new zealand
ENERGY CORP

Management's Discussion and Analysis

Year Ended 31 December 2024

(Expressed in Canadian Dollars)

This Management's Discussion and Analysis ("MD&A") is dated 3 June 2025, for the year ended 31 December 2024. It should be read in conjunction with the audited consolidated financial statements for the year ended 31 December 2024 of New Zealand Energy Corp. ("NZEC" or the "Group") 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 Group's website at www.newzealandenergy.com.

NZEC's BUSINESS

NZEC, through its subsidiaries (collectively "NZEC" or "the Group") is engaged in the production, development, appraisal, and exploration for oil and natural gas, as well as the operation of midstream assets, in New Zealand. The Group's assets are located on New Zealand's North Island in the Taranaki Basin, 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 each of which it has an interest. It holds a 50% interest in PML 38138 ("Tariki Licence"), PML 38140 ("Waihapa Licence") and PML 38141 ("Ngaere Licence") (known collectively as the "TWN Licences"). L&M Energy Limited ("L&M") holds the remaining 50% in these licences.

NZEC has a 100% interest in Mining Permit PMP 55491 ("Copper Moki PMP") and Exploration Permit PEP 51150 (the "Eltham Permit").

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 (known collectively as the "TWN Assets"). These provide a range of services to its own operated assets and to third parties including, oil handling and pipeline throughput, gas processing and transport, LPG storage and produced water handling and disposal.

The following are the operating highlights for the quarter:

1. **Safety:** Seven incidents associated with the Tariki-5/5A drilling program occurred in this quarter. No incidents were associated with harm to personnel. All incidents were classed as Minor with one having the potential to escalate to Medium. The majority of incidents had vehicle use associated with the incident, i.e. either a minor spill occurred or contact was made with a stationary object. Three incidents had a component of not following procedures and one was a non-compliance relating to the certification of a diesel tank. The volume of work at Waihapa increased over Q4 due to the commencement of drilling activities at Tariki-A and the modification of the A train at Waihapa to enable it to process Tariki 5 Gas. An ongoing focus on HSE by the site personnel resulted in a consistent volume of meaningful observation cards.

2. **Copper Moki-1:**Copper Moki-1 has been shut in since 30 April 2023 due to a failure of the equipment supporting the artificial lift pump. A well intervention to remove the existing failed pump and rods using a crane was attempted in June 2024 and was unsuccessful in restoring production as the existing pump could not be retrieved. This means that removal of the production tubing will be required tore-establish production. Planning for this is advanced, with Long Lead Items ordered and the work is scheduled to take place in Q2 of 2025.

3. **Copper Moki-2:** Copper Moki-2 has been shut in since 30 September 2022 due to a failure of the artificial lift pump. A remediation plan was prepared and work commenced in late May 2024 and was carried out in June 2024. The intervention was unable to be completed due to a leak identified in the existing tubing. This requires the tubing to be removed which was beyond the scope of that activity. Planning for a workover including tubing replacement is advanced, with Long Lead Items ordered and the work scheduled to take place in Q2 of 2025.

4. **Waihapa Production Station Low OPEX Mode:** Operations through Q4 focussed primarily on third-party oil, gas and water handling services.

5. **Waihapa-Ngaere Production:** The average rate (NZEC share) for Q4 2024 was 14 bopd (100% oil). This was an decrease from the 15 bopd NZEC share (100% oil) in Q3 2024. At quarter end the Waihapa and Ngaere Fields were producing 14 bopd. See "2024 Outlook" and "Property Review and Outlook". This reduction was primarily due to work associated with enabling Tariki Gas production to pass through the WPS A-train separator.

6. **Production:** Aggregate production for Q4 2024 was 1,249 boe (86% oil) (average 14 boe per day); compared to Q3 2024 when production was 1,395 boe (100% oil) (average 15 boe per day).

