NEW ZEALAND ENERGY CORP.

Third Quarter 2013
Management's Discussion and Analysis

September 30, 2013

(Expressed in Canadian Dollars)

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements of New Zealand Energy Corp. ("NZEC" or the "Company") for the year ended December 31, 2012, and the unaudited condensed consolidated interim financial statements for the period ended September 30, 2013, as publicly filed on the System for Electronic Document Analysis and Retrieval ("SEDAR") website at www.sedar.com.

NZEC reports in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and the following disclosure, and associated unaudited condensed consolidated interim financial statements, are presented in accordance with IFRS. This MD&A is prepared as of November 25, 2013 and includes certain statements that may be deemed "forward-looking statements". All amounts are in Canadian dollars unless otherwise noted.

NZEC's shares are listed on the TSX Venture Exchange under the symbol "NZ" and on the OTCQX International Exchange under the symbol "NZERF". Additional information is available on SEDAR and on the Company's website at www.newzealandenergy.com.

DESCRIPTION OF BUSINESS

NZEC, through its wholly-owned subsidiaries (collectively "NZEC" or "the Company") is engaged in the exploration, development and production of oil and natural gas resources in New Zealand. The Company's major assets are located in the Taranaki Basin and East Coast Basin of New Zealand's North Island.

In the Taranaki Basin, NZEC controls 159,864 acres across three Petroleum Mining Licenses ("PMLs") and three Petroleum Exploration Permits ("PEPs"). The Company holds a 100% interest in PEP 51150 (the "Eltham Permit"), a 65% interest in PEP 51151 (the "Alton Permit") in partnership with L&M Energy Limited ("L&M"), and a 60% interest in PEP 54867 (the "Manaia Permit") in partnership with New Zealand Oil & Gas Limited. NZEC is the operator of all three PMLs and all three PEPs.

Effective October 28, 2013, NZEC acquired a 50% interest in strategic upstream and midstream assets in the Taranaki Basin from Origin Energy Resources NZ (TAWN) Limited, a wholly-owned subsidiary of Origin Energy Limited (collectively "Origin"). The acquisition included PML 38138 (the "Tariki License"), PML 38140 (the "Waihapa License") and PML 38141 (the "Ngaere Permit), (collectively, the "TWN Licenses"), as well as the Waihapa Production Station and associated gathering and sales infrastructure (collectively, the "TWN Assets"). NZEC is the operator of the TWN Licenses and the TWN Assets in accordance with a joint arrangement entered into with L&M to explore, develop and operate the TWN Licenses and the TWN Assets ("TWN Joint Arrangement"). See *Acquisition of Interest in Upstream and Midstream Assets.*

NZEC has drilled ten exploration wells in the Taranaki Basin and advanced four wells to production, and is in the process of reactivating oil production from six wells that were drilled by a previous operator. Two additional wells are pending further evaluation of the installation of artificial lift, and results are pending from one well.

In the East Coast Basin, NZEC holds a 100% interest in PEP 52694 (the "Castlepoint Permit") and a 100% interest in PEP 38342 (the "Ranui Permit"), will hold a 100% interest in PEP 52976 (the "East Cape Permit") pending the grant of that permit by New Zealand Petroleum & Minerals ("NZPAM"), and will hold an 80% interest in PEP 38346 (the "Wairoa Permit") pending NZPAM approval. NZEC is considering relinquishing the Ranui Permit, but has not yet made a definitive decision in that regard. The application for the East Cape Permit is uncontested and the Company expects the permit to be granted by year-end 2013. NZEC has entered into a binding agreement with Westech Energy New Zealand ("Westech"), a wholly-owned subsidiary of Energy Corporation of America, to acquire 80% ownership and become operator of the Wairoa Permit. Preliminary approval of transfer of ownership was obtained from NZPAM on December 20, 2012 and formation of a joint arrangement with Westech is subject to final NZPAM approval.

APPROACH TO BUSINESS

New Zealand offers a unique opportunity to develop hydrocarbon resources in multiple underexplored onshore and offshore sedimentary basins. All of the current production in the country is derived from the Taranaki Basin in conventional targets using mostly vertical wells and limited enhanced technology. Despite highly prospective geology and more than 50 years of oil and gas production from significant onshore and offshore discoveries, New Zealand remains vastly underexplored. All of the wells drilled in the past 60 years are equivalent in number to approximately two weeks of vigorous drilling activity in western Canada. With its stable geopolitical setting and supportive fiscal regime, favourable government policies and tremendous resource potential, New Zealand offers an exciting oil and gas development opportunity, with the benefit of Brent crude oil pricing.

NZEC has chosen to focus its activities in New Zealand and has developed a business model with four main steps: identifying high-quality assets on trend with oil and gas producing fields and executing strategic acquisitions or farm-in agreements; developing local partnerships through open communication and collaboration; prioritizing production and exploration opportunities that are close to infrastructure, allowing for rapid tie-in of production upon success; and growing reserves, production and cash flow with oil-focused exploration success.

As part of its commitment to developing local partnerships, in February 2012 NZEC entered into a Cooperation Agreement with Te Runanga o Ngati Ruanui Trust ("TRoNRT"), an iwi (tribe) located in South Taranaki near NZEC's Eltham and Alton permits. Under the terms of the agreement, TRoNRT will support NZEC's exploration, development and production activities within the Ngati Ruanui area and NZEC will contribute to positive cultural, economic and social outcomes for the development of Ngati Ruanui and its communities. NZEC is working closely with Ngati Ruanui as exploration and development proceeds in the Taranaki Basin, and also communicates regularly with a number of iwi groups in the East Coast Basin to discuss the Company's exploration and development plans.

NZEC's near-term exploration and production activities are focused in the Taranaki Basin, which offers production potential from five drill-proven formations. NZEC's Taranaki exploration permits are on trend with numerous oil and gas producing fields that have been producing for decades, including NZECs recently acquired TWN Licenses which have historically produced in excess of 23 million barrels of oil. NZEC's Taranaki exploration strategy is to prioritize low-cost high-reward production opportunities in existing wells drilled by previous operators, followed by drilling of new wells based on analysis of 3D seismic data. NZEC's exploration activities in the near-term will be focused in the Tikorangi and Mt. Messenger formations. Exploration of the deeper Kapuni formation, which has been highly productive on offsetting permits, is expected to be undertaken with a joint venture partner to reduce NZEC's expenditure risk.

In the East Coast Basin, 300 oil and gas seeps have been sourced back to two oil shale formations, the Waipawa and the Whangai. Historical exploration in the basin has been focused on conventional Miocene sands sitting above the oil shales. NZEC's goal is to unlock the potential of the oil shale formations using modern technology. The Company is actively seeking a joint venture partner to participate in exploration and development of NZEC's East Coast permits.

NZEC is committed to meeting the highest environmental and safety standards and bringing long-term benefits to the communities in which it works.

FINANCIAL SNAPSHOT

	Nine months ended September 30, 2013	Three months ended September 30, 2013	Nine months ended September 30, 2012	Three months ended September 30, 2012
Production	60,694 bbl	11,958 bbl	155,285 bbl	37,850 bbl*
Sales	63,852 bbl	14,648 bbl	154,533 bbl	38,565 bbl
Price	107.63 $/bbl	108.84 $/bbl	107.33 $/bbl	100.93 $/bbl
Production costs	62.08 $/bbl	44.80 $/bbl	25.22 $/bbl	32.58 $/bbl
Royalties	4.98 $/bbl	5.14 $/bbl	4.98 $/bbl	4.77 $/bbl
Field netback	40.57 $/bbl	58.90 $/bbl	77.13 $/bbl	63.58 $/bbl
Revenue	$6,553,968	$1,519,010	$13,527,930	$3,708,254
Pre-production recoveries	-	-	-	-
Total comprehensive (loss) income	($3,339,589)	$1,347,788	$98,313	($2,018,634)
Net finance expense (income)	$66,794	$27,220	($200,003)	41,377
(Loss) earnings per share – basic and diluted	($0.06)	($0.02)	($0.01)	($0.02)
Current assets	$6,403,134		$49,680,292	
Total assets	$105,313,813		$98,882,087	
Total long-term liabilities	$11,094,916		$2,042,768	
Total liabilities	$12,749,253		$6,518,365	
Shareholders' equity	$92,564,560		$92,263,722	

Note: The abbreviation **bbl** means barrel or barrels of oil.

At the date of this MD&A, the Company had an estimated $6 million in working capital.

Nine-month Operating Results

During the nine-month period ended September 30, 2013, the Company produced 60,694 barrels of oil and sold 63,852 barrels for total oil sales of $6,872,180 with an average oil sale price of $107.63 per barrel. Total recorded production revenue, net of a 5% royalty payable to the New Zealand Government (an average of $4.98 per barrel), was $6,553,968. Production costs during the nine-month period ended September 30, 2013 totalled $3,964,141, or an average of $62.08 per barrel, generating an average field netback of $40.57 per barrel during the period. NZEC calculates the netback as the oil sale price less fixed and variable production costs and a 5% royalty. The notable reduction in netback during the nine-month period ended September 30, 2013, when compared to the same period in 2012, is predominantly the result of decreased oil production, considering the large proportion of fixed production cost. As previously announced, the Company had shut in the Waitapu-2 well during May 2013 in order to gather critical data for a Mt. Messenger reservoir study and to evaluate and install artificial lift. In addition, the Company experienced lower production from the Copper Moki wells as partial work-over activities were undertaken on two of the three wells.

