MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated February 15, 2016, for the three and nine months ended December 31, 2015 and should be read in conjunction with the Company's accompaning condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2015.

The condensed consolidated interim financial statements for the three and nine months ended December 31, 2015, have been prepared in accordance with IAS, Interim Financial Reporting Standards ("IAS 34"), as issued by the International Accounting Standards Board, and its interpretations. Results for the period ended December 31, 2015, are not necessarily indicative of future results. All figures are expressed in Canadian dollars unless otherwise stated.

ABOUT TAG OIL LTD.

TAG Oil Ltd. ("TAG" or the "Company") is a Canadian registered oil and gas producer and explorer with assets in the Taranaki Basin of New Zealand. As of December 31, 2015, the Company controls a land holding consisting of nine oil and gas permits amounting to 57,000 net acres of land onshore and 21,000 net acres offshore.

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

Given the continued uncertainty in commodity prices, TAG continues to take steps to make its operations more efficient by focusing on its core operations in the Cheal field, and has deferred the majority of its exploration focused capital program. In addition, TAG has relinquished several existing permits that had either large commitments or were no longer core to the Company's strategy. Furthermore, management continues to focus on preserving its capital and reducing production and administrative costs wherever possible.

The Company's long-term strategy is to maximize the value of its core producing operations year-over-year through the implementation of a number of initiatives. These include increasing reserves and production, reducing risk through robust planning and the execution of key projects, and minimizing costs, which includes optimizing production to lower per barrel production costs. In addition, the Company continues to focus on increasing cash flow from existing operations while reducing its risk exposure on exploration drilling.

Going forward, TAG's management will continue to focus on production, appraisal, and exploitation, as well as maintaining a disciplined approach to exploration opportunities where appropriate. Management has adapted where necessary to changing commodity prices and shareholder appetite for risk. At the same time, TAG continues to focus on the future and will:

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

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

THIRD QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At December 31, 2015, the Company had $15.9 million (December 31, 2014: $31.1 million) in cash and cash equivalents and $22.3 million (December 31, 2014: $33.0 million) in working capital.
- Average net daily production decreased by 6% for the quarter ended December 31, 2015 to 1,263 BOE/d (75% oil) from 1,341 BOE/d (69% oil) for the quarter ended September 30, 2015. A breakdown of net production is as follows:
  - Average net daily oil production increased by 2% to 945 bbl/d compared with 930 bbl/d for the quarter ended September 30, 2015. The increase is primarily due to Cheal-A1, B5 and B1 wells returning to production during the quarter following the completion of the workover program.
  - Average net daily gas production decreased by 23% to 1.9 MMSCFD compared with 2.5 MMSCFD for the quarter ended September 30, 2015. The decrease is primarily due to lower gas volumes from the Sidewinder mining permit (PMP 53803) due to the gas wells shut-in for extended build up.
- Due to the sale of the electricity generation business, the assets and liabilities relating to Opunake Hydro Limited ("OHL"), a wholly owned subsidiary of Coronado Resources Ltd. ("Coronado"), have been classified separately as assets or liabilities held for sale, with operating results classified as discontinued operations totalling a net loss for the nine months ended December 31, 2015 of $7.2 million. This includes revenue of $4.9 million, production costs of $5.1 million, other costs of $1.6 million and property impairment of $5.4 million.
- Revenue from oil and gas sales decreased by 11% for the quarter ended December 31, 2015 to $5.1 million from $5.7 million for the quarter ended September 30, 2015. The 11% decrease is due to a 7% decrease in average Brent oil prices and 6% decrease in oil and gas sales volumes.
- Operating netback decreased by 31% for the quarter ended December 31, 2015 to $13.57 per BOE compared with $19.75 per BOE for the quarter ended September 30, 2015. The decrease is attributable to the 7% decrease in average Brent oil prices and a 14% increase in production costs per BOE due to the repairs and maintenance workover of the Cheal-A1 well and operating costs associated with pressure data gathering in support of the pressure maintenance and water-flood program.
- Capital expenditures totalled $3.2 million for the quarter ended December 31, 2015 compared to $2.8 million for the quarter ended September 30, 2015. The majority of the expenditure in Q3 2016 related to the workovers of the Cheal-B5 and B1 wells.
- On December 4, 2015, the Company submitted notice to New Zealand Petroleum and Minerals ("NZP&M") of the surrender of PEP 38349 (Boar Hill). All associated costs related to the permit have been expensed as at December 31, 2015.

TAG Oil maintains a high working interest ownership in production facilities and associated pipeline infrastructure within its operations, so successful discoveries from the majority of TAG's drilling locations can be placed efficiently into production.

