NEW ZEALAND ENERGY CORP.

Management's Discussion and Analysis

Year Ended December 31, 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, 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 consolidated financial statements, are presented in accordance with IFRS. This MD&A is prepared as of April 30, 2014 and includes certain statements that may be deemed "forward-looking statements" (see *Forward-looking Information*). 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 subsidiaries (collectively "NZEC" or "the Company") is engaged in the production, exploration and development of conventional and unconventional oil and natural gas resources in New Zealand, as well as the operation of the midstream assets in which the Company holds a working interest. The Company's assets are located in the Taranaki Basin and East Coast Basin of New Zealand's North Island.

In the Taranaki Basin, NZEC holds 97,637 net acres across three Petroleum Mining Licenses ("PMLs") and two Petroleum Exploration Permits ("PEPs"). NZEC is the operator of all of the PMLs and PEPs. Following a strategic acquisition in October 2013 ("TWN Acquisition"), NZEC holds a 50% interest in the Waihapa Production Station, PML 38138 (the "Tariki License"), PML 38140 (the "Waihapa License") and PML 38141 (the "Ngaere License") (collectively the "TWN Licenses") with L&M Energy Limited ("L&M"). NZEC also holds a 100% interest in PEP 51150 (the "Eltham Permit") and a 65% interest in PEP 51151 (the "Alton Permit") with L&M. NZEC has advanced 12 wells to production in the Taranaki Basin – four on the Eltham Permit and eight on the TWN Licenses – and expects to advance additional wells to production in 2014.

In the East Coast Basin, NZEC holds 1,813,741 net acres across three PEPs. The Company holds a 100% interest in PEP 52694 (the "Castlepoint Permit"), a 100% interest in in PEP 52976 (the "East Cape Permit") and an 80% interest in PEP 38346 (the "Wairoa Permit") with Westech Energy New Zealand ("Westech"). To date the Company has focused on advancing its technical understanding of the East Coast oil shales, and is now looking for a farm-in partner to fund the drilling of exploration wells in the East Coast Basin.

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.

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 NZEC and L&M's 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 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, many of the basin's 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 farm-in 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. 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.

The Company often forms joint arrangements with other oil and gas companies to advance its properties. These partnerships reduce NZEC's operating and capital risk, while bringing additional technical expertise and New Zealand operating insight. To date, the Company has formed joint arrangements with L&M Energy Limited and Westech Energy New Zealand, and forged a strong relationship with New Zealand Oil & Gas. NZEC is actively seeking farm-in partnerships to advance its East Coast permits, along with its Eltham and Alton permits in the Taranaki Basin.

FINANCIAL SNAPSHOT

	For the quarter ended December 31, 2013		For the year ended December 31, 2013	For the year ended December 31, 2012	For the year ended December 31, 2011
Production	16,790 bbl		77,484 bbl	162,444 bbl	11,623 bbl
Sales	13,968 bbl		77,820 bbl	162,077 bbl	9,567 bbl
Price	115.77 $/bbl		109.09 $/bbl	106.71 $/bbl	106.83 $/bbl
Production costs	43.39 $/bbl		58.73 $/bbl	31.57 $/bbl	23.44 $/bbl
Royalties	10.53 $/bbl		5.98 $/bbl	5.06 $/bbl	4.96 $/bbl
Field netback	61.84 $/bbl		44.38 $/bbl	70.08 $/bbl	78.43 $/bbl
Revenue	4,108,911		10,662,879	16,475,971	974,517
Pre-production recoveries	-		-	2,449,231	950,440
Total comprehensive loss	(5,963,723)		(9,303,312)	(1,235,492)	(6,655,829)
Finance income (expense)	(30,804)		(97,598)	211,511	119,583
Loss per share - basic and diluted	(0.06)		(0.12)	(0.03)	(0.08)
Current assets	15,147,197		15,147,197	49,137,637	19,293,345
Total assets	116,782,687		116,782,687	116,059,939	31,152,804
Total long-term liabilities	7,068,585		7,068,585	2,598,840	120,429
Total liabilities	15,337,630		15,337,630	23,442,632	1,383,376
Shareholders' equity	101,445,057		101,445,057	92,617,307	29,769,428

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

At the date of this MD&A, the Company had an estimated $2.7 million in working capital.

Fourth Quarter Operating Results

During the three-month period ended December 31, 2013, the Company produced 16,790 bbl and sold 13,968 bbl for total oil sales of $1,617,139, with an average oil sale price of $115.77 per barrel. Total recorded production revenue, net of a 5% royalty payable to the New Zealand Government (an average of $105.24 per bbl), was $1,470,005. Production costs during the three-month period ended December 31, 2013 totalled $606,153 or an average of $43.39 per bbl, generating an average field netback of $61.84 per bbl during the period.

As discussed in *Annual Operating Results*, oil production decreased following the shut-in of Waitapu-2 and workover activities on the Copper Moki-1 and Copper Moki-3 wells. Within one month of completion of the TWN Acquisition, however, the Company was able to reactivate oil production from six existing Tikorangi wells on the TWN Licences, for total production during the quarter of 7,584 bbl net to NZEC. This resulted in an overall increase in production (total 16,790 bbl) compared to the previous quarter (total 11,958 bbl). The field netback also increased during the quarter as a result of increased oil production coupled with reduced production costs at the Copper Moki site. The Company achieved an overall field netback of $61.84 per bbl for the three months ended December 31, 2013, compared to $58.90 per bbl during the previous quarter ended September 30, 2013.

Annual Operating Results

During the year ended December 31, 2013, the Company produced 77,484 bbl and sold 77,820 bbl for total oil sales of $8,489,319 with an average oil sale price of $109.09 per bbl. Total recorded production revenue, net of a 5% royalty payable to the New Zealand Government (an average of $103.11 per barrel), was $8,023,973. Production costs during the period ended December 31, 2013 totalled $4,570,294, or an average of $58.73 per bbl, generating an average field netback of $44.38 per bbl during the period. NZEC calculates the field netback as the oil sale price less fixed and variable production costs and the effective royalties (see *Non-IFRS Disclosures*). The reduction in field netback during the year ended December 31, 2013, when compared to the same period in 2012, is predominantly due to the result of decreased oil production from the Eltham Permit, considering the large proportion of fixed production costs associated with the Eltham Permit. The Company 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 a result of workover activities on two of the three wells. The decrease in production from the Eltham Permit, however, was offset by oil production from the reactivation of six wells on the TWN Licenses, in which the Company holds a 50% interest.

The Company undertook a number of reservoir and production tests during 2013 with the objective of optimizing oil production, and these tests added to production costs. During the year ended December 31, 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.