7. **Sales (oil):** Oil sales for Q4 2024 of 2,161 bbl realised $186,771 (with an average oil sale price of $86.45 per bbl) compared to the Q3 2024 sales of 823 bbl which realised $79,926 (with an average oil sale price of $97.12 per bbl). Lower sales are a result of lower production and less lifting during the year.

8. **Processing revenue:** The TWN Assets (NZEC share) generated $75,882 from processing fees for Q4, compared to $145,065 for the previous quarter, with several third-party customers accessing a range of services including site operations, oil processing and handling, oil and gas pipeline throughput services, water disposal and gas processing.

9. **Tariki PML 38138**: Drilling and completion of the Tariki-5 gas development well commenced on 30th September and was completed on 5th December 2025. The primary well Tariki-5 did not encounter the target Tariki Sands as it passed through the main thrust fault an estimated 15 to 20m above the Tariki sands. The well was subsequently sidetracked as Tariki-5A and this well successfully encountered the Tariki sandstone at 2587.5mAH (2172 mTVDSS), some 10m above the top Tariki sand in prior production well Tariki-1A. Tariki-5A intersected a total of 72.5 mAH (69.7 mTVD) of Tariki Sand. The Gas-Water-Contact was interpreted at 2191 mTVDSS making ~19mTVD gross of currently gas bearing sands. The well was completed with 3 ½" chrome tubing and set up for perforating of the top 7m of sand on wireline on 23rd December 2024. The well commenced production on 28th December initially to flare at site, and then to separation and flare at the Waihapa Production Station via the existing ~25km of 8" pipeline. Within 36 hours of startup the well was producing to market via WPS and the Cheal Production Station at rates of 1.5 to 2 TJ/d (1.3 to 1.8 mmscf/d) with a CGR of ~25 stb/mmscf (as expectation). The sales gas rates were restricted by the operating pressure of the third party Cheal facility and when that was dropped to 8 barg on January 2nd, 2025, the gas rates spiked to more than 4.5 TJ/d (4 mmscf/d). Subsequently, the gas rates declined and by mid January the well was unable to sustain gas rates higher than 0.5 TJ/d (0.45 mmscf/d). At this stage a Static pressure & temperature gradient survey was carried out and this showed that the two perforated sands were of limited size and poorly connected to the rest of the field. The decision was made to add a further 5 m of perforations and these were added on January 15th and well pressures were immediately increased back to expectation of ~3000 psia. Tariki-5A was then restarted and again initially at 1.5 to 2 TJ/d but ultimately ceased flowing due to liquids loading from some water production. The 3 ½" tubing requires more than 2.5 mmscf/d to lift water. Reservoir modelling indicates that lifting the water and gas for a 1-to-2-week period should be sufficient to establish gas coning from the up-dip gas volume and Tariki-5A could then produce at commercially attractive gas rates. Well engineering is being planned to restart gas flow by use of a velocity string in Q2 of 2025. Updated Reservoir Modelling to support conversion of the Tariki Field to Gas Storage operations is underway and is being carried out in close cooperation with Genesis Energy Ltd, who have previously purchased 12 months exclusive negotiation rights for accessing Tariki Gas Storage.

2025 OUTLOOK

Key objectives for the year include:

1. **Health and Safety:** The Group's focus remains on keeping safety as an embedded component of everyday operations, zero harm to people and the environment remains foremost in planning and implementing all Group and contractor activities. The Group continues to work with regulators, other operators, local community businesses, communities and iwi to maintain safe operations and HSE performance.

2. **Tariki**: The primary focus for the Company in 2025 is maturation of the Tariki Field to a Gas Storage Project within the next 18 months. There are three workstreams associated with this work; technical (sub-surface and facility), commercial, and operational/implementation. The sub-surface technical work commenced in mid Q1 2025 and the scope, cost and schedule for the proposed "Stage 1" (a.k.a demonstration project) is being developed in Q2 for implementation in early 2026, or earlier if suitable equipment can be sourced/modified within the region. Commercial discussions to development the framework for providing storage capacity rights and usage fees have commenced. An operational review of the Tariki-5/5A project was scoped in Q1 2025 and will be carried out in Q2 2025 so that the lessons from last year are retained and the Stage 1 project is achieved safely, on schedule and within budget.

