been produced from the date of the PMP 53803 (formerly PEP 38748) permit acquisition leaving 188,755 (June 30, 2012: 195,628) barrels of production required before the royalty reduction to 2.5%. Sidewinder royalties also include a 3.33% royalty on net oil and gas proceeds payable to a previous partner.

Production, Transportation and Storage

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Total production costs	**2,582,020**	1,836,184	1,402,119
Electricity production costs	**(743,757)**	(596,658)	-
Oil and gas production costs*	**1,838,263**	1,239,526	1,402,119
Per BOE ($)	**8.58**	7.96	8.95
Tansportation and storage costs	**898,779**	734,985	948,664
Per BOE ($)	**4.20**	4.72	6.06

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

Oil and gas production costs were 4% lower on a BOE basis in the current quarter when compared to the same quarter last year. Overall production costs were 31% higher in the quarter ended June 30, 2013 when compared with the quarter ended June 30, 2012 due primarily to increased production rates, higher electricity demands and costs related to the operation of the gas plant upgrade commissioned in March 2013. Production costs will continue to be monitored for areas to increase efficiency as the new Cheal gas plant upgrade becomes closer to normal operations after initial start-up.

Electricity production costs to June 30, 2013 were higher than the costs for the quarter ended March 31, 2013 as costs were related to two months of operation after acquisition compared to a full three months in the current quarter.

Transportation and storage costs have decreased 31% per BOE in the quarter ended June 30, 2013, compared to the same period last year and have decreased 11% from the quarter ended March 31, 2013. The decrease is due to a higher proportion of natural gas to oil produced in the current quarter (natural gas does not incur transportation or storage costs).

Oil and Gas Operating Netback ($/BOE)

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Revenue	**63.38**	79.02	75.52
Royalties	**(6.88)**	(8.84)	(8.49)
Transportation and storage costs	**(4.20)**	(4.72)	(6.06)
Production costs	**(8.58)**	(7.96)	(8.95)
Netback per BOE ($)	**43.72**	57.50	52.02

Operating netback is the cash margin the company receives from each barrel of oil equivilent sold. The netback on a BOE basis for the current quarter is 16% lower when compared to the netback in the same period last year and 24% lower than the netback for the quarter ended March 31, 2013. The lower per BOE revenue, royalties and transportation and storage costs in Q1 2014 compared to the Q4 2013 and Q1, 2013 are due to a higher proportion of natural gas produced from Sidewinder and Cheal after the commissioning of the gas plant as natural gas has a lower price per BOE resulting in lower royalties and does not incur transportation charges. Production costs on a BOE basis were higher in Q1 2014 compared to Q4 2013 due to additional costs in the first month of operation of the Cheal gas plant upgrade.

Emmissions Trading Scheme

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Emmissons trading scheme ($)	**9,888**	12,251	51,778

ETS costs decreased 81% this quarter when compared to the same period last year, despite increased natural gas production from the Sidewinder field, due to decreased carbon unit prices in the first quarter of fiscal year 2014.

Insurance

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Directors and officers	**11,577**	11,576	14,925
Insurance	**104,682**	177,120	105,672
	116,259	188,696	120,597
Per BOE ($)	**0.54**	1.21	0.77

Insurance decreased 4% during the three months ending June 30, 2013 when compared to the same quarter in fiscal year 2013. Insurance was higher in the quarter ended March 31, 2013 compared to the current quarter as a prepaid insurance adjustment was made in Q4, 2013 to allocate insurance costs related to the 2013 financial year end.

Equity Loss in Associated Companies

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Equity loss in associated company ($)	**57,312**	36,073	-

During fiscal year 2013, the Company acquired an 40% interest in Coronado, and has accounted for its share of its loss. The investment in Coronado was completed to capitalize the Company and pursue growth opportunities, including the acquisition of OHL.

General and Administrative Expenses ("G&A")

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Consulting fees	**65,834**	23,377	21,016
Directors fees	**76,796**	69,250	64,500
Filing, listing and transfer agent	**65,896**	132,010	95,686
Reports	**12,398**	66,800	130,124
Office and administration	**164,041**	100,093	99,337
Professional fees	**168,306**	482,700	34,153
Rent	**62,035**	50,156	57,756
Shareholder relations and communications	**144,617**	230,215	129,505
Travel	**110,663**	121,425	115,340
Wages and salaries	**606,092**	543,604	329,586
	1,476,678	1,819,630	1,077,003
Per BOE ($)	**6.89**	11.69	6.88

During the current quarter, G&A costs have remained stable on a per BOE basis when compared with the same quarter last year and have decereased 41% when compared to the quarter ended March 31, 2013. Overall, G&A costs have increased 37% in the current quarter when compared with the same period in fiscal year 2013. The main reasons for the differences in G&A costs in the quarter ended June 30, 2013, compared to the quarter ended June 30, 2012 are:

a) Consulting fees have increased in the current quarter due to increased resources required to support the growth of the Company's expanded operations in the current year;
b) Reports costs have decreased in the current year due to most the cost being accrued in the prior year;
c) Professional fees and shareholder relations and communications have increased due to joining the New Zealand Petroleum Association, legal and other costs associated with the expanded operations of the Company; and
d) Office and administration costs and wages and salaries have increased in the first three months of fiscal year 2014, compared to last year as the Company employed more staff to support expanded activities related to drilling, operations, acquisitions and financing.

Share-based Compensation

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Share-based compensation	**937,898**	1,276,261	840,721
Per BOE ($)	**4.38**	8.20	5.37

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 an 18% decrease in share-based compensation on a BOE basis and a 12% increase in total share–based compensation costs in the quarter ended June 30, 2013 when compared the same period last year. The overall increase in total share-based compensation costs was due to options issued in the 2013 fiscal year having a higher option value assigned to each grant due to the increase in the Company's share price at the time of grant. In the first quarter ended June 30, 2013, the Company granted nil (2013: nil) options and 71,429 (2013: 116,666) options were exercised at a weighted average price of $2.34 (2013: $4.44) per share.

Depletion, Depreciation and Accretion

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Depletion, depreciation and accretion	**3,911,450**	3,741,947	1,885,796
Per BOE ($)	**18.26**	24.04	12.04

Depletion, depreciation and accretion increased 107% in the first three months of fiscal year 2014 compared to the same period in fiscal year 2013. The increase in depletion in the current quarter when compared to the same period in fiscal year 2013 is due to the additional capital costs of the new Sidewinder wells and increased initial natural gas production in the quarter from these wells based on the 2P reserves calculated at March 31, 2013 and used for the units of production depletion calculation. Depletion at Cheal is also higher reflecting the higher drilling costs subject to depletion associated with last years drilling campaign. Depreciation costs on facilities is also higher in the quarter ended June 30, 2013 compared to the quarters ended June 30, 2012 and March 31, 2013 as it is the first quarter of depreciation for the newly commissioned Cheal gas processing facilities.

Foreign Exchange (Gains) / Losses

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Foreign exchange (gain) / loss ($)	**(145,971)**	(426,343)	(280,575)

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

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Interest Income	**181,601**	239,194	268,962

Decreased interest income reflects the lower cash balances held during the current quarter when compared to comparative quarters.

Net Income and Operating Margin

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Net income ($)	**3,520,609**	16,891	4,719,243
Per share, basic ($)	**0.06**	0.00	0.08
Per share, diluted ($)	**0.06**	0.00	0.09
Operating margin ($) (1)	**9,743,535**	8,642,071	8,145,601

(1) Operating margin refers to production revenue less production costs, transporation and storage costs and royalties

In the quarter ended June 30, 2013, the Company generated net income of $3,520,609 compared to $4,719,243 in the quarter ended June 30, 2012. Operating margin increased by $1.3 million in quarter ended June 30, 2013, compared to the quarter ended June 30, 2012 with a $2.9 million increase in revenue, a $1.1 million increase in production, transportation and storage costs and a $0.2 million increase in royalty costs as a result of higher production at Cheal and Sidewinder. The increase in operating margin was offset by a $3.2 million increase in depreciation, depletion and accretion, a $0.1 million increase in share-based compensation, a $0.4 million increase in general and administrative costs and a $0.2 million decrease in foreign exchange gain in the quarter ended June 30, 2013 compared to the quarter ended June 30, 2012.

