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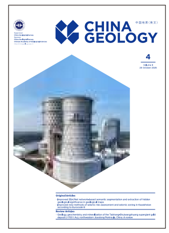

Organic geochemistry and basin modeling of the Eocene Mangahewa source rock system in the Pohokura oilfield, Taranaki Basin (New Zealand) and their indication of oil and gas potential

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A B S T R A C T

The importance of organic geochemistry and basin modeling is widely recognized and used to understand the source rock potential and hydrocarbon generation history of the Mangahewa Formation, and thereby given the foundational role in the petroleum exploration. This study utilized the total organic carbon (TOC) content and hydrogen index (HI) to investigate the dominant kerogen type and hydrogen richness for the significance of petroleum generative potential. The Mangahewa coals and carbonaceous shales exhibit an excellent source rocks, with high total organic content (TOC) of more than 22%. The coals and carbonaceous shales were also characterised by Type II–III kerogen with Type III kerogen, promising oil- and gas-prones. The Mangahewa Formation reached the main oil generation, with vitrinite reflectances between 0.53% and 1.01%. Vitrinite reflectance was also used in developing themal models and reveal the transformation (TR) of 10–50% kerogen to oil during the Late Miocene. The models also showed that the Mangahewa source rock has a significant oil generation and little expulsion competency, with a TR of up to 54%. These findings support the substantial oil-generating potential in the Taranaki Basin's southern graben and can be used as a guide when developing strategies for an oil exploration program.

1. Introduction

During the last few decades, organic-rich strata have been considered significant hydrocarbon resources globally and have gained attention as a fundamental source rock for conventional and nonconventional oil and gas production (Wilkins RW and George SC, 2002). Researchers have also verified the facts mentioned above through their investigation studies (Abdullah WH et al., 2017; Hazra B et al., 2022; Singh AK et al., 2020; Hakimi MH et al., 2023; Kumar A et al., 2020; Singh AK and Kumar A, 2020). Previous studies indicate that the Tertiary coal and coaly sediments from Brunei (Osli LN et al., 2022), Malaysia (Hakimi MH et al., 2013; Abdullah WH et al., 2017; Makeen YM et al., 2019 and 2020) and New Zealand (Talha Qadri SM et al., 2016; 2021) reveal a significant source rock character and capability to generate substantial volumes of hydrocarbon once thermal maturity is attained. Besides understanding source rock features and hydrocarbon generative potential, other tools such as geochemical and microscopic investigations are critically important in highlighting the conventional and unconventional prospects.

This study focuses on the Pohokura Oilfield, which is situated in the northeastern section of the Taranaki Basin and is primarily offshore with some onshore components. (Fig. 1).

The Taranaki Basin in New Zealand is the most recent petroleum-exploration region for oils and condensates, which comprises approximately 9 km thick succession from the Late

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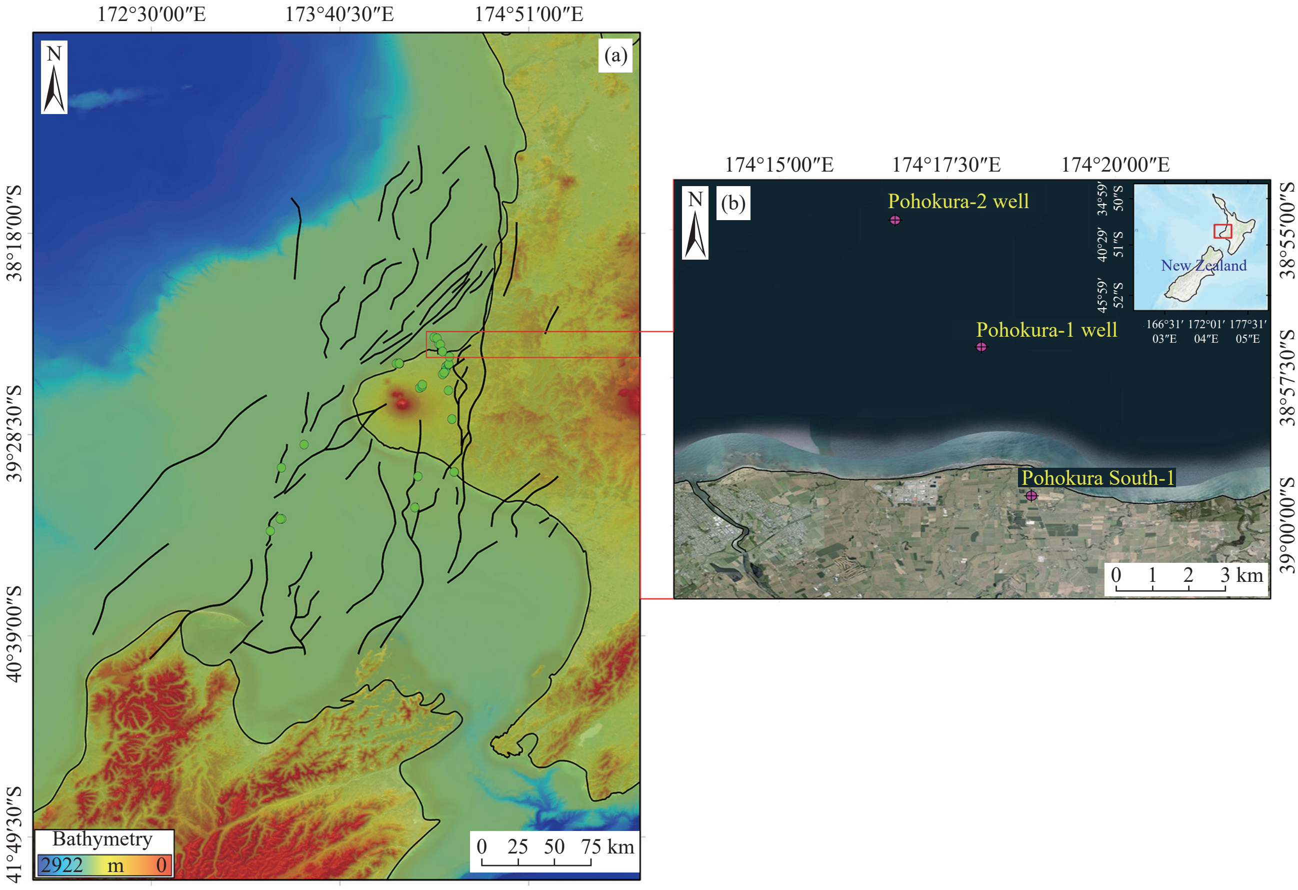

Fig. 1. Location maps of the Taranaki Basin displaying key wells, producing fields, structure and bathymetry, including studied wells (Pohokura-1, Pohokura-2, Pohokura-3 and Pohokura- South1).

Cretaceous to the Quaternary era (Fig. 2; King PR and Thrasher GP, 1996), and host several organic matter-rich strata in the Cretaceous to Miocene succession.

These organic-rich sediments of the Cretaceous to Miocene succession are considered high-quality oil- and gas-prone source rocks (Shalaby MR et al. 2019). In this case, several researchers have analysed the origin, paleodepositional conditions, organic matter's geochemical character, and the petroleum generation potential of the organic-rich sediment in the Mesozoic and Cenozoic sequences based on the geochemical and microscopic investigations (King PR and Thrasher GP, 1996; Sykes R et al., 2014; Talha Qadri SM et al., 2016; Jumat N et al., 2018; Shalaby MR et al. 2019; Lathbl MA et al., 2024).The recognized source rocks within the Taranaki Basin are represented mainly by coal and carbonaceous shale of the Late Cretaceous Rakopi and Paleocene Farewell formations. These geological formations play a crucial role as significant source rocks for both oil and gas hydrocarbons in the Taranaki Basin (King PR and Thrasher GP, 1996; Sykes R et al., 2014; Jumat N et al., 2018; Lathbl MA et al., 2024). However, more analyses are still needed in the Taranaki Basin, more specifically to the Eocene organic-rich rocks, to investigate the source rock properties, and their related petroleum generation and exploration. Although scientific investigation on organic-rich Mangahewa sediments within the sedimentary deposition in the Taranaki Basin during the Eocene time, emphasizing the source rock features and petroleum generative capability-related domains (Talha Qadri SM et al., 2016), the simulation of the petroleum generation history of the Mangahewa source rock system has not previously been studied in detail. Hence, an integration of the geochemical results, along with the basin modelling study was conducted in the current research for better characterizing the organic matter-bearing sediments (coal and carbonaceous shale) of the Eocene Mangahewa Formation in the Pohokura oilfield, northeastern Taranaki Basin (Fig. 1). Therefore, this research aims to better understanding the source rock properties of the coals and associated carbonaceous shale rocks in the Eocene Mangahewa Formation based on conventional geochemical methods and vitrinite reflectance measurements from four wells in the Pohokura oilfield, northeastern Taranaki Basin. In addition, this study discusses the application of 1D basin modeling for studying the geothermal burial history within the Pohokura oil field in relation to the kerogen cracking of the studied Mangahewa source rock, thereby deciphering the hydrocarbon exploration potential of the basin.

