FORM 51-101F1
Statement of Reserves Data and Other Oil and Gas Information

PART 1: DATE OF STATEMENT

This statement of reserves data and other oil and gas information is dated April 29, 2015 and the effective date of the data is December 31, 2014.

References to oil, natural gas, natural gas liquids, reserves (gross, net, proved, developed, developed producing, developed non-producing, undeveloped), forecast prices and costs, constant prices and costs, operating costs, development costs, future net revenue and future income tax expenses, shall, unless expressly stated to be to the contrary, have the meaning attributed to such terms as set out in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and Companion Policy 51-101CP.

All dollar figures are in Canadian dollars unless otherwise specified.

PART 2: DISCLOSURE OF RESERVES DATA

New Zealand Energy Corp. (the "**Company**") has one petroleum mining permit ("**PMP**") with reserves and two petroleum mining licenses ("**PML**") with reserves. The Permits are adjacent and located in the Taranaki Basin on the North Island of New Zealand.

Since December 2010 the Company has held a 100% interest in the Copper Moki PMP (split out of the Eltham Petroleum Exploration Permit in July 2014). The Company also holds a 50% interest in and has reserves attributable to the Waihapa and Ngaere PMLs.

The oil and natural gas reserves and net present value of future net revenue of the Copper Moki PMP and the Waihapa and Ngaere PMLs were evaluated by Deloitte LLP ("**Deloitte**"), which prepared a report regarding such reserves dated effective December 31, 2014 (the "**Reserve Report**").

The following tables are based on information contained in the Reserve Report, and calculations prepared by the Company, which show oil and natural gas reserves associated with the Company's Copper Moki, Waihapa and Ngaere permits and the net present value of estimated future revenue for these reserves using forecast prices and costs as indicated. The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Reserve Report will be attained, and variances could be material. Assumptions relating to costs and other matters are included in the Reserve Report. The recovery and reserve estimates of the Company's oil and natural gas reserves included in this statement of reserves data are estimates only and there is no guarantee that the estimated reserves will be recovered. Risks and uncertainties that could cause the actual reserves to differ from those anticipated include, but are not limited to, the underlying risks of the oil and gas industry (operational risks in development, exploration and production; potential delays or changes in plans with respect to work programs or expenditures; uncertainty of reserves estimates; uncertainty in production and cost projections; political and environmental factors), and commodity price and exchange rate fluctuations.

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.

The term barrels of oil equivalent ("**BOE**") may be misleading, particularly if used in isolation. The Company uses a standard measure of six thousand cubic feet of natural gas ("**Mcf**") to one barrel of oil ("**bbl**" or "**stb**") when converting natural gas to barrels of oil equivalent, or BOE. This conversion ratio is based on an energy equivalency method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

OIL AND GAS RESERVES SUMMARY
Forecast Pricing and Costs
As at December 31, 2014

	Light & Medium Oil		Natural Gas		Barrels Oil Equivalent	
Reserves Category	**Gross Mstb**	**Net Mstb**	**Gross MMcf**	**Net MMcf**	**Gross Mboe**	**Net Mboe**
Proved						
Developed Producing	388.1	350.2	680.0	625.2	501.4	454.4
Developed Non-Producing	216.8	191.1	634.8	581.7	322.6	288.0
Undeveloped	124.3	110.5	87.0	78.1	138.8	123.6
Total Proved	**729.2**	**651.8**	**1,401.8**	**1,285.1**	**962.8**	**866.0**
Probable	366.1	327.5	723.8	662.7	486.7	437.9
Total Proved and Probable	**1,095.3**	**979.3**	**2,125.6**	**1,947.8**	**1,449.6**	**1,303.9**

Notes:

(1) Mbbl – Thousand barrels, MMcf – Million cubic feet, MBOE – Thousand barrels of oil equivalent
(2) Gross reserves are the Company's working interest share before the deduction of royalty obligations payable to the New Zealand Government and Origin Energy Resources NZ (TAWN) Limited.
(3) Net reserves are the Company's working interest share after deduction of royalty obligations payable to the New Zealand Government and Origin Energy Resources NZ (TAWN) Limited.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
Before Tax
Forecast Prices and Costs
As at December 31, 2014