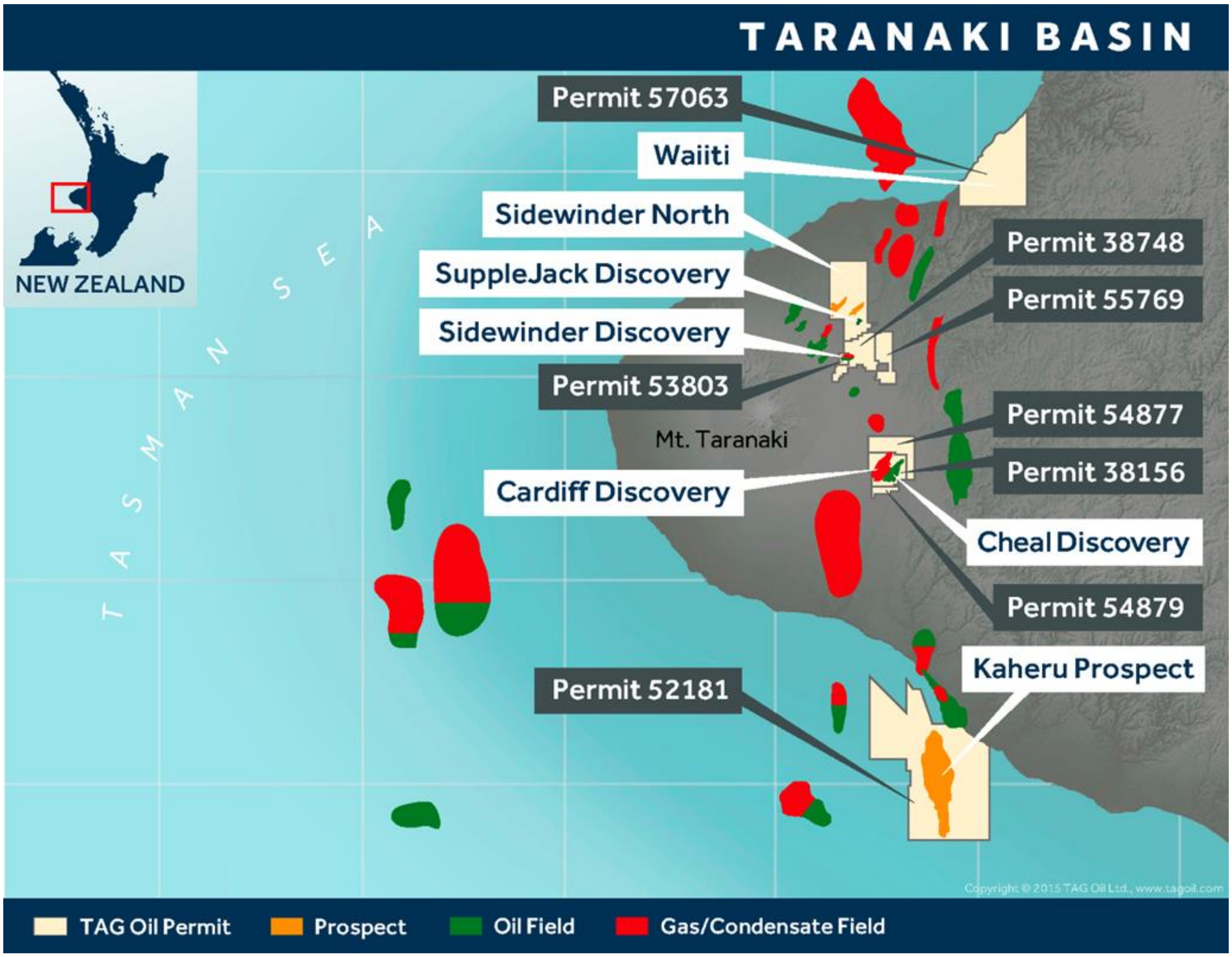
RECENT DEVELOPMENTS

On February 5, 2016, the Company submitted notice to NZP&M of the surrender of PEP 38748 (Sidewinder B). All asociated costs related to the permit have been expensed as at December 31, 2015.

PROPERTY REVIEW

Taranaki Basin:

The Taranaki Basin is an oil, gas and condensate province located on the North Island of New Zealand. It remains under-explored compared to many comparable rift complex basins of its size and potential. Although the Taranaki Basin covers an area of about 100,000 sq. km., fewer than 500 exploration and development wells have been drilled since 1950. To date, proven Taranaki oil reserves of 534 million barrels, and proven gas reserves of 7.3 trillion cubic feet have been discovered.



The Taranaki Basin offers production potential from multiple formations ranging from the shallow Miocene to the deep Eocene prospects. Within the Taranaki Basin, TAG holds the following working interests:

- 100% interest in the Cheal PMP 38156 and the Sidewinder PMP 53803 mining permits.
- 100% interest in the Sidewinder PEP 38748, PEP 55769 and PEP 57065 (Sidewinder North) exploration permits.
- 100% interest in PEP 57063 (Waiiti) exploration permit.
- 70% interest in the Cheal North East PEP 54877 exploration permit.
- 50% interest in the Cheal South PEP 54879 exploration permits.
- 40% interest in the Kaheru Offshore PEP 52181 exploration permit.

Shallow / Miocene Development and Exploration

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

TAG's shallow Miocene net production averaged 1,263 BOE/d (75% oil) in Q3 2016, compared to an average of 1,341 BOE/d (69% oil) in Q2 2016 and 1,991 BOE/d (77% oil) in Q3 2015. The decrease compared to Q2 2016 is mainly due to the Sidewinder gas wells being shut-in for an extended build up and the Cheal-E2, E5 and E6 wells being offline due to downhole mechanical issues. Furthermore, production decreased due to the periodic shut-in of selected Cheal wells to gather pressure data to support the pressure maintenance and water-flood program.

The Cheal A, B and C facilities (PMP 38156: TAG 100% interest) produced an average of 808 BOE/d (91% oil) in Q3 2016, compared to an average of 685 BOE/d (89% oil) in Q2 2016 and 1,238 BOE/d (86% oil) in Q3 2015. The increase from Q2 2016 is primarily due to Cheal-B5, B1 and A1 wells returning to production following the completion of the workover program.

The Cheal North East permit (PEP 54877: TAG 70% interest) produced an average of 380 net BOE/d (56% oil) in Q3 2016 versus an average of 522 BOE/d (61% oil) in Q2 2016 and 642 BOE/d (74% oil) in Q3 2015. The decrease compared to Q2 2016 is due to the Cheal-E6 well being offline due to downhole mechanical issues and due to natural field decline rates.

The Cheal oil field continues to provide TAG with a long-life resource that generates substantial cash flow. TAG plans to continue to develop the Cheal oil and gas field, which has been substantially de-risked by the 36 wells drilled to date across the field. Permit-wide 3D seismic coverage indicates that there are additional drilling targets across the Cheal permit area and potential reserve upside from a pressure maintenance and water-flood program. With drilling and completion costs of under US$2.5 million per well, there is an unrecognized upside and economic potential that exists within TAG's acreage.

The Sidewinder field produced an average of 75 BOE/d (1% oil) in Q3 2016, compared to an average of 134 BOE/d (2% oil) in Q2 2016 and 111 BOE/d (2% oil) in Q3 2015. The Sidewinder facility was shut-in for 32 days during Q3 2016, compared to just 14 days in Q2 2016, as the Company continues to optimize the well operating mode to maximize well deliverability and economics.

Deep / Eocene Exploration

TAG's 100% controlled mining permit, PMP 38156, where the Company's Cheal oil field is located, also contains the large Cardiff structure of the deeper Kapuni Group formations, which is on trend and geologically similar to the large legacy deep gas condensate fields that have been discovered in the Taranaki Basin.

The Cardiff structure, identified on seismic, is an extensive linear fault bound high which is ~12 km long and 3 km wide. Cardiff-3, drilled by TAG in FY2014, encountered 230 meters of gas and condensate bearing sands over three target zones within the Kapuni Group. The deepest zone, the "K3E" is one of the producing intervals of the Kapuni Field, a legacy pool with estimated recoverable reserves of over 1.4 Tcf of gas. The upper two zones which remain untested in the Cardiff well are the main producing intervals in the offsetting deep gas condensate fields including McKee, Mangahewa, and Pohokura. TAG will look at completing engineering, designing and associated planning to assess all viable options to re-test Cardiff or testing of a series of other Kapuni group (deep) formations identified within the wellbore within the next 12 months.

