



# Hydrocarbon generation modeling and source rock characterization of the Cretaceous–Paleocene Taratu Formation, Great South Basin, New Zealand

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## Abstract

Hydrocarbon generation modeling and source rock characterization have been carried out on rock samples of the Taratu Formation in the Great South Basin, New Zealand. The Paleocene and Late Cretaceous Taratu Formation samples from Tara-1 well are utilized for geochemical studies. Rock-Eval pyrolysis results show that Taratu formation accommodates organic matter of excellent quantity and quality, with prolific kerogen type II-III (oil and gas prone) and minor kerogen type III (gas prone). Hydrogen index (HI) of this formation ranges from 165.0 to 327.5 mg HC/g TOC and only Late Cretaceous source rock samples are thermally mature, with maximum pyrolysis temperature ( $T_{max}$ ) up to 459 °C and vitrinite reflectance (%  $R_o$ ) from 0.40 to 1.15%  $R_o$ . One-dimensional basin modeling shows a best fit in a calibration of measured and modeled temperatures and vitrinite reflectance. The top of oil window was encountered 51 Ma ago at 3100 m and gas generation took place at 4132 m in 8 Ma ago.

**Keywords** Taratu Formation · Source rock characterization · Burial history modeling · Great South Basin · New Zealand

## Introduction

The area of study is located to the south of the South Island, Great South Basin in New Zealand. The Great South Basin (GSB) is the largest deepwater basin in the Campbell Plateau (Fig. 1), with dimensions extending approximately up to an area of 100,000 km<sup>2</sup> (Evans 1982; Killops et al. 1997). This basin comprises primarily grabens and half-grabens, containing sediments from the Late Cretaceous to Early Tertiary (Schjølter et al. 2009; Evans 1982; Beggs 1993; Cook et al. 1999). Based on hydrocarbon potential studies undergone by Killops et al. (1997), Cook et al. (1999), and Constable et al. (2013), this basin is found to contain promising source rocks despite not having a commercial hydrocarbon production and limited exploration. Hydrocarbon-bearing formations in this basin are mainly coals and black marine shales from

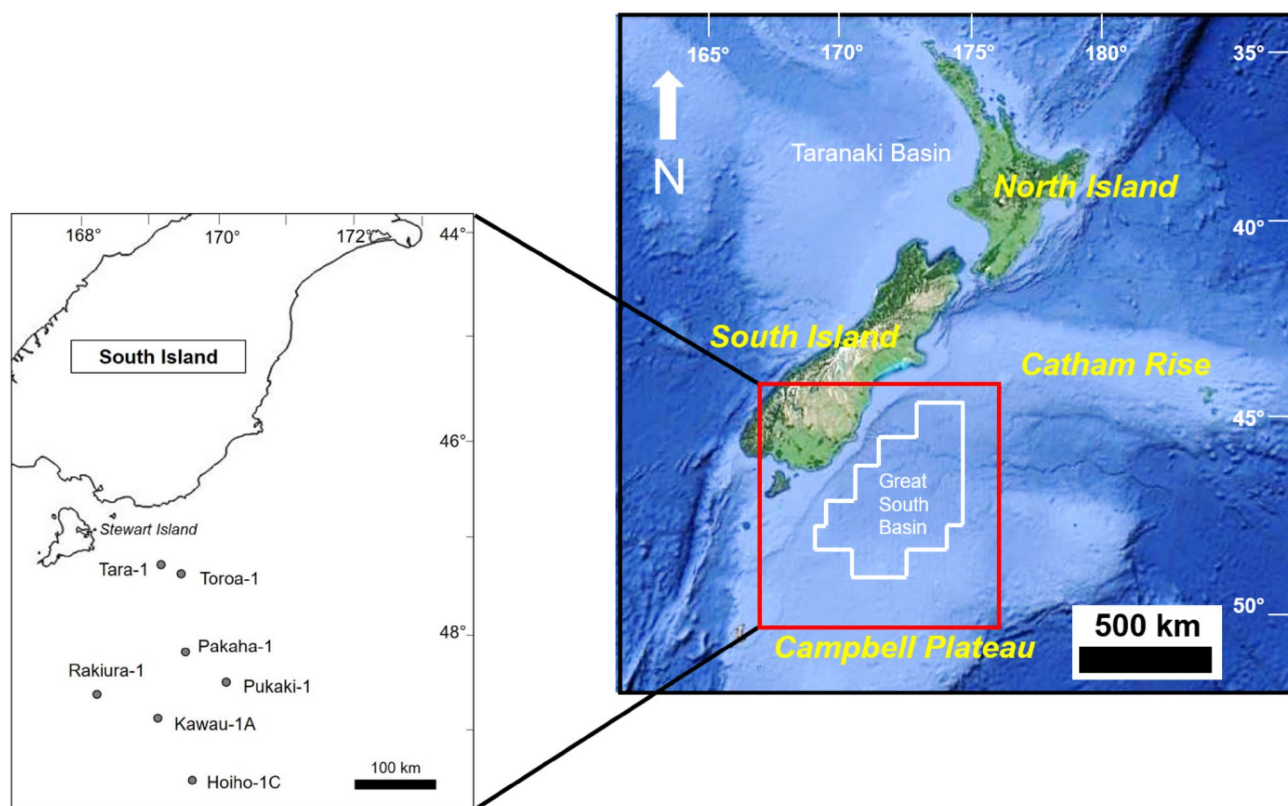
Cretaceous and Paleocene (Uruski and Baillie 2001; New Zealand Petroleum and Minerals 2014).

The Taratu Formation is important for the complete petroleum system in the Great South Basin (Killops et al. 1997) and was previously studied by Killops et al. (1997, 2001, 2008) as well as Sykes et al. (1998). It is characterized by cross-bedded pebble conglomerate, sandstones, shale, and coal measures with carbonaceous siltstone (McMillan and Wilson 1997). There is an abundance of vein quartz that later becomes the source of the Haast Schist (Aitchison et al. 1993). Coals of this formation are lignite to sub-bituminous. Fine-to-coarse-grained sandstones, which make up the reservoir unit of this formation, are also present. The Taratu Formation was subjected to marine influence and the coals are produced by brackish water (Raine et al. 1993; Wilson and McMillan 1996).

From the 1970s to the present, only eight wells have been drilled in the Great South Basin, four of which displayed an affirmative response for the presence of hydrocarbon (New Zealand Petroleum and Minerals 2014). Wells that encountered gas condensates in Cretaceous Formations are Kawau-1A, Toroa-1, and Pakaha-1 wells, with minor methane detected in Pukaki-1 well. Takapu-1 and Rakiura-1 wells failed to record the presence of hydrocarbon. Two source

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**Fig. 1** Map of New Zealand with locations of the Great South Basin and study area. Modified after Schiøler et al. (2009)

rocks are detected in Hoiho-1C well, but no hydrocarbon show is recorded in those rocks.

The main objective of this study is to evaluate the Taratu Formation using geochemical data to assess the organic matter quality, quantity, and hydrocarbon generation potential. Various techniques of assessing a source rock as performed by Shalaby et al. (2011), Qadri et al. (2016) and Jumat et al. (2017, 2018) have been referred to in this research. Following geochemical analysis, this study also constructs a one-dimensional basin model using stratigraphic, temperature, and vitrinite reflectance data to investigate the exact timing and depth of hydrocarbon generation windows for the Taratu Formation.