	Net Present Values of Future Net Revenues After Income Tax, Discounted at %/year					
RESERVES CATEGORY	**0% $000**	**5% $000**	**10% $000**	**15% $000**	**20% $000**	**Unit Value 10% ($/BOE)**
Proved						
Developed Producing	8,890.1	7,679.5	6,801.9	6,143.0	5,622.7	14.98
Developed Non-Producing	10,479.3	8,981.2	7,708.4	6,660.0	5,807.8	26.77
Undeveloped	1,341.4	542.8	16.0	-327.5	-551.7	0.13
Total Proved	**20,710.8**	**17,203.5**	**14,526.3**	**12,475.5**	**10,878.7**	**16.77**
Probable	24,165.4	16,834.1	12,336.0	9,435.2	7,470.1	28.16
Proved and Probable	**44,876.3**	**34,037.6**	**26,862.3**	**21,910.7**	**18,348.8**	**20.60**

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
After Tax
Forecast Prices and Costs
As at December 31, 2014

	Net Present Values of Future Net Revenues After Income Tax, Discounted at %/year					
RESERVES CATEGORY	0% $000	5% $000	10% $000	15% $000	20% $000	Unit Value 10% ($/BOE)
Proved						
Developed Producing	8,890.1	7,679.5	6,801.9	6,143.0	5,622.7	14.98
Developed Non-Producing	10,479.3	8,981.2	7,708.4	6,660.0	5,807.8	26.77
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Total Proved and Probable	**44,876.3**	**34,037.6**	**26,862.3**	**21,910.7**	**18,348.8**	**20.60**

TOTAL FUTURE NET REVENUE
Undiscounted
Forecast Prices and Costs
As at December 31, 2014

Reserves Category	Revenue $000	Royalties $000	Operating Costs $000	Investment Costs $000	Abandonment Costs $000	Revenue Before Income $000	Income Taxes $000	Revenue After Income Taxes $000
Proved								
Developed Producing	45,817.2	4,511.7	25,307.4	0.0	7,107.9	8,890.1	$ 0.00	8,890.1
Developed Non-Producing	22,803.9	2,625.3	7,371.7	2,000.0	327.7	10,479.3	$ 0.00	10,479.3
Undeveloped	13,879.3	1,552.8	6,040.5	4,619.8	324.7	1,341.4	$ 0.00	1,341.4
Total Proved	**82,500.4**	**8,689.8**	**38,719.6**	**6,619.8**	**7,760.4**	**20,710.8**	**$ 0.00**	**20,710.8**
Probable	50,501.8	5,246.4	21,919.6	0.0	-829.7	24,165.4	$ 0.00	24,165.4
Total Proved and Probable	**133,002.1**	**13,936.2**	**60,639.2**	**6,619.8**	**6,930.7**	**44,876.3**	**$ 0.00**	**44,876.3**

Future Net Revenue By Production Group
Before Tax, Discounted at 10%/year
Forecast Prices and Costs
As at December 31, 2014

Reserves Category	Production Group	Future Net Revenue ($000)	Unit Value ($/BOE)
Total Proved	Light and Medium Crude Oil	14,526	15.08
	Natural Gas	-	-
	Natural Gas Liquids	-	-
	Total BOE	14,526	15.08
Proved + Probable	Light and Medium Crude Oil	26,862	18.53
	Natural Gas	-	-
	Natural Gas Liquids	-	-
	Total BOE	26,862	18.53

PART 3: PRICING ASSUMPTIONS

Price and market forecasts prepared by Deloitte and used in the Reserve Report are summarized below. The prices are Deloitte's best estimate of future pricing, based on the many uncertainties that exist in the petroleum industry, and considering inflation forecasts and exchange rates.

Summary of Pricing and Inflation rate Assumptions
Forecast Prices and Costs
As at December 31 2014

	Oil	Gas	Inflation rate	Exchange rate
	US$/bbl	US$/Mcf	(%/year)	(CDN/USD)
2015	$72.00	$9.50	0.0%	0.86
2016	$77.00	$9.90	2.0%	0.86
2017	$82.00	$10.10	2.0%	0.86
2018	$84.00	$10.25	2.0%	0.86
2019	$86.00	$10.40	2.0%	0.86
2020	$88.00	$10.55	2.0%	0.86
2021	$90.00	$10.70	2.0%	0.86
2022	$90.00	$10.80	2.0%	0.86
2023	$90.00	$10.95	2.0%	0.86
2024	$90.00	$11.00	2.0%	0.86
2025	$90.00	$11.05	2.0%	0.86
2026	$90.00	$11.15	2.0%	0.86
2027	$90.00	$11.25	2.0%	0.86
2028	$90.00	$11.25	2.0%	0.86
2029	$90.00	$11.25	2.0%	0.86
2030	$90.00	$11.25	2.0%	0.86
2031	$90.00	$11.25	2.0%	0.86
2032	$90.00	$11.25	2.0%	0.86
2033	$90.00	$11.25	2.0%	0.86
2034	$90.00	$11.25	2.0%	0.86