In the quarter ended June 30, 2013, the Company generated net income of $3,520,609 compared to $16,891 quarter ended March 31, 2013. Operating margin was higher in the quarter ended June 30, 2013 compared to March 31, 2013 due to decreased production during the infrastructure build resulting in lower revenue along with lower production costs and decreased royalty costs in the quarter ended March 31, 2013.

Cash Flow

	3 Months Ended		
	2014 Q1	2013 Q4	2013 Q1
Cash-flow provided by operating activities ($)	**9,564,346**	19,090,478	9,171,528
Per share, basic ($)	**0.16**	0.32	0.15
Per share, diluted ($)	**0.15**	0.30	0.14

Cash-flow from operating activities increased 4% in the quarter ended June 30, 2013 when compared to the quarter ended June 30, 2012. The increase is due to improved operating margin from higher production, a decrease in receivables related to the timing of payments from oil sales based on 30 days from shipment date in the quarter ended June 30, 2013.

Cash-flow from operations in the current quarter decreased when compared to the quarter March 31, 2013 due to $11.2 million of other revenue related to the East Coast settlement received in the comparable quarter, decreased operating margin from lower production, an increased cash outflow from inventory purchases used for drilling operations and an increase in accounts receivable due to timing of oil shipments in the quarter ended March 31, 2013 compared to quarter ended June 30, 2013.

COMMITMENTS

The Company had the following commitments for Capital Expenditure at June 30, 2013**:**

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases *(1)*	806,094	253,541	552,553
Other long-term obligations *(2)*	73,287,000	38,783,000	34,504,000
Total Contractual Obligations *(3)*	**74,093,094**	**39,036,541**	**35,056,553**

(1) The Company has commitments relating to office leases situated in New Plymouth, 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	489,000	
	Drill 1 deep gas well in Cardiff structure	10,000,000	
	Upgrade of production and pipeline infrastructure	454,000	
PMP 53803	Workovers, optimisations and lease improvements	894,000	
	Drilling of A5, A6 and A7 wells	728,000	
PEP 54873	Drilling of one deep exploration well and reprocess 2D seismic	11,490,000	
PEP 54876 (1)	Drilling of one shallow exploration well and reprocess 2D seismic	1,061,000	
PEP 54877 (1)	Drilling of three shallow exploration wells	4,282,000	
PEP 54879 (1)	Drilling of two shallow exploration wells	2,039,000	
PEP 38748	Drilling of two shallow exploration wells	-	4,076,000
PEP 50940	Nil	-	
PEP 52181	Drilling Kaheru-1	476,000	17,645,000
PEP 52589	Permit costs and 2D seismic	794,000	
PEP 52676	Permit costs and geochemical sampling	675,000	
PEP 53674	Permit costs and geochemical sampling	86,000	
PEP 38348	Drilling of two shallow exploration wells and 2D seismic acquisition	5,089,000	6,363,000
PEP 38349	Drilling of one shallow exploration wells and 2D seismic acquisition	226,000	6,420,000
TOTAL COMMITMENTS		**38,783,000**	**34,504,000**

(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 June 30, 2013, the Company had $57.2 million (2013: $68.9 million) in cash and cash equivalents and $63.5 million (2013: $64.9) 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 revenue 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 or relinquished.

Please refer to subsequent events for additional information.

USE OF PROCEEDS

On May 5, 2010, the Company closed an equity offering with net proceeds of $18,711,150. The Company completed the intended use of the net proceeds in the short form prospectus by December 31, 2011 and have allocated all these proceeds

The Company completed an equity offering on November 26, 2010, for net proceeds of $56,353,740. The Company has allocated all these proceeds.

On May 15, 2012, the Company closed a bought deal offering of common shares at a price of $10.45 per common share for gross proceeds of $46,345,750 and net proceeds of $43,365,746. The Company filed a final short form prospectus in each of the provinces of Canada except Québec on May 7, 2012.

Property	Operation	Anticipated use of proceeds in Short Form Prospectus, including over-allotment	Current anticipated use of actual proceeds received	Status of operation
Taranaki Basin: PMP 38156	Drill one exploration well	$ 2,000,000	$3,300,000	Completed
	Drill two exploration wells	-	11,800,000	Completed
	Cheal facilities upgrade	-	6,948,746	Completed
PMP 53803	Drill one exploration well	2,000,000	3,500,000	Completed
	Drill two exploration wells	-	7,400,000	Completed
PEP 52181	Drill one exploration well	8,000,000	-	Changed program
New business opportunities:	Identify and pursue new business opportunities including future land acquisitions in the Taranaki Basin	28,000,000	-	
PEP 53674, PEP 52676 and PEP 52589	Acquire permit interests from Rawson Resources Ltd.	-	2,300,000	Completed
Coronado Resources Ltd.	Acquire approximately 40% interests in Coronado Resources Ltd.	-	3,117,000	Completed
Opunake Hydro Ltd.	Acquire 90% of Opunake Hydro Ltd	-	5,000,000	Completed
Working capital		3,365,746	-	
Total		**$43,365,746**	**$43,365,746**	

(1) The anticipated original use of proceeds for PMP 38156 and PMP 53803 assumed drilling costs only where as the current anticipated use of proceeds assumes drilling and completion costs.
(2) The Company's use of proceeds at Cheal, permit PMP 38156, includes the drilling and completion of the shallow Cheal-A11 and Cheal-A12 wells, the drilling and completion of the deeper Cheal-B8 well and the completion of the Cheal facilities upgrade.
(3) The Company's use of proceeds at Sidewinder, permit PMP 53803, includes the drilling and completion of the shallow Sidewinder-A5, Sidewinder-A6 wells and the drilling of the Sidewinder-A7 well.
(4) The Company's use of proceeds at Kaheru, PEP 52181 includes the 40% interest in the drilling of the offshore Kaheru-1 well and funds have been allocated to completing the Cheal facilities upgrade.
(5) The Company entered into an agreement with Rawson Taranaki Limited and Zeanco (NZ) Ltd. to acquire three New Zealand exploration permits; Petroleum Exploration Permit 52589, Petroleum Exploration Permit 52676 and Petroleum Exploration Permit 53674. Under the terms of the agreement, TAG will undertake all future exploration work program commitments and paid $2,300,000 for 100 % interest in the permits.
(6) TAG participated in a private placement and acquired 25,975,000 shares for $3,117,000 for an approximate 40% interest in Coronado Resources Ltd
(7) TAG purchased a 90% interest in Opunake Hydro Ltd. for proceeds of approximately $5.0 million (New Zealand dollars six million).

Please refer to the Company's final short-form prospectus filed on May 7, 2012.

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 June 30:

	2013	2012
Share-based compensation	$ 568,620	$ 586,335
Management wages and director fees	245,629	246,863
Total management compensation	$ 814,249	$ 833,198

On May 13, 2013, TAG agreed to sell its 90% stake in OHL pursuant to a definitive share purchase agreement between TAG, Coronado and the vendor of the remaining 10% interest in OHL.

SHARE CAPITAL

a. At June 30, 2013, there were 59,344,052 common shares outstanding
b. At August 14, 2013, there were 59,196,752 common shares outstanding and there are 3,708,334 stock options outstanding, of which 2,628,334 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 11 of the accompanying condensed consolidated interim financial statements.