SIGNIFICANT DEVELOPMENTS

In the fourth quarter of 2013, NZEC completed the TWN Acquisition, assumed joint control of the acquired assets and reactivated oil production in six wells drilled by previous operators; booked additional reserves and resources related to the TWN Acquisition; closed an oversubscribed private placement for gross proceeds of $16.1 million; completed its acquisition of an 80% interest in the Wairoa Permit; extended the exploration period for the Alton Permit and the Eltham Permit; and relinquished the Ranui Permit.

Subsequent to year-end, NZEC advanced three additional wells to production on the TWN Licenses and recommenced production from one well on the Eltham Permit. The Company has also made a number of changes to its New Zealand senior management team, released an updated reserve estimate and relinquished its interest in the Manaia Permit.

Initial development plans for the TWN Licenses included drilling a crestal well to access oil reserves attributed to the Tikorangi Formation. The TWN JA has determined that the crestal well will not be drilled in 2014. Drilling the Tikorangi crestal well was integral to NZEC achieving its year-end 2014 production guidance. With the Tikorangi well deferred, NZEC has made the decision to retract is year-end 2014 production guidance, as previously announced on August 6, 2013.

Acquisition of Interest in Upstream and Midstream Assets

On October 28, 2013, the Company closed the acquisition of strategic upstream and midstream assets (the "TWN Acquisition") from Origin Energy Resources NZ (TAWN) Limited, a wholly-owned subsidiary of Origin Energy Limited (collectively "Origin"). NZEC now owns, through its 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 JA") to explore and develop the TWN Licenses and operate the TWN Assets, with NZEC as the operator.

The purchase price for the TWN Acquisition was $33.7 million in cash, with $30 million paid to Origin and $3.7 million paid to Contact Energy Limited ("Contact"), a subsidiary of Origin. The Company had previously 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 JA will also pay Origin a 9% net revenue royalty on all future hydrocarbon production from the TWN Licenses. That royalty can be reduced at any time by up to 4% by paying Origin $4.25 million per percentage point. The TWN Licenses are also subject to a "grandfathered" 10% net revenue royalty payable to New Zealand Petroleum & Minerals ("NZPAM").

Concurrent with closing of the TWN Acquisition, NZEC booked additional reserves and resources attributable to the TWN Licences, increasing the Company's Proved plus Probable (2P) reserves by 150% and bringing additional contingent and prospective resources to NZEC. The Company's reserves estimate was subsequently updated at year-end 2013, as outlined in *Reserve Update*. Additional information regarding the Company's reserves is available in the Company's Form 51-101F1 Statement of Reserves Data dated April 2, 2014, which is filed on SEDAR at www.sedar.com.

The entity in which the TWN Assets are held (the "TWN Limited Partnership") also operates Contact's Ahuroa Gas Storage Facility ("AGS"), located in the Contact-owned permit adjacent to the TWN Assets. In exchange, the TWN Limited Partnership receives a monthly operating fee from Contact of NZ$200,000.

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 TWN 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 the Company's Property Portfolio

In December 2013, the Company received final approval from NZPAM to acquire 80% ownership of the Wairoa Permit from Westech. NZEC had entered into a binding agreement with Westech in October 2012 to acquire an 80% interest and become operator of the Wairoa Permit, paying Westech US$725,000 and assuming responsibility for the work program. The Wairoa Permit covers 267,862 acres (1,084 km^2) in the East Coast Basin. Unlike other areas of the East Coast Basin, the Wairoa Permit has had some modern exploration, with more than 500 km of 2D seismic data across the permit and log data from 16 wells drilled on the property.

In December 2013, NZEC also announced the decision to focus its East Coast Basin exploration efforts on the Wairoa, Castlepoint and East Cape permits, and to relinquish the Ranui Permit.

As part of its objective to increase production while reducing costs, NZEC is focusing its Taranaki Basin exploration efforts on advanced properties with near-term production potential. As a result, in April 2014, NZEC and New Zealand Oil & Gas made the decision to relinquish the early-stage Manaia Permit in the Taranaki Basin. NZEC held a 60% interest in the permit, with New Zealand Oil & Gas holding the other 40%.

The Company has been granted extensions to two of its Taranaki Basin exploration permits. NZEC and L&M were granted a second five-year exploration term for the Alton Permit, extending the permit to September 23, 2018. As part of the extension, NZEC and L&M were required to relinquish 50% of the permit acreage, resulting in the current configuration of 59,565 onshore acres (241.1 km^2). NZEC was also granted a second five-year exploration term for its Eltham Permit, extending the permit to September 23, 2018. As part of that process, NZEC relinquished 50% of the permit area. The Company has also lodged an application with NZPAM to convert 939 acres (3.8 km^2) of the Eltham Permit into a petroleum mining permit ("PMP") with an initial duration of 15 years. The land included in the PMP application comprises the Copper Moki and Waitapu fields. The total acreage of the current Eltham Permit, including the area that will be separated into the PMP, is 47,387 acres (191.8 km^2), of which approximately 2,029 acres (24.4 km^2) is offshore.

Changes to Senior Management

David Robinson has been hired to the new position of Chief Executive Officer of the Company's New Zealand business. He will commence his employment on May 19, 2014, and will also join NZEC's Board of Directors at that time. Mr. Robinson has been CEO of the Petroleum Exploration and Production Association of New Zealand ("PEPANZ") since December 2012. As CEO of PEPANZ, Mr. Robinson made a significant contribution to New Zealand's oil and gas industry, managing key stakeholder relationships, representing the interests of oil and gas producers, explorers and service companies, and contributing to the development of government policies and legislation. Prior to joining PEPANZ, Mr. Robinson was Commercial General Manager for Z Energy, was a Director of Shell New Zealand, and held a number of senior downstream commercial positions with Shell both within New Zealand and overseas.

Derek Gardiner joined NZEC in January 2014 as Chief Financial Officer. Mr. Gardiner is a New Zealand Chartered Accountant and Chartered Secretary with both a Bachelor and Master of Business Studies and more than 25 years of experience in the oil and gas industry in New Zealand, Australia and Asia. He has held senior financial, business planning and accounting positions and brings strong leadership skills and experience in managing joint venture arrangements.

Chris Bush, New Zealand Country Manager, Cliff Butchko, General Manager Upstream Operations, and Celeste Curran, Vice President Corporate and Legal Affairs, left NZEC at the end of December 2013 to pursue new opportunities. In March 2014, NZEC announced that Bruce McIntyre and Ian Brown would take early retirement from their respective roles of Acting General Manager of Exploration and General Manager Development & Corporate Affairs. Mr. McIntyre remains a member of the Board of Directors. Susan Baas, General Counsel, will be leaving NZEC in May to join an established law firm in Wellington, New Zealand.