Notes:

1. The Company has an agreement with Shell (Petroleum Mining) Company Limited, pursuant to which Shell (Petroleum Mining) Company Limited has agreed to purchase the company's crude oil on a Brent price basis. The values in the table are the Brent spot price. Based on the previous year sales differentials, the Company receives Brent pricing less $1.00/bbl.
2. The gas price represented in the above table is referenced to UK NBP. Differentials of $6.30/Mcf and $7.05/Mcf respectively have been applied to Copper Moki and Waihapa as a reasonable expectation of what the Company will receive.

The weighted average price received by the Company for oil in the year ended December 31, 2014 was $104.39 per barrel.

PART 4: RECONCILIATION OF CHANGES IN RESERVES

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE
Forecast Prices and Costs
As at December 31, 2014

	Light & Medium Oil			Associated & Non-Associated Gas			Natural Gas Liquids		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	Mstb	Mstb	Mstb	MMcf	MMcf	MMcf	Mstb	Mstb	Mstb
December 31, 2013	**934.3**	**413.3**	**1,347.6**	**1,796.4**	**768.5**	**2,564.9**	**80.2**	**37.3**	**117.5**
Production	-74.9	0.0	-74.9	-155.4	0.0	-155.4	-0.7	0.0	-0.7
Technical Revisions	-127.3	-50.4	-177.7	-231.2	-52.3	-283.5	-79.0	-37.8	-116.8
Extensions & Improved Recove	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquistions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	-3.1	3.1	0.0	-7.8	7.8	0.0	-0.5	0.5	0.0
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
December 31, 2014	**729.0**	**366.0**	**1,095.0**	**1,402.0**	**724.0**	**2,126.0**	**0.0**	**0.0**	**0.0**

Note: Mstb – Thousand barrels of oil, MMcf – Million cubic feet of natural gas

PART 5: ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Proved and Probable Undeveloped Reserves
As at December 31, 2014
Forecast Prices and Costs

Reserves Category	Light & Medium Oil (Gross Mstb)		Natural Gas (Gross MMcf)		Natural Gas Liquids (Gross Mstb)		Barrels Oil Equivalent (Gross MBOE)	
	First Attributed	Aggregate	First Attributed	Aggregate	First Attributed	Aggregate	First Attributed	Aggregate
Proved Undeveloped								
31-Dec-11	-	-	-	-	-	-	-	-
31-Dec-12	21	21	32	32	2	2	28	28
31-Dec-13	130	130	104	104	4	4	151	151
31-Dec-14	-	124	-	87	-	-	-	139
Probable Undeveloped								
31-Dec-11	-	-	-	-	-	-	-	-
31-Dec-12	31	31	49	49	3	3	43	43
31-Dec-13	76	76	61	61	2	2	88	88
31-Dec-14	-	76	-	53	-	-	-	85

Note: Mstb – Thousand barrels. MMcf – Million cubic feet.

Prior to 2011, the Company did not report under NI 51-101.

Proved and probable undeveloped reserves are generally those reserves related to well(s) awaiting the installation of an artificial lift system. Proved and probable undeveloped reserves have been assigned to a crestal well on the Waihapa Permit with a Tikorangi Formation target. The initial rate and profile of the well was estimated based on the performance of the other wells in the field.

The Company does not anticipate any unusually high development costs (noting the proposed use of ESPs) or operating costs related to development of the reserves, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

Estimated development costs deducted in the estimation of future net revenue attributable to the reserve categories noted below are as follows:

Estimated Future Development Costs
Forecast Prices and Costs
As at December 31, 2014
(in thousands of dollars)

Year	Proved Reserves	Proved plus Probable Reserves
2015	2,000	2,000
2016	4,619	4,619
2017	-	-
2018	-	-
2019	-	-
Total	**6,619**	**6,619**

The Company expects to fund the above development costs from a combination of existing working capital, cash flow from operations, and new debt or equity issues (if available on favourable terms). The cost of funding is not expected to have an effect on disclosed reserves or future net revenue, or to make the development of the properties uneconomic.