The Company undertook a number of reservoir and production tests during the period with the objective of optimizing oil production, and these tests added to production costs. During the nine-month period ended September 30, 2013, fixed production costs represented approximately 88% of total production costs. Installation of the Copper Moki surface facilities was completed in May and, as expected, this resulted in a reduction in production costs for the Copper Moki site since June 2013. Although shutting in the Waitapu-2 well in May 2013 reduced some of the fixed operating costs, the Company continued to incur costs on that site. However, the field netback improved significantly for the quarter ended September 30, 2013 compared to the quarter ended June 30, 2013, as outlined in *Three-month Operating Results*.

Three-month Operating Results

During the three-month period ended September 30, 2013, the Company produced 11,958 barrels of oil and sold 14,648 barrels for total oil sales of $1,594,302, with an average oil sale price of $108.84 per barrel. Total recorded production revenue, net of a 5% royalty payable to the New Zealand Government (an average of $5.14 per barrel), was $1,519,010. Production costs during the three-month period ended September 30, 2013 totalled $656,264, or an average of $44.80 per barrel, generating an average field netback of $58.90 per barrel during the period.

As discussed in *Nine-month Operating Results*, reduced production following the shut-in of Waitapu-2 and work-overs on the Copper Moki-1 and Copper Moki-3 wells greatly impacted the nine-month netback results. A significant reduction in production costs on the Copper Moki site in the third quarter resulted in a marked increase in the netback results reported for the three months ended September 30, 2013, with the netback improving from $22.46/bbl during the quarter ended June 30, 2013 to $58.90/bbl during the quarter ended September 30, 2013.

RECENT DEVELOPMENTS

Subsequent to the period end, NZEC completed a strategic acquisition, assumed joint control of the acquired assets and commenced the work required to reactivate oil production in six wells drilled by the previous operator; booked additional reserves and resources related to the acquisition; closed an oversubscribed private placement for gross proceeds of $16.1 million; and made a number of changes to its New Zealand senior management team.

Acquisition of Interest in Upstream and Midstream Assets

On October 28, 2013, the Company closed the acquisition of strategic upstream and midstream assets (the "Acquisition") from Origin. The Acquisition was originally announced on May 31, 2012 and is described in more detail in Note 2 to the Condensed Consolidated Interim Financial Statements for the quarter ended September 30, 2013. NZEC now owns, through its wholly-owned subsidiaries, a 50% interest in the Tariki, Waihapa and Ngaere PMLs ("TWN Licenses") in the main Taranaki Basin production fairway, as well as a 50% interest in the Waihapa Production Station and associated gathering and sales infrastructure (collectively, "TWN Assets"). NZEC and L&M acquired the assets jointly and formed a 50/50 joint arrangement ("TWN Joint Arrangement") to explore and develop the TWN Licenses and operate the TWN Assets, with NZEC as the operator.

The purchase price for the Acquisition was $33.7 million in cash, with $30 million payable to Origin and $3.7 million (NZ$4.25 million) payable to Contact Energy Limited ("Contact"), a subsidiary of Origin. The Company paid a $5 million deposit to Origin for the Acquisition in June 2012 and a further $1 million deposit in August 2013. The remaining $27.7 million was paid on closing, of which $18.25 million was contributed by L&M and $9.45 million was contributed by NZEC. The TWN Joint Arrangement will also pay Origin a 9% net revenue royalty on all future hydrocarbon production from the TWN Licenses, and can reduce the royalty at any time by as much as 4% by paying Origin $4.25 million per percentage point. The TWN Licenses are also subject to a "grandfathered" NZPAM 10% net revenue royalty.

The Company, through its wholly-owned subsidiaries, entered into a formal joint operating agreement with L&M (the "JOA") regarding the TWN Licenses. The JOA governs the relationship between the joint owners for the exploration, appraisal, development and production work on the TWN Licenses, and defines the joint owners' respective rights, interests and obligations in respect of such work, as well as any oil and gas produced from the TWN Licenses. Decisions regarding operations will be made by operating committees with equal representation from the Company and L&M, while the Company's subsidiaries have been appointed operator of the TWN Licenses. The costs of operations and development are shared equally by L&M and the Company. The JOA sets out the rights of the parties to conduct certain activities on a sole risk basis if the other party does not wish to participate in that activity, establishes the terms upon which any sole risk oil and gas discovery will be dealt with, and the terms upon which the other party may participate in such discovery. The JOA sets out how the parties will deal with defaults under the agreement, including suspension of rights, deemed withdrawal from the JOA and the applicable TWN Licenses, and transfer of the defaulting party's interest in the applicable TWN Licenses to the other party.

The Company, through a wholly-owned subsidiary, also entered into a shareholder's agreement (the "Shareholder's Agreement") with L&M Coal Seam Gas Limited, a wholly-owned subsidiary of L&M, with respect to equal ownership of the shares of NZEC Ngaere Limited. NZEC Ngaere Limited is the general partner of the TWN Limited Partnership, which manages and operates the TWN Assets. The costs and benefits of such operations are paid and received equally by both parties in accordance with their respective interests in the TWN Limited Partnership. The limited partnership agreement and the Shareholder's Agreement set out how the parties will deal with dispute resolution, defaults and termination of the respective agreements. Decisions regarding operations will be made by management committees with equal representation from both companies.

TWN Limited Partnership also operates Contact's Ahuroa Gas Storage Facility ("AGS"), located in the Contact-owned permit adjacent to the TWN Assets. Contact pays TWN Limited Partnership a monthly operating fee of NZ$201,000.

Results of TWN Operations Since Closing

The Company took joint control of the TWN Licenses and TWN Assets on October 28, 2013. The Company immediately commenced the work required to reactivate oil production from six existing wells that had been drilled by a previous operator and produced oil from the Tikorangi Formation. The reactivation activities are proceeding as expected. Production results will be released once all six wells have commenced production, which is anticipated to occur by the end of November 2013.

TWN Reserves and Resources

Concurrent with closing of the Acquisition, NZEC booked reserves and resources related to the TWN Licenses. The TWN reserves and resources, as outlined below, are in addition to the Company's existing reserves attributable to its Eltham Permit, and to the resources attributable to its Eltham, Alton, Castlepoint, Ranui and pending East Cape permits.

NZEC commissioned Deloitte LLP (formerly AJM Deloitte) to prepare a reserve estimate and economic evaluation for the Tikorangi formation on the TWN Licenses, along with a resource evaluation for the Urenui, Mt. Messenger, Moki and Kapuni formations. The estimates and evaluations were prepared in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities with an effective date of April 30, 2013. On October 28, 2013, the Company filed an Interim Statement of Reserves and Resources under National Instrument 51-101.

Marketable Oil and Gas Reserves Attributable to New Zealand Energy Corp.
Waihapa and Ngaere Petroleum Mining Licenses
As at April 30, 2013
Forecast Prices and Costs

Reserves Category	Light & Medium Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Barrels Oil Equivalent (Mboe)
Proved Developed (Non-producing)	492	381	13	569
Proved Undeveloped	129	103	4	150
Total Proved	**621**	**484**	**17**	**719**
Probable	305	240	8	354
Proved + Probable	**926**	**724**	**25**	**1,072**

Notes:

(1) Reserves are presented net of the Company's working interest share before the deduction of royalty obligations payable to the New Zealand government.

(2) Mbbl – thousand barrels. MMcf – million cubic feet. Mboe – thousand barrels of oil equivalent using a conversion ratio of 6 Mcf : 1 bbl. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. The boe conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the

actual remaining quantities recovered will exceed the estimated proved reserves. Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. See Cautionary Note Regarding Reserve and Resource Estimates.

(4) Numbers may not sum due to rounding.

Net Present Value of Future Net Revenue Attributable to New Zealand Energy Corp.
Waihapa and Ngaere Petroleum Mining Licenses
Before Tax
As at April 30, 2013
Forecast Prices and Costs

	Net Present Value of Future Net Revenues Before Tax, Discounted at % per year						
Reserves Category	**0% ($'000)**	**5% ($'000)**	**8% ($'000)**	**10% ($'000)**	**15% ($'000)**	**20% ($'000)**	**Unit Value 10% ($/boe)**
Proved Developed (Non-producing)	27,216	21,828	19,424	18,071	15,339	13,277	31.78
Proved Undeveloped	5,937	4,584	3,995	3,670	3,029	2,558	24.48
Total Proved	**33,153**	**26,412**	**23,419**	**21,741**	**19,368**	**15,835**	**30.26**
Probable	22,261	13,949	11,101	9,697	7,248	5,700	27.41
Proved + Probable	**55,414**	**40,316**	**34,520**	**31,438**	**25,615**	**21,535**	**29.32**

Note: Numbers may not sum due to rounding

Oil and Gas Resources Attributable to New Zealand Energy Corp.
Waihapa and Ngaere Petroleum Licenses
As at April 30, 2013

	Mboe		
Resource Category	**Low**	**Best**	**High**
Contingent Resources	277	580	1,225
Prospective Resources	5,327	11,706	27,422
Discovered Petroleum Initially in Place (PIIP)	764	1,488	2,945
Undiscovered Petroleum Initially in Place (PIIP)	15,573	31,978	69,390

Notes:

(1) Oil resources restricted to the Miocene sands (Urenui, Mt. Messenger and Moki formation with an assumed P50 recovery of between 9 and 14%. Natural gas and natural gas liquids resources restricted to the Kapuni Group with an assumed P50 recovery of 50%. See Cautionary Note Regarding Reserve and Resource Estimates.