3. **Waihapa-Ngaere Production:** Production had been operating on cyclic well unloads without the use of gas-lift until late September 2024 when unloading became much more sporadic due to plant changes at WPS to accommodate high pressure gas and liquids from Tariki. As Tariki production has stalled, production operations at Waihapa-Ngaere using cyclic well unloading have resumed and production is marginally higher than historic trends due to the 3 to 4 months of reduced unloading/offtake.

4. **Copper Moki:** Production at Copper Moki has been offline due to mechanical failures in Copper Moki 2 well in 2022 and in Copper Moki 1 in 2023. Activities to return these wells to production are now planned for May 2025 and are funded by Monumental Energy.

5. **Eltham PEP 51150:** Arakumu-2A is an oil discovery well that has produced minor volumes of oil to surface but has a viscous waxy low GOR oil, and hence no reservoir energy or drive. A trial of water injection into nearby offset wells was carried out through 2023/24 and a review of the data from this shows that no communication between these wells and Arakamu-2A was seen. Hence a Change of Conditions application was lodged with the regulator and was approved to replace the 1H 2025 Work Program with reservoir studies to evaluate alternative improved recovery technologies, i.e. heat and/or solvent injection. .

6. **Appraisal & Exploration:** The Company's portfolio of appraisal and exploration activities has been prioritised and was on hold while the Company focused on the Tariki redevelopment project. These projects will be updated and implementation expected to start in later in 2025 after a thorough external review process, and depending on available funding. These opportunities include accessing undeveloped discovered hydrocarbons in the Waihapa-Ngaere and Tariki permits, and exploration potential within the Waihapa/Ngaere and Tariki Licences and the Copper Moki and Arakamu Permits.

7. **Third Party services:** The Group continues to provide a number of services to third parties including disposal of oil processing and transportation, deep well waste fluids disposal, and storage of LPG, all of which provide a helpful source of additional revenue

FINANCIAL SNAPSHOT

	Three months ended 31 December 2024	***Year ended 31 December 2024***	***Year ended 31 December 2023***	***Year ended 31 December 2022***
	Bbl	***Bbl***	***bbl***	***bbl***
Production (oil)	1,077	5,704	9,657	26,118
Sales (oil)	2,161	6,233	10,143	25,842
	$/bbl	***$/bbl***	***$/bbl***	***$/bbl***
Price	86.45	91.28	89.75	122.29
Production costs	79.39	121.87	95.41	56.47
Royalties	(2.20)	2.93	1.82	6.92
Field netback	9.26	(33.52)	(7.48)	58.90
	$	**$**	**$**	**$**
Revenue	307,335	1,236,768	1,935,774	4,692,856
Total comprehensive profit/(loss)	(4,231,389)	(8,179,276)	(2,075,929)	1,840,340
Net finance expense	(135,640)	(524,823)	(533,333)	(487,291)
Profit/(loss) per share – basic and diluted	(0.27)	(0.59)	(0.69)	0.79
Current Assets		2,190,841	2,331,789	2,182,759
Total Assets		17,485,624	15,269,475	15,892,545
Total long-term liabilities		8,283,315	10,361,353	8,269,574
Total liabilities		13,348,158	11,674,472	12,440,663
Shareholders' equity		4,137,466	3,595,003	3,451,882

Note: The abbreviation bbl means barrel of oil.

PROPERTY REVIEW AND OUTLOOK

This section reviews activities and developments during the reporting period in respect of the Group's assets (see map following).