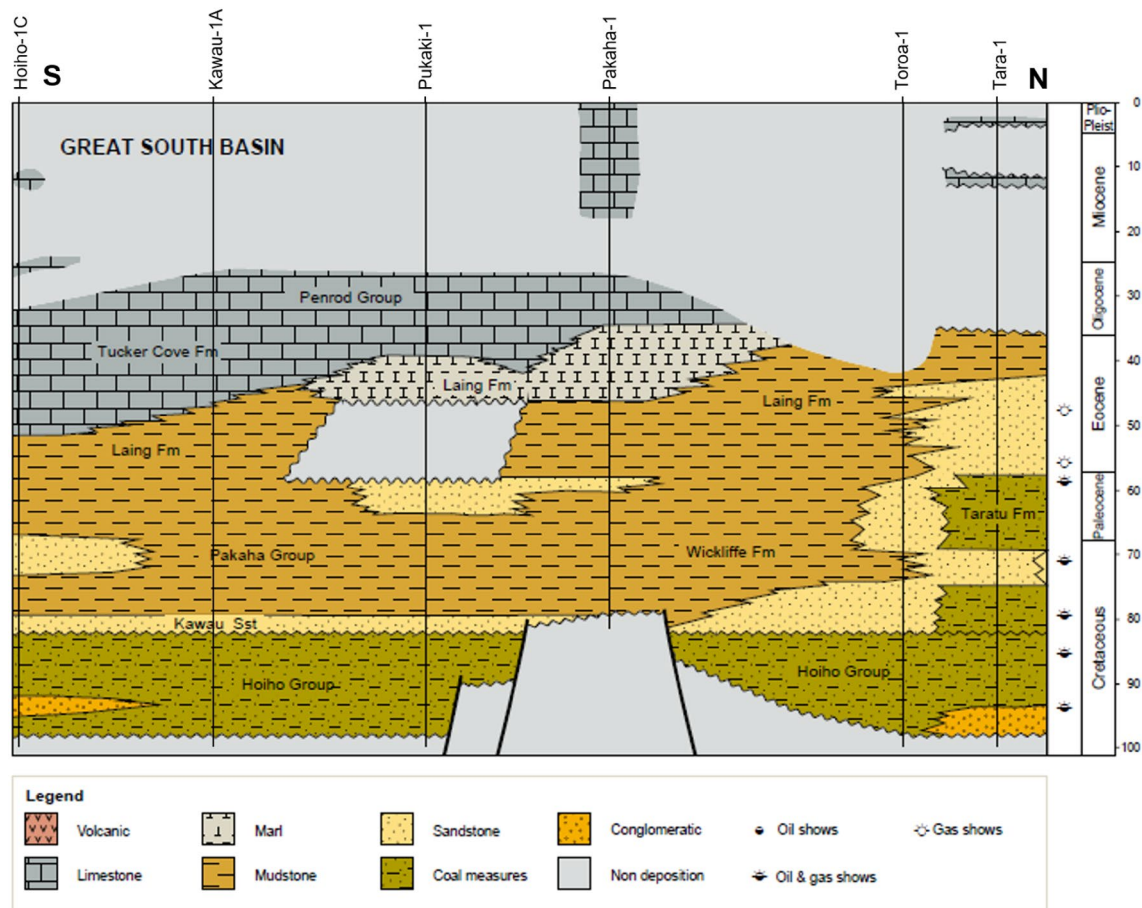
## Geological setting and stratigraphy

Schiøler et al. (2009), McMillan and Wilson (1997), and Constable et al. (2013) have studied on the Great South Basin's stratigraphy and geological settings. Major tectonic activities that led to the formation of the Great South Basin began in the Cretaceous (New Zealand Petroleum and Minerals 2014). The convergent tectonic regime in the eastern margin of New Zealand began to shift into an extensional pattern at this period. Phoenix Plate was no longer subducted

at 105–100 Ma and rifting began, causing the separation of New Zealand from Gondwana (Laird and Bradshaw 2004). As a result, a global uplifting and erosion of land occurred, leading to the formation of the Albian Unconformity that affected New Zealand. New Zealand was completely separated from the east of Gondwana in the Late Cretaceous, and this phenomenon was represented by widespread marine transgression that peaked in Oligocene, which eventually led to the formation of the Tasman Sea (Laird and Bradshaw 2004).

Rifting in the Great South Basin completely halted in the Late Cretaceous and was succeeded by thermal subsidence that continued until the Paleogene (Constable et al. 2013). At this time, transgressive marine sediments that include sandstone, greensand, and mudstone were deposited (Fig. 2). Further subsidence of the basin led to the deposition of carbonates and calcareous mudstone (Killops et al. 1997; New Zealand Petroleum and Minerals 2014).

At the western margin of the Great South Basin, a prograding delta which was initiated by thermal subsidence was formed in the Paleocene. Sediment supply to this delta halted following the final opening of the Solander and Emerald sub-basins. This margin was also heavily affected by tectonic activities in Oligocene–Miocene (King 2000; Constable et al. 2013).



**Fig. 2** Stratigraphy of the Great South Basin. Modified after New Zealand Petroleum and Minerals (2014)

Due to the ongoing compressional stresses from the orogeny along the Alpine Fault in the Miocene, the western margin of the Great South Basin was folded into anticlines and synclines, therefore causing this part of New Zealand to be uplifted (New Zealand Petroleum and Minerals 2014). As a result, a thick sequence illustrating marine progression is located at the western margin of the basin that trends north east (Laird and Bradshaw 2004; Schjøler et al. 2009). In Neogene, pelagic sediments began to accumulate on the eastern part of the Great South Basin (Killops et al. 1997).

Upon the initiation of rifting in Mid-Cretaceous, grabens and half-grabens that are oriented in the NW–SE directions are formed, which later accumulated sediments (Constable et al. 2013). Conglomerates, sandstones, mudstones, and coal from fluvial and lacustrine environments fill up these grabens to make up the Hoiho Formation and rests unconformably on the basement rocks of the Great South Basin (Fig. 2; Laird and Bradshaw 2004; Constable et al. 2013; New Zealand Petroleum and Minerals 2014).

The Hoiho Group is overlain by the Pakaha Group, which is formed by the deposition of fine-grained marine siliciclastics in the Late Cretaceous to Paleocene. Transgressive

sandstones of the Kawau Formation makes up the base of the Pakaha Group, which is overlain by the Wickliffe Formation (Fig. 2). Sandstones of the Taratu Formation in turn overlie the Kawau sandstones (Schjøler et al. 2009).

The Taratu Formation comprises quartzose grit, conglomerates, sandstone, and shales with coal measures (Fig. 2). Coals of this formation were deposited in brackish water as it has been subjected to marine influence (Raine et al. 1993; Wilson and McMillan 1996).

## Data and methods

The Ministry of Business, Innovation and Employment (MBIE) of New Zealand and GNS Science have provided and permitted the usage of all data for this study. A total of 32 drill cutting samples from Tara-1 well from depths 2225 to 4109 m are utilized for geochemical analyses. Taratu Formation rock samples belong to two different ages; from Late Cretaceous to Paleocene, with the Paleocene Taratu Formation encountered at depths shallower than 2700 m, while the

formation at greater depth belongs to Late Cretaceous. The observed lithology in this formation is coal and mudstone.