(2) Mboe – thousand barrels of oil equivalent using a conversion ratio of 6 Mcf : 1 bbl. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. The boe conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. PIIP – Petroleum Initially In Place.

Private Placement

On October 28, 2013, the Company closed a $16.1 million non-brokered private placement, raising $1.1 million more than the original objective of $15 million. Of the funds raised, $8.2 million was earmarked for financing costs and general working capital while the remainder was used to finance the Acquisition.

The Company issued 48.9 million subscription receipts ("Subscription Receipts") at a price of $0.33 per Subscription Receipt. The Subscription Receipts were convertible into units (the "Units") consisting of one common share (a "Share") and one-half of one non-transferable share purchase warrant (each whole warrant referred to as a "Warrant") of the Company. Each Warrant will entitle the holder to acquire one Share at a price of $0.45 with an expiry date of October 28, 2014.

NZEC filed a short form prospectus with the applicable regulatory authorities in each of the provinces of Canada where Subscription Receipts were sold. On November 21, 2013, following final receipt for the prospectus by the applicable regulatory authorities, each Subscription Receipt converted into one Unit and the Shares and the Shares underlying the Warrants became free-trading. In relation to the private placement, NZEC paid $1 million in finder's fees and issued three million finder's special warrants, which converted into finder's warrants on November 21, 2013. Each finder's warrant entitles the finder to acquire one Share at an exercise price of $0.33 with an expiry date of October 28, 2014. The Shares underlying the finder's warrants will be free-trading on exercise of the finder's warrants.

Changes to Senior Management

The Company has made a number of changes to its New Zealand leadership team. With the Acquisition complete and well reactivations proceeding as planned, NZEC is set to significantly increase its exploration and production activities. Clarifying roles and responsibilities in New Zealand has refocused and streamlined the team.

New Zealand Leadership Team

- Chris Bush – New Zealand Country Manager
- Gerrie van der Westhuizen – Interim Chief Financial Officer
- Mike Oakes – General Manager Operations
- Bruce McIntyre – Director and Acting General Manager Exploration
- Ian Brown – General Manager Development & Corporate Affairs
- Susan Baas – Legal Counsel

Chris Bush was appointed New Zealand Country Manager in October 2012. Chris is an experienced oil and gas professional with more than 30 years of experience in both upstream and downstream sectors. Prior to joining NZEC he was employed by Origin Energy as New Zealand Country Manager/Director. As NZEC's New Zealand Country Manager, Chris leads the New Zealand team in all relevant activities, including delivery of the work programs and budgets, as well as health and safety performance.

Gerrie van der Westhuizen joined NZEC in November 2012 as Vice President Finance and was appointed Interim Chief Financial Officer in October 2013. Gerrie is a Chartered Accountant with considerable experience in the resource industry. As Interim Chief Financial Officer, Gerrie is responsible for all aspects of the Company's financial management and reporting. Gerrie is supported by a New Zealand based accounting team and Newton Cockerill, who was appointed Financial Controller in October 2013.

Mike Oakes joined NZEC in August 2012 as General Manager Midstream Operations. In his new role as General Manager Operations, Mike will oversee all of NZEC's exploration and production activities and operation of the Waihapa Production Station. Mike has worked in the oil and gas industry for 33 years overseeing design, commissioning and start up, staffing and operation of both onshore and offshore oil and gas fields and production facilities. Most recently Mike worked for Origin Energy in New Zealand as Operations Manager, Asset Manager and Operational Excellence Advisor.

Bruce McIntyre, in addition to his role as Director of NZEC (which he has performed since January 2011), has been appointed to the role of Acting General Manager Exploration. Bruce is a professional geologist with more than 30 years of oil and gas experience. As Acting General Manager Exploration Bruce will oversee the Company's technical activities, working with the Wellington-based technical team to de-risk drill targets and expand the Company's drilling inventory, manage permitting and reporting activities, and identify new opportunities in New Zealand's petroleum basins.

Ian Brown, Chief Operating Officer of the Company since March 2011, has assumed the role of General Manager Development & Corporate Affairs. Ian is a chartered professional engineer with more than 25 years of geological consulting experience in New Zealand. In his new role, Ian will be responsible for community engagement and government relations, compliance with environmental regulations, and overseeing the resource consent and land access agreement process. Ian is also responsible for implementing the Company's East Coast strategy and is actively seeking strategic partners to fund exploration and development of NZEC's East Coast Basin permits.

Susan Baas joined NZEC in February 2013 as Legal Counsel and has since been appointed an officer of the Company. Susan has both a Bachelor and Master of Law and initially worked as a solicitor in private practice in New Zealand for five years. In 2004 Susan moved into an in-house corporate law position, taking on progressively senior roles with Contact Energy until joining NZEC in 2013. As Legal Counsel, Susan will provide legal support, oversee corporate governance and regulatory compliance, and assist with commercial negotiations and contract drafting and administration.

The Company has also appointed Dan MacDonald as Drilling Manager, commencing November 25, 2013. Dan is a mechanical engineer with an MBA and more than 30 years of oil and gas drilling experience. Reporting to the General Manager Operations, Dan will be responsible for all drilling and completion work, including design, approvals and implementation of the drilling program.

Cliff Butchko, General Manager Upstream Operations, and Celeste Curran, Vice President Corporate and Legal Affairs, will both be leaving NZEC at the end of December to pursue new opportunities.

PROPERTY REVIEW

Taranaki Basin

The Taranaki Basin is situated on the west coast of the North Island and is currently New Zealand's only oil and gas producing basin, with total production of approximately 130,000 barrels of oil equivalent per day ("boe/d") from 18 fields. Within the Taranaki Basin, NZEC holds a 100% interest in the Eltham Permit, a 65% interest in the Alton Permit in joint arrangement with L&M, a 60% interest in the Manaia Permit in joint arrangement with NZOG, and a 50% interest in the TWN Licenses and the TWN Assets in joint arrangement with L&M. The Eltham Permit covers approximately 93,166 acres (377 km^2) of which approximately 31,877 acres (129 km^2) are offshore in shallow water. The Company has lodged an application to convert 18.73 km^2 of the Eltham Permit into a PMP, as outlined in *Application for Eltham Petroleum Mining Permit*, and to extend the Eltham Permit for another five years to allow for continued exploration. In November 2013, NZEC extended the Alton Permit for a second five-year term, and was required to relinquish 50% of the permit as part of the extension. The new Alton Permit covers approximately 59,565 onshore acres (241 km^2). The Manaia Permit covers approximately 27,426 onshore acres (111 km^2) and was granted to NZEC and NZOG in December 2012 as part of the annual New Zealand block offer for exploration permits. The TWN Licenses cover approximately 23,049 onshore acres (93 km^2).

<u>Production</u>

TWN Licenses

Following closing of the Acquisition, the Company immediately proceeded with the work required to reactivate oil production in six wells, drilled by the previous operator. The Company has entered each of the wells by wireline to ensure that the tubing is clear and has installed well head meters to allow the Company to monitor oil and gas production rates on a well-by-well basis.

The Company has commenced reactivation of production in a number of wells using an existing gas lift system. The reactivations are proceeding as planned. Information regarding oil and gas production rates will be released once all six wells have commenced production, which is expected to occur by the end of November 2013.

Eltham Permit

At the date of this MD&A, two of the Company's four commercially producing wells are in active production. The Waitapu-2 well is currently shut-in awaiting further work-over to complete the installation of artificial lift, with the expectation that production will resume before year-end 2013. During the quarter, the Company also temporarily shut-in its Copper Moki-1 well to replace rods, while the Copper Moki-3 well is currently undergoing maintenance on its down-hole pump. The Eltham Permit wells produce light ~41^{o} API oil from the Mt. Messenger formation. Oil is trucked to the Shell-operated Omata tank farm and sold at Brent pricing. Cumulatively to October 28, 2013, the Company has produced approximately 271,671 barrels of oil from its Eltham Permit wells, with cumulative pre-tax oil sales of approximately $29.2 million, including sales from oil produced during testing (net results of operations are discussed under *Results of Operations*). The Company is not yet generating cash flows from extracted gas, since the rich gas being produced from NZEC's Copper Moki wells requires blending to meet the specifications required to sell the gas in New Zealand. NZEC intends to blend its Copper Moki natural gas with gas produced from the reactivated TWN License wells, and anticipates that the blended gas will meet the required specifications for sale, allowing NZEC to begin generating cash flows from its natural gas and associated natural gas liquids production before year-end 2013.