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

TWN Petroleum Mining Licences

Waihapa/Ngaere

The Waihapa Ngaere wells produce oil and gas from the fractured Oligocene Tikorangi Limestone at a depth of ~2700m. The field has been on production since 1988. It has produced up to 18,000 bopd in the past and has produced ~24 mmstb cumulative oil. Reservoir modelling indicates that there was initially ~44 mmstb Oil-In-Place and after ~24 mmstb cumulative oil production (i.e. recovery factor of ~55%) there remains ~20 mmtb Oil-In-Place in the field. The recovery factor in reservoirs of this type, where the connected porosity is entirely within open fracture networks, can be in excess of 80%.

The current focus is on assessing the opportunities for restoring production from wells which have had mechanical issues. Two of these wells have been prioritised, i.e. Waihapa H1 and Waihapa-6A, and work is progressing to implement these opportunities in mid 2025, with actual timing depending on the selected intervention methodology, Long Lead delivery times, and budget. Waihapa-H1 is a horizontal penetration of the crestal Tikorangi that produced well for ~6 weeks until the section of the open-hole close to the shoe collapsed. The well unloads ~70 bbls of oil that has seeped through the collapse every week. Waihapa-6A is the highest oil cut well in the field but has a poorly performing gas lift completion.

Tariki

Following completion of the updated reservoir modelling based on the results of the 2021 3D seismic survey at the Tariki field, a number of opportunities are being progressed.

a) Tariki formation – gas production

Deloitte has provided an independent evaluation confirming there are proved and probable reserves within Tariki, primarily up-dip of wells Tariki-5A and Tariki-1A. The Tariki Joint Venture is planning an activity to access this gas and confirm its presence and size from performance analyses. The presence of economically recoverable reserves within Tariki is not essential to a Gas Storage project but would be of material benefit to the Joint Venture and any storage participants.

b) Tariki formation – gas storage

The results from Tariki-5/5A and the subsequent re-interpretation of the structure supports the position that more than 20 PJ of gas can reliablybe stored in the Tariki formation, and at pressures less than the initial reservoir pressure of 4620 psia.
The achievable injection and extraction rates are in the range of 25TJ/day from a single well (and up to 75TJ/day from 3 wells). Discussions with counterparties are ongoing and plans are in progress for a demonstration Stage 1 project within 12 to 18 months.

c) Tikorangi formation

The Tikorangi formation, from which over 24 mmstb oil hase been produced at Waihapa/Ngaere, is present in the Tariki permit. The Tariki-2C well produced over 100,000 barrels of oil from the Tikorangi formation – a fractured limestone. The new seismic data indicates the Tariki-2C well penetrated the Tikorangi formation approximately 200 metres down dip from the crest of the structure. Shows were seen in the Tikorangi section drilled near the crest in Tariki-5 and in earlier well Kupara-1, both from the same Tariki A site. Kupara-1/1A and Tariki-4A and being reviewed for possible use to access the Tikorangi in this vicinity.
In addition, a restart of production from Tariki-2C is being investigated and this may be achievable by Q3 2025.