2. Geological setting

The Taranaki Basin evolved during multiple tectonic

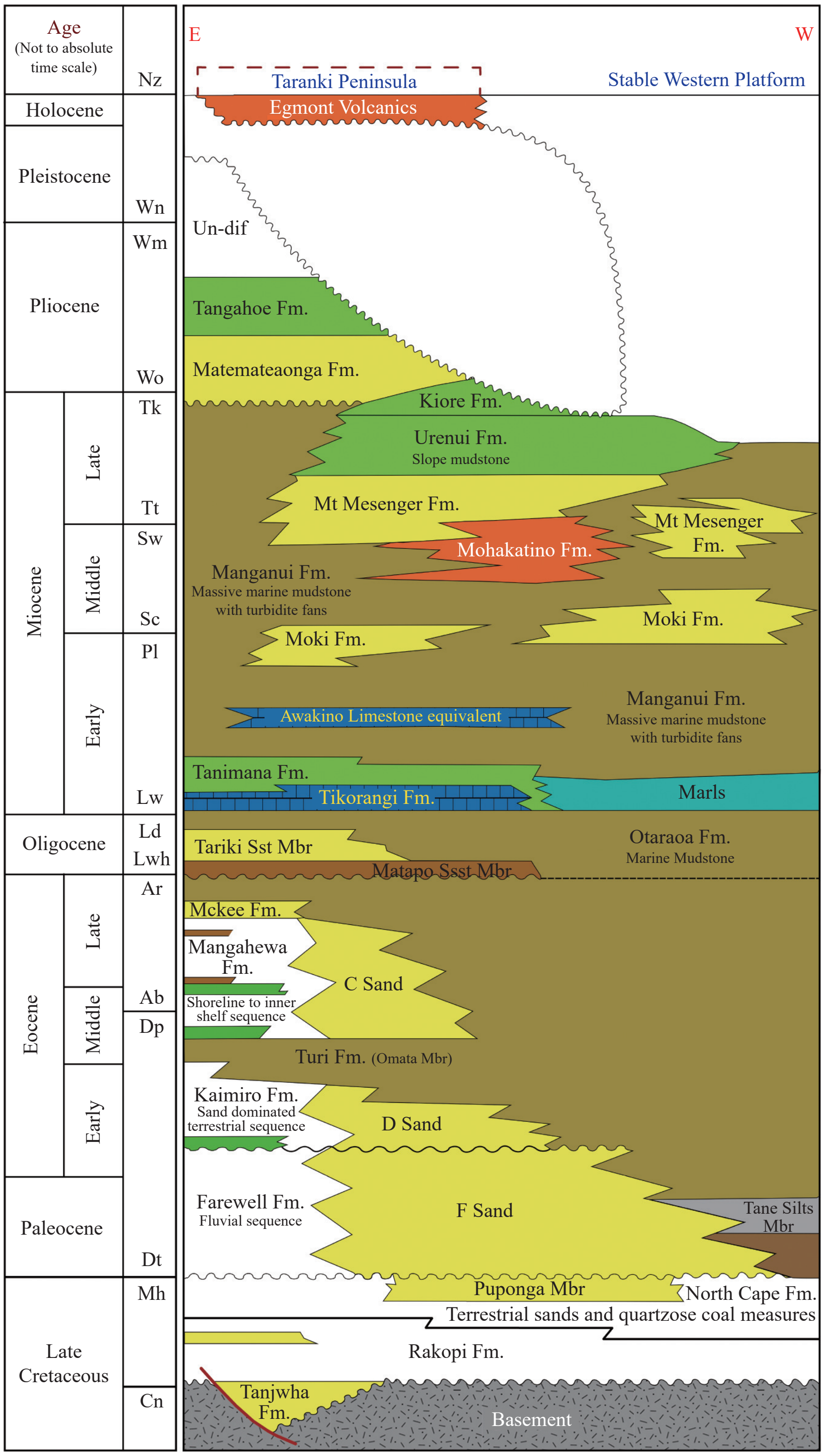

Fig. 2. Stratigraphic column of the Taranaki Basin (modified from O'Neill SR et al., 2018).

stages (Sykes R et al. 2014). The first rifting mechanism of the Taranaki Basin was initiated during the Mid-Cretaceous to Paleocene and associated with the break-up of Gondwanaland (Sykes R et al. 2014). The second tectonic phase of the basin evolution started during the Eocene and was terminated by the Early Oligocene, resulting in passive margin development. The third and most recent evolutionary phase was initiated during the Oligocene and continues today. The basin was changed into an active margin basin as a convergence between the Australian and Pacific plates (Sykes R et al., 2014). These tectonic phases have also resulted in relatively less deformed blocks (the Western Stable Platform) and severely deformed blocks, such as the Southern inversion zone and Manaia Graben, as shown in Fig. 3.

The Manaia Graben, also recognised as the Eastern Mobile Belt (King PR and Thrasher GP, 1996), exhibits the

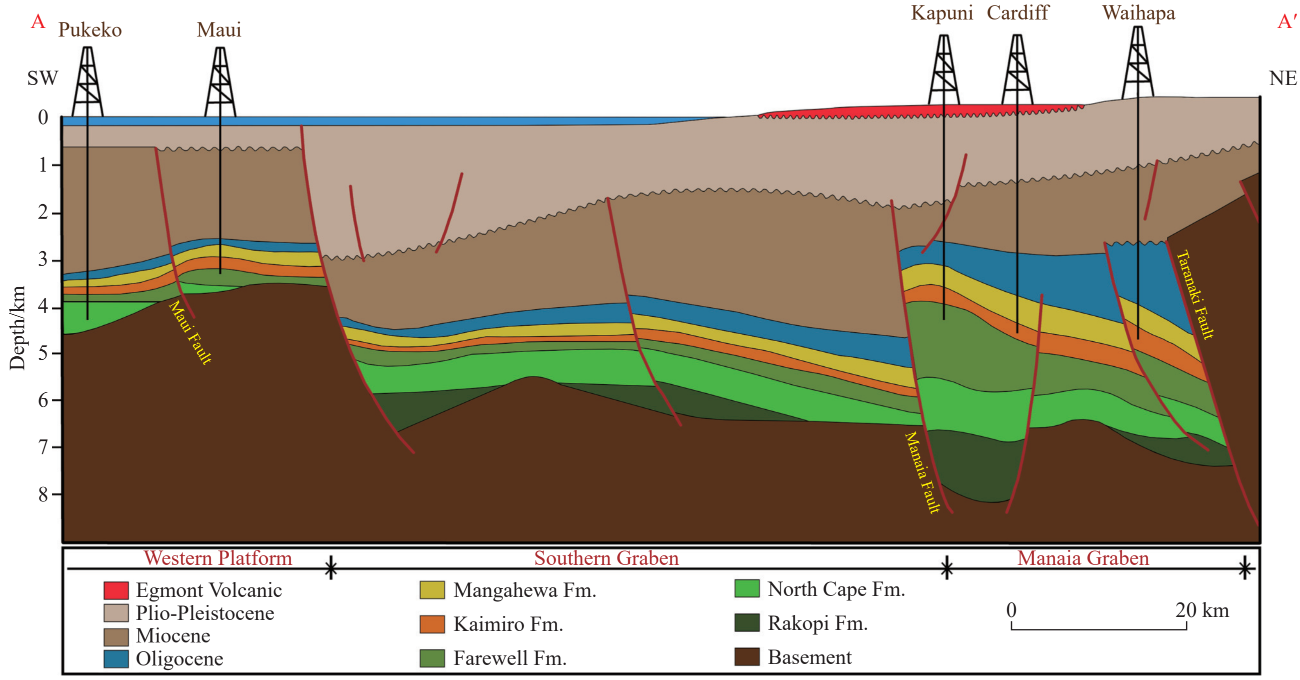

Fig. 3. Cross section displays the structural elements in the Taranaki Basin (modified from King PR and Thrasher GP, 1996).

dominance of compressional tectonic regimes resulting in structural features such as the Taranaki and Manaia Faults (Qadri SMT et al. 2017; Talha Qadri SM et al. 2019), where basement over thrusts Neogene and older formations (Fig. 3). The eastern boundary of the Taranaki Basin is marked by the Taranaki Fault, formed during the Mid-Cretaceous to Paleocene (Stagpoole V and Nicol A, 2008; Sykes R et al., 2014; Kamp P et al., 2014).

The Taranaki Basin also exhibits thick sedimentary succession with several significant unconformities (Fig. 2). It received a mixture of mainly clastic and carbonate sediments of the Mesozoic (Late Cretaceous) to Quaternary (Late Pliocene-Holocene), with a maximum recorded thickness for the Cenozoic (Paleocene-early Pliocene) sedimentary succession (Fig. 2).