The Company has taken significant steps to reduce overhead, consolidating its New Plymouth premises into one office in New Plymouth, and eliminating a number of consulting and employment positions. NZEC continues to review its corporate structure and staffing requirements with the objective of reducing overhead and streamlining the Company.

PROPERTY REVIEW

Taranaki Basin

The Taranaki Basin is situated on the west coast of New Zealand's North Island and is currently the country'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 with L&M, and a 50% interest in the TWN Licenses and the TWN Assets with L&M. The Eltham Permit currently covers 47,387 acres (191.8 km^2), of which approximately 2,029 acres (24.4 km^2) is offshore. The Company has lodged an application with NZPAM to convert 939 acres (3.8 km^2) of the Eltham Permit into a PMP. When approved, the Eltham Permit acreage will be reduced by the size of the PMP. The Alton Permit covers approximately 59,565 onshore acres (241 km^2). The TWN Licenses cover approximately 23,049 onshore acres (93 km^2).

NZEC is actively seeking farm-in partners for its Eltham and Alton permits, with the intention that the farm-in partner would fund the drilling of high-priority targets on the properties in return for an interest in the permits.

The Taranaki Basin offers production potential from multiple prospective formations, ranging from the Kapuni sandstones at a depth of approximately 4,000 metres, the Tikorangi limestones at approximately 3,000 metres, the Moki sandstones at approximately 2,500 metres, and the shallower Mt. Messenger and Urenui sandstones at approximately 2,000 metres. All of NZEC's production to date is from the Tikorangi and Mt. Messenger formations.

Production and Processing Revenue

At the date of this MD&A, the Company had advanced 12 wells to production: four wells on the Eltham Permit and eight wells on the TWN Licenses. The Company's oil production during March 2014 averaged 233 bbl/d net to NZEC (not including production from the Waihapa-8 well). On March 29, 2014 the Waihapa-8 well commenced production, on April 12, 2014 the Toko-2B well recommenced production following installation of high-volume lift, and on April 17, 2014 the Waihapa-2 well commenced production following a successful uphole completion. Production during April 2014 averaged 228 bbl/d net to NZEC. Production from Toko-2B, Ngaere-2 and Ngaere-3 is combined into one single pipe that goes through the B-train separator at the Waihapa Production Station. Ngaere-2 and Ngaere-3 were taken offline on April 12, 2014 to allow for full evaluation of Toko-2B. In addition, the Copper Moki-3 well remains shut-in awaiting installation of a new pump later in Q2-2014. Details regarding the Company's efforts to increase production from existing wells and bring new wells into production are available in the *Outlook* section below.

TWN Licenses

The TWN JA has identified two opportunities for low-cost, near-term production on the TWN Licenses: reactivating oil production from the Tikorangi and Mt. Messenger formations in existing wells that were produced historically, and recompleting existing wells uphole in shallower formations that have not been produced. At the date of this MD&A, the TWN JA had advanced eight wells to production for a total of 43,594 bbl produced since closing of the TWN Acquisition (21,797 bbl net to NZEC), with cumulative pre-tax oil sales net to NZEC of approximately $2,330,664 (net results of operations are discussed under *Results of Operations*). The wells produce light ~41^{o} API oil that is delivered by pipeline to the Waihapa Production Station and then piped to the Shell-operated Omata tank farm, where it is sold at Brent pricing less standard Shell costs.

Following closing of the TWN Acquisition, the TWN JA immediately proceeded with the work required to reactivate oil production from the Tikorangi Formation in six wells drilled by previous operators. On December 2, 2013, NZEC announced that all six wells had been reactivated and were flowing into the Waihapa Production Station. In March 2014, the TWN JA also reactivated oil production from the Mt. Messenger Formation in a well that had been drilled and produced from the Mt. Messenger Formation by a previous operator (Waihapa-8).

The TWN JA continues to evaluate and optimize production from the reactivated wells. As part of the optimization process, in April 2014, the TWN JA installed high-volume lift ("ESP") on one of the reactivated wells (Toko-2B). The ESP was operated initially using a portable generator, which limited the pumping capacity and did not draw down fluid levels in the well. The TWN JA is connecting the Toko-2B high-volume lift to a permanent power source and will gradually increase the pumping rate. The ESP is capable of pumping up to 10,000 barrels of total fluid per day.

A number of wells on the TWN Permits, with previous production from the Tikorangi Formation, have uphole completion potential in the shallower Mt. Messenger Formation. The TWN JA has recompleted one well uphole in the Mt. Messenger Formation (Waihapa-2) and achieved production from that well in April 2014. This successful recompletion confirms that production can be achieved from an uphole reservoir. The TWN JA has identified three more wells with uphole completion potential, and will continue to evaluate these opportunities. One additional well offers production potential from both the Tikorangi and Mt. Messenger formations. The TWN JA is focusing first on reactivating production from the Tikorangi Formation, but will proceed with an uphole completion in the Mt. Messenger Formation if appropriate.

The TWN JA continues to identify opportunities to generate revenue from the Waihapa Production Station and associated infrastructure. Third-party revenue from the Waihapa Production Station since closing the TWN Acquisition totals approximately NZ $687,000 net to NZEC. In addition, during February 2014, the TWN JA entered into an agreement with a gas marketing counterparty to transport gas along a section of the TAW gas pipeline for a term of four years with a five-year right of renewal. The arrangement is expected to generate between NZ$250,000 and NZ$1 million revenue per year (net to NZEC). First gas is expected to flow on May 5, 2014.

Eltham Permit

To date the Company has drilled ten exploration wells on the Eltham Permit. Four have been advanced to production. At the date of this MD&A, the Company has produced approximately 279,842 bbl from its Eltham Permit wells (including oil produced during testing), with cumulative pre-tax oil sales from inception of approximately $31.2 million (net results of operations are discussed under *Results of Operations*). Of the remaining six wells, one well (Copper Moki-4) made an oil discovery in the Urenui Formation and has been shut-in pending additional economic analysis and evaluation of artificial lift options. One well (Arakamu-2) made an oil discovery in the Mt. Messenger Formation and has been shut-in pending evaluation of artificial lift options. One well (Wairere-1A) was drilled to the Mt. Messenger Formation and encountered hydrocarbon shows, with completion pending. Waitapu-1 is shut-in pending further testing or sidetrack to an alternate target and Arakamu-1A, a Moki Formation well, is suspending pending further evaluation. Only one well, Wairere-1, failed to encounter hydrocarbons and was immediately sidetracked.