The Cardiff-3 well was drilled from the Cheal C-Site, which is connected by pipeline to the Cheal A-Site processing facilities and provides open access to the New Zealand gas sales network.

The Hellfire prospect, located within PMP 53803, has been identified on 3D seismic and also has similar geological features to the producing Kapuni field. Hellfire is a contingent well that could be drilled upon success of either Cardiff and/or on location of a suitable joint venture partner to join TAG in its exploration drilling activities. The Sidewinder processing facility is currently available to allow for efficent commercialization of a discovery.

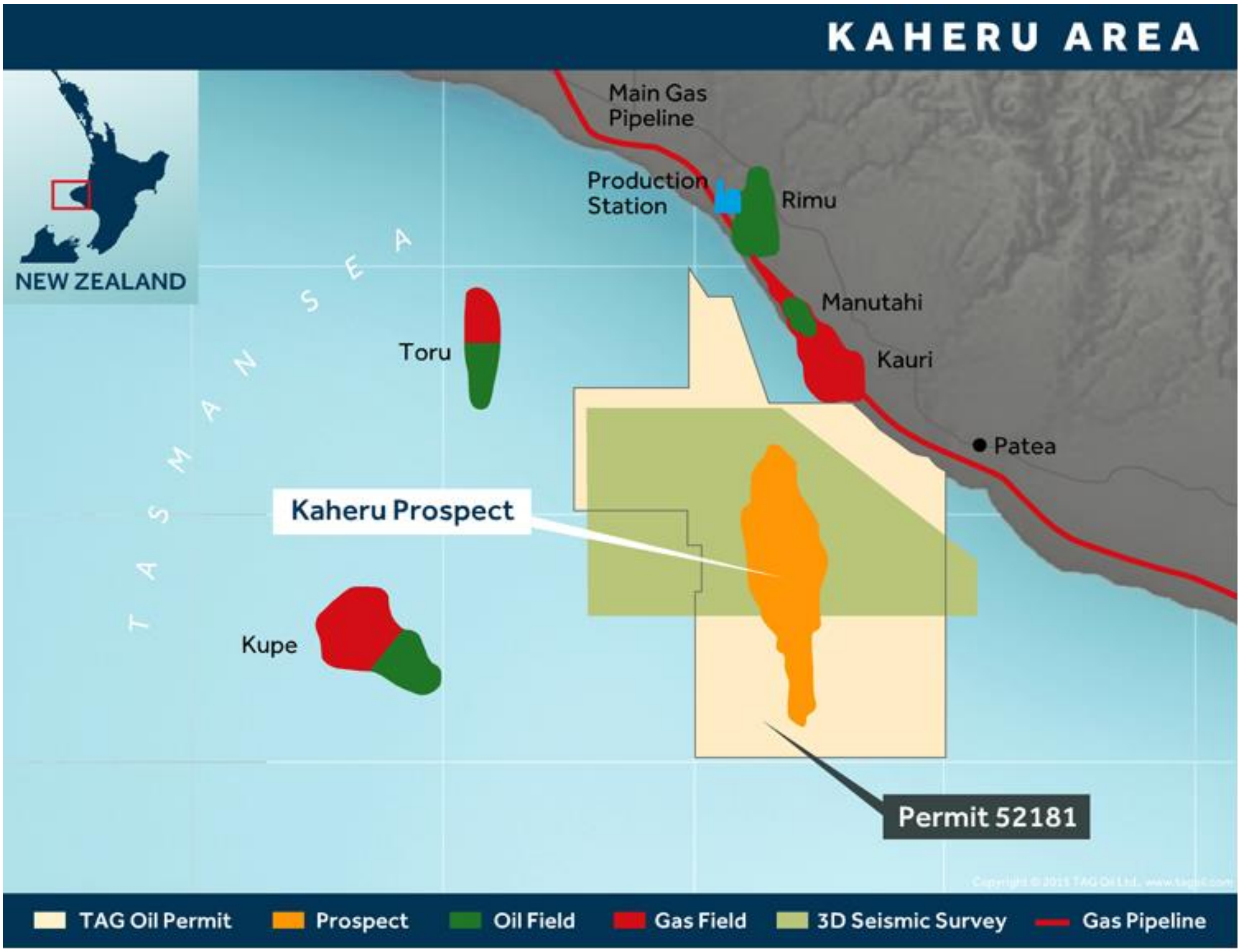
Offshore Exploration

Planning and preparation work by the Operator, New Zealand Oil and Gas, continues to be ahead of the shallow-water Kaheru-1 well. The Kaheru prospect located in PEP 52181 (40% TAG), is a large technically robust sub-thrust anticline with mapped four way dip closure at the Miocene, Oligocene, and Cretaceous stratigraphic intervals.

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

A work programme and budget for the June 2015 to May 2016 permit year focuses on the well design, long lead inventory and required G&G work necessary for the design and execution of the Kaheru-1 exploration well.

The Company is actively seeking joint venture partners to participate in funding the well, reducing the Company's interest in the Kaheru permit to a more suitable risk level.



East Coast Basin:

On December 4, 2015 the Company submitted notice to NZP&M of the surrender of PEP 38349 (Boar Hill). All associated costs related to the permit have been expensed as at December 31, 2015.

Opunake Hydro Limited and Coronado Resources Limited:

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

Following the appointment of Coronado's new CEO on March 6, 2015, management announced on April 17, 2015, that it had initiated a review of all assets of Coronado including its power generation assets. In the course of their evaluation, the board of directors (the "Coronado Board") consulted with its management and other advisors, reviewed a significant amount of information and considered a number of factors. This includes that it may be some time before the oil and gas industry recovers, so without the requisite generation to act as a source of supply and as a natural hedge to fluctuating spot rates, Coronado is not prepared to commit to further funding the expansion of OHL's business. Also, the current market conditions have been an ongoing concern by limiting Coronado's ability to access funds from the capital markets and other sources to develop the business. This led to Coronado canvassing a number of interested parties over the course of approximately six (6) months in an attempt to sell OHL as a going concern. However, in the current global energy market very few entities were willing to incur any capital expenditures to increase capacity. As a result, management and the Coronado Board decided that selling part of its generation equipment at market value in order to reduce debt and then selling OHL to the most suitable purchaser available, was the best course of action for Coronado and its shareholders.