The Late Cretaceous sediments are mostly clastic, unconformably overlying the basement rocks (Fig. 2). Meanwhile, the clastics and carbonate sediments dominate the Cenozoic succession. The Paleocene clastics from the Farewell Formation indicated the sedimentation during the early Cenozoic followed by the Eocene clastic sediments of the Kaimiro and Mangahewa formations (Fig. 2). The Mangahewa Formation, the primary subject of this investigation, is dominated by the intercalation of sandstone, siltstone, mudstone, coal and carbonaceous mudstone, and is further subdivided into terrestrial and coastal facies (King PR and Thrasher GP, 1996). It is considered one of the leading exploration targets in the Taranaki Basin, with a thickness ranging from 400 to 830 m (Talha Qadri SM et al., 2016). Furthermore, the lithofacies characteristics of the Paleocene-Eocene section (Farewell, Kaimiro, and Mangahewa Formations) reveals that this section hosts also the major reservoir rocks in the Kupe, Kapuni, Mangahewa, and Turangi gas condensate fields (O’Neill SR et al., 2018).

3. Materials and methods

3.1. Sampling and experimental methods

In the current study, 22 coal and carbonaceous shale drill cutting samples of the Eocene Mangahewa Formation were collected from different depths (Table 1) in four exploration wells (6 samples from Pohokura-1, 6 samples from Pohokura-2, 6 samples from Pohokura-3 and 4 samples from Pohokura South-1) in the Pohokura oilfield, northeastern Taranaki Basin as shown in Fig. 1B. The acquired samples were cleaned from the drilling mud by using the cold water before conducting organic geochemical and optical analyses as highlighted in the following subsections.

The samples were crushed to the fine powder and then subjected to geochemical analysis such as evaluating the total organic carbon content (TOC), i.e., total organic carbon (TOC) content and programmed pyrolysis (Rock-Eval) using a Rock-Eval II unit along with a total organic carbon module.

The Rock-Eval pyrolysis was conducted on approximately 100 mg of the powdered samples and was heated up to 600°C within a helium atmosphere, following the scheme designed by Espitalie J et al. (1977). The oven’s temperature was maintained at 300°C for 3 minutes and then increased to 25°C per minute. The parameters which were evaluated during the pyrolysis scheme included free hydrocarbon (S_1), remaining hydrocarbon (S_2), the amount of CO_2 during the thermal alteration of the oxygenated organic compounds (S_3), and maximum temperature (T_{max}) as shown in Table 1. The estimation of the parameters above was instrumental in deriving the Hydrogen index (HI), Oxygen index (OI) and petroleum yield (PY) using Rock-Eval scheme of Peters KE et al (1994).

Based on the varied burial depths within the studied wells,

Table 1. Geochemical results of the analyzed coal and carbonaceous shale samples of the Eocene Mangahewa Formation from four exploration well locations (Pohokura-1, Pohokura-2, Pohokura-3 and Pohokura- South1) in the Pohokura oilfield, Taranaki Basin (New Zealand), including TOC content, programmed pyrolysis (Rock-Eval-II) and measured vitrinite reflectance (VR%).

Well	Depth/m		TOC/%	Rock-Eval pyrolysis data							VR/%
				S_1/(mg/g)	S_2/(mg/g)	S_3/(mg/g)	T_{max}/°C	HI/(mg/g)	OI/(mg/g)	PY/(mg/g)	
Pohokura-1	3532	Coal	77.35	10.06	234.29	1.78	433	304	2	244.35	0.75
	3536	Coal	78.68	12.33	237.18	1.87	431	303	2	249.51	0.69
	3541	Coal	45.10	12.75	147.75	10.50	436	327	23	160.50	
	3543	Coal	73.15	13.21	222.32	4.80	432	306	7	235.53	
	3550	Carbonaceous shale	31.29	4.92	73.42	3.31	428	236	11	78.34	
	3552	Coal	70.98	15.00	195.66	195.66	431	275	18	210.66	0.61
Pohokura-2	3595	Carbonaceous shale	25.31	6.01	48.49	9.60	429	193	38	54.50	
	3597	Coal	57.36	8.99	193.25	3.20	414	338	6	202.20	0.53
	3601	Coal	49.20	14.7	128.20	18.80	426	261	38	142.90	0.65
	3604	Coal	66.70	19.00	160.60	12.01	431	241	18	179.60	0.72
	3611	Coal	74.53	6.53	176.50	8.71	432	238	12	183.03	
	3614	Carbonaceous shale	30.24	3.51	75.57	2.43	430	252	8	79.08	
Pohokura-3	3637	Carbonaceous shale	22.65	3.87	36.49	2.09	446	163	9	40.36	
	3640	Coal	60.60	8.70	98.20	10.55	429	162	17	106.90	
	3645	Coal	68.90	7.90	105.60	7.25	433	153	11	113.50	
	3650	Coal	60.10	11.50	113.70	13.90	428	189	23	125.20	
	3655	Coal	67.70	22.00	121.80	24.86	435	180	37	143.80	
	3659	Coal	63.10	18.00	104.40	15.60	422	165	25	122.40	
Pohokura South-1	3683	Coal	78.70	11.07	244.39	32.30	431	308	41	255.50	0.88
	3690	Coal	79.80	13.34	249.90	17.00	427	311	21	263.00	0.93
	3692	Coal	73.70	14.77	220.50	25.60	430	296	35	235.20	0.98
	3695	Coal	57.80	12.7	198.90	13.66	436	348	24	211.60	1.01

Notes: TOC–Total organic carbon; S_1-peak–Free contents of hydrocarbon(mg HC/g rock); S_2-peak–Remaining hydrocarbon potential (mg HC/g rock); S_3 peak–Produced carbon dioxide (mg CO_2/g rock); HI–Hydrogen index [S_2×100/TOC(mg HC/g rock)]; OI–Oxygen index [S_3×100/TOC (mg CO_2/g TOC)]; PY= Petrolum yelid [S_1+S_2 (mg HC/g rock)] T_{max}–maximum temperature at peak of S_2(°C); VR=measured vitrinite reflectance (%)

10 representative coal samples of the Eocene Mangahewa Formation from three studied wells (Pohokura-1, Pohokura-2 and Pohokura South-1) were subjected to vitrinite reflectance measurement through the standard polished block scheme (Taylor GH et al., 1998). The samples were embedded in the latex moulds using epoxy resin and hardened. The next step was applying ASTM D2797-04, silicon carbide paper and alumina powder to further smooth and polish the blocks.

After polishing, the shale samples were dipped in oil under white plane-polarised reflected light. To run the calibration, Leitz Orthoplan/MPV photometry and Zeiss microscope were utilized, and the mean values of vitrinite reflectance were recorded from more than 50 measurements/sample. This procedure helped in measuring the vitrinite reflectance in a better way.

3.2. 1-D Basin modeling

The geological and thermal maturity data (i.e., VR) were used as input data for reconstructing burial and thermal history models of the Pohokura Field's source rock using Schlumberger's PetroMod 1D modelling platform. The datasets of three exploration wells (Pohokura-1, Pohokura-2, and Pohokura South-1) drilled to a total depth of up to 4613 m, were used (Table 2). Some essential components for reconstructing the 1D models included sedimentary rock types and depositional periods, which were mustered from the well log reports of the investigated wells (Table 2). The age of sedimentary successions mentioned in Table 2 was derived from the data published by Martin KR et al. (1994). The maturity data derived from the estimated vitrinite reflectance (%V*R*o) played a vital role in understanding the evolution of geothermal history for any basin, which is critical as it influences the source rock maturation timing as well as the petroleum generation over the geological time (He S and Middleton M, 2002; Abeed Q et al., 2013; Makeen YM et al., 2016; Mohamed AY et al., 2016; Botor D and Bábek O, 2019). In this regard, the sedimentation rate, erosional record, temperature fluctuation during the burial and paleo heat flow (HF) developments are some of the critical components to reconstruct the basin's geothermal history (Allen PA and Allen TR, 1990).

Among all the aforementioned components, the paleo heat flow is one of the most critical gauges for the basin's thermal evolution, that depends mainly on subsidence events (linked to tectonic episodes) (Lachenbruch AH, 1970). Although it is not a simple process, heat flow can be approximated using the optical thermal calibration data obtained by using vitrinite reflectance (Waples DW, 1980; Sweeney JJ and Burnham AK, 1990; Hakimi MH et al., 2010; Hakimi MH and Abdullah WH 2015; Hadad YT et al., 2017; Shalaby MR et al., 2013). The vitrinite reflectance data helped also in establishing the thermal maturation history of the coal and

Table 2. Basin model input data used to reconstruct the burial history of three studied wells (Pohokura-1, Pohokura-2 and Pohokura-South1) in the Pohokura oilfield, Taranaki Basin (New Zealand).