<u>Application for Eltham Petroleum Mining Permit</u>

During the quarter ended June 30, 2013, the Company lodged an application with NZPAM to convert 4,628 acres (18.73 km^2) on the Eltham Permit into a PMP with an initial duration of 15 years. The land included in the PMP application comprises the Copper Moki field and surrounding acreage with petroleum discoveries. Once the request has been reviewed and approved, NZEC will relinquish 50% of the remainder of the Eltham Permit (which will have been reduced by the area converted to a PMP) as part of the Company's application to extend the permit for its second five-year term to September 23, 2018.

<u>Alton Permit Extended</u>

On November 6, 2013, the Company announced receipt of approval to extend the Alton Permit for a second five-year term to September 23, 2018. Concurrent with the extension, the Company and L&M relinquished 50% of the Alton Permit. The new permit area comprises 59,565 acres (241 km^2). The Company and L&M also received an extension to the obligation to drill a commitment well on the Alton Permit. The new work program requires the Company to drill two exploration wells, process 20 km^2 of 3D seismic and 20 km of 2D seismic, and complete a number of technical studies and reports. The Company plans to drill the first commitment well (the Horoi well) targeting the Mt. Messenger formation in late February 2014.

East Coast Basin

The East Coast Basin of New Zealand's North Island hosts two prospective oil shale formations, the Waipawa and Whangai, which are the source of more than 300 oil and gas seeps. Within the East Coast Basin, NZEC holds a 100% interest in the Castlepoint Permit, which covers approximately 551,042 onshore acres (2,230 km^2), and a 100% interest in the Ranui Permit, which covers approximately 223,087 onshore acres (903 km^2) and is adjacent to the Castlepoint Permit. NZEC is considering relinquishing the Ranui Permit but has not yet made a definitive decision in this regard. On September 3, 2010, NZEC applied to the Minister of Energy to obtain a 100% interest in the East Cape Permit. The application is uncontested and the Company expects the East Cape Permit to be granted to NZEC upon completion of NZPAM's review of the application. The East Cape Permit covers approximately 1,067,495 onshore acres (4,320 km^2) on the northeast tip of the North Island. In addition, NZEC has entered into a binding agreement with Westech to acquire 80% ownership and become operator of the Wairoa Permit, which covers approximately 267,862 onshore acres (1,084 km^2) south of the East Cape Permit. Preliminary approval of transfer of ownership was obtained from NZPAM on December 20, 2012 and formation of a joint arrangement with Westech is subject to final NZPAM approval.

The Company has completed the coring of two test holes on the Castlepoint Permit. The Orui (125 metres total depth) and Te Mai (195 metres total depth) collected core data across the Waipawa and Whangai shales. NZEC also completed a test hole on the Ranui Permit. Ranui-2 was drilled to 1,440 metres, coring the Whangai shale across several intervals. In Q2-2012, NZEC completed 70 line km of 2D seismic data across the Castlepoint and Ranui permits to further its technical understanding of the area and identify targets for exploration.

The Wairoa Permit has been actively explored for many years, with extensive 2D seismic data across the permit and log data from more than 15 wells drilled on the property. Historical exploration focused on the conventional Miocene sands. NZEC's technical team has identified conventional opportunities as well as potential in the unconventional oil shales that underlie the property. NZEC's team knows the property well and provided extensive consulting services (through the consulting company Ian R Brown Associates) to previous permit holders, assisting with seismic acquisition and interpretation, well-site geology and regional prospectivity evaluation. In addition, NZEC's team assisted with permitting and land access agreements and worked extensively with local district council, local service providers, land owners and iwi groups, allowing the team to establish an excellent relationship with local communities. During Q1-2013 the Company completed a 50 km 2D seismic program on the property, the results of which are currently being processed and reviewed and will help to identify exploration targets on the permit.

OUTLOOK

Completing the acquisition of the TWN Licenses and TWN Assets has been transformative for NZEC, resulting in a fully integrated upstream/midstream company with the cash flow, infrastructure and inventory to support long-term growth.

Taranaki Basin

Closing the Acquisition, which has added a full-cycle production facility to the Company's infrastructure, will allow NZEC to optimize the development of all of its Taranaki Basin permits. As NZEC continues to explore the Eltham and Alton permits, the Company will focus on drill targets that are close to the Waihapa Production Station and associated pipelines, allowing for rapid and cost effective tie-in of both oil and gas production.

The Company anticipates that the TWN wells will initially produce oil at higher rates as a result of flush production, and then flow rates will gradually decline to stabilized rates. Based on data collected using well meters, the Company will identify the two best-performing wells and will install high-volume electric submersible pumps ("ESPs") to further increase production. The ESPs will be installed once flow rates have stabilized, with the expectation of installing the first ESPs in Q1-2014.

The Company announced its initial development plans for the TWN Licenses and other permits in the Taranaki Basin on August 6, 2013. As outlined in the Company's Taranaki Basin development program, NZEC anticipates that successful execution of the work program planned for 2013 and 2014 will result in NZEC producing 2,300 boe/d (82% oil) by year-end 2014, based on the Company's working interest in its various permits. This forecast reflects management's mid-case production assumptions, as outlined in *Forward-looking Information* at the end of this document. The Company continues to refine these plans as production and development work proceeds on the TWN Licenses and in order to reflect:

- A closing date for the Acquisition of October 28, 2013

- Installing the first Tikorangi high-volume lift in Q1-2014
- Drilling the Horoi well on the Alton Permit in Q1-2014

Development and operating costs are to be funded initially by existing working capital and cash flows from production. However, in order to carry out all of the planned development activities, the Company is considering a number of options to increase its financial capacity. These options include increasing cash flow from oil production, additional joint arrangements, commercial arrangements or other financing alternatives.

East Coast Basin

The Company is actively seeking a joint venture partner for its East Coast permits, to participate in and help fund exploration and development in the East Coast Basin.

NZEC has drilled two stratigraphic holes on its 100% working interest Castlepoint Permit and one stratigraphic hole on its 100% working interest Ranui Permit. These three stratigraphic test wells have advanced NZEC's understanding of the Waipawa and Whangai formations. A review of the geochemical and physical properties of the two shale packages, coupled with information from seismic data, has focused NZEC's exploration strategy for the area. The Company is currently considering its plans for the Ranui Permit, including possible relinquishment of the permit.

NZEC has received approval from NZPAM to extend the deadline for drilling the exploration well on the Castlepoint Permit to May 2014. The Company has identified its preferred drill location and continues to work towards obtaining the requisite consents and land access agreements. The Company has met regularly with local communities to discuss its exploration plans.

NZEC completed a 50-km 2D seismic survey on the Wairoa Permit in Q2-2013 and is currently processing the data. The Company will finalize its exploration plans for the permit after reviewing all of the seismic and well log data.

The Company's application for the East Cape Permit is uncontested and NZEC expects the permit to be granted before year-end 2013, at which time the Company will begin planning its exploration plans for the permit.

SUMMARY OF QUARTERLY RESULTS

	2013-Q3 $	2013-Q2 $	2013-Q1 $	2012-Q4 $
Total assets	105,313,813	127,318,182	129,545,992	116,059,939
Exploration and evaluation assets	55,859,632	52,357,470	49,610,922	37,379,726
Property, plant and equipment	26,621,043	26,135,651	25,793,089	23,867,758
Working capital	4,748,797	9,517,742	17,533,636	28,293,845
Revenues	1,519,010	2,109,700	2,925,258	2,948,041
Accumulated deficit	(27,292,947)	(24,616,053)	(22,386,089)	(19,992,243)
Total comprehensive income (loss)	1,347,788	(6,000,775)	1,313,397	(1,333,805)
Basic (loss) earnings per share	(0.02)	(0.02)	(0.02)	(0.02)
Diluted (loss) earnings per share	(0.02)	(0.02)	(0.02)	(0.02)

	2012-Q3 $	2012-Q2 $	2012-Q1 $	2011-Q4 $
Total assets	98,882,087	98,814,102	96,979,923	31,152,804
Exploration and evaluation assets	26,377,188	25,373,718	12,103,712	6,052,699
Property, plant and equipment	16,293,123	8,674,152	8,150,802	5,509,511
Working capital	45,204,695	53,844,035	70,401,191	18,030,398
Revenues	3,708,254	5,910,993	3,908,683	974,517
Accumulated deficit	(17,804,045)	(15,613,594)	(16,548,180)	(16,911,070)
Total comprehensive income (loss)	(2,018,634)	1,317,915	799,032	(1,258,314)
Basic (loss) earnings per share	(0.02)	0.01	0.00	0.01
Diluted (loss) earnings per share	(0.02)	0.01	0.00	0.01

New Zealand Energy Corp. was incorporated on October 29, 2010 under the Business Corporations Act of British Columbia. Upon incorporation, 40,000,000 common shares were granted to certain directors and officers of the Company in lieu of the services performed and substantial financial guarantees provided to assist in obtaining legal rights to the Castlepoint and East Cape exploration permits within the East Coast Basin. The Company then raised seed capital of $7,000,000 upon the subsequent issuance of 28,000,000 common shares in Q4-2010 and Q1-2011 to engage in the exploration, acquisition and development of petroleum and natural gas assets in New Zealand. This financing was followed by another private placement completed in Q1-2011 for gross proceeds of $5,257,500 on the issuance of 7,010,000 common shares. The Company also entered into an agreement in Q1-2011 with Ian R Brown Associates ("IRBA") pursuant to which it would acquire certain assets and provide employment to certain personnel in consideration for $400,000 and the issuance of 2,000,000 common shares. Also in Q1-2011, upon satisfying the conditions of a deed of assignment, the Company took ownership of its Eltham Permit. Further exploration and evaluation expenditures continued on the Eltham Permit throughout fiscal 2011, which ultimately saw the commercialization of the Copper Moki-1 well in Q4-2011. All costs related to the Copper Moki-1 well were transferred to property, plant and equipment in Q4-2011. In Q2-2011, the Company agreed to acquire a 50% interest in the Alton Permit for AUD2,000,000 and fund 100% of the Talon-1 well development costs, which totalled $2,544,131. The Talon-1 well development costs were written off in Q3-2011 due to management's view that the well would not provide any future benefits. In Q2-2011, the Company completed the acquisition of its Ranui Permit for US$1,000,000 and the issuance of 1,000,000 common shares.

