Management's Discussion and Analysis

Year Ended 31 December 2017

(Expressed in Canadian Dollars)

This Management's Discussion and Analysis ("MD&A") is dated 30 April 2018, for the year ended 31 December 2017. It should be read in conjunction with the audited consolidated financial statements for the year ended 31 December 2017 of New Zealand Energy Corp. ("NZEC" or the "Company") 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 associated consolidated financial statements, are presented in accordance with IFRS.

This MD&A includes certain statements which may be deemed "forward-looking statements" (see *Forward-looking Information*). All amounts are in Canadian dollars unless otherwise stated.

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

NZEC's BUSINESS

NZEC, through its subsidiaries (collectively "NZEC" or "the Company") is engaged in the production of and exploration for oil and natural gas, as well as the operation of midstream assets, in New Zealand. The Company's assets are located on New Zealand's North Island in the Taranaki Basin which is New Zealand's only commercial oil and gas producing area.

Background

NZEC is the Operator of three Petroleum Mining Licences ("PMLs"), one Petroleum Mining Permit ("PMP") and one Petroleum Exploration Permit ("PEP") in which it has an interest. It holds a 50% interest, in the PML 38138 ("Tariki Licence"), PML 38140 ("Waihapa Licence") and PML 38141 ("Ngaere Licence") (collectively the "TWN Licences"). L&M Energy Limited ("L&M") hold the remaining 50%.

NZEC has a 100% interest in PMP 55491 ("Copper Moki PMP") and PEP 51150 (the "Eltham Permit") – see Recent Developments.

NZEC holds a 50% working interest (with New Dawn Energy Limited) in, and is operator of, the Waihapa Production Station and associated gathering and sales infrastructure (collectively the "TWN Assets"), providing a range of services to third parties including operation of the Ahuroa gas storage facility, oil handling and pipeline throughput, gas processing and transport, LPG storage and produced water handling and disposal.

ANNUAL AND QUARTERLY OPERATING & FINANCIAL HIGHLIGHTS

The following are the operating and financial highlights for the quarter and year to date:

1. **Safety:** Achieved over 2 years Harm Free until a first aid treatment case was reported on 5 May 2017. There have been no harm cases reported since then.

2. **Waihapa-Ngaere Production:** The average rate for the fourth quarter was 64 boe per day (73% oil). This was an increase from the 46 boe per day NZEC share (84% oil) in the third quarter as the production wells recovered from the planned, and some unplanned, compressor down time in July and early August. Oil production has stabilised at increased rates, as expected, into Q1-18.

3. **TWN Enhanced Oil Recovery Project (Stages 1, 2 and 3):** The project is successfully reducing reservoir pressure and at voidage rates of 5000 to 7000 bfpd or more the natural aquifer effects are negated. Stage 2 was completed in Q1-17 with continuous gas-lift being implemented in two additional wells bringing the total number of wells on continuous production to four. The increase in water and gas throughput generated by this necessitated gas processing modifications and upgrades (Stage 3) prior to bringing further production volumes on line. This work was completed late in 2017 and planning for Stage 4, a high rate ESP installation, is underway with the activity scheduled for mid-2018 (see Recent Developments).

4. **TWN Waihapa Production Station:** Upgrades to the gas processing system to restore full gas dehydration and measurement have been completed. Arrangements to enable sales of non-specification gas to third parties, beyond blending within the production system, are being finalised with the relevant infrastructure operators.

5. **Copper Moki:** Production from Copper Moki-1 was constrained for the fourth quarter, with pump related mechanical issues resulting in the well being shut in from 14 November (see Recent Developments). Production prior to shut-in

had been stable at ~40bopd, which was higher than before water injection commenced (~26bopd) in late 2015. The Copper Moki-1 well water cut become significant in February 2017 and some decline in oil rates was seen through the first half of 2017. The stable production through the third and fourth quarters was largely the result of the removal of production system back-pressure at the Copper Moki site in early July 2017. Copper Moki-2 currently produces with no significant decline in oil rate through the last 9 months and with no significant water. The average rate from the Copper Moki wells for the fourth quarter was 41 boe per day all NZEC share (100% oil); and for the full year was 64 boe per day (94% oil).