Pohokura-1 Well						
Formation	Top	Bottom	Thickness/m	Lithology	Deposition ages/Ma	
					From	To
Surficial deposits	0	100	100	Gravels	3	0
Matemateaonga	100	500	400	Sandstone	7.2	3
Urenui	500	1126	626	Mudstone	11.6	7.2
Mt. Messanger	1126	1648	522	Sandstone	13.8	11.6
Manganui	1648	3080	1432	Mudstone	20.4	13.8
Taimana	3080	3150	70	Marl and mudstone	25	20.4
Tikorangi	3150	3200	50	Marl and limestone	29	25
Otaraoa	3200	3280	80	Mudstone	35	29
Turi	3280	3500	220	Mudstone	40	35
Mangahewa	3500	4220	720	Coal, Carbonaceous shale and sandstone	47	40
Total depth/m	4220					
Pohokura-2 Well						
Formation	Top	Bottom	Thickness/m	Lithology	Deposition ages/Ma	
					From	To
Surficial deposits	0	100	100	Gravels	3	0
Matemateaonga	100	520	420	Sandstone	7.2	3
Urenui	520	1320	800	Mudstone	11.6	7.2
Mt. Messanger	1320	1760	440	Sandstone	13.8	11.6
Manganui	1760	3115	1355	Mudstone	20.4	13.8
Taimana	3115	3180	65	Marl and mudstone	25	20.4
Tikorangi	3180	3210	30	Marl and limestone	29	25
Otaraoa	3210	3255	45	Mudstone	35	29
Turi	3255	3540	285	Mudstone	40	35
Mangahewa	3540	4340	800	Coal, shale and sandstone	47	40
Total depth/m	4340					
Pohokura- South1Well						
Formation	Top	Bottom	Thickness/m	Lithology	Deposition ages/Ma	
					From	To
Surficial deposits	0	100	100	Gravels	3	0
Matemateaonga	100	490	390	Sandstone	7.2	3
Urenui	490	1042	552	Mudstone	11.6	7.2
Mt. Messanger	1042	1590	548	Sandstone	13.8	11.6
Manganui	1590	3149	1559	Mudstone	20.4	13.8
Taimana	3149	3263	114	Marl and mudstone	25	20.4
Tikorangi	3263	3335	72	Marl and limestone	29	25
Otaraoa	3335	3435	100	Mudstone	35	29
Turi	3435	3558	123	Mudstone	40	35
Mangahewa	3540	3765	225	Coal, shale and sandstone	47	40
Total depth/m	3765					

coaly shale source rock system of the Mangahewa Formation within the studied wells.

4. Results and discussion

4.1. Vitrinite reflectance measurements

Vitrinite reflectance values in the coal samples were measured and used to assess the thermal maturity stages of the Mangahewa Formation in the studied wells. In this case, the mean random vitrinite reflectance ranges between 0.53% and 1.01% (Table 1), indicate that the Mangahewa Formation exhibits varied levels of thermal maturity between early mature to the beginning of the late mature oil generation window (Fig. 4).

These V*R*o values are well correlated with the burial depths. The Mangahewa coals samples from the Pohokura South-1 well buried at a deep burial depth between 3680 and 3695 m, exhibited peak-mature to late mature oil generation window with V*R*o between 0.88% and 1.01% (Fig. 4). Other coal samples from the wells Pohokura-1 and Pohokura-2 attained a relatively low thermal maturity, which is congruent with early mature (V*R*o=0.53%) to moderate mature (V*R*o=0.75%) of oil generation window (Fig. 4). However, the relatively high maturity level in the coal sequence of the Mangahewa Formation in the Pohokura South-1 well is attributed to the higher temperature burial than the Pohokura-1 and Pohokura-2 wells (Fig. 4). Therefore, the Mangahewa source rock Formation has been yielded commercial quantities of oil and hold substantial promise for future exploration activities in relatively deep wells.

4.2. Organic matter abundance and its generative potential

Table 1 compared the TOC and Rock-Eval data (i.e., S_1, S_2, S_3, T_{max}, HI, OI and PY) for the examined coal and carbonaceous samples of the Mangahewa Formation in the studied wells and used to estimate the sufficient amount of organic matter and its hydrocarbon generation potential

The TOC content in the Mangahewa coals and carbonaceous shales is high, ranging from 22.65 wt% to 79.80 wt% (Table 1). The 45 wt% threshold is exceeded by the majority of coal samples, while four carbonaceous shale samples show TOC ranging between 22.65 wt% and 31.29 wt% (Table 1). This high amount of organic matter strongly exhibits excellent source rock characteristics and underscores the hydrocarbon generation potential of the Eocene Mangahewa formation' coal and carbonaceous shale samples (Fig. 5). The high potential of the hydrocarbon generation from the Mangahewa coal and carbonaceous shale sediments is also confirmed by the positive correlation between TOCs and the S_2 values yielded during the pyrolysis of kerogen (Fig. 6a). The S2 results also show that most of the coal samples of the Mangahewa Formation from the studied wells have S_2 higher than those for the carbonaceous shale samples (Table 1).

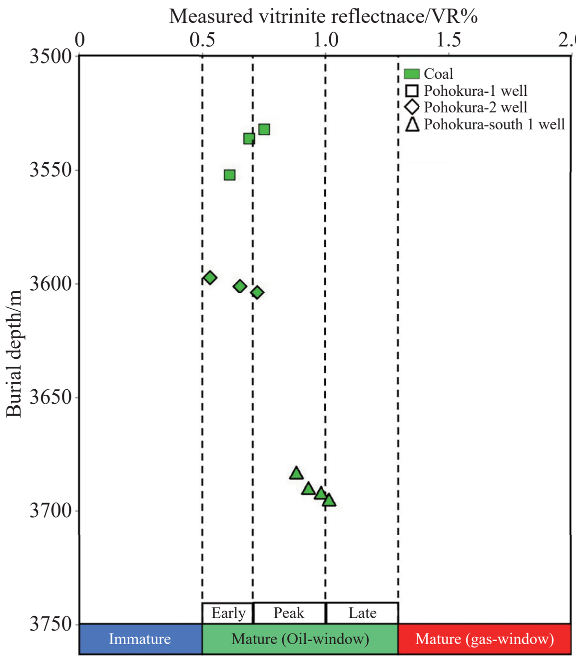

Fig. 4. Distributions of the vitrinite reflectance data within adjacent depths in the studied three wells (Pohokura-1, Pohokura-2 and Pohokura- South1), indication that the Mangahewa Formation reached different thermal maturity stages in the range of early-mature to peak mature of oil generation window.

Moreover, the pyrolysis data revealed that the free

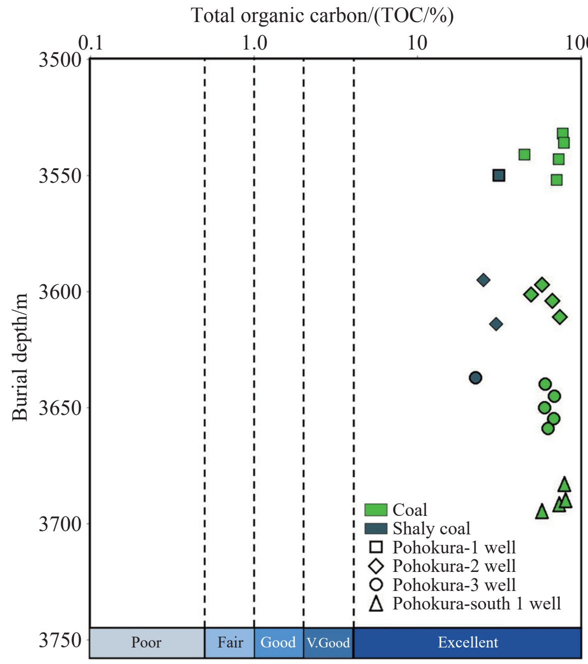

Fig. 5. Distributions of the total organic carbon (TOC) content adjacent depths in the studied wells, indication that the coal and shaly coal samples are excellent source rocks.