Source rock evaluation through pyrolysis using Rock-Eval 2 that serves as the main focus in this study involves assessing the source rock maturity, type of organic matter, hydrocarbon generation, burial, and thermal histories of the Taratu source rock. To achieve this, Rock-Eval pyrolysis results such as volume of free hydrocarbon generated before pyrolysis ( $S_1$ ), amount of hydrocarbon generated during pyrolysis ( $S_2$ ), amount of carbon dioxide emitted ( $S_3$ ), total organic carbon (TOC), and maximum pyrolysis temperature ( $T_{max}$ ) are used. Derivations of these parameters are also important to utilize to evaluate the source rock. Such indices include hydrogen index ( $HI = S_2/TOC \times 100$ ), oxygen index ( $OI = S_3/TOC \times 100$ ), production yield ( $PY = S_1 + S_2$ ), production index ( $PI = S_1/S_1 + S_2$ ), and  $S_2/S_3$  (Tissot and Welte 1984; Peters 1986; Mukhopadhyay 1994).

Sea water was used as the drilling mud in this study. Drill cuttings are collected from the shaker screen and washed through a 2-mm sieve using fresh water to eliminate mud-cakes and small-sized particles. No organic solvents are used to avoid removal of soluble constituents. Samples to be analyzed are then air-dried at 40 °C and should be weighed to 50 g prior to commencing any analysis.

Vitrinite reflectance ( $\% R_o$ ) as a maturity indicator has been determined for a total of 28 samples. Analysis of vitrinite reflectance has been carried out on ditch cuttings at two to four hundred feet intervals. Vitrinite reflectance was measured according to ASTM (1975) standard, in which a sample was made into two pellets and 200 point counts are required for one pellet. Mean values of the counts are then calculated to obtain the vitrinite reflectance values.

One-dimensional basin model is generated using the PetroMod software (version 9.0) to analyze the burial and thermal maturity histories for the Taratu Formation. All parameters mandatory for basin modeling are prepared for the well under study, including name of formations as detected in the well, formation age (Ma), formation thickness (m), measured borehole temperature (celsius), and measured vitrinite reflectance ( $\% R_o$ ). This research uses a constant heat flow of a constant heat flow of 60 mW/m<sup>2</sup> (Godfrey et al. 2001) and a kinetic model introduced by Pepper and Corvi (1995). This model suggests that the central parameter that controls expulsion of hydrocarbon is the hydrogen index of the formation and applies five organofacies in characterizing a source rock. This study applies the kinetic model type III DE for the source rock of study because this model type is suitable for terrigenous, non-marine, and waxy source rock, such as the Taratu Formation. In this study, kinetic model type III DE is applied for the source rock of study as the Taratu Formation. A water depth of 123.4 m beneath sea level is another boundary condition in 1-D modeling. Petroleum system elements that each formation represents

together with other relevant geochemical parameters belonging to the studied source rock such as TOC and HI are also useful.

In logging operations, bottomhole temperature is often documented before equilibrium between the formation and drilling mud temperatures is reached. Therefore, temperature values extracted from composite logs must be corrected prior to calibration. Correction of borehole temperatures in this study has been carried out based on studies by Waples and Ramly (1994, 2001), Peters and Nelson (2012) and Bullard (1947).

## Results and discussion

### TOC and Rock-Eval pyrolysis results

The  $S_1$  peak indicates the amount of existing hydrocarbon that is easily discharged during pyrolysis. More kerogen is broken down with further thermal degradation of source rock, which is illustrated in the  $S_2$  readings. In this research,  $S_1$  values obtained range from 3.6 to 21.4 mg HC/g rock, indicating very good results. Values ranging from 31.8 to 200.4 mg HC/g rock are obtained for  $S_2$  and the  $S_3$  peak contain readings from 2.3 to 16.4 mg HC/g rock. The Taratu source rock comprises TOC readings that range from 23 to 89%; therefore, the source rock is considered to have excellent quantity based on the classification introduced by Peters (1986).

OI and HI are the most important parameters that can be correlated together to do kerogen typing of source rocks. OI and HI as calculated for the Taratu source rock ranges from 5.00 to 25.7 mg CO<sub>2</sub>/g TOC and 165.0 to 327.5 mg HC/g TOC respectively. The ratio between  $S_2$  and  $S_3$  is another index that can be applied in the classification of kerogen and has values from 7.69 to 38.0. A complete record of the aforementioned parameters is listed in Table 1.

A classification of hydrocarbon generation windows by  $T_{max}$  values has been done by Peters and Cassa (1994). In this classification, the mature oil window is encountered at a  $T_{max}$  range of 435–450 °C; any lower temperature below 435 °C indicates that a source rock is thermally immature and  $T_{max}$  values above 470 °C is indicative of a thermally over-mature source rock. This classification also states that the gas window of a source rock is reached at  $T_{max}$  values of 450–470 °C.  $T_{max}$  values of this study ranges from 420 to 459 °C, which differs between the Paleocene and Late Cretaceous source rocks, making it a useful index to measure thermal maturity that might vary for organic matter with different ages.

Vitrinite reflectance ( $\% R_o$ ) is a good parameter that is applicable in the evaluation of source rock thermal maturity. The Taratu source rock records vitrinite reflectance

**Table 1** Results of Rock-Eval pyrolysis from Tara-1 well used in this study

Depth (m)	Lithology	$S_1$	$S_2$	$S_3$	TOC	OI	HI	PI	$S_2/S_3$	$PY = S_1 + S_2$	$T_{max}$
2225	Coal	8.00	117	15.0	58.3	25.7	200	0.06	7.78	125	421
	Mudstone	3.60	54.2	6.80	29.5	23.1	184	0.06	7.97	57.8	423
2344	Coal	13.2	148	13.4	64.6	20.7	230	0.08	11.1	162	420
	Mudstone	8.70	120	8.60	45.5	18.9	263	0.07	13.9	129	423
2509	Coal	20.1	162	11.9	62.4	19.1	260	0.11	13.6	182	423
	Mudstone	7.80	89.6	5.80	29.2	19.9	307	0.08	15.4	97.4	426
2719	Coal	12.6	153	12.5	63.7	19.6	240	0.08	12.2	165	429
	Mudstone	5.90	82.9	5.60	26.0	21.5	319	0.07	14.8	88.8	429
2797	Coal	7.80	161	11.8	69.3	17.0	232	0.05	13.6	169	433
2886	Coal	13.9	187	9.50	72.4	13.1	259	0.07	19.7	201	433
2938	Coal	14.9	169	9.10	64.6	14.1	262	0.08	18.6	184	433
	Mudstone	5.60	70.8	4.10	24.9	16.5	284	0.07	17.2	76.4	435
3158	Coal	21.1	200	9.60	70.2	13.7	286	0.10	20.9	222	437
	Mudstone	7.10	77.3	4.10	23.6	17.4	328	0.08	18.8	84.4	437
3313	Coal	21.0	187	8.20	77.2	10.6	242	0.10	22.8	208	442
	Mudstone	7.10	66.2	4.20	27.7	15.2	239	0.10	15.8	73.3	443
3469	Coal	16.4	126	16.4	63.7	25.7	198	0.12	7.69	143	440
	Mudstone	5.60	57.6	3.50	20.1	17.4	287	0.09	16.5	63.2	443
3575	Coal	21.4	178	5.00	88.9	5.62	200	0.11	35.5	199	450
3578	Coal	21.4	172	9.10	79.8	11.4	216	0.11	18.9	194	451
	Mudstone	5.90	53.4	3.30	21.1	15.6	253	0.10	16.2	59.3	449
3734	Coal	19.8	158	9.50	72.6	13.1	217	0.11	16.6	178	451
	Mudstone	6.60	59.3	4.60	26.4	17.4	225	0.10	12.9	65.9	449
3749	Coal	19.2	156	4.10	81.9	5.00	191	0.11	38.0	175	454
3871	Coal	20.6	144	8.70	74.1	11.7	194	0.13	16.5	164	453
	Mudstone	7.50	56.2	3.70	27.5	13.5	204	0.12	15.2	63.7	453
3962	Coal	20.7	129	8.40	77.0	10.9	167	0.14	15.3	149	457
	Mudstone	6.30	42.6	2.90	22.9	12.7	186	0.13	14.7	48.9	458
4109	Coal	10.1	125	9.60	75.5	12.7	165	0.13	13.0	144	459
	Mudstone	4.20	31.8	2.30	16.2	14.2	196	0.12	13.8	36.0	459