6. **Production:** Production for the fourth quarter was 9,660 boe (84% oil) (with an average 105 boe per day); and for the year 46,982 boe (87% oil) (with an average 129 boe per day).

7. **Sales (oil):** Oil sales for the quarter of 9,466 bbl realised $704,678 (with an average oil sale price of $74.45 per bbl); and for the year 48,814 bbl realised $3,174,677 (with an average oil sale price of $65.04 per bbl).

8. **Processing revenue:** Increased third party processing volumes were achieved in 2017. The TWN Assets generated $622,444 from processing fees for the last quarter, and $2,461,946 for the year, with a number of third-party customers accessing a range of services including site operations, oil processing and handling, pipeline throughput services, gas processing, LPG storage and handling, and produced water disposal. Ahuroa Gas Storage related contracts were renewed on substantially the same terms as previously.

9. **Operating Cost Reductions**: The Company has implemented a series of changes and achieved a reduction of ~$1 million in annualised cash operating costs. This included moving the New Plymouth Operations office to smaller and less expensive premises closer to oil service companies and pipe yards in May 2017.

10. **Royalty Transfer Transaction**: In March, an Overriding Royalty (Royalty Agreement) was acquired from a third party which contained an obligation due by a related party. Concurrently it was agreed to fully discharge and cancel the related party's obligations under the Royalty Agreement in return for payment from the related party. Payment to the third party and receipt from the related party is spread over 2 years, with future payments/receipts secured by back-to-back bank guarantees. The arrangement was immediately cash positive for NZEC by the amount of the gain under the arrangement of NZ$154,000 (after transaction costs).

11. **Annual General Meeting (AGM):** The Company held its AGM on 27 July 2017 with all resolutions being passed, including resolutions to set the number of directors at three (3) and re-elect James Willis, Mark Dunphy and David Llewellyn to the Board. In addition, PricewaterhouseCoopers (New Zealand) were appointed auditors.

2018 OUTLOOK

Key objectives for the year include:

1. Refreshing our Safety Culture in order to maintain our goal of zero harm to people and the environment in partnership with the local community in respect of the Company assets;

2. Continuing the incremental development of the Waihapa-Ngaere Enhanced Oil Recovery Project. This will include installation of an ESP in one well in central Waihapa-Ngaere during 2018;

3. Optimising the management of the Copper Moki waterflood and extending the waterflood area where commercially viable;

4. Identifying opportunities within the Company assets for low cost developments. This includes opportunities within the producing Waihapa, Ngaere and Copper Moki assets as well as those in the Tariki licence that are accessible from existing wells.

RECENT DEVELOPMENTS

1. **Copper Moki-1:** In mid-November 2017 Copper Moki-1 experienced pump related mechanical issues resulting in the well being shut in pending a pump replacement. A rig-based workover was completed in mid-February 2018, with subsequent production results above expectation. By the end of February Copper Moki-1 was producing at ~100 bopd and 115 bwpd. In early March some pump-jack servicing was carried out and the stroke rate was increased by 15%. The result was a further increase in production volumes and through the balance of March 2018 Copper Moki-1 produced at an average of 160 bopd and with a decreasing water cut.

2. **Waihapa/Ngaere:** The joint venture has approved in principle moving to implement Stage 4 of the enhanced oil project, with the installation of an ESP in the Ngaere-1 well being progressed for mid-2018. This activity will predominantly use equipment that is in inventory or available to be deployed from elsewhere in the operated assets. The objective of Stage 4 is to increase the fluid volume being produced from Waihapa-Ngaere and accelerate the pressure depletion and hence oil production.

3. **Eltham PEP 51150:** An Appraisal Extension Application has been lodged with a modified Work Program and over a reduced area of PEP 51150. The application area includes the 2012 Arakamu- 2 discovery well, which produced oil from the Miocene Mt. Messenger Formation when tested in Q1 2013. The Appraisal Extension is being assessed by the regulatory authority, New Zealand Petroleum and Minerals.