In Q1-2012, the Company continued its development plans by drilling the Copper Moki-2 and Copper Moki-3 wells. In addition, the Company entered into an agreement to increase its interest by 15% within the Alton Permit and completed a bought deal financing for gross proceeds of $63.5 million during the first quarter through issuance of 21,160,000 common shares at a price of $3.00/share. During Q2-2012, the Company reached commercial production with Copper Moki-2, initiated testing of Copper Moki-3 and drilled Copper Moki-4. During Q2-2012, the Company also entered into the Origin Agreement with Origin to acquire upstream and midstream assets for $42 million in cash, payable in the US$ equivalent of US$40.6 million applying a fixed C$/US$ exchange rate of 1.0349, and such other adjustments as may be required at closing. A $5 million deposit was paid to Origin. During Q3-2012, the Company reached commercial production with Copper Moki-3, and commenced drilling the first of eight wells planned in the Company's second Eltham/Alton drill program. During Q4-2012 the Company drilled a total of four exploration wells. The Waitapu-2 well reached commercial production towards the end of the quarter. The Waitapu-1 well was suspended pending further evaluation or potential sidetrack. As at the end of Q4-2012, the Company issued a reserve update based on reservoir and production data from the Copper Moki-1, Copper Moki-2, Copper Moki-3 and Waitapu-2 wells, resulting in a 151% increase to 2P reserves compared to year-end 2011. During Q4-2012 the Company also expanded its exploration portfolio by 230,673 net acres and entered into two strategic partnerships; the Company entered into an agreement with Westech to acquire 80% and assume operatorship of the Wairoa Permit in the East Coast Basin, and entered into a joint arrangement with NZOG to explore the Manaia Permit in the Taranaki Basin.

During Q1-2013, following the drilling of three more wells and side-tracking of another, the Company announced that it was delaying the remaining two wells in the Eltham/Alton drill program in order to focus on the commercial opportunities in the pending Acquisition of the TWN Licenses and TWN Assets. During Q2-2013, the Company continued to work towards the completion of the Acquisition, negotiating a revised purchase consideration of $33.7 million with simplified the deal terms (see *Note 2 in the Consolidated Interim Financial Statements*). The Company also entered into the TWN Joint Arrangement with L&M (see *Acquisition of Interest in Upstream and Midstream Assets*). The Company also shut in its Waitapu-2 well while completing a Mt. Messenger reservoir study and evaluating and installing artificial lift. During Q3-2013, the Company continued to produce its Copper Moki wells and continued work-over activities on Waitapu-2 to install artificial lift and surface facilities. The Company met the financing condition precedent related to the Acquisition at the quarter-end and progressed to completion of the Acquisition on October 28, 2013.

Since the Company's inception, general and administrative costs have been incurred to assist in establishing the operating structure, setting up offices in both Canada and New Zealand, securing key personnel and general business development.

RESULTS OF OPERATIONS FOR THE THREE-MONTH PERIOD ENDED SEPTEMBER 30, 2013

Revenue

During the three-month period ended September 30, 2013, the Company produced 11,958 barrels (2012: 37,850 barrels) of oil and sold 14,648 barrels (2012: 38,565 barrels) for total oil sales of $1,594,302 (2012: $3,892,223), or $108.84 per barrel (2012: $100.93). Total recorded revenue was $1,519,010 (2012: $3,708,254), which is accounted for net of royalties of $75,292 (2012: $183,969), or $5.14 per barrel sold (2012: $4.77).

Expenses and Other Items

Production costs during the three-month period ended September 30, 2013 totalled $656,264 (2012: $1,256,361) or $44.80 per barrel (2012: $32.58). The decrease in production costs in Q3-2013 compared to Q3-2012 was due to the installation of the production facilities on the Copper Moki site, while lower quantities of oil were produced than in the comparative period in 2012. During the three-month period ended September 30, 2013, fixed operating costs represented approximately 84% of total production costs, giving rise to lower field netbacks in light of reduced oil production compared to Q3-2012. However, the savings in production costs resulting from the installation of production facilities at the Copper Moki site resulted in significantly reduced production costs and thus much higher field netbacks when compared to Q2-2013.

Depreciation costs incurred during the three-month period ended September 30, 2013 totalled $537,263 (2012: $777,290), or $36.68 per barrel of oil sold (2012: $20.15). Depreciation is calculated using the unit-of-production method by reference to the ratio of production in the period to the related total proved and probable reserves of oil and natural gas, taking into account estimated future development costs necessary to access those reserves. The increase in per barrel depreciation in Q3-2013 is reflective of the additional wells (and therefore additional development costs associated with such wells) that achieved commercial production since Q3-2012.

Stock-based compensation for the three-month period ended September 30, 2013 totalled $531,554 compared to $329,981 during the same period in 2012. The increase in stock-based compensation corresponds to a higher number of stock options granted during the period related to new hires.

General and administrative expenses for the three-month period ended September 30, 2013 totalled $1,132,267 compared to $1,004,070 incurred in the same period in fiscal 2012. The increase in general and administrative costs corresponds to increases in salaries related to new hires, as the Company prepared for the expansion of operations following the Acquisition.

Transaction costs for the three-month period ended September 30, 2013 totalled $861,413 compared to $282,658 incurred in the same period in fiscal 2012. The transaction costs incurred during the period include legal and professional fees incurred in relation to the Acquisition.

Net finance expense for the three-month period ended September 30, 2013 totalled $27,220 compared to a net finance income of $41,377 in the same period in fiscal 2012. Finance expense relates to interest payable on the Company's operating line of credit, and accretion of the Company's asset retirement obligations, presented net of interest earned on the Company's cash and cash-equivalent balances held in treasury and on term deposits.

Foreign exchange loss for the three-month period September 30, 2013 amounted to $174,440 compared to a $1,085,551 loss realized in the same period of fiscal 2012. The foreign exchange loss incurred in the current year is a result of the strengthening of the New Zealand dollar against the US dollar, during a period that the Company's subsidiaries (which have a New Zealand dollar functional currency) held US dollar denominated working capital in anticipation of completing the Acquisition.

Total Comprehensive Loss

Total comprehensive income for the three-month period ended September 30, 2013 totalled $1,347,788 after taking into account a foreign translation reserve gain of $4,047,868 on the translation of foreign operations and monetary items that form part of NZEC's net investment in foreign operations. Total comprehensive loss for the three-month period ended September 30, 2012 was $2,018,634.

Based on a weighted average shares outstanding balance of 121,969,105, the Company realized a $0.02 basic and diluted loss per share for the three-month period ended September 30, 2013. During the three-month period ended September 30, 2012, the Company realized $0.02 basic and diluted loss per share, based on a weighted average share balance of 121,769,105.

RESULTS OF OPERATIONS FOR THE NINE-MONTH PERIOD ENDED SEPTEMBER 30, 2013

Revenue

During the nine-month period ended September 30, 2013, the Company produced 60,694 (2012:132,928) barrels of oil and sold 63,852 (2012: 132,176) barrels for total oil sales of $6,872,180 (2012: $14,186,648), or $107.63 (2012: $107.33) per barrel. Total recorded gross production revenue was $6,553,968 (2012: $13,527,930), which accounted for royalties of $318,212 (2012: $658,718), or $4.98 (2012: $4.98) per barrel sold.

Expenses and Other Items

Production costs during the nine-month period ended September 30, 2013 totalled $3,964,141 (2012: $3,333,122), or $64.20 (2012: $25.22) per barrel sold. Included in production costs are all site-related expenditures, including applicable equipment rental fees, site services, overheads and labour; transportation and storage costs including trucking, testing, tank storage, processing and handling; and port dues as incurred prior to the sale of oil. However, the Company is starting to see the positive effect on production costs of installation of surface facilities as reflected in reduced production costs related to the Copper Moki site since June 2013.

Depreciation costs incurred during the nine-month period ended September 30, 2013 totalled $2,403,543 (2012: $3,219,570), or $37.64 (2012: $24.36) per barrel sold. Depreciation is based on using the unit-of-production method by reference to the ratio of production in the period to the related total proved and probable reserves of oil and natural gas, taking into account estimated future development costs necessary to access those reserves. The increase in per barrel depreciation during the nine-month period ended September 30, 2013 is reflective of the additional wells (and therefore additional development costs associated with such wells) that achieved commercial production since Q3-2012.