SUBSEQUENT EVENTS

Subsequent to June 30, 2013, the Company purchased and cancelled 147,300 common shares under its normal course issuer bids at an average weighted price of $3.42 per common share.

On July 19, 2013, the Company submitted to New Zealand Petroleum and Minerals a notice to surrender PEP 50940, which was granted on July 23, 2013.

The Company provided notice to New Zealand Petroleum and Minerals of its intention to surrender PEP 52676 on July 1, 2013 and the surrender was granted on July 12, 2013.

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 June 30, 2012.

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 three months of fiscal 2014. Please also refer to Forward Looking Statements.

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 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.

(c) 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.

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

Management reported on its disclosure controls and procedures and the design of its internal controls over financial reporting in the year end 2013 MD&A. There has been no material change to the Company's disclosure controls or procedures or to the design of internal controls over financial reporting since that time.

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 August 14, 2013, 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 Hydrocarbon-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. There is no certainty that any portion of the undiscovered resources will be discovered or that, if discovered, it will be economically viable or technically feasible to produce.

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

Ronald Bertuzzi, Director
Vancouver, British Columbia

Blair Johnson, CFO
Auckland, 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.

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 6, 2012 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 August 14, 2013, there were 59,196,752, shares issued and outstanding.
Fully diluted: 62,905,086 shares.

WEBSITE
www.tagoil.com

Condensed Consolidated Interim Financial Statements
(Stated in Canadian Dollars)

June 30, 2013
(Unaudited)

TAG Oil Ltd.
www.tagoil.com

Corporate Office
885 West Georgia Street
Suite 2040
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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

Condensed Consolidated Interim Statements of Financial Position
Expressed in Canadian Dollars

Unaudited

	June 30, 2013	March 31, 2013
Assets		
Current:		
Cash and cash equivalents	$ 57,245,170	$ 68,931,018
Amounts receivable and prepaids	9,499,245	10,176,847
Advance receivable (Note 3)	1,307,972	1,969,415
Inventory	3,074,659	3,106,510
	71,127,046	84,183,790
Restricted cash	64,788	64,636
Advance receivable (Note 3)	281,719	294,198
Exploration and evaluation assets (Note 4)	11,241,226	4,328,113
Property, plant and equipment (Note 5)	114,931,985	118,633,974
Goodwill (Note 6)	186,700	186,700
Investments (Note 7)	214,737	197,045
Investments in associated company (Note 7(a))	2,991,546	3,048,858
	$ 201,039,747	$ 210,937,314
Liabilities and Shareholders' Equity		
Current:		
Accounts payable and accrued liabilities	$ 7,653,136	$ 16,110,414
Asset retirement obligations (Note 9)	3,262,193	3,133,303
	10,915,329	19,243,717
Share capital (Note 10 (a))	213,522,047	214,204,375
Share-based payment reserve (Note 10 (b))	14,808,857	13,870,959
Foreign currency translation	2,308,468	7,671,518
Available for sale marketable securities	(418,678)	(436,370)
Deficit	(40,596,734)	(44,119,881)
Equity attributable to owners of the Company	189,623,960	191,190,601
Non-controlling interests	500,458	502,996
	190,124,418	191,693,597
	$ 201,039,747	$ 210,937,314

Nature of operations (Note 1)
Commitments (Note 14)
Subsequent events (Note 16)

See accompanying notes.

Approved by the Board of Directors:

("Garth Johnson") *("Ron Bertuzzi")*

Garth Johnson, Director **Ron Bertuzzi, Director**

Condensed Consolidated Interim Statements of Comprehensive (Loss) Income
Expressed in Canadian Dollars
Unaudited

	Three months ended June 30, 2013	2012
Revenues		
Production revenue	$ 14,698,198	$ 11,825,925
Production costs	(2,582,020)	(1,402,119)
Transportation and storage costs	(898,779)	(948,664)
Royalties	(1,473,864)	(1,329,541)
	9,743,535	8,145,601
Expenses		
Depletion, depreciation and accretion	3,911,450	1,885,796
Directors & officers insurance	11,577	14,925
Foreign exchange	(145,971)	(280,575)
Insurance	104,682	105,672
Interest income	(181,601)	(268,962)
Emissions trading scheme	9,888	51,778
Share-based compensation	937,898	840,721
Consulting fees	65,834	21,016
Directors fees	76,796	64,500
Filing, listing and transfer agent	65,896	95,686
Reports	12,398	130,124
Office and administration	164,041	99,337
Professional fees	168,306	34,153
Rent	62,035	57,756
Shareholder relations and communications	144,617	129,505
Travel	110,663	115,340
Wages and salaries	606,092	329,586
	(6,124,601)	(3,426,358)
Other Items		
Equity in loss of associated company (Note 7(a))	(57,312)	-
Loss on hedge mark to market	(41,013)	-
	(98,325)	-
Net income for the period	3,520,609	4,719,243
Other comprehensive (loss) income (Note 11)		
Cumulative translation adjustment	(5,363,050)	3,539,737
Change in fair value adjustment on available for sale financial instruments:		
Investments	17,692	(57,850)
Comprehensive (loss) income for the period	$ (1,824,749)	$ 8,201,130
Earnings per share - basic (Note 10(c))	$ 0.06	$ 0.09
Earnings per share - diluted (Note 10(c))	$ 0.06	$ 0.08

Consolidated Statements of Comprehensive (Loss) Income
Expressed in Canadian Dollars
Unaudited

	Three months ended June 30, 2013	2012
Net income attributable to:		
Owners of the Company	$ 3,523,147	$ 4,719,243
Non-controlling interests	(2,538)	-
Net income for the year	3,520,609	4,719,243
Total comprehensive (loss) income attributable to:		
Owners of the Company	(1,822,211)	8,201,130
Non-controlling interests	(2,538)	-
Total comprehensive (loss) income for the period	$ (1,824,749)	$ 8,201,130

See accompanying notes.

Condensed Consolidated Interim Statements of Cash Flows
Expressed in Canadian Dollars
Unaudited

	Three months ended June 30, 2013	2012
Operating Activities		
Net income for the period	$ 3,520,609	$ 4,719,243
Changes for non-cash operating items:		
Deemed interest expense	(152)	(1,879)
Depletion, depreciation and accretion	3,911,450	1,885,796
Share-based compensation	937,898	840,721
Equity in loss of associated company	57,312	-
Loss on hedge mark to market	41,013	-
	8,468,130	7,443,881
Changes for non-cash working capital accounts:		
Amounts receivable and prepaids	677,602	1,681,657
Accounts payable and accrued liabilities	386,763	51,856
Inventory	31,851	(5,866)
Cash provided by operating activities	9,564,346	9,171,528
Financing Activities		
Shares issued – net of share issue costs	-	43,433,253
Shares purchased and returned to treasury	(849,625)	-
Options and warrants exercised	167,297	517,995
Cash provided by financing activities	(682,328)	43,951,248
Investing Activities		
Exploration and evaluation assets	(7,219,846)	(708,577)
Property and equipment	(14,021,942)	(11,876,668)
Repayment of loan advances	673,922	-
Loan receivable	-	(200,000)
Cash used in investing activities	(20,567,866)	(12,785,245)
Net (decrease) increase in cash during the period	(11,685,848)	40,337,531
Cash and cash equivalents – beginning of the period	68,931,018	63,006,461
Cash and cash equivalents – end of the period	$ 57,245,170	$ 103,343,992
Supplementary disclosures:		
Interest received	$ 181,601	$ 67,831

Non-cash investing activities:
The Company incurred $261,996 in exploration and evaluation expenditures which amounts were in accounts payable at June 30, 2013 (March 31, 2013: $381,286). The Company incurred $6,393,889 in property and equipment expenditures which amounts were in accounts payable at June 30, 2013 (March 31, 2013: $15,118,640).