PART 6: OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The Company has, to date, focused its activities in two areas of the North Island of New Zealand that it considers to be prospective for oil and natural gas. In the Taranaki Basin, on the west coast of the island, the Company has a 100% working interest in PMP 55491 ("**Copper Moki Permit**"), PEP 51150 ("**Eltham Permit**"), a 65% interest in PEP 51151 ("**Alton Permit**"), a 50% interest in PML 38138 ("**Tariki Permit**"), PML 38140 ("**Waihapa Permit**") and PML 38141 ("**Ngaere Permit**") (collectively, the "**TWN Permits**"), and a 50% interest in the Waihapa Production Station, a full-cycle midstream processing facility. In the East Coast Basin the Company has a 100% working interest in PEP 52976 ("**East Cape Permit**"). Collectively, these permits cover 1.18 million acres on New Zealand's North Island.

Taranaki Basin

Copper Moki Permit

The Copper Moki PMP was granted on 28th July 2014 for an initial period of 8 years. The field comprises the Copper Moki-1 and Copper Moki-2 wells which produce from the Mt Messenger Formation (Late Miocene) using beam pump artificial lift, and associated surface production facilities. Gas is piped to the nearby Waihapa Production Station. Copper Moki-3, a former high water-cut producer, is currently shut in pending a workover to repair a downhole pump. Waitapu-2, located on the Waitapu wellsite, also produced oil and gas from the same pool as Copper Moki-1, using dedicated surface facilities. Since March 28 2015, Waitapu-2 has been shut in after a downhole pump failure. The wells have collectively produced a total of 327,426 bbl from the Mt. Messenger Formation as at the end of March 2015, including oil produced during testing. The wells produce ~41º degree API oil that is trucked approximately 45km to the Shell-operated Omata Tank Farm in New Plymouth and sold at Brent pricing.

Eltham Permit

Until the Company completed the acquisition of a 50% interest in the TWN Permits in October 2013, the Eltham Permit was the Company's only property with attributed reserves. The Eltham Permit was originally granted to the

previous permit holder on September 23, 2008 for a period of five years. 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 lodged an application with New Zealand Petroleum & Minerals ("**NZPAM**") to convert 939 acres (3.8 km^2) of the Eltham Permit into a petroleum mining permit ("**PMP**"). This was granted in July 2014 (with the Copper Moki PMP split out of the Eltham PEP. The total acreage of the current Eltham Permit, is 46,444 acres (187.9 km^2), of which approximately 6046 acres (24.5 km^2) is offshore.

The Company has drilled ten exploration wells on the Eltham Permit, four of which were successful producers and together with Copper Moki-4 were transferred to the Copper Moki PMP. The remaining exploration wells (see "Oil Wells" below) following evaluation, have been deemed not commercial.

TWN Permits and Waihapa Production Station

The Company closed the acquisition of assets from Origin on October 28, 2013. The assets include three PMLs (the Tariki Permit, Waihapa Permit and Ngaere Permit) ("TWN Permits") covering 23,049 onshore acres that are contiguous with the northern border of the Eltham and Alton Permits, as well as the Waihapa Production Station (collectively, "**TWN Assets**"). The Company holds a 50% interest in the TWN Assets (11,524.6 acres) together with L&M Energy ("**L&M**"), which acquired the other 50%. The Company and L&M have formed a 50/50 joint arrangement to explore, develop and operate the TWN Assets, with the Company acting as the operator.

The TWN Permits offer multi-zone potential from the Urenui, Mt. Messenger, Moki, Tikorangi and Kapuni formations. Included with the TWN Permits are 16 established drill pads, most of which have oil and gas gathering pipelines in place to deliver production to the Waihapa Production Station. The acquisition also includes 93 km^2 of 3D seismic data covering the south end of the TWN Permits and 585 km of 2D seismic data, along with log data from 27 previously drilled wells.