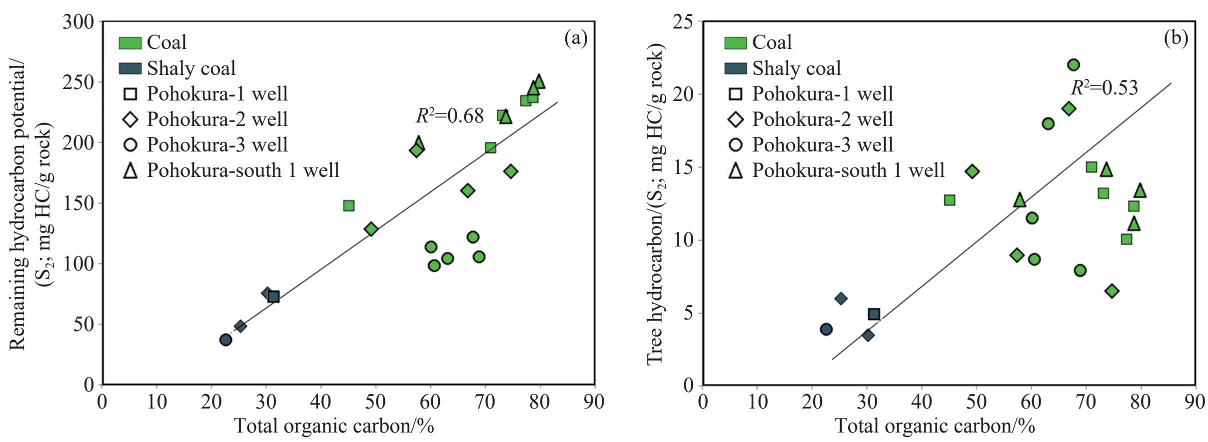

Fig. 6. a–Cross plot of TOC content versus petroleum yield (S2) pyrolysis of the coal and shaly coal succession in the studied wells. b–Cross plot between TOC content versus free hydrocarbon (S1) pyrolysis of the coal and shaly coal succession in the studied wells. These two cross plots indicate that the direct proportional between TOC content and S1 and S2 parameters.

petroleum (S_1) yields in a good number of investigated coal samples from the Mangahewa Formation are higher than in the carbonaceous shale samples (Table 1). The free petroleum yield (S_1) was leveraged in conjunction with TOC contents and shows that there is a positive correlation with a R^2 = 0.53 (Fig. 6b).

This is also serve as evidence that the coal and carbonaceous shale samples within the Eocene Mangahewa Formation are excellent source rocks, as illustrated in Figure 7 between the petroleum yields (PY=S_1+S_2) and TOCs. The higher TOC contents, along with the substantial petroleum generation potential (PY) of the studied Mangahewa coal and carbonaceous shale samples in the Pohokura oilfield between 40.36 and 263.00 (Table 1), clearly highlighting their strong capability to generate commercial amounts of petroleum.

4.3. Kerogen typing and its implication for the petroleum generative potential

The assessment of kerogen type is critical for understanding the petroleum generative potential of the investigated rocks and sediments. It facilitates exploration and production by providing insights into the organic richness, hydrocarbon yield, thermal maturity and resource prospectivity. Therefore, it plays a vital role in the efficient and effective exploration and exploitation of hydrocarbon resources.

The assessment of bulk kerogen types and hydrocarbon potential capability within the studied Mangahewa coal and carbonaceous shale samples in the Pohokura oilfield, northeastern Taranaki Basin, were primarily established based on the results of the programmed pyrolysis. In this case, hydrogen index (HI) and oxygen index (OI) pyrolysis parameters are exercised for assessment the bulk kerogen types (Hakimi MH et al., 2013; Peters KE et al., 1994; Bordenave ML et al., 1993).

In this study, the S_2 and S_3 yielded during the pyrolysis analysis were linked to the TOC contents and utilized for

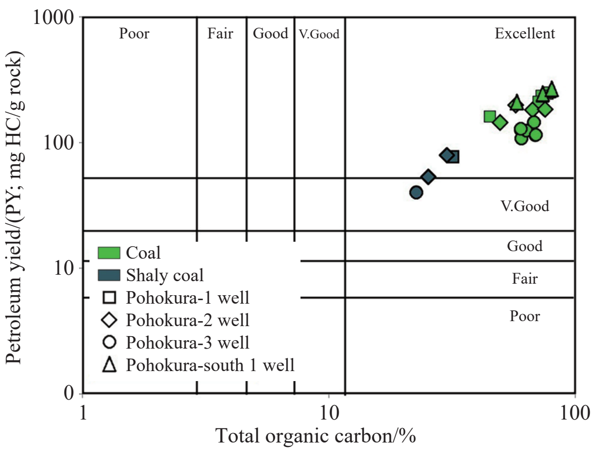

Fig. 7. Cross plot of TOC content versus petroleum yield (PY), showing that the Eocene coal and shaly coal succession in the studied wells ranks from very good to excellent petroleum generation potential.

calculation the HI and OI values (Table 1). The HI of the samples under consideration varies between 153 mg/HC/g TOC and 348 mg HC/g TOC (Table 1). A considerable number of samples in the studied wells exhibit HI > 250 mg HC/g TOC (252−348), whereas a lower number of samples showed HI values between 153 mg/HC/g TOC and 241 mg HC/g TOC (Table 1). Accordingly, the examined Mangahewa coal and carbonaceous shale samples comprise dominantly mixed types II and III kerogen with minor Type III kerogen, as revealed from the van Krevelen diagram of OI vs. HI (Fig. 8a). The extraordinary influence of the hydrogen-rich, mixed II/III kerogen contributions validates the T_{max} vs. HI cross plot (Fig. 8b).

Significantly, the coal and carbonaceous shale succession of the Eocene Mangahewa Formation prominently feature a high contribution of oil generation potential of hydrogen-rich kerogen, with high HI values between 300 mg/HC/g TOC and 348 mg HC/g TOC. This finding ties well with the outputs from TOC and HI cross plots, reflecting the oil and gas source rocks, with high oil generation potential (Fig. 9).

4.4. Geothermal history evolution and its consequences on organic maturation

In this study, the 1D-basin simulation approach was used to estimate the geothermal history in the studied oilfield geological information (available from the three exploration wells) together with measured vitrinite reflectance (%V*R*o) as geothermal maturation data (Table 1). During the analysis, multiple heat flow scenarios were employed to establish a reasonable fit between Sweeny and Burnham’s maturation (Easy%*R*o) and conclude a suitable thermal history model (Fig. 10a). An appropriate and dependable geothermal history model was achieved by considering a 45−80 mW/m^2 of the paleo/present HF (Fig. 10b). The paleo-HF reached high values up to 80 mW/m^2 during the Late Cretaceous to Early Paleocene (Fig. 10b). This high HF rate (80 mW/m^2) was taken as an indication of the initial episode of basin-wide rifting, during the middle Cretaceous and Paleocene time, triggered while disintegrating from the eastern Gondwanaland. The second rifting phase was allocated a heat flow value of 68 mW/m^2, began due to the expansion of passive margins, post-rift thermal contraction and regional scale subsidence throughout the Eocene to Early Oligocene time (Sykes R et al., 2014).

The relatively low HF between 45 mW/m^2 and 58 mW/m^2 reached in the Taranaki Basin (Fig. 10b), triggered by the collision between the Australian and Pacific plates, which initiated in the Oligocene period and is continued till today (Sykes R et al., 2014). Furthermore, a realistic heat flow model was also utilized to generate the thermal maturation history of the source rocks of the investigated formation and then interpret the petroleum generation timing. The thick overlying strata (Table 2 shows more than 3 km of thickness) and the collision between the Pacific and Australian plates are two influential factors in the thermal history of the