values that range from 0.39 to 1.15%. PY is defined as the summation of  $S_1$  and  $S_2$ , which contain values ranging from 36 to 221.5 mg HC/g TOC for the Taratu Formation. The ratio between  $S_1$  and PY makes up the PI, where it is the proportion of the amount of free hydrocarbons already generated to the total amount of hydrocarbon that the organic matter is capable of generating. This parameter can be used to measure source rock thermal maturity (Peters 1986; Shalaby et al. 2011, 2012a, b; El Nady et al. 2015; Qadri et al. 2016; Jumat et al. 2018; Osli et al. 2018). In this study, PI values range from 0.0642 to 0.117.

The origin of hydrocarbon generated by the Taratu source rock has been examined through a cross-plot of  $S_1$  versus TOC (Fig. 3). The graph shows that the hydrocarbon of the Taratu Formation is uncontaminated and was created in situ. Hydrocarbon generation potential can also be investigated using the graph of PY versus TOC (Fig. 4). This cross-plot shows that all coal samples are

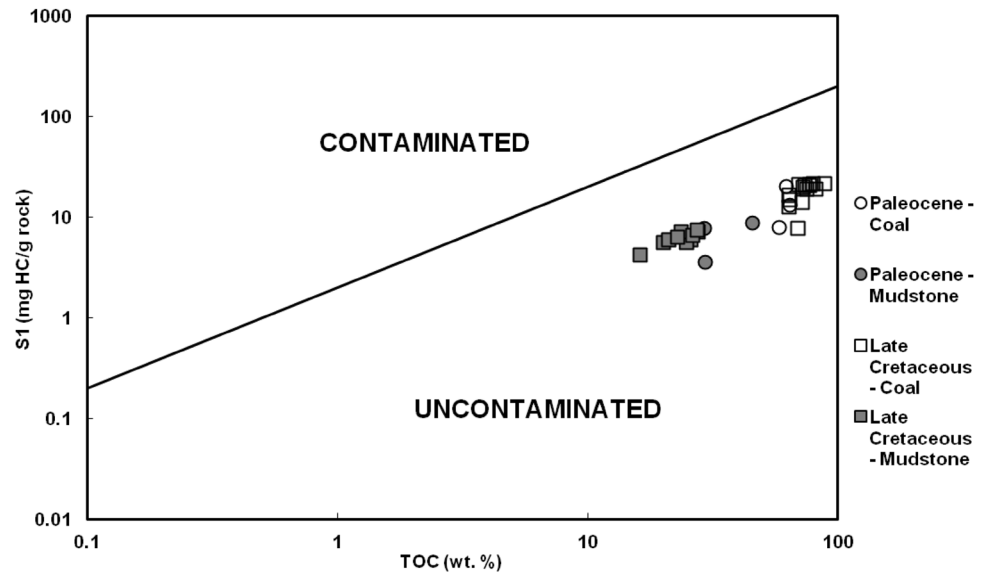
characterized by higher TOC and PY regardless of its age, as compared to the corresponding samples from mudstone.

### Type of organic matter

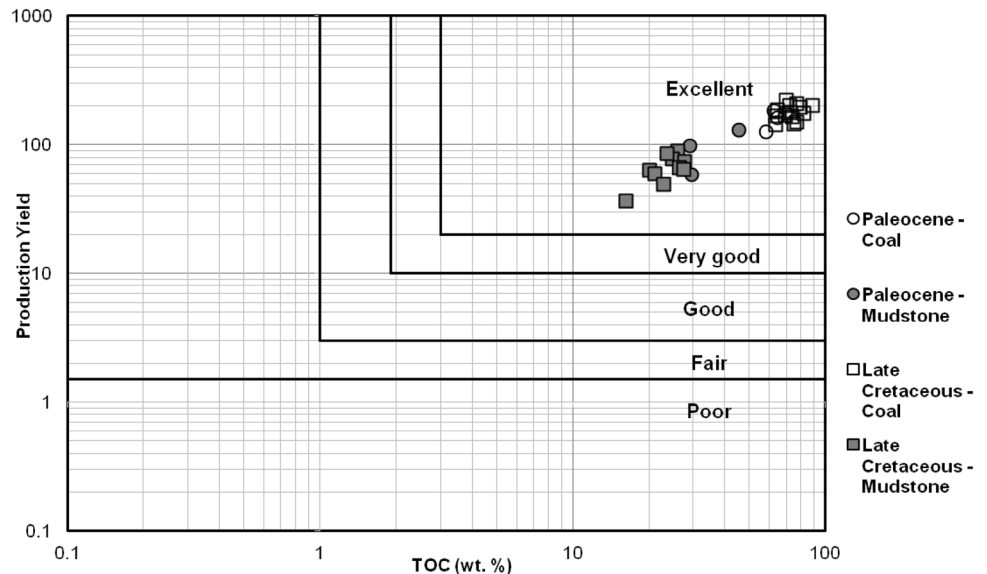
A combination of several pyrolysis results and their derivations are applied to determine the type of organic matter and hydrocarbon generated of the Taratu Formation source rock. The relationship between  $S_2$  and TOC will investigate the type of organic matter present (Fig. 5; Langford and Blanc-Valleron 1990). Kerogen type II–III is the most dominant kerogen type in this well from both coals and mudstone samples from the Late Cretaceous to Paleocene. Few gas-prone kerogen type III is detected from the coal samples.

The modified Van Krevelen diagram is functions to demonstrate the type of kerogen present by correlating HI and OI of a source rock. Figure 6 shows that both coal and mudstone samples have the same range of values of HI (165–327.5 mg

**Fig. 3** A cross-plot of  $S_1$  versus total organic carbon (TOC) to indicate the origin of hydrocarbon in the Taratu Formation (Fakhri et al. 2013)



**Fig. 4** A cross-plot of production yield (PY) versus total organic carbon (TOC) to exhibit the generating potential of the Taratu Formation