All of 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 less standard Shell costs. During January 2014, NZEC began delivering natural gas produced from wells on the Copper Moki site through a pipeline to the Waihapa Production Station, where it is blended with gas produced from the TWN Licenses and used by the TWN Partnership to lift the TWN JA reactivated wells and run the Waihapa Production Station compressors. Using internally generated gas for these activities, rather than purchasing it, has significantly reduced operating costs at the Waihapa Production Station and brought modest natural gas revenue to the Company.

<u>Reserves Update</u>

As required under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, the Company commissioned Deloitte LLP to prepare a year-end oil reserve estimate and economic evaluation with an effective date of December 31, 2013. NZEC's Proved + Probable (2P) reserves have increased 145% when compared to the reserves reported at December 31, 2012, reflecting the acquisition of a 50% interest in the TWN Licenses. The reserve estimate and economic evaluation reflects NZEC's 100% interest in the Eltham Permit and its 50% interest in the Waihapa and Ngaere PMLs. Additional information regarding the Company's reserves is available in the Company's Form 51-101F1 Statement of Reserves Data dated April 2, 2014, which is filed on SEDAR.

NZEC also has additional contingent and prospective resources, as outlined in the Company's Interim Statement of Reserves and Resources dated October 28, 2013, which is filed on SEDAR.

Marketable Oil and Gas Reserves Attributable to New Zealand Energy Corp. [1]
As at December 31, 2013
Forecast Prices and Costs

Reserves Category	Light & Medium Oil (bbl) [2]	Natural Gas (Mcf) [3]	Natural Gas Liquids (bbl)	Barrels Oil Equivalent (boe) [4]
Proved				
Developed Producing	517,000	935,000	40,000	713,000
Developed Non-Producing	181,000	554,000	27,000	301,000
Undeveloped	111,000	88,000	3,000	129,000
Total Proved	**809,000**	**1,576,000**	**71,000**	**1,143,000**
Probable	359,000	683,000	34,000	506,000
Proved + Probable	**1,168,000**	**2,260,000**	**104,000**	**1,649,000**

Notes:
(1) Net reserves to NZEC after deduction of royalty obligations payable to the New Zealand government and Origin Energy Resources NZ (TAWN) Limited. Numbers may not sum due to rounding. See Cautionary Note Regarding Reserve Estimates.
(2) bbl – barrels.
(3) Mcf – thousand cubic feet of natural gas.
(4) boe – 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.

Net Present Value of Future Net Revenue Attributable to New Zealand Energy Corp. [1]
After Tax, Discounted at % per year
As at December 31, 2013
Forecast Prices and Costs

Reserves Category	0% ($'000)	5% ($'000)	8% ($'000)	10% ($'000)	15% ($'000)	20% ($'000)	Unit Value 10% ($/boe)
Proved							
Developed Producing	$ 42,349.6	$ 24,786.3	$ 20,986.3	$ 18,452.9	$ 15,261.1	$ 13,286.9	$ 22.42
Developed Non-Producing	14,141.9	20,443.9	19,922.3	19,574.6	17,762.9	16,042.2	57.57
Undeveloped	6,591.4	4,911.0	4,248.2	3,806.3	3,043.8	2,489.1	3.27
Total Proved	**63,082.9**	**50,141.1**	**45,156.8**	**41,833.8**	**36,067.8**	**31,818.2**	**31.84**
Probable	34,266.6	22,110.1	18,487.2	16,072.0	12,556.5	10,264.8	27.76
Proved + Probable	**97,349.5**	**72,251.2**	**63,644.0**	**57,905.8**	**48,624.3**	**42,083.0**	**30.59**

Notes:
(1) Net present value of future net revenue to NZEC after deduction of royalty obligations payable to the New Zealand government and Origin Energy Resources NZ (TAWN) Limited. Numbers may not sum due to rounding.

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 believed to be 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 East Cape Permit which covers approximately 1,048,406 onshore acres (4,243 km^2) on the northeast tip of the North Island. In addition, NZEC holds an 80% working interest in the Wairoa Permit, which covers approximately 267,862 onshore acres (1,084 km^2) south of the East Cape Permit. NZEC is the operator of all three permits.

The Company has completed the coring of two test holes and collected 35 line km of 2D seismic data on the Castlepoint Permit. The Wairoa Permit has been actively explored for many years, with extensive 2D seismic data across the permit and log data from more than 16 wells drilled on the property. Members of NZEC's geological and geophysical team understand the property well and had previously provided extensive consulting services 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 Wairoa Permit.

OUTLOOK

Taranaki Basin

Completing the acquisition of the TWN Licenses and TWN Assets has transformed NZEC into a fully integrated upstream/midstream company. Having a 50% interest in a full-cycle production facility and associated infrastructure should allow NZEC to optimize the development of all of its Taranaki Basin permits. As NZEC continues to explore its Taranaki Basin property portfolio, the Company will focus on developing targets that are close to the Waihapa Production Station and associated pipelines, allowing for accelerated and cost effective tie-in of both oil and gas production.

The majority of the Company's near-term production and exploration efforts will be focused on the TWN Licenses, where existing wells offer low-cost, near-term production potential. The TWN JA has already reactivated production from seven wells and advanced one uphole completion to production. In addition, the TWN JA expects to achieve an increase to production from one well following installation of high-volume lift, and is considering installing high-volume lift in additional wells. The TWN JA continues to review well logs, historical drilling records and seismic data across the TWN Licenses to identify additional opportunities to advance existing wells to production. The TWN JA has identified production potential from both the Tikorangi and Mt. Messenger formations in additional existing wells, and will continue to evaluate these opportunities. Reactivations and uphole completions are significantly less expensive and faster than drilling new wells, and economic discoveries can often be tied in to the Waihapa Production Station using existing oil and gas gathering pipelines.

During 2014, the Company plans to drill a new exploration well on the Alton Permit. The current work program for the Alton Permit requires the Company to drill an exploration well by June 22, 2014. The Company has applied to NZPAM to extend the deadline by three months to accommodate environmental consulting work. The Company has identified a drill target in the Mt. Messenger Formation and has initiated the community engagement and technical assessments required to obtain land access consents and permits. In addition, new exploration targets in the Mt. Messenger, Tikorangi and Kapuni formations on the TWN Licenses and the Eltham and Alton permits could be drilled in future exploration programs. NZEC is actively seeking farm-in partnerships to advance both its Eltham and Alton permits.