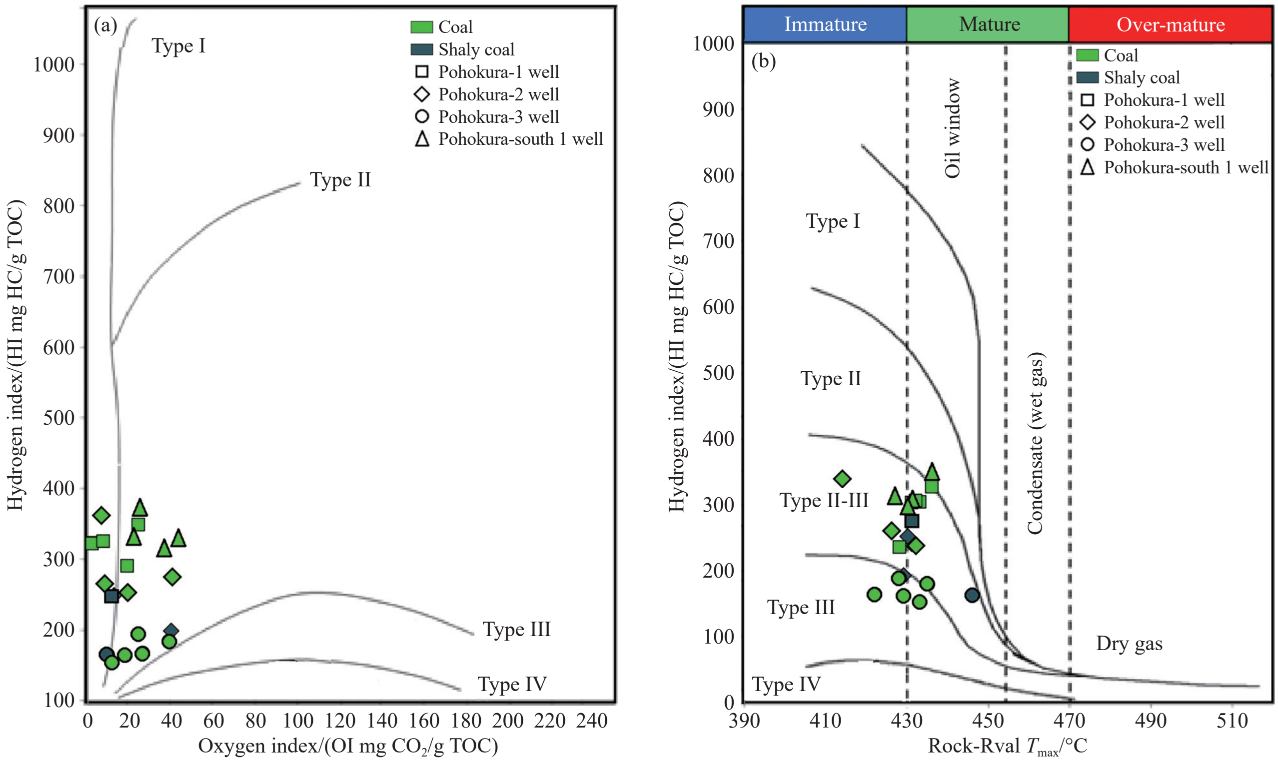

Fig. 8. Chemical type of kerogen in the the Eocene coal and shaly coal succession in the studied wells based on a−hydrogen index (HI) and Tmax and b−hydrogen index (HI) and Tmax. These two cross plots show mainly hydrogen-rich Type II-III kerogen, with small amounts of Type III kerogen.

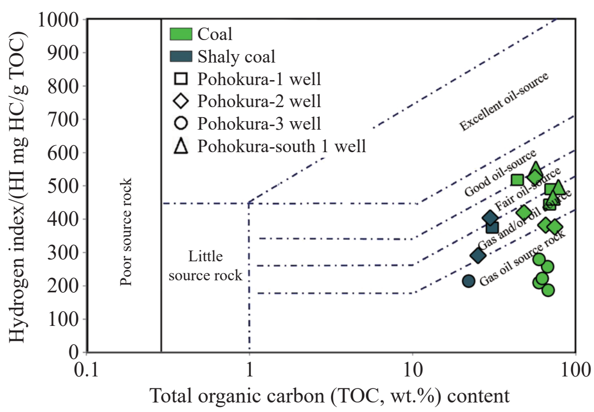

Fig. 9. Cross plot of TOC content versus hydrogen index (HI), showing that the Eocene coal and shaly coal succession in the studied wells are both oil- and gas-source rock, with high potential for oil generation.

Mangahewa source rock system (Fig. 10b; Sykes R et al., 2014). In this case, the maturity models imply that the Mangahewa source rock system is presently in the main stage of oil generation. This finding was also verified by the early-mature to mature oil window reflecting EASY %*R*o values between 0.55% and 1.06% (Fig. 11). The investigations from burial and thermal models also reveal the termination of the Mangahewa Formation at a depth of 4000 m, highlighting high burial temperatures between 83°C and 140°C prevailing from Middle Miocene time to the present day (16–0 Ma; Fig. 11). Important information revealed from models is the variation in maturation and oil generation from the Mangahewa source rock within the investigated wells (Fig. 11).

Based on the EASY%*R*o models (Fig. 11), the investigated formation within the examined wells accomplished the attained the requisite state of thermal maturity to the main oil window in the Late Miocene to the current date, with higher maturity rates at Pohokura- South1 well (Fig. 11). Based on the thermal history models in the studied wells (Fig. 11), the base of the Mangahewa Formation go into the early mature of oil-window (0.55–0.70 EASY%*R*o) during Middle Miocene to Late Pliocene time (16–9 Ma) as shown in Fig. (Fig. 11), agreeing to the fluctuation in burial temperatures between 83°C–122°C (Fig. 12).

Peak oil generative window occurred throughout the Late Miocene to Late Pliocene (age 10–3 Ma), corresponding to an EASY%*R*o values between 0.84 and 0.89 at Pohokura-1 and Pohokura-2 wells and from 0.70 to 1.00 EASY%*R*o at the Pohokura-South1 (Fig. 11). The temperature during the Late Miocene to present day reached an elevated value between 122°C and 140°C (Fig. 12). This is probably attributed to the high thickness of more than 3 km for the overburden sediments (Table 1) together with the third tectonic event of the collision between Australia and Pacific plates during the Oligocene to present day (Sykes R et al., 2014). Subsequently, the base Mangahewa Formation in the studied Pohokura-South1 well reached the beginning of the late oil-window maturity during the Late Pliocene around 3 Ma and has persisted to the current time (Fig. 11).

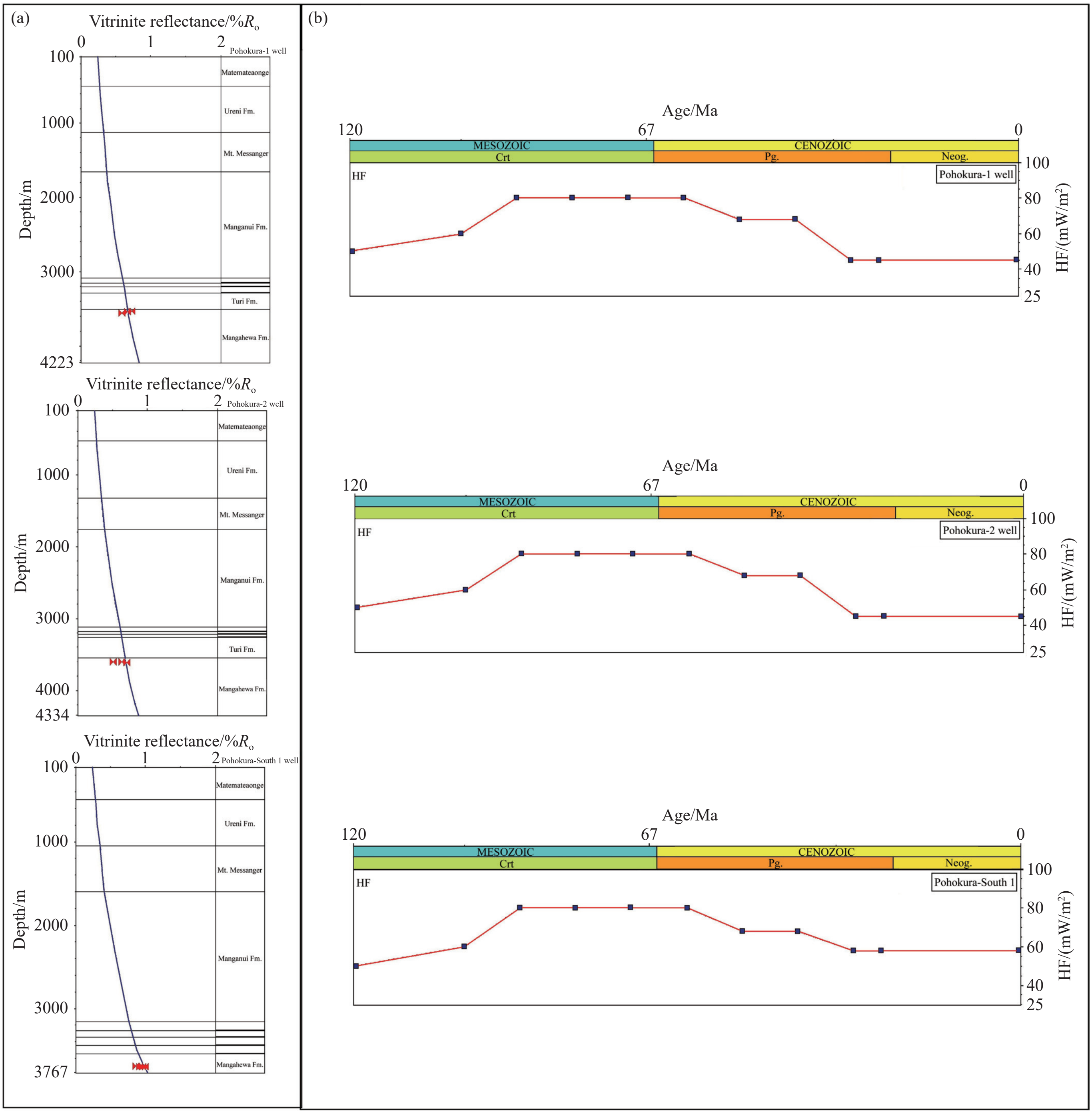

Fig. 10. a−Optimised fit of calibrated data i.e., measurement vitrinite reflectance (%V*R*o) and models of EASY%*R*o through the studied three wells (Pohokura-1, Pohokura-2 and Pohokura- South1), and b−the estimated heat flow values that achieved from calibration data (%V*R*o).