See accompanying notes.

Condensed Consolidated Interim Statements of Changes in Equity
Expressed in Canadian Dollars
Unaudited

	Number of Shares (Note 10)	Share Capital (Note 10)	Reserves: Share-based Payments Reserves	Reserves: Foreign Currency Translation Reserve	Reserves: Available for sale Marketable Securities	Deficit	Total	Non-Controlling interests	Total Equity
Balance at March 31, 2013	59,532,623	$214,204,375	$ 13,870,959	$ 7,671,518	$ (436,370)	$ (44,119,881)	$ 191,190,601	$ 502,996	$ 191,693,597
Re-purchase shares	(260,000)	(849,625)	-	-	-	-	(849,625)	-	(849,625)
Exercise of options	71,429	167,297	-	-	-	-	167,297	-	167,297
Share-based payments	-	-	937,898	-	-	-	937,898	-	937,898
Currency translation adjustment	-	-	-	(5,363,050)	-	-	(5,363,050)	-	(5,363,050)
Unrealized loss on available-for-sale investments	-	-	-	-	17,692	-	17,692	-	17,692
Net income for the period	-	-	-	-	-	3,523,147	3,523,147	(2,538)	3,520,609
Balance at June 30, 2013	59,344,052	$213,522,047	$ 14,808,857	$ 2,308,468	$ (418,678)	$ (40,596,734)	$ 189,623,960	$ 500,458	$ 190,124,418

Condensed Consolidated Interim Statements of Changes in Equity
Expressed in Canadian Dollars
Unaudited

	Number of Shares (Note 10)	Share Capital (Note 10)	Reserves: Share-based Payments Reserves	Reserves: Foreign Currency Translation Reserve	Reserves: Available for sale Marketable Securities	Deficit	Total	Non-Controlling interests	Total Equity
Balance at March 31, 2012	55,206,591	$171,169,355	$ 8,699,571	$ 2,854,612	$ (142,456)	$(49,212,899)	$133,368,183	$ -	$133,368,183
Exercise of options	116,666	517,995	-	-	-	-	517,995	-	517,995
Transfer to share capital on exercise of options	-	320,718	(320,718)	-	-	-	-	-	-
Short form prospectus	4,435,000	43,433,253	-	-	-	-	43,433,253	-	43,433,253
Share-based payments	-	-	840,721	-	-	-	840,721	-	840,721
Currency translation adjustment	-	-	-	117,592	-	-	117,592	-	117,592
Unrealized loss on available-for-sale investments	-	-	-	-	(57,850)	-	(57,850)	-	(57,850)
Net income for the period	-	-	-	-	-	4,719,243	4,719,243	-	4,719,243
Balance at June 30, 2012	59,758,257	$215,441,321	$ 9,219,574	$ 2,972,204	$ (200,306)	$(44,493,656)	$182,939,137	$ -	$182,939,137

See accompanying notes.

Notes to the Condensed Consolidated Interim Financial Statements
Three Months Ended June 30, 2013
Expressed in Canadian Dollars
Unaudited

Note 1 – Nature of Operations

The Company is incorporated under the Business Corporations Act (British Columbia) and its major activity is the development and exploration of international oil and gas properties.

The Company is in the process of exploring, developing and producing from its oil and gas properties and has two oil and gas properties that contain reserves that are economically recoverable. The success of the Company's exploration and development of its oil and gas properties requires significant additional exploration and development activities to establish additional proved reserves and to commercialize its oil and gas exploration properties. The Company is also influenced by significant financial risks as well as commodity prices. In addition, the Company will use cash and operating cash flow to further explore and develop its properties towards planned principal operations. The Company monitors its cash and cash equivalents and adjusts its expenditure plans to conform to available funding. The Company plans to fund exploration and development activities through existing cash resources.

Note 2 – Accounting Policies and Basis of Presentation

Basis of presentation and statement of compliance with International Financial Reporting Standards

These condensed consolidated interim financial statements have been prepared in accordance with IAS 34, Interim Financial Reporting ("IAS 34"), as issued by the International Accounting Standards Board, and its interpretations. Accordingly, these condensed consolidated interim financial statements do not include all of the information and foot notes required by International Financial Reporting Standards ("IFRS") for complete financial statements for year end reporting purposes. Results for the period ended June 30, 2013, are not necessarily indicative of future results.

These condensed consolidated interim financial statements have been prepared on a historical cost basis except for financial instruments classified as available-for-sale, which are stated at their fair value. In addition these condensed consolidated interim financial statements have been prepared using the accrual basis of accounting, except for cash flow information.

The Company has used the same accounting policies and methods of computation as in the annual consolidated statements for the year ended March 31, 2013. The accounting policies have been applied consistently by the Company and its subsidiaries.

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 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.

(c) 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.

The condensed consolidated interim financial statements were authorized for issuance on August 14, 2013 by the directors of the Company.

Foreign Currency translation

Items included in the financial statements of each of the Company's entities are measured using the currency of the primary economic environment in which the entity operates ("the functional currency"). The Company's entities' functional currencies are the Canadian Dollar and the New Zealand Dollar. The consolidated financial statements are presented in Canadian Dollars which is the Company's presentation currency.

The functional currency of the Company's New Zealand subsidiaries has been determined as the New Zealand dollar as:

1. Natural gas sales are denominated in New Zealand dollars although oil is denominated in United States dollars.
2. New Zealand is the country whose competitive forces and regulations mainly determine the sales prices of natural gas and oil.
3. The New Zealand dollar is the currency that mainly influences labor, materials and other costs of providing oil and natural gas.

Transactions in currencies other than the functional currency are recorded at the rates of exchange prevailing on dates of transactions. Monetary assets and liabilities that are denominated in foreign currencies are translated at the rates prevailing at each reporting date. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are retranslated to the functional currency at the exchange rate at the date the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated. Foreign currency translation differences are recognized in profit or loss, except for differences on the retranslation of available-for-sale instruments which are recognized in other comprehensive income.

For the purpose of presenting consolidated financial statements, the assets and liabilities of the Company's foreign operations are expressed in Canadian dollars using closing rates at the date of financial position. Income and expense items are translated at the average exchange rates for the period. Exchange differences arising, if any, are recognized directly into equity and transferred to the foreign currency translation reserve. Such exchange differences are recognized in profit or loss in the period in which the foreign operation is disposed of.

Cash and Cash Equivalents

At June 30, 2013, cash and cash equivalents were $57,245,170 comprising cash balances of $15,546,314 (2012: $13,015,879) and term investments together with accrued interest thereon, which are readily convertible to known amounts of cash, of $41,698,856 (2012: $90,328,113).

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its subsidiaries.

The Company's subsidiaries are:

Name of Subsidiary	Place of Incorporation	Proportion of Ownership Interest	Principal Activity
TAG Oil (NZ) Limited	New Zealand	100%	Oil and Gas Exploration
Cheal Petroleum Limited	New Zealand	100%	Oil and Gas Exploration
TAG Oil (Offshore) Limited	New Zealand	100%	Oil and Gas Exploration
Eastern Petroleum Limited	New Zealand	100%	Oil and Gas Exploration
Orient Petroleum Limited	New Zealand	100%	Oil and Gas Exploration
Opunake Hydro Limited	New Zealand	90%	Electricity Generation and Retailing
Trans Orient Petroleum Limited	Canada	100%	Oil and Gas Exploration
DLJ Management Services Limited	Canada	100%	Inactive

Subsidiaries

Control exists when the Company has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain benefits from its activities, generally accompanying a shareholding of more than one half of the voting rights. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing whether the Company controls another entity.

The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases. All inter-company transactions and balances have been eliminated on consolidation.