The Company announced its initial development plans for the TWN Licenses and other permits in the Taranaki Basin on August 6, 2013. NZEC and the TWN JA continue to review development plans for the TWN Licenses and have identified new production opportunities in existing wells. As a result, timing of a number of a planned exploration and development activities has shifted. The TWN JA will prioritize low-cost, low-risk opportunities that are expected to bring near-term production and cash flow, and will defer higher-cost, higher-risk operations until the TWN JA has established a strong production and cash flow base.

NZEC believes that optimization efforts can increase production from existing wells. The TWN JA is connecting the Toko-2B high-volume lift to a permanent power source and will gradually increase the pumping rate. The ESP is capable of pumping in excess of 10,000 barrels of total fluid per day. Pumping rates are being gradually increased at the Waihapa-2 well to maximize production. The Waihapa-8 well is currently being produced using an existing gas lift system that was installed by the previous operator, but the TWN JA may consider installing more sophisticated artificial lift. In addition, the Copper Moki-3 well on the Eltham Permit is expected to resume production in Q2-2014 following installation of a new pump. The TWN JA has identified four additional production opportunities in existing wells on the TWN Licenses: three uphole completions in the Mt. Messenger Formation and one well that offers production potential from both a Tikorangi reactivation and a Mt. Messenger uphole completion. The TWN JA will continue to evaluate these opportunities with the objective of advancing these wells to production.

NZEC remains focused on reducing costs while increasing production from existing wells with the objective of organically building up working capital through internally-generated cash flow. In addition, NZEC is actively seeking farm-in partners for its Eltham and Alton permits, with the intention that the farm-in partner would fund the drilling of high-priority targets on the properties in return for an interest in the permits.

The Company's ability to execute its exploration and development activities is contingent on its financial capacity. Based on available working capital, as well as forecasted positive net cash flow from operations, management has estimated that the Company has sufficient working capital to meet short-term operating requirements. However, since these estimates rely on certain development activities that are still underway as at the date of this report, there are no assurances that these activities will be successful, or that the Company will be able to attain sufficient profitable operations from those activities. In light of the reliance on successful completion of ongoing development activities, there is significant doubt about the Company's ability to continue as a going concern.

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.

East Coast Basin

The Company is actively seeking a farm-in partner for its East Coast permits, to participate in and fund exploration and development in the East Coast Basin in return for an interest in the permits.

NZEC used information from two stratigraphic test holes and a 2D seismic survey to focus its exploration plans for the Castlepoint Permit. The current work program requires the Company to drill an exploration well by May 23, 2014, but the Company expects NZPAM to grant a six-month extension to this deadline. The Company has identified its preferred drill location and has initiated the community engagement and technical assessments required to obtain land access and resource consents.

The current work program for the Wairoa Permit requires the Company to drill an exploration well by July 2, 2014, but the Company has applied to NZPAM for a six-month extension to this deadline. The Company has identified the preferred drill location and has initiated the community engagement and technical assessments required to obtain land access and resource consents.

The Company anticipates completing fieldwork and geochemical studies on the East Cape Permit in 2014.

SUMMARY OF QUARTERLY RESULTS

	2013-Q4 $	2013-Q3 $	2013-Q2 $	2013-Q1 $
Total assets	116,782,687	105,313,813	127,318,182	129,545,992
Exploration and evaluation assets	51,500,037	55,859,632	52,357,470	49,610,922
Property, plant and equipment	49,169,997	26,621,043	26,135,651	25,793,089
Working capital	6,878,152	4,748,797	9,517,742	17,533,636
Revenues	4,108,911	1,519,010	2,109,700	2,925,258
Accumulated deficit	(35,099,834)	(27,292,947)	(24,616,053)	(22,386,089)
Total comprehensive income (loss)	(5,963,723)	1,347,788	(6,000,775)	1,313,397
Basic (loss) earnings per share	(0.06)	(0.02)	(0.02)	(0.02)
Diluted (loss) earnings per share	(0.06)	(0.02)	(0.02)	(0.02)

	2012-Q4 $	2012-Q3 $	2012-Q2 $	2012-Q1 $
Total assets	116,059,939	98,882,087	98,814,102	96,979,923
Exploration and evaluation assets	37,379,726	26,377,188	25,373,718	12,103,712
Property, plant and equipment	23,867,758	16,293,123	8,674,152	8,150,802
Working capital	28,293,845	45,204,695	53,844,035	70,401,191
Revenues	2,948,041	3,708,254	5,910,993	3,908,683
Accumulated deficit	(19,992,243)	(17,804,045)	(15,613,594)	(16,548,180)
Total comprehensive income (loss)	(1,333,805)	(2,018,634)	1,317,915	799,032
Basic (loss) earnings per share	(0.02)	(0.02)	0.01	0.00
Diluted (loss) earnings per share	(0.02)	(0.02)	0.01	0.00

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.

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 TWN Acquisition 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. 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 TWN Acquisition, negotiating a revised purchase consideration of $33.7 million with simplified deal terms (see *Note 2 in the Consolidated Interim Financial Statements*). The Company also entered into the TWN JA 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 workover activities on Waitapu-2 to install artificial lift and surface facilities. The Company met the financing condition precedent related to the TWN Acquisition at the quarter-end. During Q4-2013, the Company progressed to completion of the TWN Acquisition and continued with its development plan for the TWN Licenses, reactivating the six Tikorangi wells on existing gas lift system and also initiating the first uphole completion to the Mt. Messenger Formation. The Company also decided to focus its East Coast Basin exploration activities on the Castlepoint, East Cape and Wairoa permits, and relinquished its Ranui Permit.

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 DECEMBER 31, 2013

Revenue

During the three-month period ended December 31, 2013, the Company produced 16,790 bbl (2012: 29,516 bbl) of oil and sold 13,968 bbl (2012: 29,901 bbl) for total oil sales of $1,617,139 (2012: $3,109,206), or $115.77 per bbl (2012: $103.98).

During the three-month period ended December 31, 2013, the Company recorded sales from purchased oil and condensate of $664,168 and $1,506,068, respectively (2012: $nil and $nil). The Company also received $468,671 (2012: $nil) of processing revenue from the Company's interest in the Waihapa Production Station.

Total recorded revenue during the three-month period ended December 31, 2013 was $4,108,911 (2012: $2,948,042), which is accounted for net of royalties of $147,134 (2012: $161,164).