On October 30, 2015, Coronado announced that its wholly owned subsidiary, Lynx Clean Power Corp. ("Lynx"), entered into a definitive share purchase agreement with Opunake Hydro Holdings Limited ("OHHL") dated October 30, 2015 (the "SPA"). Under the terms of the SPA, Lynx has agreed to sell to OHHL all of the issued and outstanding common shares of OHL, which holds Coronado's interest in its hydro generation and gas-fired generation facilities, and OHHL will pay Lynx NZ$200,000 in cash at closing and assume all existing liabilities of OHL (the "OHL Sale Acquisition"). Coronado has since received the requisite shareholder and TSX Venture Exchange ("TSX-V") approvals for the OHL Sale Acquisition, and is currently in the process of completion.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2016		2015	Nine months ended December 31,	
Daily production volumes (1)	**Q3**	Q2	Q3	**2016**	2015
Oil (bbl/d)	**945**	930	1,543	**1,036**	1,426
Natural gas (BOE/d)	**318**	411	448	**395**	437
Combined (BOE/d)	**1,263**	1,341	1,991	**1,431**	1,863
% of oil production	**75%**	69%	77%	**72%**	77%
Daily sales volumes (1)					
Oil (bbl/d)	**922**	958	1,536	**1,043**	1,422
Natural gas (BOE/d)	**256**	300	208	**270**	195
Combined (BOE/d)	**1,178**	1,258	1,744	**1,313**	1,617
Natural gas (MMcf/d)	**1,536**	1,798	1,248	**1,619**	1,172
Product pricing					
Oil ($/bbl)	**52.94**	56.89	77.29	**62.84**	100.36
Natural gas ($Mcf)	**4.16**	4.22	3.60	**3.97**	4.55
Oil and natural gas revenues (3) - gross *($000s)*	**5,078**	5,713	11,333	**19,797**	40,717
Oil & natural gas royalties (2)	**(485)**	(484)	(1,070)	**(1,773)**	(3,706)
Oil and natural gas revenues - net *($000s)*	**4,593**	5,229	10,263	**18,024**	37,011

(1) Natural gas production converted at 6 Mcf:1BOE (for BOE figures).
(2) Relates to government royalties and includes an ORR of 7.5% royalty related to the acquisition of a 69.5% interest in the Cheal field.
(3) Oil and Gas Revenue excludes electricity revenue related to Coronado.

Average net daily production decreased by 6% for the quarter ended December 31, 2015 to 1,263 BOE/d (75% oil) from 1,341 BOE/d (69% oil) for the quarter ended September 30, 2015. The decrease compared to Q2 2016 is mainly due to the Sidewinder gas wells being shut-in for an extended build up and the Cheal-E2, E5 and E6 wells being offline due to downhole mechanical issues. Furthermore, the periodic shut-in of selected Cheal wells to gather pressure data to support the pressure maintenance and water-flood program was also part of the decrease. The 6% decrease was a combination of a 44% decrease in the Sidewinder gas production offset by an 18% increase in production from PMP 38156 (Cheal) due to Cheal-A1, B5 and B1 wells returning to production during the quarter following the completion of the workover program.

Oil and natural gas gross revenue decreased by 11% for the quarter ended December 31, 2015 to $5.1 million compared with $5.7 million for the quarter ended September 30, 2015. The decrease is attributable to a 7% decrease in average Brent oil prices and a 6% decrease in oil and gas sales volumes.

SUMMARY OF QUARTERLY INFORMATION

	2016			2015				2014
Canadian $000s, except per share or BOE	**Q3** ***(2)***	Q2 *(2)*	Q1 *(2)*	Q4 *(2)*	Q3 *(2)*	Q2 *(2)*	Q1 *(2)*	Q4 *(2)*
Net production volumes (BOE/d)	**1,263**	1,341	1,689	1,837	1,991	1,845	1,750	1,486
Total revenue	**5,078**	5,713	9,006	8,660	11,333	15,008	14,375	12,896
Operating costs	**(3,607)**	(3,428)	(4,133)	(3,928)	(4,790)	(5,222)	(4,630)	(4,551)
Foreign exchange	**(279)**	810	553	757	(344)	1,206	(312)	2,246
Share-based compensation	**(218)**	(403)	(896)	(380)	(586)	(356)	(44)	(175)
Other costs	**(4,668)**	(4,495)	(5,600)	(6,654)	(6,276)	(5,605)	(5,291)	(4,797)
Exploration impairment	**(2,104)**	(2,740)	(715)	(71,714)	-	-	-	101
Property impairment	**-**	-	-	(9,182)	-	-	-	-
Net (loss) income from discontinued operations	**(6,472)**	(132)	(615)	(775)	(281)	16	(408)	108
Net (loss) income before tax	**(12,270)**	(4,675)	(2,400)	(83,216)	(944)	5,147	3,690	5,828
Basic (loss) income $ per share (BT)	(0.20)	(0.08)	(0.04)	(1.30)	(0.01)	0.08	0.06	0.09
Diluted (loss) income $ per share (BT)	(0.20)	(0.08)	(0.04)	(1.30)	(0.01)	0.08	0.06	0.09
Capital expenditures	**3,266**	2,755	2,916	10,465	16,655	11,126	11,370	22,767
Operating cash flow ***(1)***	**(1,540)**	1,263	3,071	2,826	3,968	9,702	7,715	6,774

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

(2) Due to the sale of the OHL business the operations are considered discontinued and results exclude the related electrical generation operating segments and are know included in net (loss) income from discontinued operations.

Revenues generated from oil and gas sales decreased by 11% for the quarter ended December 31, 2015 to $5.1 million from $5.7 million for the quarter ended September 30, 2015. The 11% decrease is due to a 7% decrease in average Brent oil prices and 6% decrease in oil and gas sales volumes.

Operating costs increased by 5% for the quarter ended December 31, 2015 to $3.6 million from $3.4 million for the quarter ended September 30, 2015. Operating costs related to oil and gas activities increased by 5% due to the repairs and maintenance workover of the Cheal A-1 well and costs associated with pressure data gathering in support of the pressure maintenance and water-flood program.

Other costs increased by 4% for the quarter ended December 31, 2015 to $4.7 million from $4.5 million for the quarter ended September 30, 2015. The 4% increase compared to 2016 Q2 is mainly due to a 22% increase in oil and gas general and administrative costs related to a decrease in timewriting allocations to capital projects, as work programs are adjusted for the low oil price environment.

Net loss before tax for the quarter ended December 31, 2015 was $12.3 million compared to a net loss of $4.7 million for the quarter ended September 30, 2015. Excluding impairment expense and net loss from discontinued operations, on a comparative basis, equates to a net loss before tax of $3.7 million for the quarter ended December 31, 2015 compared to a net loss of $1.8 million for the quarter ended September 30, 2015.