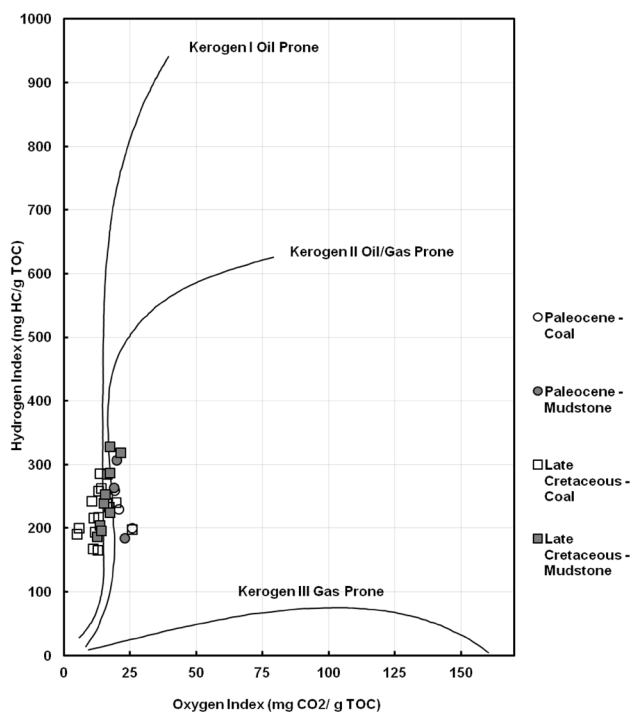
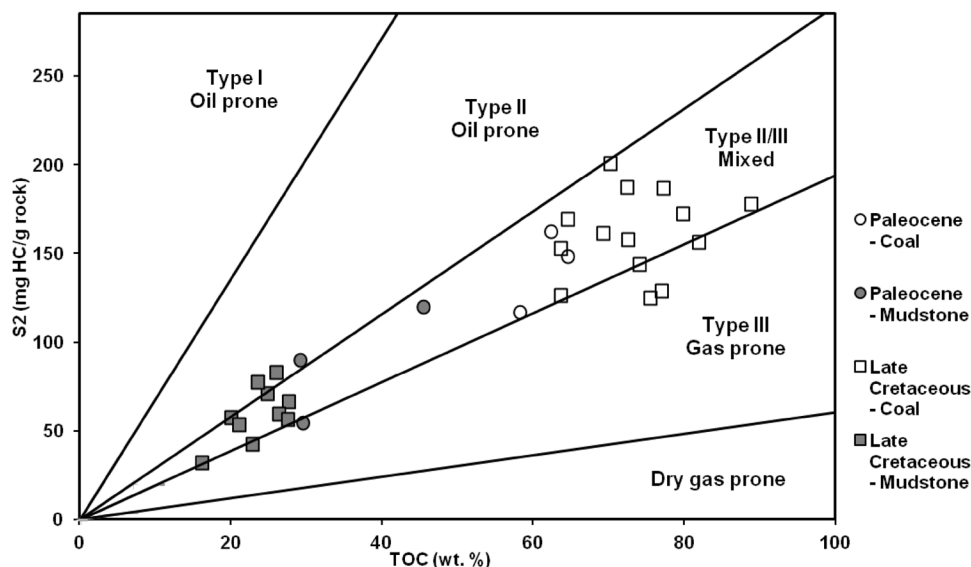
HC/g TOC) and OI (5–25.7 mg CO<sub>2</sub>/g TOC), with no sharp difference between both lithologies. For this reason, the Van Krevelen diagram thus shows the dominance of kerogen type II–III in the Taratu Formation, which is in a good agreement with Fig. 5.

### Thermal maturity and hydrocarbon generation potential

Thermal maturities of the Taratu Formation in this study are measured using  $T_{max}$ , measured vitrinite reflectance (%  $R_o$ ) and PI. Source rocks with more evolved organic matter will generate higher  $T_{max}$  values, illustrating a more thermally mature state (Barker 1974; Espitalié 1986).

A cross-plot between  $T_{max}$  and HI in Fig. 7 shows that the thermal maturity of the Taratu source rock increases with age, regardless of lithology. Both Paleocene-aged coal and mudstone samples lie within the immature window as the  $T_{max}$  values range between 420 to 426 °C.  $T_{max}$  values for source rock samples from the Late Cretaceous for both lithologies gradually increase from 429 to 459 °C with increasing depth, thus located in the mature oil window where oil and gas generation has commenced. Few data points from the Late Cretaceous are detected in the condensate wet gas zone. Therefore, Fig. 7 shows that the younger, Paleocene-aged Taratu Formation comprises only kerogen type II–III while the older Cretaceous-aged formation is capable of generating gas, as it has become more thermally mature with time. It can thus be concluded that the age with depth

**Fig. 5** A cross-plot of  $S_2$  versus total organic carbon (TOC) to identify the type of hydrocarbon produced from both Paleocene and Cretaceous in well Tara-1 (Langford and Blanc-Valleron 1990)



**Fig. 6** A cross-plot of hydrogen index (HI) versus oxygen index (OI) in the modified Van Krevelen diagram shows the type of kerogen available in the Taratu source rock (Espitalié et al. 1985)

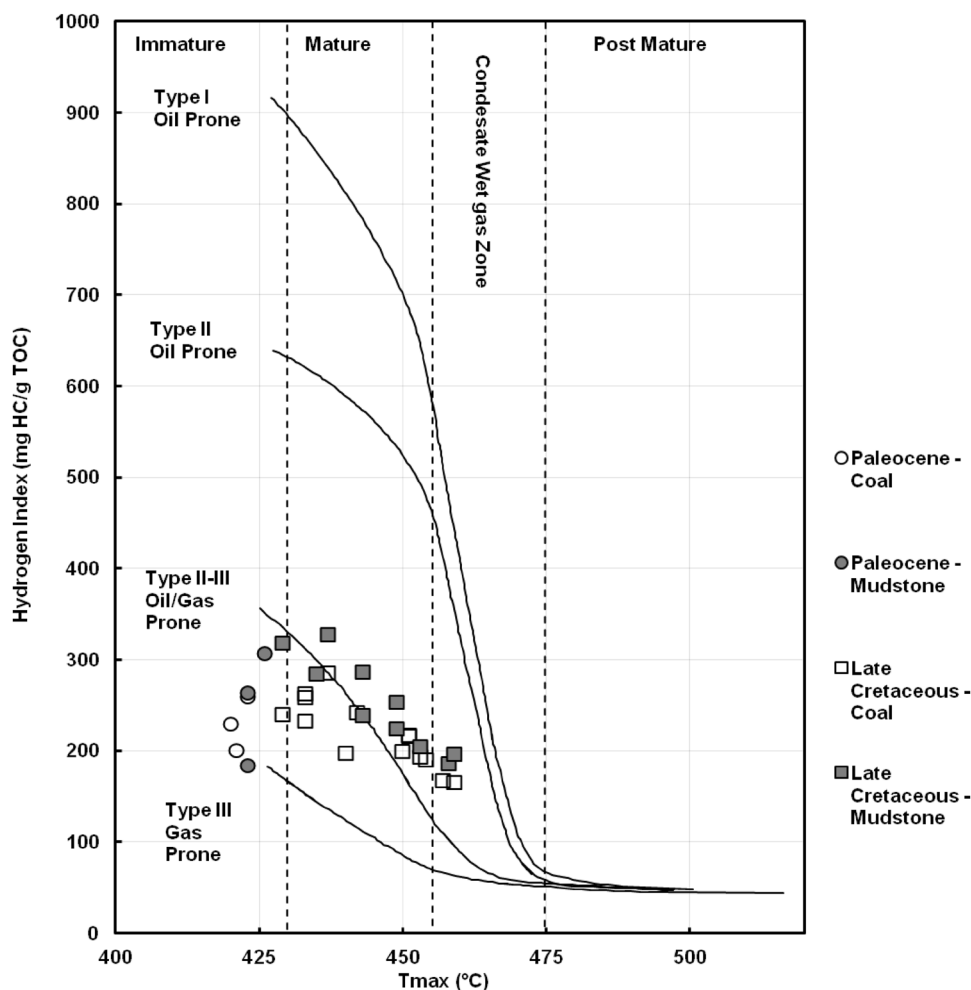
and time are the controlling factors to maturity of source rock samples from the Taratu Formation regardless of its lithology.