Expenses and Other Items

Production costs related to oil sales during the three-month period ended December 31, 2013 totalled $606,153 (2012: $1,782,939) or $43.39 per bbl (2012: $59.63). The decrease in production costs in Q4-2013 compared to Q4-2012 was due to the installation of production facilities on the Copper Moki site. Other costs of $2,170,236 are for costs directly related to the sale of purchased oil and condensate, where the Company entered into an arrangement with third parties to acquire 50% and sell the crude oil and condensate arising from the TWN Licenses and TWN Assets. During the three-month period ended December 31, 2013, fixed operating costs represented approximately 88% of total production costs, giving rise to lower field netbacks in light of reduced oil production compared to Q4-2012.

Depreciation costs incurred during the three-month period ended December 31, 2013 totalled $790,242 (2012: $883,835), or $56.58 per bbl of oil sold (2012: $29.56). 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.

Stock-based compensation for the three-month period ended December 31, 2013 resulted in a recovery of $626,754, compared to a $217,694 expense during the same period in 2012. The recovery in the three-month period ended December 31, 2013 corresponds to a reversal of stock-based compensation previously expensed but now forfeited, as the employees left the Company during the period.

General and administrative expenses for the three-month period ended December 31, 2013 totalled $2,856,161 compared to $2,624,126 incurred in the same period in fiscal 2012. The increase in general and administrative costs corresponds to an increase in travel and insurance in connection with the TWN Acquisition.

Transaction costs for the three-month period ended December 31, 2013 totalled $184,505 compared to $678,220 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 TWN Acquisition.

Net finance expense for the three-month period ended December 31, 2013 totalled $30,804 compared to a net finance income of $11,548 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. During the quarter ended December 31, 2013, the Company incurred more accretion expense due to more asset retirement obligations incurred from the acquisition of the TWN Licenses and TWN Assets.

Foreign exchange loss for the three-month period December 31, 2013 amounted to $599,078 compared to a $165,146 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 in which the Company's subsidiaries (which have a New Zealand dollar functional currency) held US dollar denominated working capital in anticipation of completing the TWN Acquisition.

Impairment - During the quarter the Company made the decision to focus its East Coast Basin exploration efforts on the Wairoa, Castlepoint and East Cape permits, and relinquished its Ranui Permit. As a result, the Company wrote off $6,708,960 of exploration and evaluation assets previously capitalized to the permit.

Total Comprehensive Income / Loss

Total comprehensive income for the three-month period ended December 31, 2013 totalled $5,963,723 after taking into account a foreign translation reserve gain of $1,843,164 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 December 31, 2012 was $1,333,805.

Based on a weighted average shares outstanding balance of 127,319,719, the Company realized a $0.06 basic and diluted loss per share for the three-month period ended December 31, 2013. During the three-month period ended December 31, 2012, the Company realized a $0.02 basic and diluted loss per share, based on a weighted average share balance of 121,769,105.

RESULTS OF OPERATIONS FOR THE YEAR ENDED DECEMBER 31, 2013

Revenue

During the year ended December 31, 2013, the Company produced 77,484 (2012: 162,444) bbl and sold 77,820 (2012: 162,077) bbl for total oil sales of $8,489,319 (2012: $17,295,853), or $109.09 (2012: $106.71) per bbl. Total recorded gross production revenue was $8,023,973 (2012: $16,475,971), which accounted for royalties of $465,346 (2012: $819,882), or $5.98 (2012: $5.06) per bbl sold.

During the year ended December 31, 2013, the Company recorded sales from purchased oil of $664,168 (2012: $nil) and purchased condensate of $1,506,068 (2012: $nil). The Company also received $468,671 (2012: $nil) of processing revenue from the Company's interest in the Waihapa Production Station.

Total recorded revenue during the year ended December 31, 2013 was $10,662,879 (2012: $2,948,042), which is accounted for net of royalties of $465,347 (2012: $161,164).

Expenses and Other Items

Production costs during the year ended December 31, 2013 totalled $4,570,294 (2012: $5,116,059), or $58.73 (2012: $31.57) per bbl sold. Included in total 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. Other costs of $2,170,236 relate to purchased oil and condensates which were on-sold by the Company to a third party. The Company continues to see the positive effect on production costs from installation of surface facilities as reflected in reduced production costs related to the Copper Moki site since June 2013.

Depreciation costs incurred during the year ended December 31, 2013 totalled $3,193,785 (2012: $4,103,405), or $41.04 (2012: $25.32) per bbl sold. 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 bbl depreciation during the period ended December 31, 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 year ended December 31, 2013 totalled $685,257 compared to $1,594,780 during the same period in 2012. The decrease in stock-based compensation corresponds to fewer stock options granted and the reversal of stock-based compensation related to employees who left the Company during the period.

General and administrative expenses for the year ended December 31, 2013 totalled $7,197,024 compared to $5,896,949 incurred in the same period in fiscal 2012. The increase in general and administrative costs corresponds to salary increases related to new employees, as the Company prepared for the expansion of operations following the TWN Acquisition.

Transaction costs for the year ended December 31, 2013 totalled $1,823,243 compared to $1,161,657 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 TWN Acquisition.

Net finance expense for the year ended December 31, 2013 totalled $97,598 compared to net finance income of $211,551 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 year ended December 31, 2013 amounted to $452,176 compared to a $1,895,845 loss realized in the same period of fiscal 2012. The decrease in foreign exchange gain loss is a result of the weakening of the New Zealand dollar against the US dollar, during a period in which the Company's subsidiaries (which have a New Zealand dollar functional currency) held US dollar denominated working capital in anticipation of closing the TWN Acquisition.

Impairment - During the year, the Company made the decision to focus its East Coast exploration efforts on the Wairoa, Castlepoint and East Cape permits and relinquished the Ranui Permit. As a result, the Company wrote off $6,708,960 of exploration and evaluation assets previously capitalized to the permit. An additional $275,484 was written down to determine the fair value of the land and building held for sale.

Total Comprehensive Loss

Total comprehensive loss for the year ended December 31, 2013 totalled $9,303,312 after taking into account a gain on the exchange difference on translation of foreign currency of $5,804,279 which compared to total comprehensive loss for the year ended December 31, 2012 of $1,235,492.

Based on a weighted average shares outstanding balance of 127,319,719, the Company realized a $0.12 basic and diluted loss per share for the year ended December 31, 2013. During the year ended December 31, 2012, based on a weighted average shares outstanding balance of 117,131,297 the Company realized a $0.03 basic and diluted loss per share.