FINANCIAL SNAPSHOT

	Three months ended 31 December 2017	***Year ended 31 December 2017***	***Year ended 31 December 2016***	***Year ended 31 December 2015***
	bbl	***bbl***	***bbl***	***bbl***
Production	8,078	40,724	62,767	42,012
Sales	9,466	48,814	60,871	44,856
	$/bbl	***$/bbl***	***$/bbl***	***$/bbl***
Price	74.45	65.04	52.49	60.52
Production costs	40.39	27.32	22.14	28.11
Royalties	7.33	5.02	2.97	4.46
Field netback	26.74	32.70	27.38	27.95
	$	**$**	**$**	**$**
Revenue	2,553,907	8,678,277	5,866,607	4,937,518
Total comprehensive loss	(3,053,491)	(4,919,183)	(5,513,200)	*(5,240,854)
Net finance expense	(168,689)	(413,858)	(317,644)	(268,936)
Loss per share – basic and diluted	(0.013)	(0.020)	*(0.027)	(0.023)
Current Assets		2,939,449	1,837,928	4,071,289
Total Assets		21,157,962	23,066,531	28,200,578
Total long-term liabilities		12,491,711	10,849,429	11,006,673
Total liabilities		15,422,471	12,460,491	12,133,031
Shareholders' equity		5,735,491	10,606,040	16,067,547

Note: The abbreviation bbl means barrel of oil.

*Note: Restated for Change in Accounting Policy. See details provided in the *2016 Consolidated Financial Statements - Note 2, Changes in accounting policies*

RESERVES

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 31 December 2017.

NZEC's Proved + Probable ("2P") reserves, reflecting the Company's 100% interest in the Copper Moki Permit and its 50% interest in the Waihapa, Tariki and Ngaere PMLs, are estimated at 767,000 barrels of oil (1,039,000 barrels of oil equivalent, including associated gas[1]) with an after tax net present value discounted at 10% (at 31 December 2017) of $13.2 million.

Technical revisions reduced ~213,000 bbl of oil reserves in 2017. After producing ~41,000 bbl of oil, the net reduction in remaining oil reserves at 31 December 2017 was ~254,000 bbl. Excluding production:

1. **Copper Moki** – reduced oil reserves largely attributable to declines observed through 2017 in Copper Moki-1 (considered attributable to pump deterioration - see Recent Developments) and Copper Moki-2; and

2. **Waihapa/Ngaere** – reduced oil reserves attributable to general decline (see Recent Developments regarding the intention to move to Stage-4 of the enhanced oil project).

See the Company's *Form 51-101F1 Statement of Reserves Data* dated 30 April 2018 which is filed on SEDAR for full information on the Company reserves and in particular, *Part 4 Reconciliation of Changes in Reserves*.

[1] Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. The boe conversion ratio of 6 Mcf : 1 bbl is based on an energy equivalency conversion 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 31 December 2017						
	Light & Medium Oil		Natural Gas		Barrels Oil Equivalent	
Reserves Category	Gross[2] Mstb[1]	Net[3] Mstb	Gross MMcf[1]	Net MMcf	Gross Mboe[1]	Net Mboe
Proved						
Developed Producing	186.7	164.0	743.3	642.7	310.6	271.1
Developed Non-Producing	202.5	178.9	318.4	277.0	255.6	225.0
Undeveloped	129.3	111.2	116.3	100.2	148.6	127.9
Total Proved	**518.4**	**454.1**	**1,178.1**	**1,019.9**	**714.8**	**624.1**
Probable	248.2	217.5	455.4	395.7	324.1	283.4
Total Proved and Probable	**766.6**	**671.6**	**1,633.5**	**1,415.6**	**1,038.9**	**907.5**

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

(2) Gross reserves are the Company's working interest share before the deduction of royalty obligations payable to the New Zealand Government and Beach 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 Beach Energy Resources NZ (TAWN) Limited