Vitrinite reflectance is a maturity-measuring parameter for coals or organic matter developed in continental plants, at which an increase in vitrinite reflectance value reflects an increasing amount of thermally mature organic matter (Price and Barker 1985; Stach et al. 1982). Because vitrinite reflectance is dependent on the maturity of organic matter, which is consequently affected by depth, this parameter is also similarly different between Paleocene and Late Cretaceous source rocks of the Taratu Formation.

All of the Paleocene source rock samples contain vitrinite reflectance values of 0.4% to than 0.65%, while those belonging to Late Cretaceous age ranges from 0.65 to 1.15% (Table 2). Therefore, Cretaceous source rocks are within the mature oil and condensate wet gas windows due to their higher vitrinite reflectance values. Vitrinite reflectance can also be plotted with  $T_{max}$  to identify the state of thermal maturity for the organic matter (Qadri et al. 2016; Jumat et al. 2018). Both parameters are plotted together in Fig. 8 to show the change in thermal maturity of the Taratu Formation, from Paleocene to the Late Cretaceous.

PI values between 0.1 and 0.4 are considered a thermally mature source rock. A thermally immature source rock is characterized by PI values less than 0.1, and an over-mature source rock is indicated by PI values of more than 0.4 (Peters 1986). PI is correlated with  $T_{max}$  in Fig. 9, which shows a thermally immature source rock for Paleocene samples and a thermally mature source rock with higher  $T_{max}$  and PI for samples belonging to the Late Cretaceous. Figures 10 and 11 show how depth affects the thermal maturity of the Taratu source rock. Samples from shallower depths are most likely

**Fig. 7** A cross-plot of hydrogen index (HI) versus maximum pyrolysis temperature ( $T_{max}$ ) to indicate source rock maturity



thermally immature, while the maturity level in terms of both  $T_{max}$  and %  $R_o$  as increasing with increasing depth.

## Burial history and basin modeling

### Subsidence and burial history

One-dimensional basin model has been constructed by applying the PetroMod software. This is done to comprehend the burial history, thermal maturity history, timing and depth of hydrocarbon generation of the Taratu Formation.

In Tara-1 well, the Late Cretaceous Hoiho Formation overlies the metamorphic basement. This Formation was deposited from 100.5 to 95.2 Ma, producing a coaly shale of 83 m thick (Fig. 12). This is succeeded by the deposition of the coaly shale Taratu Formation until 71.8 Ma, and has a present thickness of 2165 m. Wickliffe Formation overlies the Taratu Formation, and it was deposited from 71.8 to 67.7 Ma, to produce a 133 m thick layer of shale. From

67.7 to 34.5 Ma, the Laing Formation was deposited in three sequences with its own lithological characteristics. From 34.5 to 15.9 Ma, limestone of the Penrod Formation was deposited and has a current thickness of 508 m (Fig. 12). From 15.9 Ma to the recent time, recent sediments are deposited. All the parameters required to generate the 1-D model for well Tara-1 is summarized in Table 3.

### Data calibration and thermal history

According to Pandey (1981), heat flows in the Great South Basin are high, with values ranging from 87.2 to 163.8 mW/m<sup>2</sup>, which is attributable to the presence of young volcanism. These young volcanic bodies take in the form of intrusions and are located above the basement. Seismic evidence also suggests the presence of a large batholith within the basement in one of the wells in the basin (Hunt International Petroleum Company 1978).



**Table 2** Vitrinite reflectance values from Tara-1 well used in thermal maturity measure used in this study

Depth (m)	% $R_o$
945	0.34
1189	0.39
1341	0.35
1585	0.38
1676	0.37
1859	0.37
2012	0.46
2438	0.45
2469	0.53
2591	0.55
2797	0.55
2835	0.58
3048	0.60
3158	0.76
3167	0.82
3313	0.87
3353	0.88
3575	0.95
3578	0.99
3578	0.98
3734	0.98
3749	1.04
3871	1.06
3962	1.12
4109	1.15

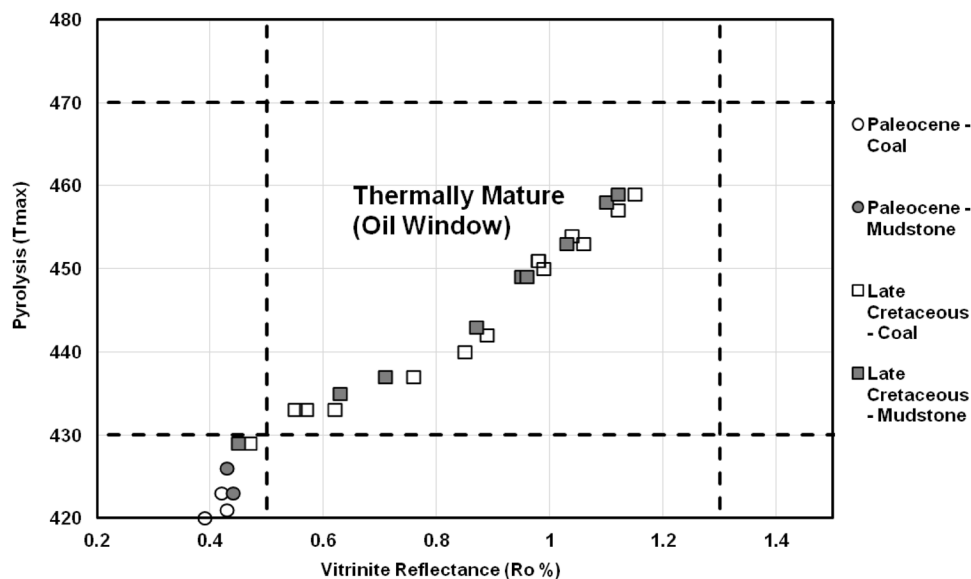
However, a more recent paper written by Godfrey et al. (2001) stated that the background heat flow in the Great South Basin is approximately 60 mW/m<sup>2</sup>, similar to that

of Taranaki Basin, thus this research will utilize this heat flow value. In a calibration between modeled and measured temperature values, a generally good fit between both is achieved (Fig. 13).

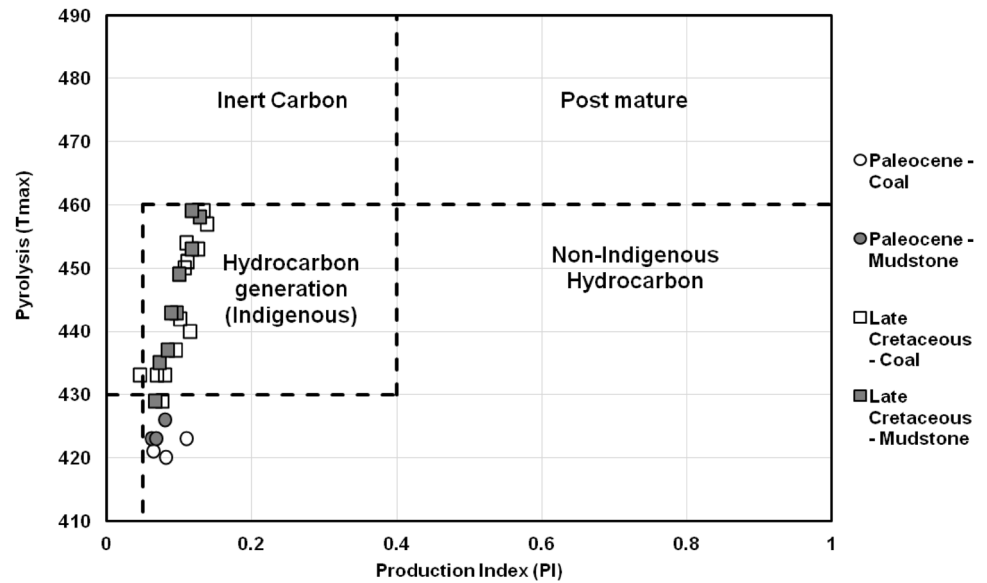
The measurement of vitrinite reflectance values does not usually reflect true values as they are often subjected to suppression due to several factors. Factors that can contribute to vitrinite reflectance suppression as suggested by Mukhopadhyay (1994), including difference in lithology, peryhydrous vitrinite formation, presence of bitumen in source rocks as indicated by  $S_1$  values, abundance of liptinite macerals, intensity of bacterial activity, and contamination of samples.