PETROLEUM PROPERTY ACTIVITIES, OPERATIONS AND CAPITAL EXPENDITURES FOR THE YEAR ENDED DECEMBER 31, 2013

Taranaki Basin

During the year ended December 31, 2013, the Company incurred $15,604,099 in exploration and evaluation expenditures on its Taranaki Basin permits, which includes well development costs of $9,577,939. Other additions included in the expenditure are $3,123,709 of overhead costs including stock-based compensation, and $478,851 in capitalized asset retirement provisions. Also during the year ended December 31, 2013, the Company recorded a positive foreign currency translation adjustment of $2,423,599. The current year net increase in exploration and evaluation expenditures can be attributed to additional exploration costs associated with the Eltham Permit of $13,928,109, additional exploration costs associated with the Alton Permit of $1,277,861 , $111,329 of evaluation and development costs associated with the TWN Licenses following completion of the TWN Acquisition and $286,800 associated with the Manaia Permit.

East Coast Basin

During the year ended December 31, 2013, the Company incurred $921,980 in capitalized exploration costs on the Castlepoint Permit. These exploration costs consist of $94,132 related to well development costs, $616,037 related to overhead costs including stock-based compensation, and positive $211,811 arising from a foreign currency translation adjustment. Cumulative expenditures incurred as of December 31, 2013 relating to the Castlepoint Permit amounted to $3,640,586.

Following the relinquishment of the Ranui Permit during the year ended December 31, 2013, the company wrote off $6,708,960 of well development, allocated overhead and asset retirement costs related to the permit.

During the year ended December 31, 2013, the Company incurred $3,516,354 in capitalized exploration costs on the Wairoa Permit, including $2,896,545 related to the 50-km 2D seismic survey, $445,237 related to overhead costs including stock-based compensation, and $174,571 attributed to a foreign currency translation adjustment.

During the year ended December 31, 2013, the company capitalized $111,512 of overhead costs to the East Cape Permit. The company also recognized a positive foreign currency translation exchange of $1,658.

CAPITAL SPENDING

During the year ended December 31, 2013, cumulative expenditure of property, plant and equipment increased to $57,022,940 from $28,434,778 in the prior year. Current year additions included $84,536 for furniture and fixture, plant and equipment of $5,134,836, $16,991,571 of oil and gas properties, additional asset retirement cost of $3,960,989, an impairment of $275,848 related to land and building, a transfer of $720,708 to assets available for sale, an addition of $1,322,751 to land and building, and a foreign currency translation and other adjustments of $2,221,521. Of the overall increase in property, plant and equipment, an amount of $20,106,277 of the before mentioned increases resulted from the completion of the TWN Acquisition.

During the year ended December 31, 2013, exploration and evaluation assets increased by $14,120,311, from $37,379,726 to $51,500,037. The Company incurred $15,604,099 in exploration, evaluation and overhead costs associated with the Taranaki Basin, of which $13,928,108 related specifically to the Eltham Permit, $1,277,861 related specifically to the Alton Permit,$111,329 related specifically to the TWN Licenses and $286,800 related to Manaia Permit. The Company incurred $921,980 of exploration and evaluation expenditure on the Castlepoint Permit, $3,516,354 on the Wairoa Permit and $113,170 of allocated overhead on the East Cape Permit. The Company wrote off $6,708,960 of previously capitalized exploration and evaluation expenditures related to the Ranui Permit.

Use of Proceeds

Gross proceeds from the private placement, completed on October 28, 2013, was $16,138,436. The Company received net proceeds of $15,133,306 after paying a finder's fee of $1,005,130. Of the net proceeds, $7,881,990 was used to complete the acquisition of the TWN Licenses and TWN Assets. The intended use of net proceeds of $7.25 million, is compared below to the actual activities undertaken by the Company during the period since October 28, 2013 to December 31, 2013:

Anticipated purpose in prospectus	Anticipated use of proceeds by December 31, 2013	Anticipated use of proceeds beyond January 1, 2014	Actual Operations for the period ended December 31, 2013	Actual expenditure incurred by December 31, 2013
Existing Tikorangi well reactivations • Reactivate six Tikorangi wells with gas lift • High volume lift installation on two initial wells	$1.2 million	$0.9 million	Existing Tikorangi well reactivations • Reactivate six Tikorangi wells with gas lift • Purchase of long-lead items required for high volume lift installation on two initial wells	$1.2 million

Anticipated purpose in prospectus	**Anticipated use of proceeds by December 31, 2013**	**Anticipated use of proceeds beyond January 1, 2014**	**Actual Operations for the period ended December 31, 2013**	**Actual expenditure incurred by December 31, 2013**
Mt. Messenger development • Two Mt. Messenger uphole completion in existing well • Horoi exploration well (including surface infrastructure)	$0.6 million	$3.9 million	Mt. Messenger development • One Mt. Messenger uphole completion in existing well	$0.2 million
Available to fund ongoing operations and remaining development plans	N/A	$0.65 million	Available to fund ongoing operations and remaining development plans	$5.85 million
Total:	**$1.8 million**	**$5.45 million**		**$7.25 million**

COMMITMENTS

As at December 31, 2013, the Company had the following undiscounted contractual obligations:

	2014	**2015 to 2016**	**2017 and onwards**	**Total**
Accounts payable	7,921,000	-	-	7,921,000
Operating lease obligations (1)	210,000	439,000	148,000	797,000
Contract and purchase commitments (2)	2,981,000	479,000	1,134,000	4,594,000
Minimum work program requirements (3)	33,717,000	35,963,000	10,279,000	79,959,000
Environmental obligations (4)	360,000	1,097,000	16,063,000	17,520,000
Total	**$ 45,189,000**	**$ 37,978,000**	**$ 27,624,000**	**$ 110,791,000**

(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 program 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 has recognized an undiscounted asset retirement obligation of $17.52 million.

PERMIT EXPENDITURE REQUIREMENTS

The Company undertakes oil and gas exploration and development activities and has contractual commitments under various agreements to complete certain exploration activities. The Company and, where relevant, the joint arrangement partner at the permit, may apply to alter the exploration programs, request extensions, reject development costs, relinquish certain permits or farm out an 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 December 31, 2013. 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. The table below reflects these commitment extensions.