4.5. Implication for Petroleum Exploration Opportunities

The exploration and development of the source rock system of the Eocene Mangahewa in the Taranaki Basin, New Zealand, is still in the early stages, due to the limited research and lack of information that are needed to determine its conventional petroleum resource potential (Qadri SMT et al., 2017). Therefore, the current study has compiled a variety of parameters (total organic carbon TOC, vitrinite reflectance %V*R*o, and kerogen types) for determining the conventional source rock potential of the Early Mangahewa source rock system and its petroleum generating capacities. The commercial petroleum exploitation is characterized by a TOC threshold of > 2.0%, with higher/lower in numerous sites (Zou CN, 2013; Bryndzia LT and Braunsdorf NR, 2014).

In this study, the analysis of geochemical data suggests that the organic-rich sediments of the Eocene Mangahewa Formation situated in the Pohokura Oilfield, northwestern Taranaki Basin hold an effective oil source rock, as evidenced by the organic matter, with a maximum TOC reaching 79.80% for coals and 31.29% for carbonaceous shales (Table 1), and mainly hydrogen-rich Type II/III kerogen (Fig. 8).

However, the estimated V*R*o values between 0.7% and 1.35% are considered to be for effective oil-source rock

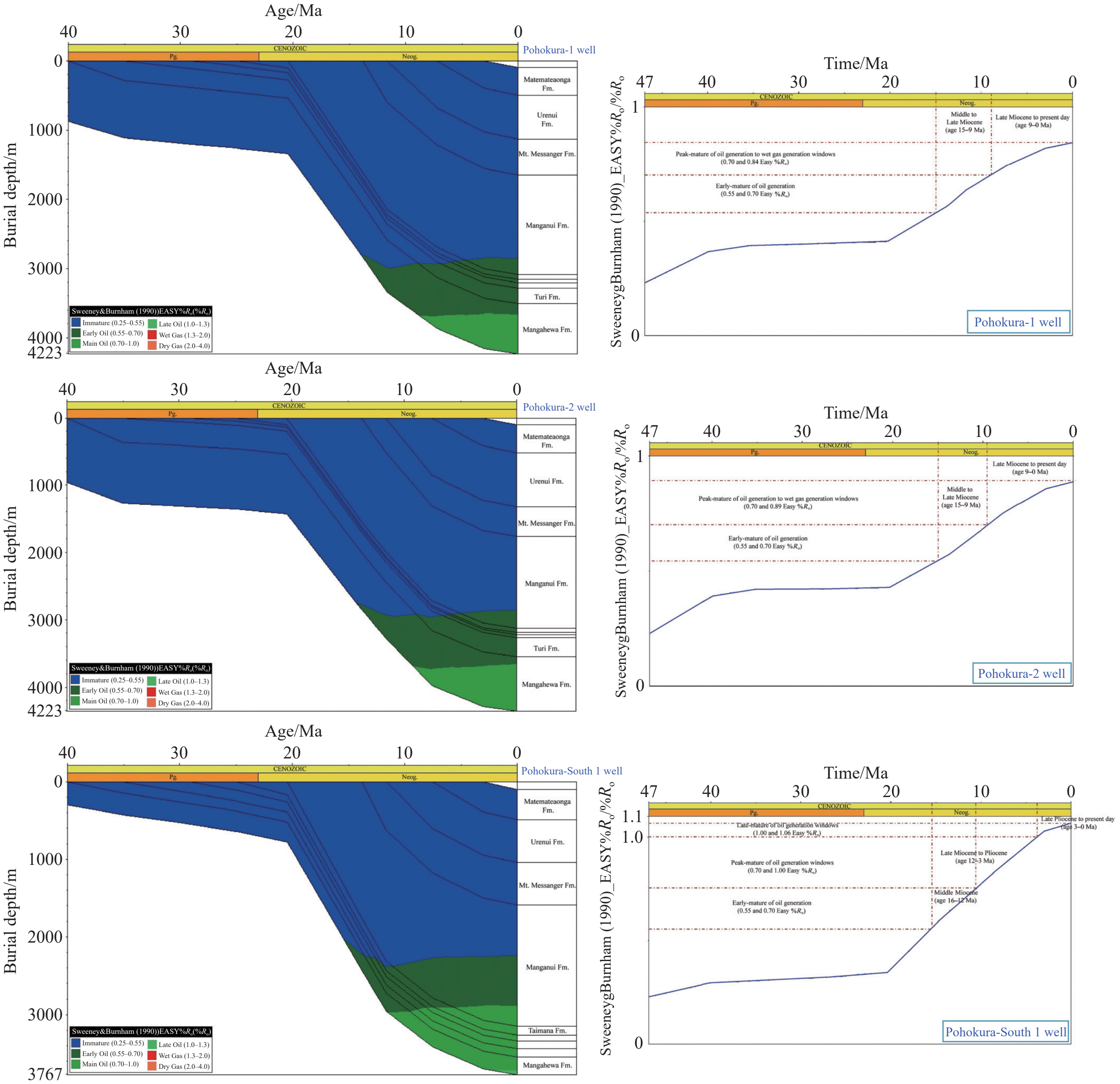

Fig. 11. Burial overlap with thermal maturity (colored areas) cross all rock units (left) and computed vitrinite reflectance (Easy%*R*o) through the studied three wells (Pohokura-1, Pohokura-2 and Pohokura- South1) (right).

development technique (Sweeney JJ and Burnham AK, 1990). In this case, the Mangahewa source rock system has entered the main stage of oil window maturity, as the basin modeling data indicated in this research (Fig. 11). The basin-scale models depict that the Mangahewa Formation reached the main oil-generating phase during the Late Miocene to present-day (between 11 and 0 Ma), with differences in the TR values between 10% and 54% (Fig. 13). This is attributed to the oil-generating window, with a corresponding V*R*o values between 0.70% and 1.06% through the studied wells (Fig. 11). In addition, the Mangahewa source rock at Pohokura-1 and Pohokura-2 wells reached a lower TR of 10%–23% during the Late Miocene around 6 Ma which persisted to present day (Fig. 13), with a corresponding V*R*o of 0.84%–0.89% (Fig. 11).

Results indicated that the Mangahewa source rock had not yet generated substantial volumes of oil. In contrast, the Pohokura South-1 well-based model suggests the TRs reached maximum values of up to 54% during the Late Miocene (age 11 Ma) and had risen with increasing thermal maturation (up to 1.06%; Fig. 11); hence, the substantial oil volumes may have generated during this time (Fig. 13). These amounts of generated oil were subsequently expelled as a result of the greatest values of more than 50% (up to 54%) for its kerogen conversion, and then migrated upward to shallow reservoir rocks during the Early Pliocene to present day (Fig. 13).

In addiation, the costs of exploration and production of the source rock is also significant control by the burial depth and