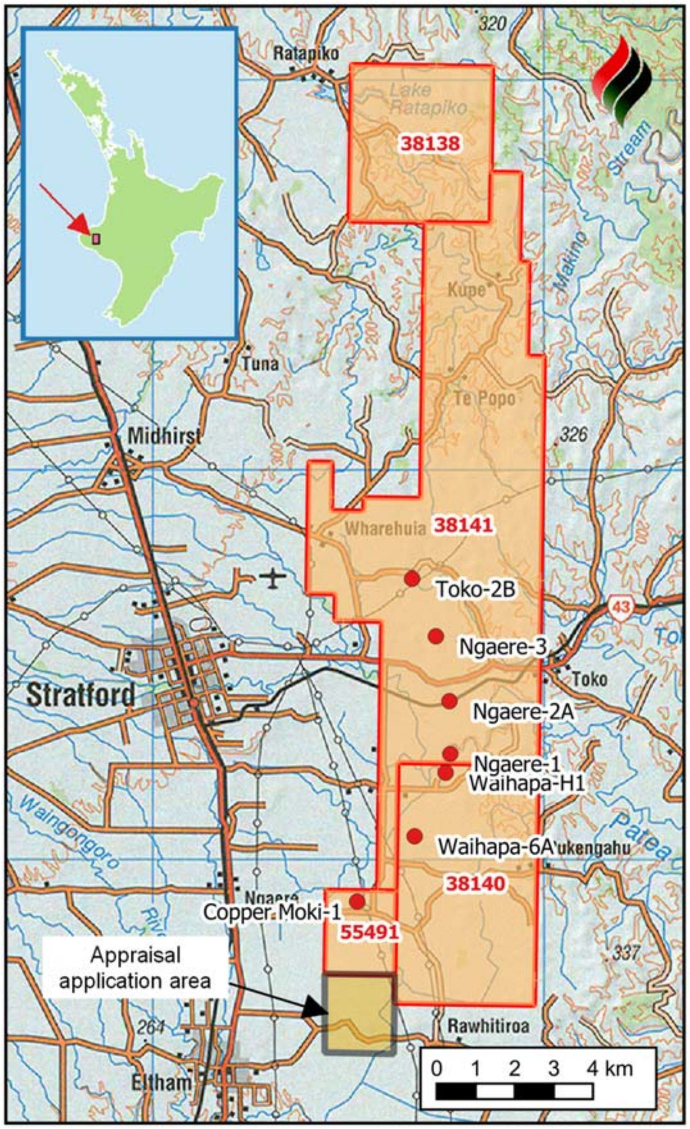
d) Mt Messenger formation

The 2021 3D seismic data has identified AVO bright spots and anomalies in the Mt Messenger formation. Oil has been produced from the Mt Messenger formation in a number of fields within the onshore Taranaki Basin, including at Copper Moki. Evaluation of these leads is continuing but is low priority.

Copper Moki Petroleum Mining Permit

Copper Moki-1: In Q4 2024 - no production.

Copper Moki-2: In Q4 2024 - no production.



A reservoir simulation study completed in Q1 2022 has provided technical assurance concerning the beneficial effects of water flood on the ultimate recovery in Copper Moki. Additional water injection is being considered using the Copper Moki-3 well. This is in addition to the water flood via the Waitapu-2 well.

Eltham Petroleum Exploration Permit

The PEP 51150 Appraisal Extension area includes the 2012 Arakamu-2 discovery well, which produced oil from the Miocene Moki and Mt Messenger Formations when tested in Q1 2013. This well had oil produced to surface and is the target of the Appraisal Extension Work Program.

Work will be undertaken to assess the effects of the water flood underway at Copper Moki on the Arakamu well.

TWN Midstream Assets

A number of third parties access services for oil, gas and water processing, handling and pipeline throughput and for storage of LPG.

RESERVES

As required under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, the Group commissioned RPS Energy Canada Limited to prepare year-end oil reserve estimates and economic evaluations with an effective date of 31 December 2024.

NZEC's Proved + Probable ("2P") reserves, reflecting the Group's 100% interest in the Copper Moki Permit and its 50% interest in the Waihapa, Tariki and Ngaere PMLs, are estimated at 553,700 barrels of oil (1,148,900 barrels of oil equivalent, including associated gas) with an after tax net present value discounted at 10% (at 31 December 2024) of $20.7 million.

Technical revisions removed 15,000 bbl of oil reserves in 2024. After producing ~1,200 bbl of oil, the net reduction in remaining oil reserves at 31 December 2024 was ~15,000 bbl. Excluding technical revisions: Technical revisions removed 2,555.8MMcf of gas, all from the Tariki Field.

1. **Copper Moki** – no reduced oil reserves during the calendar year.

2. **Waihapa/Ngaere** – reduced oil reserves attributable to volumes produced during the calendar year.

3. **Tariki** – Technical revisions made on 2P reserves.