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE						
Before & After Tax						
Forecast Prices and Costs						
As at 31 December 2017						
	Net Present Value of Future Net Revenues Before and After Tax Discounted at %/year					
Reserves Category	0% $000	5% $000	10% $000	15% $000	20% $000	Unit Value 10% ($/BOE)
Proved						
Developed Producing	-462.4	214.9	489.8	627.9	702.0	1.81
Developed Non-Producing	9,634.8	6,131.6	4,319.4	3,276.2	2,606.8	19.19
Undeveloped	5,078.3	3,566.9	2,570.3	1,904.8	1,445.5	20.10
Total Proved	**14,250.7**	**9,913.4**	**7,379.4**	**5,808.8**	**4,754.3**	**11.82**
Probable	14,405.4	8,530.7	5,790.7	4,232.2	3,232.7	20.43
Total Proved Plus Probable	**28,656.2**	**18,444.1**	**13,170.1**	**10,041.0**	**7,987.0**	**14.51**

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

PROPERTY REVIEW AND OUTLOOK

This section reviews activities and developments during the reporting period in respect of the Company's assets.

The Company produces from Waihapa and Ngaere production wells in the TWN Petroleum Mining Licences and from the Copper Moki wells in the Copper Moki Mining Permit.

TWN Petroleum Mining Licences

The enhanced oil recovery project being implemented mobilizes stranded oil by reducing reservoir pressure and increasing pressure differentials on lesser quality reservoir. Recent measurements confirm this is being achieved through direct reservoir pressure measurements and increases in oil rates from wells when total fluid rates are maintained at, or above, 6000 bfpd.

Stage-1 was implemented in H2-16 with a high fluid rate gas-lift valve system in Waihapa-6 (late July 2016). Stage 2 was completed in Q1-17 with continuous gas-lift being implemented in two additional wells bringing the total number of wells on continuous production to four. The increase in water and gas throughput generated by this necessitated gas processing modifications and upgrades (Stage 3) prior to bringing further production volumes on line. This work was completed late in 2017 and planning for an additional high fluid rate well (Stage 4) is progressing according to schedule. The objective of this stage is to double the total fluid production to 14,000 bbls per day of fluid. A subsequent Stage 5 is envisaged to enable further oil production optimisation within the plant maximum capacity limit of 18,000 bbls per day of fluid, and would likely include a further ESP.

See also *Permit Expenditure Plans* below.

Copper Moki Petroleum Mining Permit

Copper Moki-1: The Copper Moki pool waterflood implemented in late 2015 has been successful in increasing oil rates and in maintaining oil production rates at more than 40 bbls per day through 2016 and 2017. Water production commenced in February 2017 and some decline in oil rates was seen through the first half of 2017, which was largely mitigated in net oil rate terms by removal of production system back-pressure at the Copper Moki site in early July 2017. Hence oil rates through the latter half of 2017 were close to what they were in Q4-16 (i.e. > 40 bbls per day), albeit with water cuts up from less than 1% in 2016 to 54% in November 2017.

In mid-November 2017, Copper Moki-1 experienced pump related mechanical issues resulting in the well being shut in pending a pump replacement. The first attempt at replacement of the pump (using a crane) in late November 2017 was unsuccessful. A rig-based workover was completed in mid-February 2018 (see Recent Developments).

Copper Moki-2: Copper Moki-2 oil production declined relatively slowly through 2017 (from ~28 bopd in January to ~22 bopd by December 2018). Throughout this time, the water production has remained stable and typically at less than 2 stb/d.

Eltham Petroleum Exploration Permit

The Company has completed assessing its appraisal and exploration opportunities portfolio in the Eltham PEP and has applied for an Appraisal Extension over a greatly reduced area (898 acres or 3.6km^2) of PEP 51150. The application area includes the 2012 Arakamu- 2 discovery well, which produced oil from the Miocene Mt. Messenger Formation when tested in Q1-13.

The previous flow testing at Arakamu-2 was hampered by sand production and the low reservoir gas content and hence there remains significant uncertainty about the nature of the petroleum deposit. Further evaluation and testing will reduce this uncertainty and allow the Operator to determine the commerciality of this resource.

The Appraisal Extension is being assessed by the regulatory authority New Zealand Petroleum and Minerals.

TWN Midstream Assets

Services are provided to Contact Energy in relation to operation of the Ahuroa Gas Storage facility and these contracts were renewed in mid-2017 on substantially the same terms. In late 2017 Contact Energy announced the sale of the Ahuroa Gas Storage facility to Gas Services New Zealand Limited with a notional completion date of 30 June 2018. NZEC anticipate remaining in place as operator of the Ahuroa facility post completion of the sale.