In addition to the TWN Permits, the Company and L&M acquired the Waihapa Production Station from Origin, providing gathering, processing and sales infrastructure in the Taranaki Basin. The Waihapa Production Station and associated infrastructure includes a 45 mmcf/d gas processing, gas compression and liquefied petroleum gas extraction facility, a 51-km 8-inch gas sales pipeline from the Waihapa Production Station to the Stratford gas power generation plant then terminating at New Plymouth, 59 km of oil/gas mixed product pipelines including gas lift lines, a 25,000 bbl/d oil processing facility, a 49-km oil sales pipeline from the Waihapa Production Station to the Omata Tank Farm capable of transporting up to 15,500 bbl/d, and an 18,000 bbl/d water disposal processing system.

The Tikorangi Limestone reservoir underlying the TWN Permits was discovered in 1985 and has produced more than 23 million barrels of oil to date through a succession of operators. Field production peaked at 15,046 bbl/day in 1994. Six wells had been intermittently produced by previous operators using a gas liftsystem, when gas was available. The wells had been produced infrequently since 2007 since there was not a regular supply of high pressure gas, and were effectively shut-in until June 2013, when one of the wells was brought back into intermittent production by Origin.

The Company entered into an arrangement to ensure a continuous supply of high pressure gas lift and, upon closing of the acquisition of assets, immediately commenced the work required to reactivate oil production from the Tikorangi Formation in the six wells. On December 2, 2013, the Company announced that all six wells had been reactivated and were flowing into the Waihapa Production Station. The Company continues to evaluate and optimize production from the reactivated wells to increase oil and gas production. The Company and L&M have also recently reactivated oil production from the Mt. Messenger Formation in a well that had been produced historically by previous operators.

The Company's technical and engineering team has outlined a detailed development plan for the TWN Assets, which if approved would see ESPs installed in 2 of the existing 6 wells. These ESPs combined are expected to produce 15,000 of fluid a day, and draw down the reservoir pressure to historical lows. This method should result in a significant increase to the current oil production. In addition, new exploration targets in the Mt. Messenger, Tikorangi and Kapuni formations could be drilled in future exploration programs.

Alton Permit

The Alton Permit is located onshore immediately adjacent to the east of the Eltham Permit. The Company holds a 65% interest in the property and is the operator of the permit, with the remaining 35% interest held by L&M. In

November 2013 the partners were granted an extension for a second five-year term to September 2018. As part of the extension the partners were required to relinquish 50% of the permit acreage, resulting in the current configuration of 59,565 onshore acres (241.1 km^2).

The Company drilled the Talon-1 well in July 2011 as a condition to acquire its original interest in the Alton Permit and become operator of the permit. The Talon-1 well location, chosen by the previous operator of the Alton Permit using 2D seismic information, intersected over 75 metres of the targeted Manutahi reservoir with minor amounts of natural gas observed. The Company decided to not complete the well, but will use the information obtained from Talon-1 drilling to identify other viable targets in the area. 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. The Company is responsible for expenditures and is entitled to profits for its respective interest in the permit.

East Coast Basin

The Company is actively seeking a partner to share funding expenditures for exploration and development of its East Cape permit.

East Cape Permit

The East Cape Permit covers approximately 1,048,406 onshore acres (4,242.8 km^2) in the Raukumara region of the East Coast Basin, on the northeast tip of the North Island. The Company was awarded the permit on November 29, 2013, following its permit application in September 2010. 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.

Oil Wells

The following table sets forth the number and status of oil wells in which the Company had a working interest as at December 31, 2014.

			Producing		Non-Producing	
Well Name	**Permit Name**	**Purpose**	**Gross**	**Net**	**Gross**	**Net**
Copper Moki-1	Copper Moki	Exploration	1	1	-	-
Copper Moki-2	Copper Moki	Exploration	1	1	-	-
Copper Moki-3	Copper Moki	Exploration	1	1	-	-
Waitapu-2	Copper Moki	Exploration	1	1	-	-
Copper Moki-4 (1)	Copper Moki	Exploration	-	-	1	1
Waitapu-1 (2)	Eltham	Exploration	-	-	1	1
Arakamu-1A (3)	Eltham	Exploration	-	-	1	1
Arakamu-2 (4)	Eltham	Exploration	-	-	1	1
Wairere-1 (5)	Eltham	Exploration	-	-	1	1
Wairere-1A (6)	Eltham	Exploration	-	-	1	1
Toko-2B	Ngaere	Reactivated	1	0.5	-	-
Ngaere-3	Ngaere	Reactivated	1	0.5	-	-
Ngaere-2A	Ngaere	Reactivated	1	0.5	-	-
Ngaere-1	Ngaere	Reactivated	1	0.5	-	-
Waihapa-H1	Waihapa	Reactivated	1	0.5	-	-
Waihapa-6A	Waihapa	Reactivated	1	0.5	-	-
Six other wells	Tariki		-	-	6	3
Six other wells	Waihapa		-	-	6	3
Total			**10**	**7**	**18**	**12**

Notes:
(1) Copper Moki-4 made an oil discovery in the Urenui Formation and following evaluation, is deemed not commercial.