See the Group's *Form 51-101F1 Statement of Reserves Data* dated 3 June 2025 which is filed on SEDAR for full information on the Group reserves, and in particular, *Part 4 Reconciliation of Changes in Reserves*.

OIL AND GAS RESERVES SUMMARY
As at December 31, 2024

	Light/Medium Crude Oil		Natural Gas		Barrels Oil Equivalent	
CATEGORY	Gross[2] Mstb[1]	Net[3] Mstb	Gross MMcf[1]	Net MMcf	Gross Mboe[1]	Net Mboe
Proved						
Developed Producing	67.2	60.5	107.1	96.4	85.1	76.6
Developed Non-Producing	382.3	334.0	2,972.5	2,670.9	877.7	779.2
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0
Total Proved	449.5	394.5	3,079.6	2,767.3	962.8	855.8
Probable	104.1	92.3	491.6	441.1	186.0	165.9
Total Proved and Probable	553.6	486.8	3,571.2	3,208.4	1,148.8	1,021.7

(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 Group's working interest share before the deduction of royalty obligations payable to the New Zealand Government.
(3) Net reserves are the Group's working interest share after deduction of royalty obligations payable to the New Zealand Government.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE December 31, 2024 Forecast Pricing						
	Net Present Value of Future Net Revenues Before and After Income Tax Discounted at %/year					
RESERVES CATEGORY	0% M$	5% M$	10% M$	15% M$	20% M$	Unit Value 10% $/boe
Proved Developed Producing	-1,844.1	-1,536.4	-1,229.4	-933.4	-831.9	-16.0
Proved Developed Non-Producing	43,125.9	26,074.3	19,123.8	15,371.2	12,975.1	24.5
Proved Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0
Proved	41,281.8	24,537.9	17,894.4	14,377.7	12,143.2	20.9
Probable	10,741.1	4,634.1	2,806.1	1,992.5	1,535.9	16.9
Proved Plus Probable	52,022.9	29,172.0	20,700.5	16,370.3	13,679.0	20.3

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

SUMMARY OF QUARTERLY RESULTS

	2024 Q4 $	2024 Q3 $	2024 Q2 $	2024 Q1 $
Total assets	17,485,624	18,969,421	18,094,561	14,777,783
Exploration and evaluation assets	-	-	-	-
Property, plant and equipment	14,902,717	14,720,106	12,725,180	12,387,675
Working capital	(2,874,002)	(1,556,544)	3,478,720	431,543
Revenues	307,335	288,667	301,536	327,620
Accumulated deficit	(150,880,496	(146,180,549)	(144,954,992)	(143,563,638)
Total comprehensive income (loss)	(5,195,291)	(883,022)	(1,186,044)	(914,919)
Basic (loss) earnings per share	(0.34)	(0.06)	(0.08)	(0.11)
Diluted (loss) earnings per share	(0.34)	(0.06)	(0.08)	(0.11)

	2023 Q4 $	2023 Q3 $	2023 Q2 $	2023 Q1 $
Total assets	15,269,475	13,298,867	13,760,994	15,860,553
Exploration and evaluation assets	-	-	-	-
Property, plant and equipment	12,519,607	11,475,566	12,135,894	13,230,269
Working capital	1,018,670	(2,984,734)	(2,670,509)	(2,172,120)
Revenues	262,981	428,481	502,968	741,344
Accumulated deficit	(142,809,446)	(142,339,971)	(141,945,119)	(141,262,009)
Total comprehensive income (loss)	(298,870)	(391,974)	(931,585)	(453,500)
Basic (loss) earnings per share	(0.11)	(0.14)	(0.33)	(0.16)
Diluted (loss) earnings per share	(0.11)	(0.14)	(0.33)	(0.16)

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 AND YEAR ENDED 31 DECEMBER 2024

This section of the MD&A provides analysis of the Group's operations in respect of the fourth quarter of 2024 ("Three Month Period") and the full year ("Year Ended" or "Twelve Month Period") compared to results achieved for the same periods in 2023. See *Operating & Financial Highlights* and *Property Review and Outlook* for a summary of the fourth quarter and full year 2024 operational events and activities.