In addition, other parties are accessing services for oil processing, handling and pipeline throughput, gas processing and transport, and handling and disposal of produced water. The increased third-party processing volumes and revenues seen in the nine-months to September were sustained to year end.

SUMMARY OF QUARTERLY RESULTS

	2017 Q4 $	2017 Q3 $	2017 Q2 $	2017 Q1 $
Total assets	21,157,962	23,908,933	25,476,119	24,358,299
Exploration and evaluation assets	-	-	-	-
Property, plant and equipment	16,567,342	18,095,034	19,677,449	18,890,865
Working capital	8,689	70,478	(1,961)	138,203
Revenues	2,553,907	2,074,599	2,143,077	1,906,695
Accumulated deficit	(138,670,524)	(135,597,393)	(135,277,017)	(134,714,568)
Total comprehensive income (loss)	(3,053,491)	(849,855)	(87,814)	(928,023)
Basic (loss) earnings per share	(0.013)	(0.001)	(0.002)	(0.003)
Diluted (loss) earnings per share	(0.013)	(0.001)	(0.002)	(0.003)

	2016 Q4 $	2016 Q3 $	2016 Q2 $	2016 Q1 $
Total assets	23,066,531	27,767,054	27,760,038	26,626,239
Exploration and evaluation assets	-	-	-	-
Property, plant and equipment	19,360,187	24,416,925	23,697,976	22,350,797
Working capital	226,866	2,246,930	2,330,257	2,599,423
Revenues	1,476,623	1,356,500	1,574,491	1,458,994
Accumulated deficit	(134,133,724)	(132,152,473)	(131,026,279)	(130,225,100)
Total comprehensive income (loss)	(2,532,614)	(657,210)	(473,974)	(1,849,401)
Basic (loss) earnings per share	(0.010)	(0.005)	(0.004)	(0.004)
Diluted (loss) earnings per share	(0.010)	(0.005)	(0.004)	(0.004)

*Note: Restated for Change in Accounting Policy. See details provided in *2016 Consolidated Financial Statements - Note 2, Changes in accounting policies*

See "*NZEC's Business", "Property Review & Outlook" and "Results of Operations"*, for the activities to which this summary of quarterly results relates.

RESULTS OF OPERATIONS FOR THE THREE-MONTH PERIOD AND YEAR ENDED 31 DECEMBER 2017

This section of the MD&A provides analysis of the Company's operations in respect of the fourth quarter of 2017 ("Three Month Period") and the full year ("Year Ended" or "Twelve Month Period") compared to results achieved for the same periods in 2016. See *Operating & Financial Highlights* and *Property Review and Outlook* for a summary of the fourth quarter and full year 2017 operational events and activities.

Production and sales

	Three Month Period ended 31 December		Year ended 31 December	
Barrels or BOE	**2017**	**2016**	**2017**	**2016**
Production - Oil	8,078	14,750	40,724	62,767
Sales - Oil	9,466	14,609	48,814	60,871
Sales – Gas (BOE)	1,583	2,049	6,258	17,245
TOTAL Production (BOE)	9,660	16,799	46,982	80,012

The production decrease results principally from the performance of the Copper Moki-2 well, and in Q4-17 the shut in of Copper Moki-1 from mid-November 2017 due to pump related mechanical issues. Production during the same periods in 2016 exceeded expectations following installation of the new pump in December 2015.

Revenues

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Oil Sales	704,678	884,008	3,174,677	3,195,196
Gas Sales	40,822	(114,875)	148,460	436,143
Processing Revenue	622,444	544,972	2,461,946	2,091,165
Other Revenue	67,541	49,822	304,101	149,114
Purchased oil sold*	932,789	175,680	2,579,330	175,680
Royalty**	(69,346)	(62,983)	(245,215)	(180,691)
Oil sales per bbl	74.45	60.51	65.04	52.49

Note. In respect to Oil Sales, revenue is derived from oil sales volume, oil price and exchange rate. The realised per barrel price is based on the Brent crude oil price. See *item 7 in "Annual and Quarterly Operating Highlights"* above.