Where the Company's interest is less than 100%, the interest attributable to outside shareholders is reflected in non-controlling interest. Non-controlling interests in the net assets of consolidated subsidiaries are identified separately from the Company's equity therein. Non-controlling interests consist of the amount of those interests at the date of the original business combination and the non-controlling interests' share of changes in equity since the date of the combination.

Significant Accounting Estimates and Judgments

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 0.9% and a risk free discount rate of 2.5% 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.

Non oil and gas reserves

Share-based payment reserve

The share-based payment reserve records items recognized as share-based compensation expense until such time that the stock options are exercised, at which time the corresponding amount will be transferred to share capital. If the options expire unexercised, the amount remains in the reserve.

Foreign currency translation reserve

The foreign currency translation reserve records exchange differences arising on translation of subsidiaries that have a functional currency other than the Canadian dollar.

Available for sale marketable securities reserve

The available for sale marketable securities reserve records unrealized gains and losses arising on available-for-sale financial assets, except for impairment losses and foreign exchange gains and losses.

Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Financial assets and financial liabilities are recognized on the consolidated statement of financial position at the time the Company becomes a party to the contractual provisions. Upon initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods is dependent on the classification of the financial instrument. These instruments will be classified into one of the following five categories: fair value through profit or loss, held-to-maturity, loans and receivables, available-for-sale or financial liabilities at amortized cost.

i) Financial assets and liabilities at fair value through profit or loss

Financial assets and liabilities at fair value through profit or loss are measured at fair value with changes in fair value recognized in net income (loss). Cash and cash equivalents are designated as fair value through profit or loss.

ii) Held-to-maturity

Held-to-maturity investments are measured at amortized cost at the settlement date using the effective interest method of amortization.

iii) Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. Accounts receivable and advance are classified as loans and receivables.

iv) Available-for-sale

Available-for-sale financial assets are instruments that are classified in this category or not classified in any other category. They are measured at fair value at the settlement date, with changes in the fair value recognized in other comprehensive income. The Company's investment in equity securities are classified as available-for-sale.

v) Financial liabilities at amortized cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Accounts payable and accrued liabilities are classified as financial liabilities at amortized cost.

The Company has financial instruments in the form of equity securities that give rise to other comprehensive income. Instruments are classifieds current if they are assumed to be settled within one year; otherwise they are classified as non-current. The Company will assess at each reporting period whether there is any objective evidence that a financial asset, other than those measured at fair value, is impaired. When assessing impairment, the carrying value of financial assets carried at amortized cost is compared to the present value of estimated future cash flows discounted using the instrument's original effective interest rate.

Hedges

As part of its risk management strategy, the Company uses derivatives to reduce its exposure to commodity price risk. The Company designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. The Company performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash-flows of the hedged item.

The effective portion of changes in the fair value of cash-flow hedges is recognized in Other Comprehensive Income. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income. Gains or losses from cash-flow hedges that have been included in accumulated other comprehensive income are included in net income when the underlying transaction has occurred or is likely not to occur.

Exploration and evaluation costs

All costs directly associated with petroleum and natural gas reserves are initially capitalized. Exploration and evaluation costs are those expenditures for an area where technical feasibility and commercial viability has not yet been determined. These costs include costs to acquire acreage and exploration rights, geological and geophysical costs, asset retirement costs, exploration and evaluation drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to net earnings as exploration and evaluation expense.

When an area is determined to be technically feasible and commercially viable and a mining permit is granted, the accumulated costs are transferred to property, plant and equipment. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to net earnings as exploration and evaluation expense.

Property, plant and equipment

All costs directly associated with the development of petroleum and natural gas reserves are capitalized on an area by area basis. Development costs include expenditures for areas where technical feasibility and commercial viability has been determined through the granting of a mining permit. These costs include proved property acquisitions, development drilling, completion, gathering lines and infrastructure, decommissioning costs and transfers of exploration and evaluation assets. Where development costs related to drilling are incurred in an area, but the associated reserves are not able to be included in the independent reserves evaluation at year end these costs are separately categorized in property, plant and equipment as exploration in progress.

Costs accumulated within each area are depleted using the unit-of-production method based on proved and probable reserves using estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved and probable reserves but do not include exploration in progress costs which will be evaluated for impairment once proved.

For property dispositions, a gain or loss is recognized in net earnings. Exchanges of properties are measured at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured. Where the exchange is measured at fair value, a gain or loss is recognized in net earnings.

Assets attributable to electricity generation are recorded at cost less accumulated depreciation and depreciation is calculated using the declining-balance method. Corporate assets consist primarily of office equipment and leasehold improvements and are stated at cost less accumulated depreciation. Depreciation of these corporate assets is calculated using the declining-balance method.

Goodwill

Goodwill represents the excess of the cost of a business combination over the total acquisition date fair value of identifiable assets, liabilities and contingent liabilities acquired.

Cost comprises the fair value of assets given, liabilities assumed and equity instruments issued, plus the amount of any non-controlling interests in the acquiree. Contingent consideration is included at cost at its acquisition date fair value and, in the case of contingent consideration classified as a financial liability, re-measured subsequently through profit and loss. Any direct costs of acquisition are recognized immediately as an expense.

Goodwill is capitalized with any impairment in carrying value being charged to the Consolidated Statement of Comprehensive Income. Where fair value of identifiable assets, liabilities and contingent liabilities exceed the fair value of consideration paid, the excess is credited in full to the Consolidated Statement of Comprehensive Income on the acquisition date.

Impairment of non-financial assets

The carrying value of the Company's non-financial assets is reviewed at each reporting date for indicators that the carrying value of an asset or CGU may not be recoverable. These indicators include, but are not limited to, extended decreases in prices or margins for oil and gas commodities or products, a significant downward revision in estimated reserves or an upward revision in future development costs. If indicators of impairment exist, the recoverable amount of the asset or CGU is estimated. If the carrying value of the asset or CGU exceeds the recoverable amount the asset or CGU is written down with an impairment recognized in net earnings.
Exploration and evaluation costs and property, plant and equipment costs are aggregated into CGUs based on their ability to generate largely independent cash flows. The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Fair value less cost to sell is determined to be the amount for which the asset could be sold in an arm's length transaction, less the costs of disposal. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU.

Goodwill acquired in a business combination is allocated to the CGU that is expected to benefit from the combination. Gains and losses calculated on the disposal of a business include the carrying value of goodwill relating to the business sold. The Company performs its annual test for goodwill impairment at March 31.

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net earnings. The recoverable amount is limited to the original carrying amount less depletion and depreciation as if no impairment had been recognized for the asset or CGU for prior periods.

Asset retirement obligations

Asset retirement obligations include present obligations where the Company will be required to retire tangible long-lived assets such as producing well sites and facilities. Management has calculated the cost to plug and abandon current wells, dispose of facilities and rehabilitate land based on local regulations. The asset retirement obligations are measured at the present value of the expenditure expected to be incurred using an inflation rate of 0.9% and a risk-free discount rate of 2.5%.The associated asset retirement obligation is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognized as a change in the asset retirement obligation and the related decommissioning cost.

Increases in asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of comprehensive income. Actual expenditures incurred are charged against the asset retirement obligation liability as incurred.

Share-based payments

Obligations for issuance of common shares under the Company's share-based compensation plan are accrued over the vesting period using fair values. Fair values are determined at issuance using the Black-Scholes option-pricing model, taking into account a nominal forfeiture rate, and are recognized as share-based compensation with a corresponding credit to share based payments reserve.

Emission Credits

Emission credits purchased or generated internally are recorded at fair value and included in other current assets. As no active market currently exists, emission credits are recorded at cost.