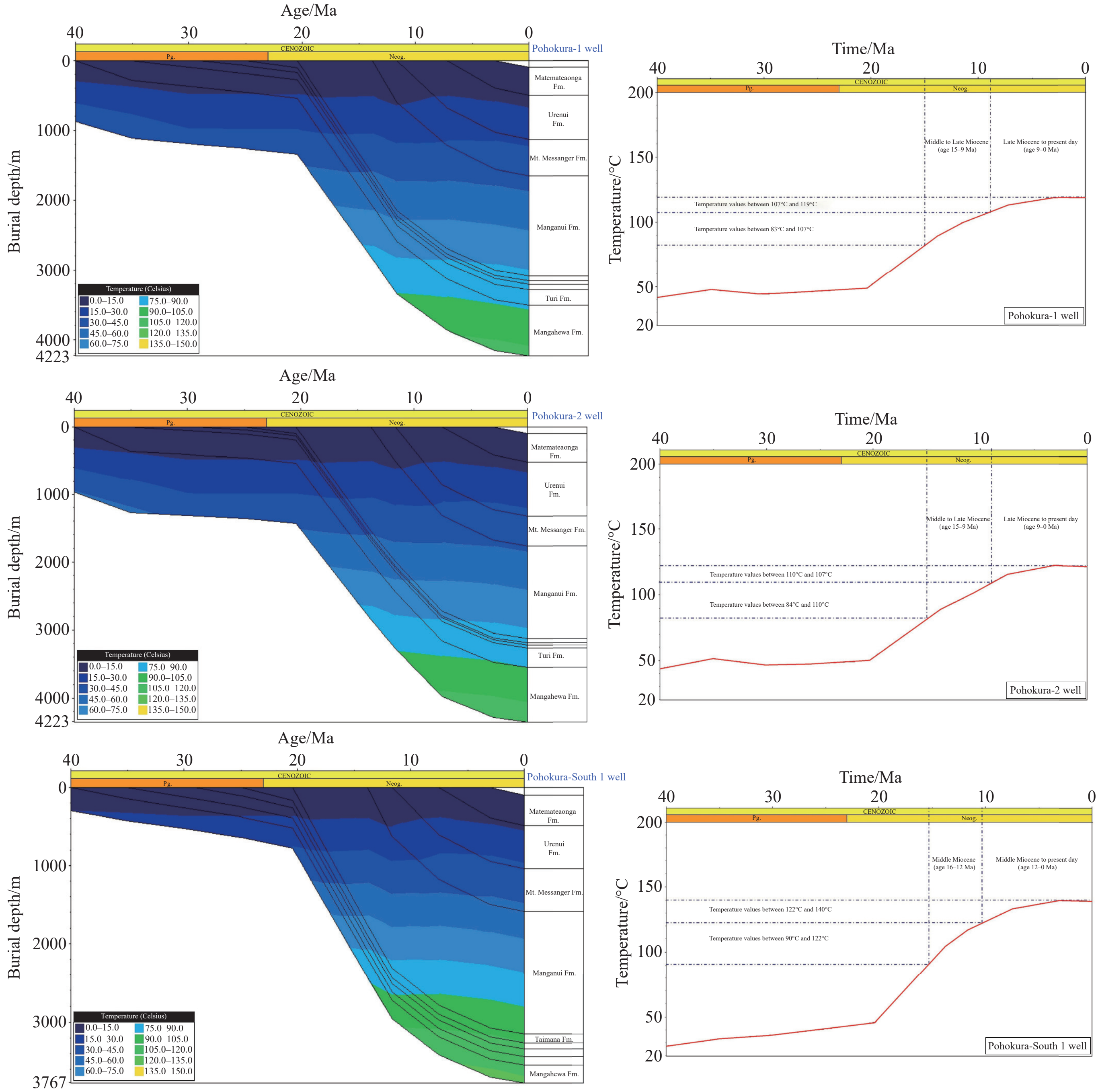

Fig. 12. Burial overlap with thermal gradient histories (colored areas) cross all rock units (left) and computed burial temperatures (°C) through the studied three wells (Pohokura-1, Pohokura-2 and Pohokura- South1) (right).

the thickness of overburden rocks. In this case, the burial depth of the Mangahewa Formation was distanced throughout the Taranaki Basin, as revealed by various scientists (e.g., King PR and Thrasher GP, 1996). The Mangahewa Formation reached burial depths between 2800 m and 3500 m in the basin's northwestern (Western Stable Platform), 3000 m and 6000 m in the eastern and southern parts of the basin (South and Manaia Grabens), as shown in the cross section throughout the Taranaki Basin (Fig. 3). This cross section show that the Mangahewa Formation in the southern Graben of the Taranaki Basin reached burial depth between 4000 m and 6000 m and thickness of overburden rocks of more than 5000 m, attaining substantial thermal maturation and can be a suitable candidate for producing commercial volumes of oil in the basin's deeper horizons. This finding also ties nicely with the petroleum discoveries within the Taranaki Basin's eastern and southern regions (Fig. 1a).

5. Conclusions

The detailed investigations, integrating optical, geochemical techniques and basin modeling were conducted on the coal and carbonaceous shale intervals within the Eocene Mangahewa Formation, derived from four exploration wells in the Pohokura oilfield, Taranaki Basin (New Zealand).

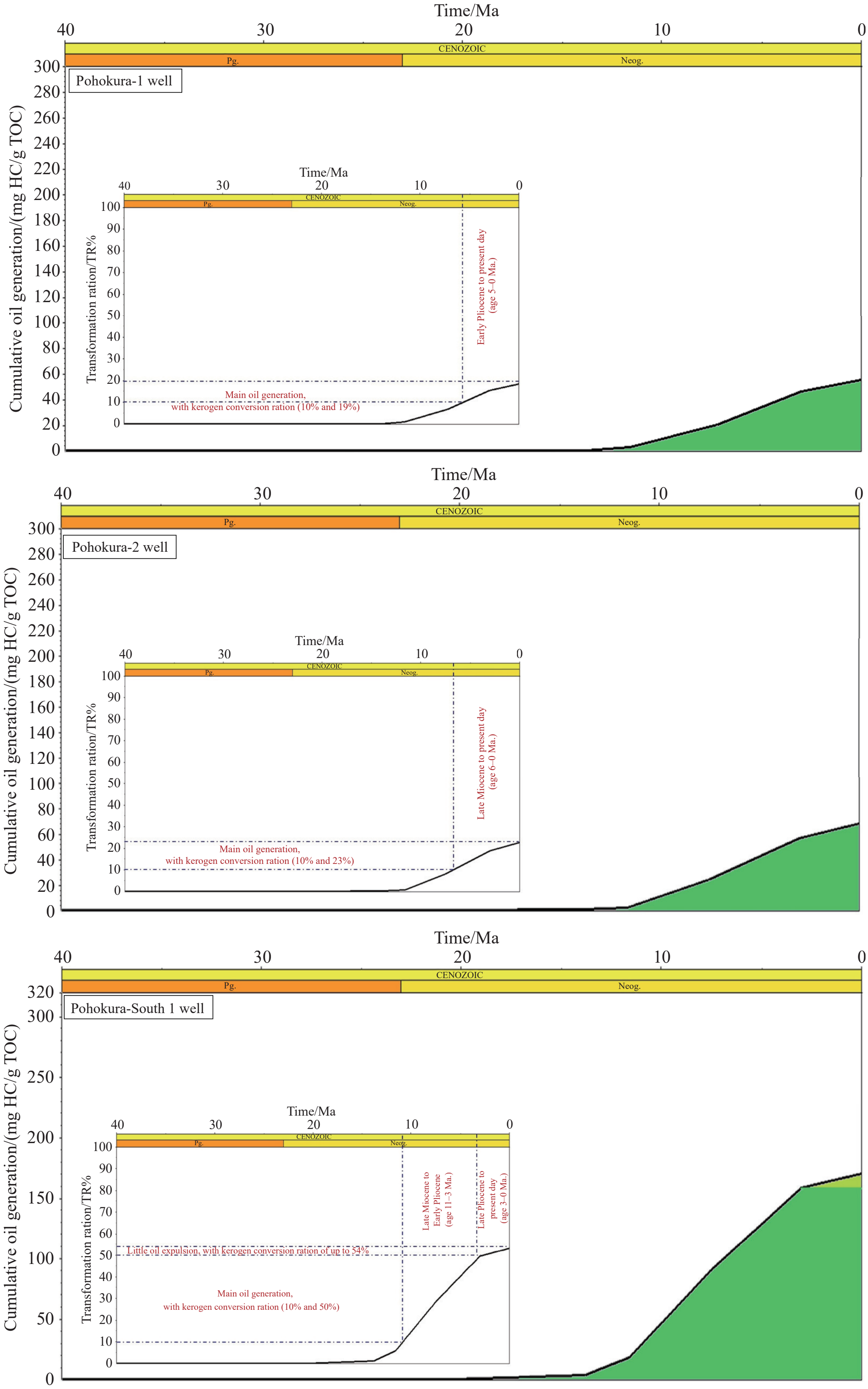

Fig. 13. Cumulative oil generation and evolution of the transformation ratio with age (blue lines) for the Eocene Mangahewa source rock system in the studied three wells (Pohokura-1, Pohokura-2 and Pohokura- South1).

The results obtained from the analyses were utilized to explore the hydrocarbon generative capability of the Mangahewa Formation, thereby deciphering the petroleum exploration targets of the investigated basin. The investigation concludes as follows:

The Mangahewa Formation exhibits significant potential as a source rock for hydrocarbons with TOC>45% complimented with the Rock-Eval pyrolysis results. The findings also reveal that the investigated Mangahewa source rock has likely generated and expelled substantial volumes of hydrocarbons, specifically in zones of higher thermal maturity.

The study indicates a range of thermal maturity levels throughout three wells in the Pohokura oilfield. Vitrinite reflectance data revealed the early mature to the beginning of the late mature oil generation window, primarily due to the variation in the burial depths and thermal history impacting the timing and extent of oil generation.

The hydrocarbon generative potential is also concluded by understanding the domination of Type II/III kerogen. A higher HI index presents the good oil generative potential and strengthens the idea that the Mangahewa source rock system can produce a significant volume of oils.

The basin modeling advocates that the Mangahewa source rock within the four studied wells reached the main oil-generating phase and kerogen conversion ratio between 10 and 54 TR% during the Late Miocene, and substantial oil volumes may have been generated during this time.

The basin models also show that the Mangahewa source rock had raised with increasing thermal maturation of up to 1.06%; hence, it reached maximum TRs values of up to 54% and minute amounts of oil were subsequently expelled during the Early Pliocene to present.

The above geochemical and basin modeling can be considered the basis of future investigations for exploring conventional and unconventional hydrocarbon resources within the successions of Manaia and southern grabens of the Taranaki Basin, where the Mangahewa source rock system is buried deep.

CRediT authorship contribution statement

Talha S.M. Qadria, Mohammed Hail Hakimi, Mahdi Ali Lathbl, Mohammed Almobarky and Aref Lashin conceived of the presented idea. Mohammed Hail Hakimi and Afikah Rahim created and interpreted the 1-D basin models. All authors discussed the results and contributed to the final manuscript.

Declaration of competing interest

The authors declare no conflicts of interest.

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