Gas sales for the 2016 Three Month Period were negative due to a year to date reclassification of costs between Gas sales and Production costs. Excluding this reclassification, the sales for the quarter would have been $50,170. For the Year ended sales reduced in line with the drop in oil production.

Processing Revenue – the increase reflects higher third-party processing volumes.

Other Revenue - the increase in the three-month period is due to consulting work done by the Company's staff for another company's abandonment program at the Ahuroa site. For the Year ended the consulting work contributed to the increase together with the Royalty Transfer Transaction (see #10 Highlights).

<u>*Purchased oil sold:</u> The Company has an arrangement with a third party whereby the Company purchases oil, charges a processing fee and subsequently sells the oil. Any unsold oil is carried as inventory.

<u>**Royalty</u>: Royalties paid are based on an ad valorem Crown royalty of 5% at Copper Moki and 10% (less allowable costs) for the TWN Licences. In addition, for the TWN Licences, there is a 9% overriding royalty payable to Beach Energy with a calculation based on the Crown royalty calculation. Total costs are related to the mix and source of production.

Production costs

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Production costs	382,266	105,793	1,333,487	1,347,697
Production cost per bbl	40.39	7.24	27.32	22.14

<u>Three Month Period</u>: Production costs were lower in 2016 due to a year to date reclassification of costs between Production Costs and Gas Sales. Excluding the reclassification, the costs would have been $270,838. Oil inventory value changes* increased costs by ~$70,000 (2016: reduction ~$70,000). If the changes due to the reclassification are accounted for and oil valuation excluded, the comparable underlying production costs would have been $312,660 (2016: $342,295) and the production cost per barrel would be $33.03 (2016: $23.43).

Excluding the changes above, underlying Production costs reduced compared to 2016 due to variable operating costs following decreased production ($30,000).

**Oil inventory value changes. In Q4-17 lower oil inventory volumes (sales being greater than production) resulted in a reduction in oil inventory value, hence an increase in production cost. In Q4-16 higher oil prices resulted in an increase in oil inventory value, hence a reduction in production cost.*

<u>Year Ended</u>: Oil inventory value changes* increased full year costs by ~$90,000 (2016: reduction ~$195,000). If the changes for the oil valuation are excluded, the comparable underlying production costs would have been $1,243,104 (2016: $1,543,414) and the production cost per barrel would be $25.47 (2016: $25.36).

Excluding the changes above, the underlying Production costs reduced compared to 2016 due to variable operating costs following reduced production ($300,000), and was reflected in the consistent production cost per barrel.

Processing costs

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Processing costs	194,198	195,413	1,071,152	908,172

The 2017 costs are higher due to the variable costs associated with the processing of purchased oil.

Depreciation and depletion

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Depreciation and depletion	313,696	513,136	1,299,230	2,043,583

Depletion on oil and gas assets is calculated using the unit-of-production method by reference to the ratio of production during the Three and Twelve-Month Periods as compared 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 decrease in 2017 principally reflects the lower levels of production.

Impairment

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Impairment PPE	1,591,776	2,955,857	1,591,776	2,955,857

Impairment – PP&E: The impairment in 2017 reflects the write-down of the Copper Moki permit as a result of reduced oil reserves largely attributable to declines observed through 2017 in Copper Moki-1 (considered attributable to pump deterioration - see Recent Developments) and Copper Moki-2 ($1,241,479). Several items of plant have also been impaired as they are no longer of use to the Company ($350,296) (2016: TWN Asset reduction associated with the utilisation of plant and related infrastructure). See further breakdown in *Consolidated Financial Statements - Note 7, Property Plant and Equipment*.

Share Based Compensation

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Share Based Compensation	12,158	12,386	48,634	51,099

The 2017 and 2016 expense reflects the fair market value attributed to options issued in November 2015. See also further detail in *Consolidated Financial Statements - Note 11b Share Purchase Options.*

General and Administrative Expenses

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
General and administrative expense	835,478	984,118	3,768,717	4,124,088

The reduced costs recorded for the Twelve-Month and Three-Month Period compared to 2016 reflect the ongoing focus on cost reductions. Of note are the reductions in Consulting fees, Rent, and Salary and Wages. See further breakdown in *Consolidated Financial Statements - Note 14, General and Administrative Expenses*.