Stock-based compensation for the nine-month period ended September 30, 2013 totalled $1,312,011 compared to $1,377,086 during the same period in 2012. The decrease in stock-based compensation corresponds to fewer stock options granted during the period.

General and administrative expenses for the nine-month period ended September 30, 2013 totalled $4,340,863 compared to $3,272,823 incurred in the same period in fiscal 2012. The increase in general and administrative costs corresponds to increases in salaries related to new hires, as the Company prepared for the expansion of operations following the Acquisition.

Transaction costs for the nine-month period ended September 30, 2013 totalled $1,638,738 compared to $483,437 incurred in the same period in fiscal 2012. The transaction costs incurred during the period include legal and professional fees incurred in relation to the Acquisition.

Net finance expense for the nine-month period ended September 30, 2013 totalled $66,794 compared to net finance income of $200,003 in the same period in fiscal 2012. Finance expense relates to interest payable on the Company's operating line of credit, and accretion of the Company's asset retirement obligations, presented net of interest earned on the Company's cash and cash-equivalent balances held in treasury and on term deposits.

Foreign exchange gain for the nine-month period ended September 30, 2013 amounted to $146,902 compared to a $1,730,699 loss realized in the same period of fiscal 2012. The foreign exchange gain incurred in the current year is a result of the weakening of the New Zealand dollar against the US dollar, during a period that the Company's subsidiaries (which have a New Zealand dollar functional currency) held US dollar denominated working capital in anticipation of closing the Acquisition.

Total Comprehensive Income (Loss)

Total comprehensive loss for the nine-month period ended September 30, 2013 totalled $3,339,589 after taking into account a gain on the exchange difference on translation of foreign currency of $3,984,300, which compared to total comprehensive income for the nine-month period ended September 30, 2012 of $98,313.

Based on a weighted average shares outstanding balance of 121,957,383, the Company realized a $0.06 basic and diluted loss per share for the nine-month period ended September 30, 2013. During the period ended September 30, 2012, based on a weighted average shares outstanding balance of 115,513,777, the Company realized a $0.01 basic and diluted loss per share.

PETROLEUM PROPERTY ACTIVITIES, OPERATIONS AND CAPITAL EXPENDITURES FOR THE NINE-MONTH PERIOD ENDED SEPTEMBER 30, 2013

Taranaki Basin

During the nine-month period ended September 30, 2013, the Company incurred $14,162,155 in exploration and evaluation expenditures on its Taranaki Basin permits, which includes well development costs of $9,755,303. Other additions included in the nine-month expenditure are $2,428,742 of overhead costs including stock-based compensation, and $552,685 in capitalized asset retirement provisions. Also during the nine-month period ended September 30, 2013, the Company recorded a positive foreign currency translation adjustment of $1,425,425. The current year net increase in exploration and evaluation expenditures can be attributed to additional exploration costs associated with the Eltham Permit and the Alton Permit of $11,490,117 and $693,928, respectively.

East Coast Basin

During the nine-month period ended September 30, 2013, the Company incurred $619,808 in capitalized exploration costs on the Castlepoint Permit. These exploration costs consist of $3,029 related to well development costs, $486,904 related to overhead costs including stock-based compensation, and positive $129,875 arising from a foreign currency translation adjustment. Cumulative expenditures incurred as of September 30, 2013 relating to the Castlepoint Permit amounted to $3,338,414.

During the nine-month period ended September 30, 2013, the Company incurred $524,796 in capitalized exploration costs on the Ranui Permit, including $78,806 related to well development costs, $183,452 related to overhead costs including stock-based compensation, negative $13,054 related to capitalized asset retirement provisions, and positive $275,592 attributed to a foreign currency translation adjustment. As of September 30, 2013, the Company had incurred $6,596,992 in cumulative capitalized acquisition costs relating to the Ranui Permit.

During the nine-month period ended September 30, 2013, the Company incurred $3,173,147 in capitalized exploration costs on the Wairoa Permit, including $2,801,782 related to the 50-km 2D seismic survey, $293,006 related to overhead costs including stock-based compensation, and positive $78,359 attributed to a foreign currency translation adjustment.

The Company did not capitalize any exploration or acquisition costs relating to the East Cape Permit during the nine-month period ended September 30, 2013.

CAPITAL SPENDING

During the nine-month period ended September 30, 2013, cumulative expenditure of property, plant and equipment increased to $33,833,190 from $28,434,778 in the prior year. Current year expenditures included $5,213,083 for furniture, equipment and fixtures of which $5,124,969 is related to surface equipment and facilities, a reduction of $131,850 for oil and gas properties (due to a change in estimate related to asset retirement costs), an impairment of $275,484 related to land and buildings, a transfer of $720,708 to assets available for sale, and a foreign currency translation and other adjustments of $1,313,371.

During the nine-month period ended September 30, 2013, exploration and evaluation assets increased by $18,479,906 to $55,859,632. The Company incurred $14,162,155 in exploration, evaluation and overhead costs associated with the Taranaki Basin, of which $13,182,216 related specifically to the Eltham Permit and $979,939 related specifically to the Alton Permit. The Company incurred $4,317,751 in exploration, evaluation and overhead costs associated with the East Coast Basin, of which $619,808 related to the Castlepoint Permit, $524,796 related to the Ranui Permit, and $3,173,147 related to the Wairoa Permit.

COMMITMENTS

As at September 30, 2013, the Company had the following undiscounted contractual obligations:

	Less than 1 year	1–3 years	3–5 years	Beyond 5 years	Total
Accounts payable	1,654,000	-	-	-	1,654,000
Operating lease obligations (1)	52,000	428,000	370,000	-	850,000
Contract and purchase commitments (2)	3,289,000	-	-	-	3,289,000
Minimum work program requirements (3)	4,400,000	58,147,000	12,708,000	-	75,055,000
TWN Joint Arrangement (4)	9,450,000	-	-	-	9,450,000
Environmental obligations (5)	-	1,078,000	374,000	2,805,000	4,257,000
Total	**18,845,000**	**59,653,000**	**13,452,000**	**2,805,000**	**94,555,000**

(1) The Company has office leases for its offices in Vancouver, Wellington and New Plymouth.
(2) The Company entered into several management and consulting agreements, some of which relate to services to be rendered in connection with exploration work programs commitments.
(3) The Company has committed to complete certain minimum work program requirements in order to maintain its various resource permits. On November 7, 2013, the Company announced certain amendments to its work program requirements which are reflected in the table above. See *Permit Expenditure Requirements*.
(4) The Company entered into definitive agreements whereby the Company would acquire a 50% working interest in the TWN Joint Arrangement. Under the terms of the various agreements described in Note 2, as at September 30, 2013, the Company was expected to pay $9.45 million towards its 50% interest in the TWN Joint Arrangement. This Acquisition was completed on October 28, 2013 (Notes 2 and 16(b)).
(5) The Company has recognized an undiscounted asset retirement obligation of $4.26 million.

PERMIT EXPENDITURE REQUIREMENTS

The Company undertakes oil and gas exploration and development activities and is contractually committed under various agreements to complete certain exploration activities. The Company may choose to alter the exploration programs, request extensions, reject development costs, relinquish certain permits or farm out its interest in permits, where practical. 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 expenditure would be required.

Maintaining the permits in good standing during the permit term is based on the fulfilment of the minimum work program and is not based on a specific expenditure level. The table below reflects management's estimates of future expenditures required to complete the minimum work programs required to maintain its permits in good standing, as at September 30, 2013.

Properties	2013 $	2014 $	2015 $	2016 $	2017 $	Total $
Taranaki Basin						
Eltham Permit (1)	-	-	-	-	-	-
Alton Permit (2)	-	2,569,000	-	2,321,000	-	4,890,000
	-	2,569,000	-	2,321,000	-	4,890,000
East Coast Basin						
Manaia Permit (3)	-	1,743,000	2,295,000	2,805,000	102,000	6,945,000
Castlepoint Permit (4)	-	21,250,000	15,725,000	-	-	36,975,000
Ranui Permit (5)	4,200,000	100,000	-	-	-	4,300,000
Wairoa Permit (6)	-	7,750,000	-	4,420,000	-	12,170,000
East Cape Permit (7)	-	2,465,000	4,250,000	3,060,000	-	9,775,000
	4,200,000	33,308,000	22,270,000	10,285,000	102,000	70,165,000
Total	**4,200,000**	**35,877,000**	**22,270,000**	**12,606,000**	**102,000**	**75,055,000**

Subsequent to period end, NZEC received approval from NZPAM to extend the commitment to drill exploration wells on its Alton and Castlepoint permits into 2014, while commitments related to the East Cape Permit are also expected to only be incurred in 2014, following grant of that permit to NZEC. The table above reflects these amendments to the relevant work programs. As at the date of this MD&A, NZEC had satisfied all of its work commitments and obligations for 2013, with the exception of the requirement to drill an exploration well on the Ranui Permit. NZEC is considering relinquishing the Ranui Permit.