Specifically for New Zealand coals, Quick (1992) indicated that vitrinite reflectance suppression took place due to the presence of sulfate-reducing bacteria. A cross-plot between sulfur concentration (%) and vitrinite reflectance (%  $R_o$ ) in Fig. 14 indicates that a negative relationship has been deduced from both parameters used. This may confirm the hypothesis that vitrinite reflectance values in this study have been subjected to suppression due to the presence of sulfate-reducing elements, therefore it must be taken into consideration.

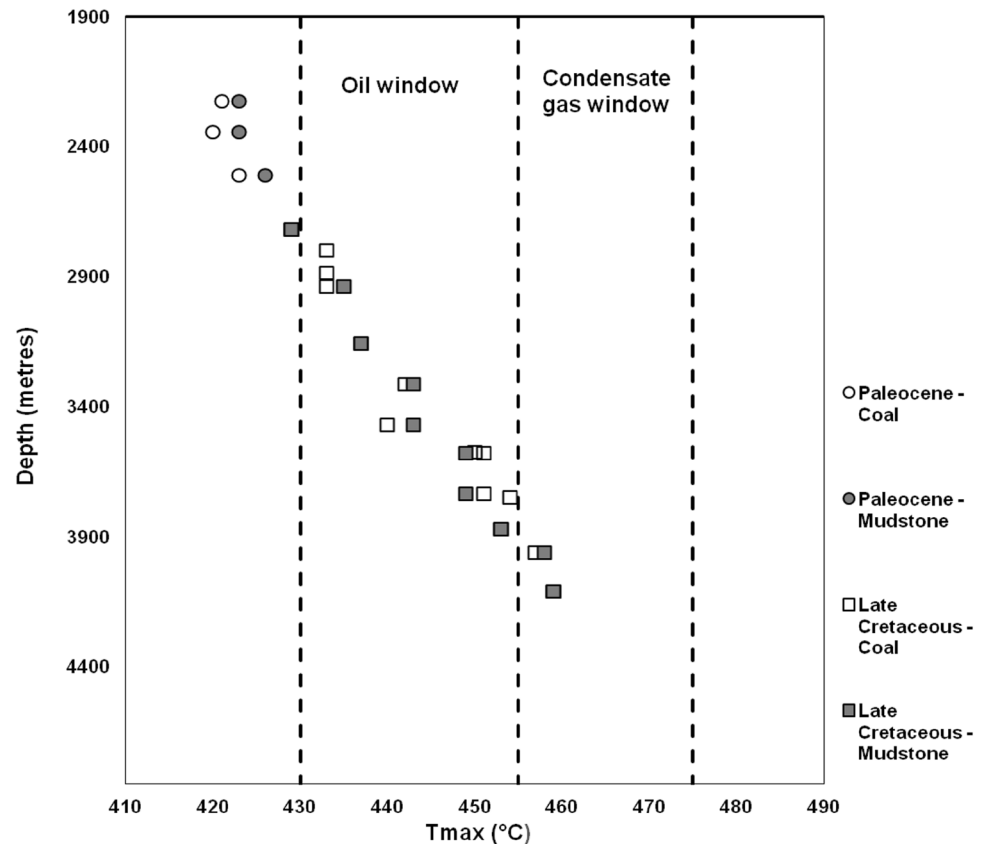
For these reasons, all vitrinite reflectance values provided for this research must be corrected to get the true values and to avoid complications during calibration in PetroMod software. In this research, several research works have been considered for better performance in the correction of vitrinite reflectance values, such as by Lo (1993), Quick (1992), and Mukhopadhyay (1994). After correction, a best fit of the modeled and measured vitrinite reflectance values has been obtained (Fig. 15).

**Fig. 8** A cross-plot of maximum pyrolysis temperature ( $T_{max}$ ) versus vitrinite reflectance (%  $R_o$ ) to indicate source rock thermal maturity

**Fig. 9** A cross-plot of maximum pyrolysis temperature ( $T_{max}$ ) versus production index (PI) to identify source rock maturity



**Fig. 10** A cross-plot of maximum pyrolysis temperature ( $T_{max}$ ) versus depth to demonstrate the distribution of the parameter with increasing depth

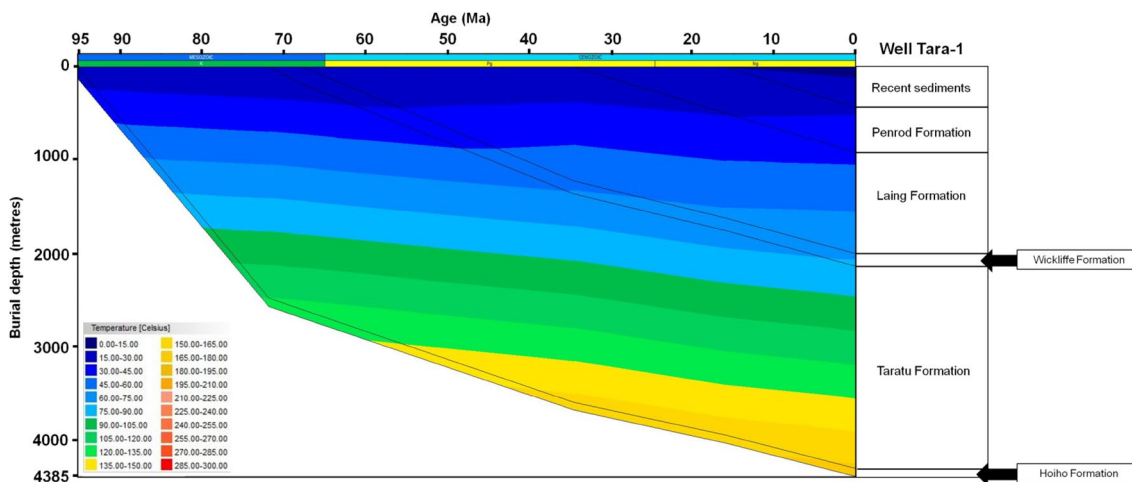
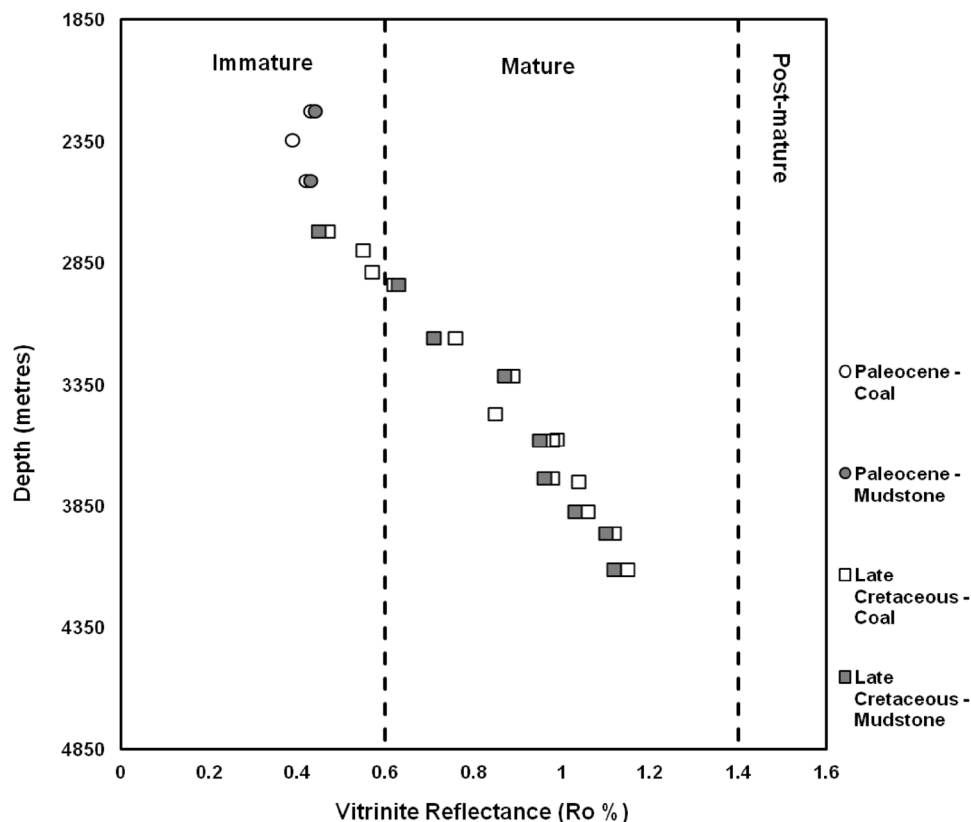