Production and sales

	Three Month Period ended 31 December		Year ended 31 December	
Barrels or BOE	**2024**	**2023**	**2024**	**2023**
Production - Oil	1,077	1,809	5,704	9,657
Sales - Oil	2,161	1,546	6,233	10,143
Sales – Gas (BOE)	160	-	160	145
TOTAL Production (BOE)	2,320	1,809	6,393	9,802

Production is lower than achieved in 2023. This is the result of lower production in Copper Moki (nil) and Waihapa/Ngaere.

Revenues

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
Oil Sales	186,771	152,375	568,941	910,347
Gas Sales	4,487	-	4,487	-
Processing Revenue	75,882	66,425	495,391	759,901
Other Revenue	40,195	35,881	167,949	265,526
Royalty	4,761	8,544	(18,255)	(18,454)
Oil sales per bbl	86.45	98.56	91.28	89.75

Note. Oil Sales revenue is derived from oil sales volume, oil price and exchange rate. The realised price per barrel is based on the Brent crude oil price less contractual discounts and the exchange rate.

Processing Revenue: Revenue is lower as result of a decrease in water disposal services. Opportunities for increasing processing revenue are being pursued, including providing water disposal services for various third parties

Other Revenue – relates mainly to LPG storage and interest.

Royalty: Royalties paid are based on an ad valorem Crown royalty of 5% for Copper Moki and 10% (less allowable costs) for the TWN Licences.

Production costs

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
Production costs	171,525	102,946	759,642	967,750
Production cost per bbl	79.39	66.59	121.87	95.41

Processing costs

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
Processing costs	255,831	291,152	1,141,076	921,015

Depreciation and depletion and amortisation

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
Depreciation, depletion and amortisation	108,264	101,908	336,053	380,121

Depletion on oil and gas assets is calculated using the unit-of-production method i.e the ratio of production during the respective periods to the total proved and probable reserves.

General and Administrative Expenses

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
General and administrative expense	492,926	341,730	2,455,034	1,314,299

See further breakdown in *Consolidated Financial Statements - Note 16, General and Administrative Expenses*

Finance Expense

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
Accretion	85,229	73,791	324,823	333,000
Loan Interest Accrued	50,411	50,411	200,000	200,000
Total Finance expense	**135,640**	**124,202**	**524,800**	**533,000**

Accretion reflects the expense associated with asset retirement obligations. See *Consolidated Financial Statements - Note 9, Long Term Asset Retirement Obligations,* for more information.

Abandonment Provision movement

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
Abandonment provision movement	(25,834)	(250,845)	(5,313)	(291,356)

The Abandonment provision movement arises from the change in estimate for abandonment of wells which have previously been fully impaired.

Exchange Difference on Translation of Foreign Currency

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
Exchange Difference – gain / (loss)	(46,211)	(21,605)	158,346	(30,871)
Exchange rate at beginning of period	0.8598	0.8057	0.8387	0.8588
Exchange rate at end of period	0.8098	0.8387	0.8098	0.8387

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

The NZD exchange rate has strengthened against the CAD over the Three Month Periods and 12 months period to 31st December 2024

PETROLEUM PROPERTY ACTIVITIES, OPERATIONS AND CAPITAL EXPENDITURES

Capital Expenditure
The Group recognised the following additions in Oil and gas assets during the Three & Twelve Month Periods:

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
NZEC	(23)	-	9,471	17,687
TWN Assets	-	-	-	-
Tariki	3,600,509	61,033	5,782,672	102,849
TOTAL	**3,600,486**	**61,033**	**5,792,143**	**120,536**

Tariki relates drilling of Tariki 5 and processing of 3D seismic, and NZEC relates to the purchase of office equipment.

COMMITMENTS

See details provided in *Consolidated Financial Statements - Note 20, Commitments*.