Finance Expense

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Accretion	70,604	101,786	301,941	313,390
Interest on Revolving Credit Facility	4,369	3,179	18,201	4,254
Interest on Financial Payables	93,716	-	93,716	-
Total Finance expense	168,689	104,965	413,858	317,644

Accretion expense is associated with asset retirement obligations and is lower in both the Three and Twelve-Month Periods compared to 2016, due to a reduction in the discount rates. See *Consolidated Financial Statements - Note 9, Long Term Asset Retirement Obligations,* for more information. The interest on the Revolving Credit Facility is higher in 2017 as the facility was in place for the full twelve months, compared to only the latter months of 2016. Interest on Financial Payables has been recognised using the effective interest method. There were no Financial Payables in 2016.

Abandonment Provision movement

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Abandonment provision movement	14,368	(1,387,342)	37,295	(1,012,307)

Abandonment provision movement during the Three and Twelve-Month Periods reflects the change in estimate for abandonment on wells which have previously been fully impaired. The credit in 2016 is principally due to a review and subsequent change in abandonment cost assumptions. The movement in the Twelve-Month period ended 31 December 2016 was also affected by the impact of a renewal, in quarter two, of the Tariki PML for a reduced 5-year term (previously assumed 20 years).

Exchange Difference on Translation of Foreign Currency

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Exchange Difference – gain / (loss)	19,640	(139,310)	(382,383)	(287,316)
Exchange rate at beginning of period	0.8978	0.9516	0.9385	0.9498
Exchange rate at end of period	0.8914	0.9385	0.8914	0.9385

Exchange differences arise from the translation of foreign operations and monetary items (largely based in NZD).

The NZD weakened against the CAD over all periods except Q4-17 resulting in translation losses.

PETROLEUM PROPERTY ACTIVITIES, OPERATIONS AND CAPITAL EXPENDITURES

Capital Expenditure

The Company recognised the following additions in Oil and gas assets during the Three and Twelve-Month Periods:

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
TWN Assets	231	4,946	62,724	269,838
Copper Moki	-	(2,860)	-	66,761
Other	-	-		
TOTAL	**231**	**2,086**	**62,724**	**336,600**

In the TWN Assets, the 2017 spend relates to a glycol dehydration unit refurbishment and a replacement export gas moisture analyser; while the 2016 spend relates to the oil plant inspection and certification and Waihapa-1B jet pump installation.

In Copper Moki, 2016 expenditure relates to Copper Moki-2 workover and water flood.

COMMITMENTS

See details provided in *Consolidated Financial Statements - Note 18, Commitments*.

PERMIT EXPENDITURE PLANS

See details provided in *Consolidated Financial Statements - Note 19, Permit Expenditure Plans*.

LIQUIDITY AND CAPITAL RESOURCES

	31 December 2017	31 December 2016
	$	**$**
Cash and cash equivalents	55,351	57,969
Revolving credit facility	(331,968)	(363,183)
Working capital	8,689	226,866

The Company continues to pursue a number of options to improve its financial capacity, including cash flow from oil and gas production, credit facilities, commercial arrangements or other financing alternatives to enable it to undertake operations required to further exploit the permits and licences it holds, with the objective of increasing petroleum production.

A number of factors have contributed to maintaining the Company's liquidity position during the year. These include increasing third party processing revenue and a continuing emphasis on cost control and reduction (e.g. General and Administrative Expenses).

The Company's ability to improve its financial capacity including its ability to retain financing facilities it currently has in place and the relative success of, and cash flow generated from, intended operations including the production achieved and the oil price obtained cannot be assured. See the *Consolidated Financial Statements - Note 1, Going Concern*.