Notes:

(1) In December 2010 NZEC acquired a 100% working interest in the Eltham Permit, which was granted to the previous permit holder on September 23, 2008 for a five-year term expiring September 22, 2013. In June 2013 the Company lodged an application with NZPAM to convert 4,628 acres (18.73 km^2) on the Eltham Permit, comprising the Copper Moki field and surrounding acreage with petroleum discoveries, into a Petroleum Mining Permit with an initial duration of 15 years. Once that request has been reviewed and approved, the Company will be required to relinquish 50% of the remainder of the Eltham Permit (which will have been reduced by the area converted to a PMP) as part of its application to extend the permit for its second five-year term to September 2018.

(2) The Minister of Energy approved the transfer of a 50% interest in the Alton Permit to the Company on October 4, 2011. In the fourth quarter of 2012 the Company earned an additional 15% interest in the Alton Permit, increasing the Company's interest from 50% to 65%, by funding the collection and processing of 3D seismic data over approximately 50 km^2 of the permit. The Alton Permit was granted to the previous permit holder on September 23, 2008 for a five-year term expiring September 22, 2013. Subsequent to September 30, 2013, the Company (and its partner L&M) received government approval to extend the exploration term to September 23, 2018. Concurrent with the extension, the Company and L&M relinquished 50% of the Alton Permit, bringing the total Alton Permit acreage to 59,565 acres (net 38,717 to NZEC). The Company and L&M also received an extension to their obligation to drill a commitment well, along with approval of a new work program for the Alton Permit. The new work program requires the partners to drill two exploration wells, process 20 km^2 of 3D seismic and 20 line km of 2D seismic, and complete a number of technical studies and reports. The Company plans to drill the first commitment well – the Horoi well – into a Mt. Messenger target commencing in late February 2014.

(3) The Company has entered into a joint arrangement with NZOG whereby the Company obtained a 60% working interest in the Manaia Permit. The permit was granted for a five-year term on December 11, 2012 as part of the 2012 New Zealand block offer. The minimum work program requires the Company to collect and process 70 km of 2D seismic data and to prepare various technical studies within 18 months of the grant date. The Company anticipates commencing activities related to land access and permitting in late 2013.

(4) The Company has a 100% working interest in the Castlepoint Permit. The permit was granted on November 24, 2010 for a five-year term expiring November 24, 2015. Subsequent to September 30, 2013, NZEC received approval from NZPAM to extend the deadline for drilling an exploration well on the Castlepoint Permit to May 2014. The Company continues to work towards obtaining the requisite consents and land access agreements for the Castlepoint Permit drill locations, and has met regularly with local communities to discuss its exploration plans. The Company is also required to drill two additional exploration wells in 2014, and drill two exploration wells and acquire 75km of 2D seismic data in 2015.

(5) The Company has a 100% working interest in the Ranui Permit. The Minister of Energy approved the transfer of the Ranui Permit to the Company on June 27, 2011. The Ranui Permit was granted to the previous permit holder on June 28, 2004, and was subsequently extended to June 27, 2014. The minimum work program requirements for 2013 include drilling an exploration well and the acquisition, processing and interpretation of 30 km of 2D seismic data. The Company is considering its plans for the Ranui Permit, including possible relinquishment.

(6) In the fourth quarter of 2012, the Company entered into a binding agreement with Westech to acquire 80% ownership and become operator of the Wairoa Permit. While acquisition of an 80% interest in the Wairoa Permit is subject to final approval by NZPAM, NZEC assumed all permit obligations when the acquisition was announced in October 2012. Upon approval of the joint arrangement, the minimum work program requirements to maintain the permit in good standing will be confirmed by NZPAM.

(7) The East Cape Permit has not yet been granted. The above reflect expenditures required to complete the expected minimum work program for each year of the permit, once granted. It is expected that the minimum work program will include reprocessing of seismic data, geochemical sampling and technical studies.

The amounts above represent the minimum expenditure requirements for each year necessary to complete the minimum work program and maintain each of the permits in good standing; otherwise, the relevant PEP must be surrendered. A PEP holder may, at the end of the initial five-year term, apply to extend the duration of an exploration permit for a second term for a period not exceeding ten years from the commencement date of the PEP. However, there are some conditions that apply, including relinquishment of 50% of the area comprising the PEP at the time of the end of the first term.

The Company may engage in technical work and exploration and development activities that exceed the minimum work program requirements for some or all of its permits. The activities planned for the permits in 2013 are outlined in the *Outlook* section.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2013 the Company had $2,003,921 in cash and cash equivalents (December 31, 2012: $5,983,121) and $4,748,797 in working capital (December 31, 2012: $28,293,845). Based on the available working capital, management has estimated that the Company has sufficient capital to meet short-term operating requirements. The Company is considering a number of options to increase its financial capacity (including increasing cash flow from oil production, credit facilities, joint arrangements, commercial arrangements or other financing alternatives) in order to meet all required and planned capital expenditures for the next 12 months.

As required under the original terms of the Origin Letter Agreement, during the period ended September 30, 2013, the Company maintained a deposit of US$35,759,159 ($37,469,043) in the Company's name with HSBC New Zealand ("HSBC"). The deposit served as security for an operating line of credit of up to US$34.5 million with HSBC. During the period ended September 30, 2013, the operating line of credit (with a balance of US$29,660,667 including accrued interest) was settled against the term deposit and the Company received the balance of US$6,099,844 into cash and cash equivalents.

The Company's objective is to maintain an adequate capital base in order to maintain financial flexibility and investor confidence, and to sustain the future development of the business. The Company's capital includes share capital and the cumulative deficit. The Company's objective when managing capital is to safeguard its ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Company's objective is met by maintaining adequate equity and working capital to meet future capital expenditure requirements. Due to the nature of the oil and natural gas industry, budgets are reviewed regularly in light of the success of the expenditures and other opportunities which may become available to the Company. To the extent required, the Company's current treasury and funds raised in financing during the period will be used to fund any negative operating cash flows in future periods.

CASH FLOWS

Operating Activities

For the nine-month period ended September 30, 2013, the Company generated a net loss of $7,300,704 (2012: $892,975). Non-cash income statement amounts recorded during the period included $1,312,011 (2012: $1,377,086) in stock-based compensation, $2,486,306 (2012: $3,219,570) in depreciation and accretion, $344,051 in foreign exchange loss (2012: $1,609,314) and 275,484 (2012: $Nil) in impairment loss. Total increase to non-cash working capital items during the period amounted to $1,778,373 (2012: reduction of $1,856,810) for aggregate cash used in operating activities of $1,104,479 (2012: cash provided by operating activities of $4,660,356).

Investing Activities

For the nine-month period ended September 30, 2013, the Company incurred $21,362,049 (2012: $24,559,102) in expenditures on its resource properties. The majority of these costs included the well development activities on the Eltham, Alton and Ranui permits. The Company incurred $137,759 (2012: $135,951) in development of a proprietary database and $4,860,420 (2012: $4,723,271) for the purchase of property and equipment. The Company made deposits of $1,000,000 (2012: $6,087,795). The Company withdrew an outstanding balance of 37,551,728 from term deposit (2012: $Nil). The company deposited $9,432,780 (2012: $Nil) received from subscription receipts in restricted cash. Total cash provided by investing activities for the period was 758,718 (2012: total cash used in investing activities of $35,527,922).

Financing Activities

For the nine-month period ended September 30, 2013, cash used by financing activities was 3,561,103 (2012: cash provided by financing activities of $59,325,205). Cash used from financing activities was the result of settling the outstanding balance of the operating line of credit for a net amount of $11,643,093 (2012: $Nil), the exercise of 200,000 advisor warrants at a price of $1.00 per share (2012: $59,325,205), and $7,881,990 (2012: $Nil) from subscription receipts.

RELATED PARTY TRANSACTIONS

Key Management and Personnel Compensation

The key management personnel include the directors and other officers of the Company. Key management compensation consists of the following:

	Three months ended September 30, 2013 $	Three months ended September 30, 2012 $	Nine months ended September 30, 2013 $	Nine months ended September 30, 2012 $
Salary and management fees	763,362	361,500	2,233,953	1,089,650
Share-based compensation	289,449	757,417	1,241,970	2,155,905
	1,052,811	1,118,917	3,475,923	3,245,555

The above transactions occurred in the normal course of operations and were measured at the consideration established and agreed to by the related parties.