Contingencies

When a contingency is substantiated by confirming events, can be reliably measured and will likely result in an economic outflow, a liability is recognized in the consolidated financial statements as the best estimate required to settle the obligation. A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events, or where the amount of a present obligation cannot be measured reliably or will likely not result in an economic outflow. Contingent assets are only disclosed when the inflow of economic benefits is probable. When the economic benefit becomes virtually certain, the asset is no longer contingent and is recognized in the consolidated financial statements.

Income tax

Income tax expense is comprised of current and deferred tax. Income tax is recognized in the statement of income except to the extent that it relates to items recognized directly in equity, in which case the income tax is also recognized directly in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted, or substantively enacted, at the end of the reporting period, and any adjustment to tax payable in respect of previous years.
In general, deferred tax is recognized in respect of temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred income tax is determined on a non-discounted basis using tax rates and laws that have been enacted or substantively enacted at the balance sheet date and are expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered.

Deferred income tax is provided on temporary differences arising on investments in subsidiaries and associates, except in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets and liabilities are presented as non-current. Tax on income in periods is accrued using the tax rate that would be applicable to expected total annual earnings.

Revenue

Revenue is recognized when it is probable that the economic benefits will flow to the Company and delivery has occurred, the sales price is fixed or determinable, and collectability is reasonably assured. These criteria are generally met at the time the product is shipped and delivered to the customer and, depending on the delivery conditions, title and risk have passed to the customer and acceptance of the product, when contractually required, has been obtained. Revenue is measured based on the price specified in the sales contract.

Earnings / loss per share

Basic earnings per share ("EPS") is calculated by dividing the net earnings (loss) for the period attributable to equity owners of TAG Oil by the weighted average number of common shares outstanding during the period.

Diluted EPS is not presented when it is anti-dilutive.

Diluted EPS is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to options, warrants and similar instruments is computed using the treasury stock method. TAG Oil's potentially dilutive common shares comprise share options granted to employees and directors, and warrants.

Future Changes in Accounting Policies

International Financial Reporting Standard 9, *Financial Instruments: Classification and Measurement* ("IFRS 9"), was issued as an amendment in 2011 to provide additional guidance to classification and measurement of the Company's financial assets, but will have an impact on classification and measurement of financial liabilities. Due to the amendment in 2011, this standard is now required to be adopted for periods beginning January 1, 2015. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

IAS 32: *Offsetting Financial Assets and Financial Liabilities* – In 2011, the IASB issued amendments to IAS32 clarifying the meaning of "currently has a legal enforceable right to set-off" and the application of the IAS 32 offsetting criteria to settlement systems which apply gross settlement mechanisms that are not simultaneous. These amendments are required to be adopted for periods beginning January 1, 2014. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

Note 3 – Advances and loans receivable

a.) *Advances receivable*

TAG Oil entered into an agreement with Petra Drilling, a 100%-owned subsidiary of New Zealand-based Webster Drilling and Exploration. The Company provided secured financing of US$2,912,174 for Petra to acquire and deliver to New Zealand the fully automated VR500 rack and pinion, top-drive drill rig. The advance is converted and repaid in New Zealand dollars at a fixed amount based on daily use of the rig and the Company has secured a fixed price for future drilling, as well as the first right of refusal on use of the rig until all financing has been repaid.

TAG Oil (NZ) Limited entered into an agreement with Rival Energy Services Limited ("Rival") on December 8, 2012. The Company provided secured financing of $1 million for Rival to relocate a Skytop RR400 skid double class III (4200m) service rig and hot oiler to New Plymouth. The advance is repaid at a fixed amount based on daily use of the rig and hot oiler and the Company has secured a fixed price for future operations, as well as the first right of refusal on use of the rig and hot oiler until all financing has been repaid.

	Petra	Rival	Total
Balance at March 31, 2013	$ 1,268,115	$ 995,498	$ 2,263,613
Less repayments	(483,107)	(190,815)	(673,922)
Balance at June 30, 2013	785,008	804,683	1,589.691
Consisting of:			
Current	785,008	522,964	1,307,972
Non-current	$ -	$ 281,719	$ 281,719

Note 4 – Exploration and Evaluation Assets

Taranaki Permits Ownership Interest	PEP38748 100%	PEP52181 40%	PEP54873 100%	PEP54876 50%	PEP54877 70%	PEP54879 50%	Total
Cost							
At March 31, 2012	$ -	$ 345,851	$ -	$ -	$ -	$ -	$ 345,851
Capital expenditures	-	103,217	13,271	21,496	21,496	21,496	180,976
Foreign exchange movement	-	18,027	586	948	948	948	21,457
At March 31, 2013	-	467,095	13,857	22,444	22,444	22,444	548,284
Capital expenditures	1,496,668	207,560	190,322	449	73,770	449	1,969,218
Foreign exchange movement	(45,411)	(26,110)	(6,362)	(965)	(3,189)	(965)	(83,002)
At June 30, 2013	$ 1,451,257	$ 648,545	$ 197,817	$ 21,928	$ 93,025	$ 21,928	$ 2,434,500
Net book value							
March 31, 2013	$ -	$ 467,095	$ 13,857	$ 22,444	$ 22,444	$ 22,444	$ 548,284
June 30, 2013	**$ 1,451,257**	**$ 648,545**	**$ 197,817**	**$ 21,928**	**$ 93,025**	**$ 21,928**	**$ 2,434,500**

Ownership Interest	PEP38348 100%	PEP50940* 100%	PEP38349 100%	PEP52676* 100%	PEP53674 100%	PEP52589 100%	Taranaki Permits	Total
Cost								
At March 31, 2012	$ 1,202,455	$ 74,484	$ 635,084	$ -	$ -	$ -	$ 345,851	$ 2,257,874
Capital expenditures	723,629	304,463	546,112	793,500	793,500	1,786,376	180,976	5,128,556
Change in ARO	4,411	-	124,470	-	-	-	-	128,881
Apache re-imbursement	(1,919,088)	(274,616)	(1,202,528)	-	-	-	-	(3,396,232)
Foreign exchange movement	(7,826)	17,478	28,935	35,046	35,046	78,898	21,457	209,034
At March 31, 2013	3,581	121,809	132,073	828,546	828,546	1,865,274	548,284	4,328,113
Capital expenditures	60,501	-	4,942,496	39,510	81,181	-	1,969,218	7,092,906
Change in ARO	-	-	252,150	-	-	-	-	252,150
Foreign exchange movement	(715)	(17,922)	(177,238)	(36,342)	(37,607)	(79,117)	(83,002)	(431,943)
At June 30, 2013	$ 63,367	$ 103,887	$ 5,149,481	$ 831,714	$ 872,120	$ 1,786,157	$2,434,500	$11,241,226
Net book value								
March 31, 2013	$ 3,581	$ 121,809	$ 132,073	$ 828,546	$ 828,546	$ 1,865,274	$ 548,284	$ 4,328,113
June 30, 2013	**$ 63,367**	**$ 103,887**	**$ 5,149,481**	**$ 831,714**	**$ 872,120**	**$ 1,786,157**	**$2,434,500**	**$11,241,226**

* - Subsequent to the period ended June 30, 2013, the Company submitted to New Zealand Petroleum and Minerals a notice to surrender the permits. Accordingly, these costs will be written-off next quarter.

The Company's oil and gas properties are located in New Zealand and its interests in these properties are maintained pursuant to the terms of exploration and mining permits granted by the national government. The Company is satisfied that evidence supporting the current validity of these permits is adequate and acceptable by prevailing industry standards in respect to the current stage of exploration on these properties.