CASH FLOW

	31 December 2017	31 December 2016
Cash provided by / (used in)	**$**	**$**
Operating activities	66,799	(782,961)
Investing activities	(40,030)	79,739
Financing activities	(31,215)	363,183

Although there was a net loss for the twelve-month period of $4,536,800 (2016: $5,225,884) cash was generated in operating activities. The more significant non-cash items included in the net loss during the period included $1,626,558 in depreciation, depletion and accretion (2016: $2,356,206), impairment of $1,591,776 (2016: $2,955,857), inventory write-down $1,020,773 (2016: $156,220), and a working capital change of $227,738 (2016: $(79,888)).

Investing activities were for the purchase of property, plant, and equipment, less $345,655 in 2016 for the release of restricted cash.

Financing activities were obtaining the revolving credit facility in 2016, and partial repayment of the facility in 2017.

RELATED PARTY TRANSACTIONS

See details provided in *Consolidated Financial Statements - Note 16, Related Party Transactions*.

OFF-BALANCE SHEET ARRANGEMENTS

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

CHANGE OF ACCOUNTING POLICY and ADOPTION OF NEW OR REVISED IFRSs

The Company has used the same accounting policies and methods of computation as in the annual consolidated financial statements for the year ended 31 December 2016.

NON-IFRS DISCLOSURES

NZEC uses certain terms for measurement within this MD&A which 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 the 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 consolidated financial statements for the three and twelve-month periods ended 31 December 2017 and 2016:

	Three Month Period ended 31 December		Year ended 31 December	
	2017	**2016**	**2017**	**2016**
	$	**$**	**$**	**$**
Net Revenue				
Oil sales	704,678	884,008	3,174,677	3,195,196
Royalties	(69,346)	(62,983)	(245,215)	(180,691)
Production Costs	(382,266)	(105,793)	(1,333,487)	(1,347,696)
Sub-total net revenue (a)	253,066	715,232	1,595,975	1,666,809
Barrels of Oil sold (b)	9,466	14,609	48,814	60,871
Field Netback [(a)/(b)] $/bbl	**26.74**	**48.96**	**32.70**	**27.38**

SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of voting common shares. As at 31 December 2017, the Company had 232,123,459 common shares outstanding.

As of the date of this MD&A, the Company's share capitalization included 232,123,459 common shares, 41,452,178 warrants and 10,608,000 share options, of which 608,000 stock options have vested and are exercisable.

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 development and exploration projects cannot be assured. In addition, the Company's operations are outside of Canada and are subject to risks arising from foreign exchange and foreign regulatory regimes. The Company works to mitigate these risks through such mechanisms as its project and opportunity evaluation processes, engagement with joint venture parties and employing appropriately skilled staff. In addition, insurance policies, consistent with industry practice, are maintained to protect against loss of assets, well blowouts and third party liability. The Company is committed to operating in accordance with all applicable laws and regulations, safely and with due regard to the environment.

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", "objective", "plan", "seek", "expect", "potential", "pursue", "subject to", "can", "could", "hopeful", "contingent", "anticipate", "look forward", and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors which 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 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, affecting the 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 which prevent the Company from raising the funds necessary for exploration and development on acceptable terms or at all; global financial market events which 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 the foregoing list of factors is not exhaustive.

Statements relating to "reserves and resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources described can be profitably produced in the future. This document includes references to management's forecasts of future development, probability of success, production and cash flows from such operations, which represent management's best estimates at the time. The 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 contained in this document, except in accordance with applicable securities laws.

CAUTIONARY NOTE REGARDING RESERVE & RESOURCE ESTIMATES

The oil and gas reserves calculations and income projections were estimated in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGEH") and National Instrument 51-101 ("NI 51-101"). The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf: one bbl was used by NZEC. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

Reserves are classified according to the degree of certainty associated with the estimates. Proved Reserves are those reserves which can be estimated with a high degree of certainty to be recoverable. It is likely the actual remaining quantities recovered will exceed the estimated proved reserves. Probable Reserves are those additional reserves which are less certain to be recovered than proved reserves. It is equally likely 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 the reserves described can be profitably produced in the future. These statements are based on current expectations which involve a number of risks and uncertainties, which could cause the actual results to differ from those anticipated. Contingent resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. Prospective resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from undiscovered accumulations. The resources reported are estimates only and there is no certainty any portion of the reported resources will be discovered and, if discovered, will be economically viable or technically feasible to produce.