ESCROWED SHARES AND TRADING SUMMARY

Escrowed Shares

In accordance with a lock-up agreement, an escrow agreement and a pooling agreement, 46,394,334 common shares owned or controlled by certain directors and officers of the Company were escrowed at August 3, 2011. The shares will be released over 36 months from August 3, 2011 as follows:

Release Date	Number of Common Shares
August 3, 2011	200,000 (released)
February 3, 2012	300,000 (released)
July 19, 2012	5,853,934 (released)
August 3, 2012	6,773,400 (released)
February 3, 2013	8,851,200 (released)
August 3, 2013	8,851,200 (released)
February 3, 2014	8,851,200
August 3, 2014	6,713,400
Total	**46,394,334**

Trading Summary

	Price Range ($)		
Period	**High**	**Low**	**Volume**
August (4 – 31), 2011	1.39	0.93	3,566,048
September 2011	1.77	1.03	8,765,348
October 2011	1.24	0.95	3,715,769
November 2011	1.10	0.93	2,670,892
December 2011	1.18	0.91	4,339,356
January 2012	1.78	1.08	11,879,904
February 2012	3.79	1.60	26,680,505
March 2012	3.45	2.79	14,666,716
April 2012	3.19	2.39	13,108,060
May 2012	2.90	2.16	9,855,900
June 2012	2.09	1.52	6,837,600
July 2012	1.98	1.61	5,311,600
August 2012	2.39	1.54	6,944,900
September 2012	2.18	2.04	4,998,700
October 2012	2.15	1.59	7,368,000
November 2012	1.74	1.15	7,313,900
December 2012	1.48	1.23	3,376,500
January 2013	1.41	0.78	10,806,663
February 2013	0.86	0.33	10,634,364
March 2013	0.70	0.40	3,999,444
April 2013	0.53	0.32	4,941,571
May 2013	0.49	0.30	7,092,560
June 2013	0.47	0.34	4,383,749
July 2013	0.41	0.32	4,188,172
August 2013	0.35	0.20	7,327,789
September 2013	0.44	0.30	9,470,753
October 2013	0.47	0.32	8,223,348
November 1 - 25, 2013	0.42	0.28	5,483,777

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not have any off-balance sheet arrangements.

ADOPTION OF NEW OR REVISED IFRSs

The Company adopted the following new International Financial Reporting Standards with an effective date of January 1, 2013:

IFRS 10 – Consolidated Financial Statements

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statements* ("IFRS 10"), which replaces IAS 27 *Consolidated and Separate Financial Statements* and SIC-12 *Consolidation – Special Purpose Entities*. IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. The Company has determined that there is no impact on its consolidated interim financial statements arising from this standard.

IFRS 11 – Joint Arrangements

In May 2011, the IASB issued IFRS 11 *Joint Arrangements* ("IFRS 11"), which replaces IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-monetary Contributions by Venturers*. IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. The Company has determined that there is no impact on its consolidated interim financial statements arising from this standard.

IFRS 12 – Disclosure of Interests in Other Entities

In May 2011, the IASB issued IFRS 12 *Disclosure of Interests in Other Entities* ("IFRS 12"), which establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities. The Company has determined that there is no impact on its consolidated interim financial statements arising from this standard; however, additional disclosures may be included in the Company's annual consolidated financial statements.

NON-IFRS DISCLOSURES

NZEC uses certain terms for measurement within this MD&A that do not have standardized meanings prescribed by IFRS, and these measurements may differ from other companies' and accordingly may not be comparable to measures used by other companies. The term "field netback" is not a recognized measure under the applicable IFRSs. Management of the Company believes that this measure is 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. Field netback is reconciled as follows to the Company's condensed consolidated interim financial statements for the periods ended September 30, 2013 and 2012:

	Nine Months Ended September 30, 2013 $	Three Months Ended September 30, 2013 $	Nine Months Ended September 30, 2012 $	Three Months Ended September 30, 2012 $
Revenue				
Oil sales	6,872,180	1,594,302	14,186,648	3,892,223
Royalties	(318,212)	(75,292)	(658,718)	(183,969)
	6,553,968	1,519,010	13,527,930	3,708,254
Production costs	(3,964,141)	(656,264)	(3,333,122)	(1,256,361)
Subtotal (a)	**2,589,827**	**862,746**	**10,194,808**	**2,451,893**
Barrels of oil sold (b)	63,852	14,648	132,176	38,565
Field netback [(a)/(b)]	**40.57**	**58.90**	**77.13**	**63.58**

SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of voting common shares. As at September 30, 2013, the Company had 121,969,105 common shares outstanding.

As of the date of this MD&A, the Company's share capitalization included 170,873,459 common shares, 24,452,173 warrants, 3,045,849 finders' warrants and 9,574,700 stock options, of which 6,898,050 stock options have vested and are exercisable.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal controls 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.

Management has overseen the design and evaluation of internal controls over financial reporting and has concluded that the design and operation of these internal controls over financial reporting were effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

RISK FACTORS

Natural resources exploration and development involves a number of risks and uncertainties, many of which are beyond management's control. The Company's business is subject to the risks normally encountered in the oil and natural gas industry such as the marketability of, and prices for, oil and natural gas, competition with companies having greater resources, acquisition, exploration and production risks, need for capital, fluctuations in the market price and demand for oil and natural gas, the regulation of the oil and natural gas industry by various levels of government and public protests. The success of further exploration or development projects cannot be assured. In addition, the Company's operations are primarily outside of Canada and are subject to risks arising from foreign exchange and foreign regulatory regimes.

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking information and forward-looking statements within the meaning of applicable securities legislation (collectively "forward-looking statements"). The use of any of the words "will", "intend", "objective", "become", "transforming", "potential", "continuing", "pursue", "subject to", "look forward", "unlocking" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such forward-looking statements should not be unduly relied upon. The Company believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. This document contains forward-looking statements and assumptions pertaining to the following: business strategy, strength and focus; the granting of regulatory approvals; the timing for receipt of regulatory approvals; geological and engineering estimates relating to the resource potential of the properties; the estimated quantity and quality of the Company's oil and natural gas resources; supply and demand for oil and natural gas and the Company's ability to market crude oil and natural gas; expectations regarding the Company's ability to continually add to reserves and resources through acquisitions and development; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the Company's ability to raise capital on appropriate terms, or at all; the ability of the Company's subsidiaries to obtain mining permits and access rights in respect of land and resource and environmental consents; the recoverability of the Company's crude oil, natural gas reserves and resources; and future capital expenditures to be made by the Company. Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in the document, such as the speculative nature of exploration, appraisal and development of oil and natural gas properties; uncertainties associated with estimating oil and natural gas resources; changes in the cost of operations, including costs of extracting and delivering oil and natural gas to market, that affect potential profitability of oil and natural gas exploration; operating hazards and risks inherent in oil and natural gas operations; volatility in market prices for oil and natural gas; market conditions that prevent the Company from raising the funds necessary for exploration and development on acceptable terms or at all; global financial market events that cause significant volatility in commodity prices; unexpected costs or liabilities for environmental matters; competition for, among other things, capital, acquisitions of resources, skilled personnel, and access to equipment and services required for exploration, development and production; changes in exchange rates, laws of New Zealand or laws of Canada affecting foreign trade, taxation and investment; failure to realize the anticipated benefits of acquisitions; and other factors. Readers are cautioned that the foregoing list of factors is not exhaustive. Statements relating to "reserves and resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources described can be profitably produced in the future. This document includes references to management's forecasts of future development, probability of success, production and cash flows from such operations, which represent management's best estimates at the time. The major assumptions applied by management include the following:

Tikorangi Reactivations (Gas Lift / High Volume Lift)

Reserves (unrisked @ 100% working interest)	150,000 bbl/well – 448,000 bbl/well
Working interest	50%
Probability of success	100%
IP rate	49 boe/day – 365 boe/day**
Decline	2% – 0.5% per month

Mt. Messenger – Uphole Completion in Existing Tikorangi Wells

EUR (unrisked @ 100% working interest)	123,000 bbl/well*
Working interest	50%
Probability of success	100%
IP rate	365 boe/day**
Decline	3% – 9% per month

Mt. Messenger Development (incl. Horoi)

EUR (unrisked @ 100% working interest)	502,000 bbl/well
Working interest	50% – 65%
Probability of success	35% – 40%
IP rate	420 boe/day – 511 boe/day**
Decline	2% per month

Tikorangi New Wells

EUR (unrisked @ 100% working interest)	561,000 bbl/well***
Working interest	50%
Probability of success	50%
IP rate	1824 boe/day**
Decline	5% – 12% per month

Kapuni New Wells

EUR (unrisked @ 100% working interest)	7.97 Bcf
Working interest	25%
Probability of success	60%
IP rate	1,013 boe/day**
Decline	1% per month

*EUR = Estimated Ultimate Recovery (management derived)
**IP rate = Estimated initial production rate
***Deloitte LLP has ascribed 2P reserves (100% basis) of 410,300 bbl of oil to one Tikorangi New well

The forward-looking statements contained in the document are expressly qualified by this cautionary statement. These statements speak only as of the date of this document and the Company does not undertake to update any forward-looking statements that are contained in this document, except in accordance with applicable securities laws.

CAUTIONARY NOTE REGARDING RESERVE AND RESOURCE ESTIMATES

The oil and gas reserves calculations and income projections were estimated in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGEH") and National Instrument 51-101 ("NI 51-101"). The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf: one bbl was used by NZEC. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates. Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Revenue projections presented are based in part on forecasts of market prices, current exchange rates, inflation, market demand and government policy which are subject to uncertainties and may in future differ materially from the forecasts above. Present values of future net revenues do not necessarily represent the fair market value of the reserves evaluated. The report also contains forward-looking statements including expectations of future production and capital expenditures. Information concerning reserves may also be deemed to be forward looking as estimates imply that the reserves described can be profitably produced in the future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause the actual results to differ from those anticipated. Contingent resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. Prospective resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from undiscovered accumulations. The resources reported are estimates only and there is no certainty that any portion of the reported resources will be discovered and that, if discovered, it will be economically viable or technically feasible to produce.