Due to the sale of the electricity generation business, the assets and liabilities relating to OHL have been classified separately as assets or liabilities held for sale, with operating results classified as discontinued operations totaling a net loss for the nine months ended December 31, 2015 of $7.2 million. This includes revenue of $4.9 million, production costs of $5.1 million, other costs of $1.6 million and property impairment of $5.4 million.

Net Production by Area (BOE/d)

Area	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
PMP 38156 (Cheal)	**808**	685	1,238	**829**	1,165
PEP 54877 (Cheal North East)	**380**	522	642	**494**	582
PMP 53803 (Sidewinder)	**75**	134	111	**107**	116
Total BOE/d	**1,263**	1,341	1,991	**1,431**	1,863

Average net daily production decreased by 6% for the quarter ended December 31, 2015 to 1,263 BOE/d (75% oil) from 1,341 BOE/d (69% oil) for the quarter ended September 30, 2015. The 6% decrease in production is primarily due to lower production volumes from PEP54877 (Cheal North East) due to Cheal-E6 being offline due to downhole mechanical issues, natural field decline rates and the Sidewinder gas wells being shut in for an extended build up. The 6% decrease was due to a combination of a 44% decrease in the Sidewinder gas production, which was offset by an 18% increase in production from PMP 38156 (Cheal) due to Cheal-A1, B5 and B1 wells returning to production during the quarter following the completion of the workover program.

Average net daily production decreased by 37% for the quarter ended December 31, 2015 to 1,263 BOE/d (75% oil) from 1,991 BOE/d (77% oil) for the quarter ended December 31, 2014. The 37% decrease versus 2015 Q3 is due to a combination of natural decline rates and wells offline.

Oil and Gas Operating Netback ($/BOE)

	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Oil and natural gas revenue	**46.85**	49.38	70.65	**54.82**	91.54
Royalties	**(4.47)**	(4.18)	(6.67)	**(4.91)**	(8.33)
Transportation and storage costs	**(8.32)**	(7.49)	(9.85)	**(8.25)**	(9.97)
Production costs	**(20.49)**	(17.96)	(13.35)	**(17.77)**	(14.24)
Netback per BOE ($)	**13.57**	19.75	40.78	**23.89**	59.00

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

Operating netback decreased by 31% for the quarter ended December 31, 2015 to $13.57 per BOE compared with $19.75 per BOE for the quarter ended September 30, 2015. The decrease is attributable to the 5% decrease in oil and gas revenue per BOE due to the 7% decrease in average Brent oil prices and a 14% increase in production costs per BOE. Production costs rose due to the repairs and maintenance workover of Cheal A-1 and costs associated with pressure data gathering ahead of the pressure maintenance and water-flood program.

Operating netback decreased by 67% for the quarter ended December 31, 2015 to $13.57 per BOE compared with $40.78 per BOE for the quarter ended December 31, 2014. The decrease is attributable to the 55% decrease in oil and gas revenue per BOE, previously due to the 32% decrease in average Brent oil sales prices and an increase in production costs per BOE of 54%.

General and Administrative Expenses (“G&A”)

	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Oil and Gas G&A expenses ($000s)	**1,711**	1,405	1,940	**4,728**	5,027
Oil and Gas G&A per BOE ($)	**14.72**	11.39	10.59	**12.78**	9.81
Mining G&A expenses ($000s)	**144**	75	150	**302**	325
Total G&A Expenses	**1,855**	1,480	2,090	**5,030**	5,352

Total G&A expenses increased by 25% for the quarter ended December 31, 2015 to $1.9 million compared with $1.5 million for the quarter ended September 30, 2015. Oil & Gas G&A expenses have increased 22% due primarily to a decrease in timewriting allocations to capital projects as work programs are adjusted for the low oil price environment.

Total G&A expenses decreased by 11% for the quarter ended December 31, 2015 to $1.9 million compared with $2.1 million for the quarter ended December 31, 2014. Oil & Gas G&A expenses have decreased 12% due primarily to lower wages and salaries costs. Electricity/Mining G&A expenses have decreased 4% due to G&A relating to the electricity business reported as discontinued operations.

Share-based Compensation

	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Share-based compensation ($000s)	**218**	403	586	**1,517**	986
Per BOE ($)	**1.87**	3.27	3.20	**3.85**	1.93

Share-based compensation costs are non-cash charges, which reflect the estimated value of stock options granted. The Company applies the Black-Scholes option pricing model using the closing market prices on the grant dates and to date the Company has calculated option benefits using a volatility ratio of 60.61% to 61.62% and a risk free interest rate of 1.66% to 1.69%. The fair value of the option benefit is amortized over the vesting period of the options, generally being a minimum of two years.

In the quarter ended December 31, 2015, the Company granted no options (September 30, 2015: nil) and no options were exercised (September 30, 2015: nil).

Share-based compensation decreased by 46% for the quarter ended December 31, 2015 to $0.2 million when compared with $0.4 million for the quarter ended September 30, 2015. The decrease in total share-based compensation costs was due to no options being granted during the quarter.

Share-based compensation decreased to $0.2 million in the quarter ended December 31, 2015 compared with $0.6 million for the quarter ended December 31, 2014. The decrease in total share-based compensation costs was due to no options being granted during the quarter.

Depletion, Depreciation and Accretion (DD&A)

	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Depletion, depreciation and accretion ($000s)	**2,819**	3,166	4,279	**9,861**	12,185
Per BOE ($)	**24.26**	25.65	23.36	**25.06**	23.78

DD&A expenses decreased by 11% for the quarter ended December 31, 2015 to $2.8 million compared with $3.2 million for the quarter ended September 30, 2015. The decrease is attributable to the 6% decrease in production.

DD&A expenses decreased by 34% for the quarter ended December 31, 2015 to $2.8 million compared with $4.3 million for the quarter ended December 31, 2014. The decrease is attributable to the 37% decrease in production.

Foreign Exchange Loss (Gains)

	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Foreign exchange loss (gains) ($000s)	**279**	(810)	344	**(1,084)**	(550)

The foreign exchange loss for the quarter ended December 31, 2015 was a result of the weakening USD against the NZD resulting in foreign exchange loss on the USD denominated oil receipts.