PERMIT EXPENDITURE PLANS

See details provided in *Consolidated Financial Statements - Note 21, Permit Expenditure Plans*.

LIQUIDITY AND CAPITAL RESOURCES

	31 December 2024	31 December 2023
	$	**$**
Cash and cash equivalents	1,131,605	1,180,393
Working capital	(2,874,002)	1,018,670

The Group continues to pursue 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 and increase petroleum production. Its ability to improve its financial capacity, including its ability to maintain financing facilities it currently has in place, cannot be assured. See the *Consolidated Financial Statements - Note 1, Going Concern*.

CASH FLOW

	31 December 2024	31 December 2023
Cash provided by / (used in)	**$**	**$**
Operating activities	(1,962,125)	(1,404,159)
Investing activities	(5,792,143)	(120,536)
Financing activities	7,757,836	2,219,050

Net loss for the year was ($8,071,050) (2023: Loss: $1,938,713). The more significant non-cash items included in the net profit during the period included $860,876 in depreciation, depletion, accretion and other items (2023: $913,454), $2,956,000 in impairment (2023: $Nil) and a change in working capital items of ($1,175,114) (2023: $118,082) all contributing to cash used in operating activities of ($1,962,125) (2023: Used $($1,404,159).

Investing activities were for the purchase of oil and gas properties.

A number of private placements were undertaken during 2024.

RELATED PARTY TRANSACTIONS

See details provided in *Consolidated Financial Statements - Note 18, Related Party Transactions*.

OFF-BALANCE SHEET ARRANGEMENTS

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

CHANGE OF ACCOUNTING POLICY and ADOPTION OF NEW OR REVISED IFRSs

The Group has used the same accounting policies and methods of computation as in the annual consolidated financial statements for the year ended 31 December 2023.

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 Group 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 Group's operating performance. Field netback is reconciled as follows to the Group's consolidated financial statements for the Three and Twelve Month periods ended 31 December 2024 and 2024:

	Three Month Period ended 31 December		Year ended 31 December	
	2024	**2023**	**2024**	**2023**
	$	**$**	**$**	**$**
Net Revenue				
Oil sales	186,771	152,375	568,941	910,347
Royalties	4,761	8,544	(18,255)	(18,454)
Production Costs	(171,525)	(102,948)	(759,642)	(967,750)
Sub-total net revenue (a)	20,007	57,971	(208,956)	(75,857)
Barrels of Oil sold (b)	2,161	1,546	6,233	10,143
Field Netback [(a)/(b)] $/bbl	**9.23**	**37.50**	**(33.52)**	**(7.48)**

SHARE CAPITAL

The Group’s authorized share capital consists of an unlimited number of voting common shares. As at 31 December 2024, the Group had 20,572,963 common shares outstanding.

During the year the Group undertook a private placement in 2024 issuing 6,666,667 shares at a price of 0.75 per share. A second private placement took place issuing 1,115,617 shares at a price of 0.85 per share. A third private placement took place issuing 4,444,444 at a price of 0.45 per share.

As of the date of this MD&A, the Group’s share capitalization included 20,547,963 common shares, and nil warrants.

During the year 1,400,000 options were issued.

RISK FACTORS

Natural resources exploration and development involves a number of risks and uncertainties, many of which are beyond management’s control. The Group’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 Group’s operations are outside of Canada and are subject to risks arising from foreign exchange and foreign regulatory regimes. The Group 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 Group 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 Group 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 Group's oil and natural gas resources; supply and demand for oil and natural gas and the Group's ability to market crude oil and natural gas; expectations regarding the Group's ability to continually add to reserves and resources through acquisitions and development; the Group's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the Group's ability to raise capital on appropriate terms, or at all; the ability of the Group's subsidiaries to obtain mining permits and access rights in respect of land and resource and environmental consents; the recoverability of the Group's crude oil, natural gas reserves and resources; and future capital expenditures to be made by the Group.

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 Group 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 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 Group 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.