Properties	2014 $	2015 $	2016 $	2017 $	2018 $	Total $
Taranaki Basin						
Eltham Permit (1)	320,000	200,000	-	4,500,000	-	5,020,000
Alton Permit (2)	2,569,000	-	2,321,000	-	-	4,890,000
Manaia Permit (3)	1,743,000	2,295,000	2,805,000	102,000	-	6,945,000
	4,632,000	2,495,000	5,126,000	4,602,000	-	16,855,000
East Coast Basin						
Castlepoint Permit (4)	21,250,000	15,725,000	-	-	-	36,975,000
Wairoa Permit (6)	7,750,000	-	4,420,000	-	-	12,170,000
East Cape Permit (7)	85,000	2,586,975	5,610,000	-	5,677,100	13,959,075
	29,085,000	18,311,975	10,030,000	-	5,677,100	63,104,075
Total	**33,717,000**	**20,806,975**	**15,156,000**	**4,602,000**	**5,677,100**	**79,959,075**

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. The Company has been granted an extension for a second five-year term to September 23, 2018, and as part of that process relinquished 50% of the permit area. The Company has also lodged an application with NZPAM to convert 939 acres (3.8 km^2) of the Eltham Permit into a PMP with an initial duration of 15 years. The land included in the PMP application comprises the Copper Moki and Waitapu fields. The total acreage of the current Eltham Permit, including the area that will be separated into the PMP, is 47,387 acres (191.8 km^2), of which approximately 2,029 acres (24.4 km^2) is offshore. The work program for 2014 requires the Company to reprocess 360 km^2 of 3D seismic data from the Kapuni 3D seismic survey.

(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. The Company and L&M have 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. In addition to drilling the commitment well (for which the before mentioned extension was obtained), the Company is required to also submit a technical study during 2014.

(3) In December 2012, the Company was granted a 60% interest in the Manaia Permit for a five-year term and entered into a joint arrangement with NZOG, with NZEC as the operator of the permit. The Company commenced technical studies and the acquisition of 2D seismic data in 2013, but in April 2014 decided to relinquish the permit. As a result, no additional exploration expenditures are expected to be incurred subsequent to the date of this report.

(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. NZEC has received approval from NZPAM to extend the deadline for drilling an exploration well on the Castlepoint Permit to May 23, 2014, but expects to be granted a further six-month extension to this deadline. The current minimum work program requirements for 2014 also include two contingent exploration wells to be drilled, as well as the submission of various technical studies. If the further extension is granted, the revised work program would defer those two contingent wells and instead require four contingent exploration wells to be drilled by November 23, 2015.

(5) In October 2012, the Company entered into a binding agreement with Westech to acquire 80% ownership and become operator of the Wairoa Permit. NZEC assumed all permit obligations when the acquisition was announced. The current work program requires the Company to drill an exploration well by July 2, 2014, but the Company has applied for a six-month extension to this deadline. Following the drilling of the exploration well, the Company is expected to submit a technical study to NZPAM, reviewing the exploration results to date.

(6) The Company's work program for the permit includes technical studies, reprocessing 145 km of 2D seismic and acquiring 40 km of new 2D seismic data, and drilling an exploration well by Q2-2016. The Company anticipates completing fieldwork and geochemical studies in 2014.

The amounts above represent the anticipated 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 total PEP period not exceeding ten years from the commencement date of the PEP. However, there are some conditions that apply, including relinquishment of part of the area comprising the PEP, up to a maximum of 75% over the total duration of the PEP.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2013, the Company had $4,902,888 in cash and cash equivalents (December 31, 2012: $5,983,121) and $6,878,152 in working capital (December 31, 2012: $28,293,845).

Based on available working capital, as well as forecasted positive net cash flow from operations, management has estimated that the Company has sufficient working capital to meet short-term operating requirements. However, since these estimates rely on certain development activities which are still underway as at the date of this report, there are no assurances that these activities will be successful, or that the Company will be able to attain sufficient profitable operations from those activities. In light of the reliance on successful completion of ongoing development activities, there is significant doubt about the Company's ability to continue as a going concern.

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.

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, in order 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 year ended December 31, 2013, the Company generated a net loss of $15,107,591 (2012: $3,081,173). Non-cash income statement amounts recorded during the period included $685,257 (2012: $1,594,780) in stock-based compensation, $3,354,945 (2012: $4,103,405) in depreciation and accretion, $83,520 (2012: $1,501,200) in foreign exchange loss, $6,984,444 (2012: $nil) in impairment loss and an acquisition gain of $1,403,587 (2012: $nil). Total increase to non-cash working capital items during the period amounted to $1,149,798 (2012: reduction of $2,639,920) resulting in aggregate cash used in operating activities of $4,253,214 (2012: cash provided by operating activities of $1,478,922).

Investing Activities

For the year ended December 31, 2013, the Company incurred $22,817,240 (2012: $32,677,542) in expenditures on its resource properties. The majority of these costs included well development activities on the Eltham permit, as well as acquisition of seismic data on the Wairoa permit on the East Coast. The Company incurred $132,226 (2012: $124,423) in development of a proprietary database and $14,863,301 (2012: $7,973,276) for the purchase of property and equipment. The Company made deposits of $nil (2012: $5,087,158). The Company withdrew an outstanding balance of $37,551,728 (2012: $nil) from term deposit. Total cash used by investing activities for the period was $261,039 (2012: total cash used in investing activities of $80,901,326).

Financing Activities

For the year ended December 31, 2013, cash provided by financing activities was $3,565,895 (2012: $69,764,178). Cash provided by financing activities was the result of settling the outstanding balance of the operating line of credit for a net amount of $11,557,727 (2012: use of $10,438,973), $200,000 (2012: $59,325,205) from the exercise of 200,000 advisor warrants at a price of $1.00 per share, and $14,923,621 (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:

	December 31, 2013 $	December 31, 2012 $
Salary and management fees	3,448,410	2,245,927
Share-based compensation	883,645	2,507,745
	4,332,055	**4,753,672**

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 (released)
August 3, 2014	6,713,400
Total	**46,394,334**

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 ("IFRS") 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 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 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 financial statements for the years ended December 31, 2013 and 2012:

	December 31, 2013 $	December 31 2012 $
Revenue		
Oil sales	8,489,319	17,295,853
Royalties	(465,346)	(819,882)
	8,023,973	16,475,971
Production costs	(4,570,294)	(5,116,059)
Subtotal (a)	**3,453,679**	**11,359,912**
Barrels of oil sold (b)	77,820	162,077
Field netback [(a)/(b)] $/bbl	**44.38**	**70.09**

SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of voting common shares. As at December 31, 2013, the Company had 170,873,459 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 advisor warrants and 11,824,950 stock options, of which 7,481,350 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.

When forecasting production, cash flow and operating costs for 2014, management made a number of assumptions, as outlined below. The assumptions were based on information available at July 31, 2013. Barrels of oil equivalent ("boe") is based on the assumption of 82% oil. Capital costs and operating costs were estimated using an oil sales price of US$99/bbl, a natural gas sales price of NZ$4.50/GJ, a LPG sales price of NZ$500/tonne, a USD/NZD exchange rate of 0.79 and a CAD/NZD exchange rate of 0.82. 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 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. 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.