(2) Waitapu-1 was drilled to the Mt. Messenger Formation following evaluation, is deemed not commercial.
(3) Arakamu-1A was drilled to the Moki Formation and following evaluation, is deemed not commercial.
(4) Arakamu-2 made an oil discovery in the Mt. Messenger Formation and following evaluation, is deemed not commercial.
(5) Wairere-1 failed to encounter hydrocarbons and was immediately sidetracked as Wairere-1A.
(6) Wairere-1A was drilled to the Mt. Messenger Formation and encountered hydrocarbon shows, however following evaluation, is deemed not commercial.

All of the Company's wells are oil wells. The Company has not specifically drilled natural gas wells.

Statutory Relinquishments

In New Zealand, PEPs awarded before legislative amendments made in mid-2013 were granted for an initial period of five years and are subject to minimum work requirements as laid out in the PEP conditions. PEPs granted after mid-2013 are granted for a period of up to 15 years, although the Company understands that 10 years is typically the maximum for an onshore PEP. The permit holder is typically required to provide the New Zealand Minister of Energy with a commitment to undertake the minimum work program for the relevant period, as specified in the permit. The terms of the permit may require the permit holder, if it is unable to provide such a commitment, to relinquish the permit. A permit holder may apply to surrender a PEP, in respect of all or part of that permit area, at any time by notice to the Minister of Energy.

The holder of an onshore PEP granted before the mid-2013 legislative amendments 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. This is required by section 35C of the *Crown Minerals Act 1991*.

In addition to the acreage that is required to be relinquished at the time of extension of the PEP period, the Minister of Energy can require, as a condition of granting a permit, the permit holder to relinquish a defined area of the permit at a later specified time, up to a maximum of 75% over the total duration of the PEP. The area remaining in the permit after this partial relinquishment must normally be contiguous, and the Minister of Energy may give consideration to the effect that the shape and location of the retained area has on the viability of the New Zealand government subsequently offering the relinquished area in a permit round process.

If a petroleum discovery is made, the PEP holder is required to apply for a petroleum mining permit ("**PMP**") prior to transitioning from petroleum exploration to petroleum mining. PMPs are granted to enable the development of an oil and/or natural gas field with the purpose of extraction and production. A PMP also allows the holder to undertake prospecting or exploration activities in the area over which the PMP is held. PMPs may be granted for a period of up to 40 years and are renewable without relinquishment, subject to government approval. Prior to 1991, petroleum mining licences (PMLs) were awarded under the Petroleum Act 1937 and essentially provide a similar framework for mining petroleum. The TWN Permits were granted before 1991 and are PMLs.

Properties with No Attributed Reserves

The following table sets out the Company's interest in unproved properties as at December 31, 2014:

Permit	Location	Working Interest (%)	Gross Acres	Net Acres
Eltham Permit	Taranaki Basin, New Zealand	100	46,444	46,444
Alton Permit	Taranaki Basin, New Zealand	65	59,713	38,813
Tariki Permit	Taranaki Basin, New Zealand	50	3,566	1,783
East Cape Permit	East Coast Basin, New Zealand	100	1,048,406	1,048,406
Total			**1,158,129**	**1,135,447**

The Company estimates that the following expenditures will be required in the five-year period commencing January 1, 2015 to complete the minimum work program and maintain the Company's Alton Permit, Tariki Permit, and East Cape Permit in good standing; otherwise, the relevant PEP or PML must be surrendered. The Company does not know what the minimum work program requirements will be at the end of the existing five-year period, or even if the

Company will apply to extend the term; therefore, expenditures beyond the end of the current five-year period have not been estimated.