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

	2016		2015	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2016**	2015
Net (loss) income before tax	**(12,270)**	(4,675)	(944)	**(19,345)**	7,893
Income tax recovery (expense) - deferred	**-**	-	-	**-**	-
Net (loss) income after tax	**(12,270)**	(4,675)	(944)	**(19,345)**	7,893
Per share, basic ($)	**(0.20)**	(0.08)	(0.01)	**(0.31)**	0.12
Per share, diluted ($)	**(0.20)**	(0.08)	(0.01)	**(0.31)**	0.12

Net loss before tax for the quarter ended December 31, 2015, was $12.3 million compared to a net loss of $4.7 million for the quarter ended September 30, 2015. Excluding impairment expense and net loss from discontinued operations from the result for these quarters, equates to a net loss before tax of $3.7 million for the quarter ended December 31, 2015, and a net loss of $1.8 million for the quarter ended September 30, 2015. The decrease is primarily related to lower revenue due to the 6% decrease in production and a 7% decrease in average Brent oil sales prices.

Net loss before tax for the quarter ended December 31, 2015, was $12.3 million compared to a net loss of $0.9 million for the quarter ended December 31, 2014. Excluding impairment expense and net loss from discontinued operations from the result for these quarters, equates to a net loss before tax of $3.7 million for the quarter ended December 31, 2015, and a net loss of $0.7 million for the quarter ended December 31, 2014. The decrease is primarily related to lower revenue due to the 37% decrease in production and a 32% decrease in average Brent oil sales prices.

Cash Flow

	2016		2015	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2016**	2015
Operating cash flow *(1)*	**(1,540)**	1,263	3,968	**2,794**	21,385
Cash provided by operating activities	**(3,052)**	3,208	8,342	**3,475**	23,293
Per share, basic ($)	**(0.05)**	0.05	0.13	**0.06**	0.37
Per share, diluted ($)	**(0.05)**	0.05	0.13	**0.06**	0.37

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

Operating cash flow decreased by $2.8 million for the quarter ended December 31, 2015, to negative operating cash flow of $1.5 million from operating cash flow of $1.3 million for the quarter ended September 30, 2015. The decrease is a result of lower revenue due to a 6% decrease in oil and gas sales volumes, a 7% decrease in average Brent oil sales prices and higher operating costs relating to workover activities.

Operating cash flow decreased by $5.5 million for the quarter ended December 31, 2015, to negative operating cash flow of $1.5 million from operating cash flow of $4.0 million for the quarter ended December 31, 2014. The decrease is a result of lower revenue due to a 32% decrease in oil and gas sales volumes and a 32% decrease in average Brent oil sales prices.

CAPITAL EXPENDITURES

Capital expenditures were $3.2 million for the quarter ended December 30, 2015, compared to $2.8 million for the quarter ended September 30, 2015, and $16.7 million for the same period last year.

Taranaki Basin ($000s)	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Mining permits	**3,025**	2,334	5,959	**6,843**	13,783
Exploration permits	**103**	147	3,282	**890**	5,110
Opunake Hydro Limited	**139**	202	589	**661**	2,560
Total Taranaki Basin	**3,267**	2,683	9,830	**8,394**	21,453

East Coast Basin ($000s)	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Exploration permits	**-**	**-**	6,602	**-**	16,786
Total East Coast Basin	**-**	**-**	6,602	**-**	16,786

Canterbury Basin ($000s)	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Exploration permits	**(30)**	1	6	**9**	55
Total Canterbury Basin	**(30)**	1	6	**9**	55

United States ($000s)	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Madison mine - exploration	**-**	19	113	**483**	537
Madison mine - development	**-**	-	-	**-**	-
Total United States	**-**	19	113	**483**	537

At December 31, 2015, the Company expensed $2.1 million relating to the surrender of PEP 38748 (Sidewinder B) and $5.4 million relating to the impairment of OHL property.

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at December 31 2015:

Contractual Obligations ($000s)	Total	Less than One Year	More than One Year
Long term debt	**-**	-	-
Operating leases *(1)*	**345**	300	45
Other long-term obligations *(2)*	**44,025**	29,727	14,298
Total contractual obligations *(3)*	**44,370**	30,027	14,343

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

(2) The Other Long Term Obligations that the Company has are in respect to the Company's share of expected exploration and development permit obligations and/or commitments at the date of this report that relate to operations and infrastructure. The Company may choose to alter the program, request extensions, reject development costs, relinquish certain permits or farm-out its interest in permits where practical.

(3) The Company's total commitments include those that are required to be incurred to maintain its permits in good standing during the current permit term, prior to the Company committing to the next stage of the permit term where additional expenditures would be required. In addition, costs are also included that relate to commitments the Company has made that are in addition to what is required to maintain the permit in good standing.

The details of the Company's material commitments shown previously are as follows:

Permit	Commitment	Less than One Year ($000s) (1)	More than One Year
PMP 38156	Workovers and lease improvements	529	
PMP 53803	Minor capital projects	-	
PEP 54876	*Relinquished (site reinstatement)*	82	
PEP 54877	Drilling of two shallow exploration wells	4,744	
PEP 54879	3D Seismic and Technical study	889	
PEP 38748	Drilling of two shallow wells including pad construction	7,575	
PEP 52181	Drilling Kaheru-1 (40% Working Interest)	15,665	
PEP 55769	Cuttings study and two exploration wells (2018)	53	7,575
PEP 57065	2-D seismic reprocessing and one exploration well (2017)	95	4,261
PEP 57063	2-D seismic reprocessing and 60km of seismic reprocessing	95	2,462
PEP 38348	*Relinquished*	-	
PEP 38349	*Relinquished*	-	
	TOTAL COMMITMENTS	**29,727**	**14,298**

(1) Included in the less than one year commitments, a total of $23.2 million is included in regard to permit obligations that will only be carried out if these commitments are funded by a suitable joint venture partner. Otherwise the permits associated with these commitments will be relinquished prior to the Company incurring these costs.

The Company may also have an obligation to pay its joint venture interest share of costs to plug and abandon the SuppleJack wells previously drilled. The Company expects to use working capital on hand as well as cash flow from oil and gas sales to meet these commitments. Commitments and work programs are subject to change.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2015, the Company had $15.9 million (December 31, 2014: $31.1 million) in cash and cash equivalents and $22.3 million (December 31, 2014: $33 million) in working capital. As of the date of this report, the Company is adequately funded to meet its planned operations and ongoing requirements for the next twelve months based on the current exploration and development programs and anticipated cash flow from the Cheal and Sidewinder oil and gas fields.

Additional material commitments, changes to production estimates, low oil prices or any acquisitions by the Company may require a source of additional financing or an alteration to the Company's drilling program. Alternatively, certain permits may be farmed-out, sold, relinquished or the Company can request changes to the work commitments included in the permit terms.