Note 5 – Property, Plant and Equipment

	Proven Oil and Gas Property PMP 38156	Proven Oil & Gas Property PMP 53803	Office Equipment and leasehold improvements	Opunake Hydro Limited	Total
Cost					
At March 31, 2012	$ 50,989,122	$ 29,913,776	$ 1,370,258	$ -	$ 82,273,156
Capital expenditures	58,545,867	5,126,954	178,236	-	63,851,057
Exploration in progress	-	5,484,738	-	-	5,484,738
Impairment	-	(13,074,069)	-	-	(13,074,069)
Transfer on acquisition	-	-	-	475,848	475,848
Change in ARO	(1,603,076)	-	-	-	(1,603,076)
Foreign exchange movement	4,479,033	3,069,724	28,948	13,503	7,591,208
At March 31, 2013	112,410,946	30,521,123	1,577,442	489,351	144,998,862
Capital expenditures	295,156	667,472	81,347	3,001,468	4,045,443
Exploration in progress	-	1,210,733	-	-	1,210,733
Foreign exchange movement	(4,691,086)	(1,351,558)	(34,430)	(19,661)	(6,096,735)
At June 30, 2013	$ 108,015,016	$ 31,047,770	$ 1,624,359	$ 3,471,158	$ 144,158,303
Accumulated depletion and depreciation					
At March 31, 2012	$ (12,338,740)	$ (573,996)	$ (834,422)	$ -	$ (13,747,158)
Depletion and depreciation	(4,225,586)	(7,291,466)	(136,889)	(6,668)	(11,660,609)
Foreign exchange movement	(597,873)	(344,389)	(14,564)	(295)	(957,121)
At March 31, 2013	(17,162,199)	(8,209,851)	(985,875)	(6,963)	(26,364,888)
Depletion and depreciation	(2,615,662)	(1,207,685)	(36,755)	(33,494)	(3,893,596)
Foreign exchange movement	721,446	384,867	16,699	(90,846)	1,032,166
At June 30, 2013	$ (19,056,415)	$ (9,032,669)	$ (1,005,931)	$ (131,303)	$ (29,226,318)
Net book value					
March 31, 2013	$ 95,248,747	$ 22,311,272	$ 591,567	$ 482,388	$ 118,633,974
June 30, 2013	**$ 88,958,601**	**$ 22,015,101**	**$ 618,428**	**$ 3,339,855**	**$ 114,931,985**

The Company's oil and gas properties are located in New Zealand and its interests in these properties are maintained pursuant to the terms of exploration and mining permits granted by the national government. The Company is satisfied that evidence supporting the current validity of these permits is adequate and acceptable by prevailing industry standards in respect to the current stage of exploration on these properties.

Note 6 – Business Acquisition and Goodwill – Opunake Hydro Limited (OHL)

On February 8, 2013, TAG Oil (NZ) Limited ("Tag NZ"), acquired 90% (controlling interest) of the share capital of Opunake Hydro Limited (OHL). OHL is engaged in the generation and retailing of electricity in New Zealand.

	February 8, 2013 Acquisition Date
Cash consideration	$ 2,426,430
OHL payable	2,593,770
Total consideration	**$ 5,020,200**
Purchase price allocation	
Assets acquired:	
Current assets	$ 5,116,218
Plant, property and equipment	475,848
Goodwill	191,646
	5,783,712
Less liabilities assumed:	

Current liabilities	$ 227,008
	5,556,704
Non-controlling interest	$ 536,504
	$ 5,020,200

The Company has allocated goodwill on the purchase of Opunake Hydro Limited ("OHL") and tests for impairment annual as described in note 2.

Balance at March 31, 2012	$ -
Additions	191,646
Foreign exchange movement	(4,946)
Balance at March 31, 2013 and June 30, 2013	$ 186,700

Note 7 – Investments

	Number of Common Shares Held	June 30, 2013 Market Value	Number of Common Shares Held	March 31, 2013 Market Value
Marketable securities available for sale	1,343,431	$ 214,737	1,343,431	$ 197,045

a) Investment in Associated Company

At June 30, 2013, the Company held an approximate 40% interest in Coronado Resources Ltd (''Coronado'') with a fair value of $9,091,250. In the second quarter of 2013, the Company participated in a private placement and acquired 25,975,000 shares for $3,117,000. The carrying value of this investment has been reduced each quarter since initial acquisition as the Company records its share of Coronado's comprehensive loss. The following table summarizes the change on the carrying value of the Company's investment in Coronado:

	June 30, 2013
Investment in Coronado shares	$ 3,117,000
Equity in Coronado's estimated comprehensive loss for the period	(68,142)
Investment in Coronado as at March 31, 2013	$ 3,048,858
Equity in Coronado's estimated comprehensive loss for the period (1)	(57,312)
Investment in Coronado as at June 30, 2013	$ 2,991,546

(1) Coronado Resources Ltd. loss for the period ended June 30, 2013 amounted to $143,280. The Company's approximate 40% interest in the loss for that period amounted to $57,312.

The following is a summary of Coronado's estimated financial position as at June 30, 2013:

Assets	$ 11,279,965
Liabilities	$ 70,116
Revenue	$ Nil
Loss for the three months ended June 30, 2013	$ 143,000

Note 8 – Related Party Transactions

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.

Key management personnel compensation for the three months ended June 30:

	2013	2012
Share-based compensation	$ 568,620	$ 586,335
Management wages and director fees	245,629	246,863
Total management compensation	$ 814,249	$ 833,198

Note 9 – Asset retirement obligations

The following is a continuity of asset retirement obligations for the three months ended June 30, 2013:

Balance at March 31, 2013	$ 3,133,303
Revaluation of ARO	244,500
Accretion expense	17,852
Foreign exchange movement	(133,462)
Balance at June 30, 2013	$ 3,262,193

The following is a continuity of asset retirement obligations for the three months ended June 30, 2012:

Balance at March 31, 2012	$ 4,375,718
Revaluation of ARO	-
Accretion expense	29,608
Foreign exchange movement	(6,217)
Balance at June 30, 2012	$ 4,399,109

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas development activity. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $4,143,000 which will be incurred between 2014 and 2032. The retirement obligation is calculated based on an assessment of the cost to plug and abandon each well, the removal and sale of facilities and the rehabilitation and reinstatement of land at the end of the life of the field.

During the period, the Company reduced the asset retirement obligations for the Sidewinder permit as the salvage value of facilities exceeds the retirement obligation for the field abandonment costs. The fair value of the liability for the Company's asset retirement obligation is recorded in the period in which it is incurred, using an inflation rate of 1.6% and discounted to its present value using a risk free rate of 2.5%.The corresponding amount is recognized by increasing the carrying amount of the oil and gas properties. The liability is accreted each period and the capitalized cost is depreciated over the useful life of the related asset using the unit-of-production method based on proved and probable reserves.

Note 10 – Share Capital

a) Authorized and Issued Share Capital

The authorized share capital of the Company consists of an unlimited number of common shares without par value at June 30, 2013

During the three months ended June 30, 2013, the Company purchased and cancelled 260,000 common shares under normal course issuer bids at an average weighted price of $3.05 per common share.

b) Incentive Share Options

The Company has a share option plan for the granting of share options to directors, employees and service providers. Under the terms of the share option plan, the number of shares reserved for issuance as share incentive options will be equal to 10% of the Company's issued and outstanding shares at any time. The exercise price of each option equals the market price of the Company's shares the day prior to the date that the grant occurs less any applicable discount approved by the Board of Directors and per the guidelines of the TSX. The options maximum term is five years and must vest over a minimum of eighteen months.

The following is a continuity of outstanding share options:

	Number of Options	Weighted Average Exercise Price
Balance at March 31, 2012	2,526,429	$ 5.76
Granted during the year	1,545,000	6.53
Exercised during the year	(208,332)	3.47
Expired during the year	(83,334)	6.62
Balance at March 31, 2013	3,779,763	$ 6.18
Exercised during the period	(71,429)	2.34
Balance at June 30, 2013	3,708,334	$ 6.26

(1) Certain outstanding options are denominated in US dollars and have been converted to Canadian dollars using the year-end closing exchange rate of the year of grant.