Permit	Year 1 ($)	Year 2 ($)	Year 3 ($)	Year 4 ($)	Year 5 ($)	Total ($)
Eltham Permit [(1)]	470,000	-	4,069,000	N/A	N/A	4,539,000
Alton Permit [(2)]	3,028,000	265,000	3,027,000	N/A	N/A	6,320,000
Tariki Permit [(3)]	N/A	N/A	N/A	N/A	N/A	N/A
East Cape Permit [(4)]	2,622,000	9,020,000	5,652,000	5,652,000	N/A	22,946,000

Notes:
(1) The minimum work program for 2015 requires the Company to undertake advanced 2D/3D processing.
(2) The minimum work program for 2015 requires the Company to drill an exploration well by November 22, 2015.
(3) The Tariki Permit is a Petroleum Mining License and therefore not subject to relinquishment. The Company and L&M are required to prove production potential on the Tariki Permit by July 20, 2016 to allow the PML to be extended.
(4) The East Cape Permit was granted to the Company in November 2013 for a five-year term, expiring on November 28, 2018. The minimum work program for 2015 includes reprocessing 145km of 2D seismic and acquiring 40km of new 2D seismic data.

For properties with no attributed reserves, the Company does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Forward Contracts

The Company does not have any forward contracts under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or natural gas.

Additional Information Concerning Abandonment and Reclamation Costs

Management estimates abandonment and reclamation costs based on past experience and analysis of industry peers.

Copper Moki Permit

As at December 31, 2014, management expected to incur abandonment and reclamation costs on five net wells located on the Copper Moki Permit. The total undiscounted amount of such costs, net of estimated salvage value, is estimated by the Company to be approximately $1,904,000 (estimated present value of $926,000 using a 10% discount rate). Within the next three financial years, the Company estimates that abandonment and reclamation costs, net of estimated salvage value, will total $Nil (estimated present value of $Nil using a 10% discount rate).

Of the abandonment and reclamation costs disclosed above, $402,000 was deducted as abandonment and reclamation costs in estimating the future net revenues disclosed in Part 2 as derived from the Reserve Report.

Eltham Permit

As at December 31, 2014, management expected to incur abandonment and reclamation costs on five net wells located on the Eltham Permit. The total undiscounted amount of such costs, net of estimated salvage value, is estimated by the Company to be approximately $1,845,000 (estimated present value of $1,317,000 using a 10% discount rate). Within the next three financial years, the Company estimates that abandonment and reclamation costs, net of estimated salvage value, will total $Nil (estimated present value of $Nil using a 10% discount rate).

Of the abandonment and reclamation costs disclosed above, $826,000 was deducted as abandonment and reclamation costs in estimating the future net revenues disclosed in Part 2 as derived from the Reserve Report.

TWN Permits and Waihapa Production Station

As at December 31, 2014, preliminary estimates carried out by management suggest that the Company's 50% interest in abandonment and reclamation costs related to 18 existing wells (9 net wells) on the TWN Permits is approximately $4,656,000 (estimated present value of $471,000 using a 10% discount rate). In addition, the Company's interest in estimated reclamation costs for the Waihapa Production Station is expected to be approximately $7,085,000 (estimated present value of $813,000 using a 10% discount rate).

Of the abandonment and reclamation costs disclosed above, $1,320,000 was deducted as abandonment and reclamation costs in estimating the future net revenues disclosed in Part 2 as derived from the Reserve Report.

Ranui Permit

In December 2013 the Company surrendered the Ranui Permit (PEP 38342), located in the East Coast Basin. As at December 31, 2014, management expected to incur abandonment and reclamation costs on the Ranui Permit related to one well. The total undiscounted amount of such costs, net of estimated salvage value, is estimated by the Company to be approximately $354,000, which is expected to be incurred within 12 months of the report date.

Tax Horizon

Regulations in New Zealand allow companies with common shareholdings to share losses and tax deductions across those companies, provided that certain requirements are satisfied. These requirements are complex and include a requirement for 49% of continuity of ownership in the loss company, while 66% of commonality of ownership has to exist in the group companies. Depending on the Company's ability to maintain shareholder continuity, as well as on the levels of production, commodity prices and capital expenditures, management currently does not expect to pay any income tax arising from cash flows on either the Copper Moki Permit or the TWN Permits.