NON-GAAP MEASURES

The Company uses certain terms for measurement within this MD&A that do not have standardized meanings prescribed by generally accepted accounting principles ("GAAP"), including IFRS, and these measurements may differ from other companies and accordingly may not be comparable to measures used by other companies. The terms "operating cash flow", "operating netback" and "operating margin" are not recognized measures under the applicable IFRS. Management of the Company believes that these terms are useful to provide shareholders and potential investors with additional information, in addition to profit and loss and cash flow from operating activities as defined by IFRS, for evaluating the Company's operating performance and leverage. References to operating cash flow are to cash revenue less direct operating expenses, which includes operations and maintenance expenses and taxes (other than income and capital taxes) but excludes general and administrative expenses. Operating netback is exclusive of electricity revenue and costs and denotes oil and gas revenue and realized gain (loss) on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses.

Operating Cash Flow ($000s)	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Cash provided by operating activities	**(3,052)**	3,208	8,342	**3,475**	23,293
Changes for non-cash working capital accounts	**1,512**	(1,945)	(4,374)	**(681)**	(1,908)
Operating cash flow	**(1,540)**	1,263	3,968	**2,794**	21,385

Operating Netback ($000s)	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Total revenue	**5,078**	5,712	11,333	**19,796**	40,717
Less royalties	**(485)**	(483)	(1,070)	**(1,773)**	(3,706)
Less transportation and storage	**(902)**	(867)	(1,579)	**(2,977)**	(4,435)
Less total production costs	**(2,221)**	(2,078)	(2,142)	**(6,418)**	(6,333)
Operating Netback	**1,470**	2,284	6,542	**8,628**	26,243

Operating Margin ($000s)	2016		2015	Nine months ended December 31,	
	Q3	Q2	Q3	**2016**	2015
Total revenue	**5,078**	5,712	11,333	**19,796**	40,717
Less royalties	**(485)**	(483)	(1,070)	**(1,773)**	(3,706)
Less transportation and storage	**(902)**	(867)	(1,579)	**(2,977)**	(4,435)
Less total production costs	**(2,221)**	(2,078)	(2,142)	**(6,418)**	(6,333)
Operating margin	**1,470**	2,284	6,542	**8,628**	26,243

OFF-BALANCE SHEET ARRANGEMENTS AND PROPOSED TRANSACTIONS

The Company has no off-balance sheet arrangements or proposed transactions.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments on the Company's balance sheet include cash, accounts receivable and accounts payable. The carrying value of these instruments approximates their fair value due to the short term nature of the instruments. The Company manages its risk through its policies and procedures, but generally has not used derivative financial instruments to manage risks other than managing electricity pricing risk through hedges that approximate electricity consumption for third parties.

RELATED PARTY TRANSACTIONS

As required under IAS 24, related party transactions include compensation paid to the Company's CEO, COO, Chairman, and CFO as well as to the remaining board of directors (the "Board") as part of the ordinary course of the Company's business. The Company reports that no related party transactions have occurred during the reporting period other than ongoing compensation as disclosed in the table below.

The Company is of the view that the amounts incurred for services provided by related parties approximates what the Company would incur to arms-length parties for the same services. Compensation paid to key management is as follows:

	2016		2015	Nine months ended	
($000s)	**Q3**	Q2	Q3	**2016**	2015
Share-based compensation	**(59)**	238	279	**911**	499
Management wages and director fees	**226**	245	873	**702**	1,388
Total Management Compensation	**167**	483	1,112	**1,613**	1,887

SHARE CAPITAL

a. At December 31, 2015, there were 62,212,252 common shares outstanding.
b. At February 15, 2016, there were 62,212,252 common shares outstanding and there are 4,280,000 stock options outstanding, of which 2,680,000 have vested.

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

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

SUBSEQUENT EVENTS

Electricity generation and retailing segment

Coronado has received the requisite shareholder and TSX-V approvals for the OHL Sale Acquisition, and is currently in the process of completion.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of the consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these consolidated financial statements.

Areas of judgment that have the most significant effect on the amounts recognized in these consolidated financial statements are recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities and functional currency.

Key sources of estimation uncertainty that have the most significant effect on the amounts recognized in these consolidated financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities, determination of the fair values of stock-based compensation and assessment of contingencies.

Recoverability, impairment and fair value of oil and gas properties

Fair values of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves, oil and gas prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material. The fair value of properties is determined based on cost and supported by the discounted cash flow of reserves based on anticipated work program. The net present value uses a discount rate of 10% and costs are determined on the anticipated exploration program, forecast oil prices and contractual price of natural gas along with forecast operating and decommissioned costs. A discount rate of 10% has been used in determining the net present value of oil and gas properties.

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing unless the recoverable amount based on value in use can be estimated for an individual asset. The determination of the Company's CGUs is based on separate business units for electricity generation, retail, and producing oil and gas fields with petroleum mining permits granted including associated infrastructure on the basis that field investment decisions are made based on expected field production and all wells are dependent on the field infrastructure.

Each CGU or asset is evaluated for impairment to ensure the carrying value is recoverable. Management looks at the discounted cash flows of capital development, income, production, reserves, and field life and asset retirement obligations of the CGU or asset in assessing the recoverable amount of the CGU or asset. A discount rate of 10% is applied to the assessment of the recoverable amount.

The decision to transfer exploration and evaluation assets to property, plant and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves. The calculation of decommissioning liabilities includes estimates of the future costs to settle the liability, the timing of the cash flows to settle the liability, the risk-free rate and the future inflation rates. The rates used to calculate decommissioning liabilities are an inflation rate of 1.6% and a risk free discount rate of 2.75%, which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

Income taxes

The calculation of income taxes requires judgment in applying tax laws and regulations, estimating the timing of the reversals of temporary differences, and estimating the reliability of deferred tax assets. These estimates impact current and deferred income tax assets and liabilities, and current and deferred income tax expense (recovery).

Share-based compensation

The calculation of share-based compensation requires estimates of volatility, forfeiture rates and market prices surrounding the issuance of share options. These estimates impact share-based compensation expense and share-based payment reserve.

Functional currency

The determination of a subsidiary's functional currency often requires significant judgment where the primary economic environment in which they operate may not be clear. This can have a significant impact on the consolidated results of the Company based on the foreign currency translation methods used.

Contingencies

Contingencies are resolved only when one or more events transpire. As a result, the assessment of contingencies inherently involves estimating the outcome of future events.