The following summarizes information about share options that are outstanding at June 30, 2013:

Number of Shares	Price per Share	Weighted Average Remaining Contractual Life	Expiry Date	Options Exercisable
83,000	$1.25	0.03	October 28, 2014	83,000
290,334	$2.60	0.17	September 9, 2015	290,334
1,065,000	$7.15	0.75	February 8, 2016	1,065,000
500,000	$6.15	0.41	July 5, 2016	500,000
225,000	$7.00	0.21	December 20, 2016	225,000
1,270,000	$6.70	1.41	August 8, 2017	423,333
50,000	$6.47	0.06	September 12, 2017	16,667
75,000	$6.66	0.09	September 19, 2017	25,000
150,000	$5.00	0.19	February 21, 2018	-
3,708,334		3.32		2,628,334

During the three months ended June 30, 2013, 71,429 share options were exercised for $167,297. The weighted average share price for the period of exercised options was $3.00.

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.

c) Income per share

Basic weighted average shares outstanding for the three months ended June 30, 2013 was 59,456,956 (2012: 55,389,246) and diluted weighted average shares outstanding for the period was 59,830,290 (2012: 57,799,009). Share options and share purchase warrants outstanding are not included in the computation of diluted loss per share when the inclusion of such securities would be anti-dilutive.

Note 11 – Accumulated Other Comprehensive Income (Loss)

		Accumulated Other Comprehensive income (loss)
Balance at March 31, 2013	$	7,235,148
Unrealized loss on available for sale investments		17,692
Cumulative translation adjustment		(5,363,050)
Balance at June 30, 2013	$	1,889,790

		Accumulated Other Comprehensive income (loss)
Balance at March 31, 2012	$	2,712,156
Unrealized loss on available for sale investments		(57,850)
Cumulative translation adjustment		117,592
Balance at June 30, 2012	$	2,771,898

Note 12 – Capital Management

The Company's primary objective for managing its capital structure is to maintain financial capacity for the purpose of sustaining the future development of the business and maintaining investor, creditor and market confidence.

The Company considers its capital structure to include shareholders' equity and working capital. Management is continually monitoring changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas industry. In the event that adjustments to the capital structure are necessary, the Company may consider issuing additional equity, raising debt or revising its capital investment programs.

The Company's share capital is not subject to any external restrictions. The Company has not paid or declared any dividends since the date of incorporation, nor are any currently contemplated. There have been no changes to the Company's approach to capital management during the period.

Note 13 – Financial Instruments

The nature of the Company's operations expose the Company to credit risk, liquidity risk and market risk, and changes in commodity prices, foreign exchange rates and interest rates may have a material effect on cash flows, net income and comprehensive income.

This note provides information about the Company's exposure to each of the above risks as well as the Company's objectives, policies and processes for measuring and managing these risks.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and to monitor market conditions and the Company's activities. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework and policies.

a) Credit Risk

Credit risk is the risk of financial loss to the Company if counterparties do not fulfill their contractual obligations. The most significant exposure to this risk is relative to the sale of oil production. All of the Company's production is sold directly to an oil super major. The Company is paid for its oil sales within 30 days of shipment. The Company has assessed the risk of non-collection from the buyer as low due to the buyer's financial condition.

Cash and cash equivalents consist of cash bank balances and short-term deposits. The Company's short-term investments are held with a Canadian chartered bank and are monitored to ensure a stable return. The Company's short-term investments currently consist of term deposits as it is not the Company's policy to utilize complex, higher-risk investment vehicles.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. The Company does not have an allowance for doubtful accounts as at June 30, 2013 and did not provide for any doubtful accounts. During the period ended June 30, 2013, the Company was required to write-off $Nil (2012 – $Nil). As at June 30, 2013, there were no significant amounts past due or impaired.

b) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its work commitments and other financial obligations as they are due. The Company's approach to managing liquidity is to ensure, to the extent possible, that it will have sufficient liquidity to meet its liabilities when due without incurring unacceptable losses or risking harm to the Company's reputation.

The Company's liquidity is dependent upon maintaining its current working capital balances, operating cash flows and ability to raise funds. To forecast and monitor liquidity the Company prepares operating and capital expenditure budgets which are monitored and updated as considered necessary. Considering these circumstances and the cash balance at June 30, 2013 of $57.2 million (March 31, 2013: $68.9 million), the Company's liquidity risk is assessed as low. As at June 30, 2013 the Company's financial liabilities included accounts payable and accrued liabilities of $7.7 million (March 31, 2013: $16.1 million).

c) Market Risk

Market risk is the risk that changes in foreign exchange rates, commodity prices and interest rates will affect the Company's cash flows, net income and comprehensive income. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

d) Foreign Currency Exchange Rate Risk

Foreign currency exchange rate risk is the risk that future cash flows, net income and comprehensive income will fluctuate as a result of changes in foreign exchange rates. All of the Company's petroleum sales are denominated in United States dollars and operational and capital activities related to our properties are transacted primarily in New Zealand dollars and/or United States dollars with some costs also being incurred in Canadian dollars.

The Company currently does not have significant exposure to other currencies and this is not expected to change in the foreseeable future as the work commitments in New Zealand are expected to be carried out in New Zealand and to a lesser extent, in United States dollars.

e) Commodity Price Risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices, affecting results of operations and cash generated from operating activities. Such prices may also affect the value of exploration and development properties and the level of spending for future activities. Prices received by the Company for its production are largely beyond the Company's control as petroleum prices are impacted by world economic events that dictate the levels of supply and demand. All of the Company's oil production is sold at spot rates exposing the Company to the risk of price movements.

The Company did not have any commodity price contracts in place as at or during the period ended June 30, 2013.

f) Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its cash and cash equivalents which bear a floating rate of interest. The risk is not considered significant.

The Company did not have any interest rate swaps or financial contracts in place during the period ended June 30, 2013 and any variations in interest rates would not have materially affected net income.

g) Fair Value of Financial Instruments

The Company's financial instruments included cash and cash equivalents, receivables, investments and accounts payable and accrued liabilities. The fair value of the financial instruments with exception of the Company's investments, approximate their carrying amounts due to their short terms to maturity. The Company's investments are at fair value as they are recorded at market value at June 30, 2013.

Note 14 – Commitments

The Company has the following commitments for Capital Expenditure at June 30, 2013:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases (1)	806,094	253,541	552,553
Other long-term obligations (2)	73,287,000	42,859,000	30,428,000
Total Contractual Obligations (3)	74,093,094	43,112,541	30,980,553

(1) The Company has commitments related to office leases signed in New Plymouth, New Zealand and Vancouver, Canada.

(2) The other long term obligations that the Company has are in respect to the Company's share of expected exploration and development permit obligations and/or commitments at the date of this report. 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.

Note 15 – Segmented Information

The Company operates in one industry: petroleum exploration and production. It operates in two geographical regions, therefore information on country segments is provided as follows:

	Canada	New Zealand	Total Company
Production revenue	$ -	$ 14,698,198	$ 14,698,198
Total non-current assets	$ 3,514,354	$ 126,398,347	$ 129,912,701

Note 16 – Subsequent Events

Subsequent to June 30, 2013, the Company purchased and cancelled 147,300 common shares under its normal course issuer bids at an average weighted price of $3.42 per common share.

On July 19, 2013, the Company submitted to New Zealand Petroleum and Minerals a notice to surrender PEP 50940, which was granted on July 23, 2013.

The Company provided notice to New Zealand Petroleum and Minerals of its intention to surrender PEP 52676 on July 1, 2013 and the surrender was granted on July 12, 2013.

Please refer to Note 4.