Costs Incurred

The following table summarizes the estimated costs incurred for each of the following categories in the most recently completed fiscal year:

Expenditure	**Twelve months ended December 31, 2014**
Property acquisition costs (proved properties)	-
Property acquisition costs (unproved properties)	-
Exploration costs [(1)]	$989,828
Development costs [(2)]	2,719,623
Total	**$ 3,709,451**

Notes:
(1) Includes geological and geophysical capital expenditures and drilling costs for exploration wells.
(2) Includes development drilling, completion and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The Company did not drill any exploratory oil wells in the most recently completed fiscal year. The Company's most important current and likely exploration and development activities on its properties in 2015 are as follows:

Taranaki Basin

TWN Permits and Waihapa Production Station

The Company continues to focus its near-term exploration and development efforts on the TWN Permits. The Company's objective is to increase production and cash flow while reducing exploration expenses, and believes that opportunities exist on the TWN Permits to achieve this objective. The proposed work programme for 2015 includes the installation

of two, ESPs on the Waihapa-6A and Ngaere-2 wells. The objective being to increase total liquid production to 12-16,000 bpd and restore normal decline trend for primary oil recovery, while also attempting to outrun aquifer, reducing reservoir pressure below historic low and mobilise stranded oil. Installation of one or two jet pumps is also being evaluated.

Copper Moki Permit

The Company is evaluating an increase to production rate and recovery factor through the introduction of a water flood project in the Copper Moki permit, with the Waitapu-2 well to be used as the injector well. Necessary consents have been received, although no decision has been made at the date of this statement. A jet pump installation is being considered for the Copper Moki-3 well.

Eltham Permit

The Company will continue to reprocess and review seismic data covering the Eltham Permit in order to prioritize targets for future drilling.

Alton Permit

The Company is planning on drilling a commitment well in 2015, for which it will be responsible for contributing 65% of the development costs. The Company has received the necessary consents for drilling and is currently required to complete drilling by November 22, 2014.

East Coast Basin

The Company is actively seeking a partner to help fund exploration activities in the East Cape Permit.

East Cape Permit

The Company expects to reprocess 145km of 2D seismic and acquire 40km of new 2D seismic data.

Production Estimates

The following table sets out the volumes of production estimated for the year ending December 31, 2015 from the Copper Moki, Waihapa and Ngaere permits, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained earlier in Part 2 of this statement of reserves data.

Category	Light and Medium Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Barrels of Oil Equivalent (BOE/d)
Copper Moki Permit				
Gross Proved Production	132.1	310.8		183.9
Gross Probable Production	7.2	16.8	-	10.0
Waihapa and Ngaere Permits				
Gross Proved Production	128.8	275.1	-	174.7
Gross Probable Production	1.9	5.2	-	2.8

Production History

The Company started producing from its wells on the Copper Moki Permit as follows: Copper Moki-1, December 2011; Copper Moki-2, April 2012; Copper Moki-3, June 2012; Waitapu-2, December 2012. The Company started producing from its six reactivated wells on the TWN Permits in November 2013. The following table summarizes certain information regarding estimated production, product prices received, estimated royalties incurred, estimated operating expenses and the estimated resulting netback for the year ended December 31, 2014:

	Quarter Ended				Year Ended
	Mar 31, 2014	Jun 30, 2014	Sep 30, 2014	Dec 31, 2014	Dec 31, 2013
Average Daily Production (NZEC share)					
Light and medium oil (bbl/d)	219	210	203	169	183
Gas (Mcf/d)	-	-	-	-	-
Natural gas liquids (bbl/d)	-	-	-	-	-
Average Prices Received					
Light and medium oil ($/bbl)	119.15	118.22	108.35	75.84	115.77
Gas ($/Mcf)	-	-	-	-	-
Natural gas liquids ($/bbl)	-	-	-	-	-
Royalties Paid (NZEC share)					
Light and medium oil ($/bbl)	12.57	9.53	9.48	5.90	10.53
Gas ($/Mcf)	-	-	-	-	-
Natural gas liquids ($/bbl)	-	-	-	-	-
Production Costs ($/bbl) (NZEC share)	44.25	43.38	27.83	27.76	33.72
Field Netback Received ($/bbl)	62.33	65.30	71.04	42.18	71.52

The Company's working interest share of production volumes, in total and for each important field, for the year ended December 31, 2014, are set out in the following table.

Production Volume	**Light and Medium Oil (bbl)**	**Natural Gas (Mcf)**	**Natural Gas Liquids (bbl)**
Copper Moki Permit	46,460	-	-
Waihapa and Ngaere Permits	26,478	-	-
Total	**72,938**	-	-