BUSINESS RISKS AND UNCERTAINTIES

The Company, like all companies in the international oil and gas sector, is exposed to a variety of risks which include title to oil and gas interests, the uncertainty of finding and acquiring reserves, funding and developing those reserves and finding storage and markets for them. In addition there are commodity price fluctuations, interest and exchange rate changes and changes in government regulations. The oil and gas industry is intensely competitive and the Company must compete against companies that have larger technical and financial resources. The Company works to mitigate these risks by evaluating opportunities for acceptable funding, considering farm-out opportunities that are available to the Company, operating in politically stable countries, aligning itself with joint venture partners with significant international experience and by employing highly skilled personnel. The Company also maintains a corporate insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts and other operating accidents and disruptions. The oil and gas industry is subject to extensive and varying environmental regulations imposed by governments relating to the protection of the environment and the Company is committed to operate safely and in an environmentally sensitive manner in all operations.

There have been no significant changes in these risks and uncertainties in the quarter ended December 31, 2015. Please also refer to Forward Looking Statements.

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

New Accounting Standards and Recent Pronouncements

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

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

Future Changes in Accounting Policies

Certain pronouncements were issued by the IASB or the International Financial Reporting Interpretations Committee ("IFRIC") but not yet effective as at December 31, 2015. The Company intends to adopt these standards and interpretations when they become effective. The Company does not expect these standards to have an impact on its financial statements. Pronouncements that are not applicable to the Company have been excluded from those described below.

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

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

Management's Report on Internal Control over Financial Reporting

Disclosure controls, procedures, and internal controls over financial reporting.

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting. Any system of internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

There have been no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

The following pertains to the Company's MD&A for the quarter ended December 31, 2015, confirming that the Company is in compliance with disclosure controls and procedures and internal controls over the financial reporting period:

The Company's management, with the participation of its Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, the Company's disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed by the Company in reports it files is recorded, processed, summarized and reported, within the appropriate time periods. Required information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

The Company's management, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Board, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with IFRS. The Company's internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets and liabilities of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2015. In making the assessment, it used the criteria set forth in the Internal Controls Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on their assessment, management has concluded that, as of December 31, 2015, the Company's internal control over financial reporting was effective based on those criteria.

Additional information relating to the Company is available on Sedar at www.sedar.com.

FORWARD LOOKING STATEMENTS

The MD&A contains forward-looking statements within the meaning of securities laws, including the "safe harbour" provisions of Canadian securities legislation. Forward-looking statements and information concerning anticipated financial performance are based on management's assumptions using information currently available. Material factors or assumptions used to develop forward-looking information include drilling programs and results, facility and pipeline construction operations and enhancements, potential business prospects, growth strategies, the ability to add production and reserves through development and exploration activities, the ability to reduce costs and extend commitments, projected capital costs, government legislation, well performance, the ability to market production, the commodity price environment and quality differentials and exchange rates. Management also assumes that the Company will continue to be able to maintain permit tenures in good standing, that the Company will be able to access equity capital when required and that the Company will maintain access to necessary oil and gas industry services and equipment to conduct its operations. Although management considers its assumptions to be reasonable based on these factors, they may prove to be incorrect.

Forward-looking information is often, but not always, identified by the use of words such as “anticipate”, “assume”, “believe”, “estimate”, “expect”, “forecast”, “guidance”, “may”, “plan”, “predict”, “project”, “should”, “will”, or similar words suggesting future outcomes. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: oil and natural gas production estimates and targets; statements regarding BOE/d production capabilities; anticipated revenue from oil and gas fields; converting the undiscovered resource potential to proved reserves; completing announced exploration acquisitions and other activities; capital expenditure programs and estimates; plans to drill additional wells; resource potential of unconventional plays; plans to grow baseline reserves, production, and cashflow in Taranaki; pursuing high-impact exploration on deep Kapuni Formation and Offshore prospects in Taranaki; and other statements set out herein”.

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

The forward-looking statements contained herein are as of December 31, 2015, and are subject to change after this date. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive and as such undue reliance should not be placed on forward-looking statements. Except as required by applicable securities laws, with the exception of events or circumstances that occurred during the period to which the MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking information for a period that is not yet complete that was previously disclosed to the public, the Company disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

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

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

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

The significant positive factors that are relevant to the estimate contained in the independent resource assessment are:

- proven production in close proximity;
- proven commercial quality reservoirs in close proximity; and
- oil and gas shows while drilling wells nearby.

The significant negative factors that are relevant to the estimate contained in the independent resource assessment are:

- tectonically complex geology could compromise seal potential; and
- seismic attribute mapping in the permit areas can be indicative but not certain in identifying proven resource.

Certain information in this MD&A may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to areas with similar geological characteristics to the lands held by the Company. Such information is derived from a variety of publicly available information from government sources, regulatory agencies, public databases or other industry participants (as at the date stated therein) that the Company believes are predominantly independent in nature. The Company believes this information is relevant as it helps to define the reservoir characteristics in which the Company may hold an interest. The Company is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor and in accordance with the COGE Handbook. Such information is not an estimate of the reserves or resources attributable to lands held or to be held by the Company and there is no certainty that the reservoir data and economics information for the lands held by the Company will be similar to the information presented therein. The reader is cautioned that the data relied upon by the Company may be in error and/or may not be analogous to the Company's land holdings.

Disclosure provided herein in respect of BOE (barrels of oil equivalent) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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

CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Toby Pierce
CEO and Director
Vancouver, British Columbia

Alex Guidi
Chairman and Director
Vancouver, British Columbia

Keith Hill, Director
Key Largo, Florida

Ken Vidalin, Director
Vancouver, British Columbia

Brad Holland, Director
Calgary, Alberta

Henrik Lundin, Director
Oslo, Norway

Chris Ferguson, CFO
New Plymouth, New Zealand

Max Murray, NZ Country Manager
New Plymouth, New Zealand

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

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REGIONAL OFFICE

New Plymouth, New Zealand

BANKER

Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL

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

AUDITORS

De Visser Gray LLP
Chartered Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT

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

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

SHARE LISTING

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

SHAREHOLDER RELATIONS

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

SHARE CAPITAL

At February 15, 2016, there were 62,212,252 shares issued and outstanding.
Fully diluted: 66,492,252 shares.

WEBSITE

www.tagoil.com

SUBSIDIARIES

TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Cheal Petroleum Limited
Trans-Orient Petroleum Ltd.
Orient Petroleum (NZ) Limited
Eastern Petroleum (NZ) Limited
Coronado Resources Ltd. (49%)
Opunake Hydro Limited (49%)

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