### Timing of hydrocarbon generation and expulsion of the Taratu Formation

Exact timing and depth of hydrocarbon generation and expulsion for the Taratu Formation can be acquired through one-dimensional basin modeling through the application of the PetroMod software. This was done based on the

formation temperature and maturation history (Qadri et al. 2016; Jumat et al. 2018). The top of oil window for the Taratu Formation in Tara-1 well was encountered 51 Ma ago at 3100 m depth from the surface (Fig. 16). Maturity to generate gaseous hydrocarbon took place at a depth of 4132 m, at 8 Ma ago.

**Fig. 11** A cross-plot of vitrinite reflectance (%  $R_o$ ) versus depth to demonstrate the distribution of the parameter with increasing depth



**Fig. 12** Burial history with temperature variations for Tara-1 well

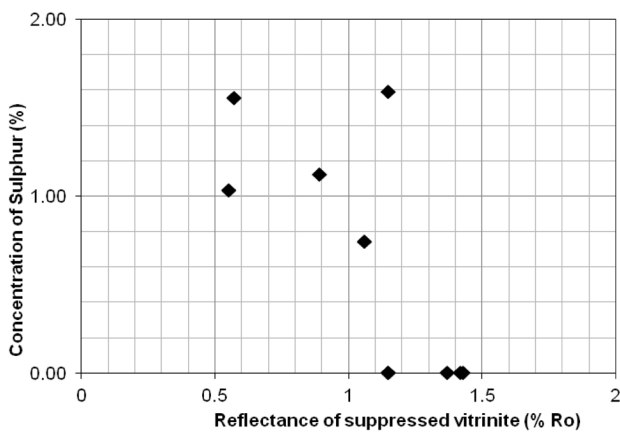
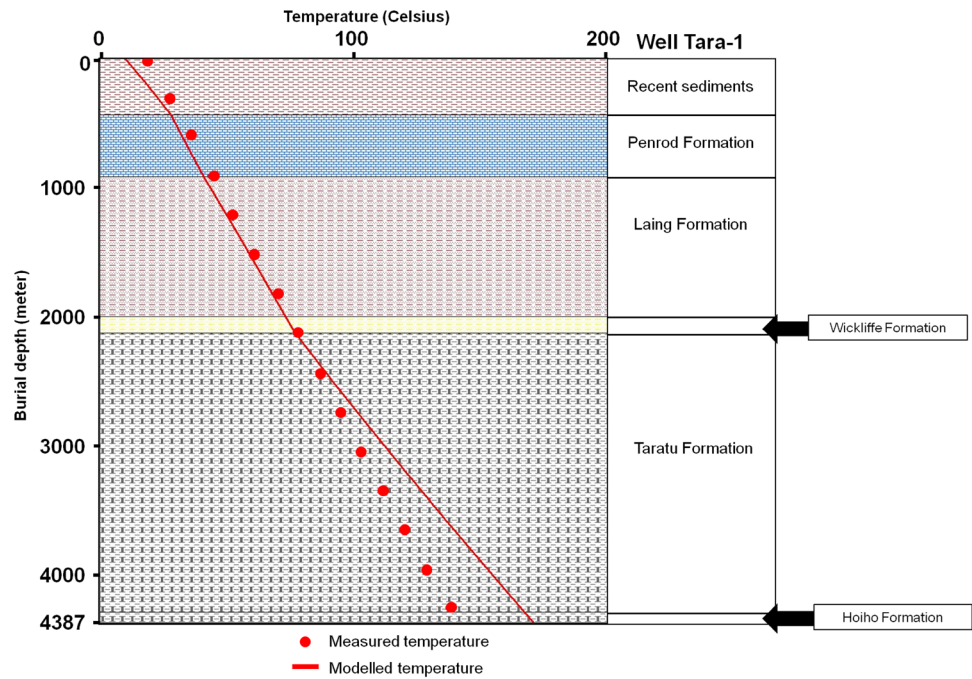
Hydrocarbon expulsion ratio model indicates the relative ratios between oil and gas generated by the source rock, which will indirectly indicate type of kerogen present and thermal maturity state of the source rock. As the formation consists of both kerogen type II–III and type III, there will be a mixture of both oil and gas in the hydrocarbon generation and this is reflected in Fig. 17. A

transformation ratio of 12% shows that until the present, the Taratu Formation has expelled more oil relative to gas as the oil window has been reached in 51 Ma upon thermal maturity. This also confirms the presence of kerogen type II/III and III present in the Taratu Formation. There was a rapid production of liquid hydrocarbon taking place from 68 Ma, with a concentration of 54 mg HC/g TOC

**Table 3** Input parameters for 1-D modeling of Well Tara-1

Formation name	Age	Top (m)	Bottom (m)	Thickness (m)	Lithology	Petroleum system elements
Recent sediments	0–15.9	0	442	442	Shale	Overburden
Penrod	15.9–34.5	442	920	478	Limestone	Overburden
Laing	34.5–67.7	920	2006	1086	Shale and sand	Seal
Wickliffe	67.7–71.8	2006	2139	130	Sand and shale	Reservoir
Taratu	71.8–95.2	2139	4304	2165	Coaly shale	Source rock
Hoiho	95.2–100.2	4304	4387	83	Coaly shale	Underburden

**Fig. 13** Calibration of measured and modeled temperature for Tara-1 well



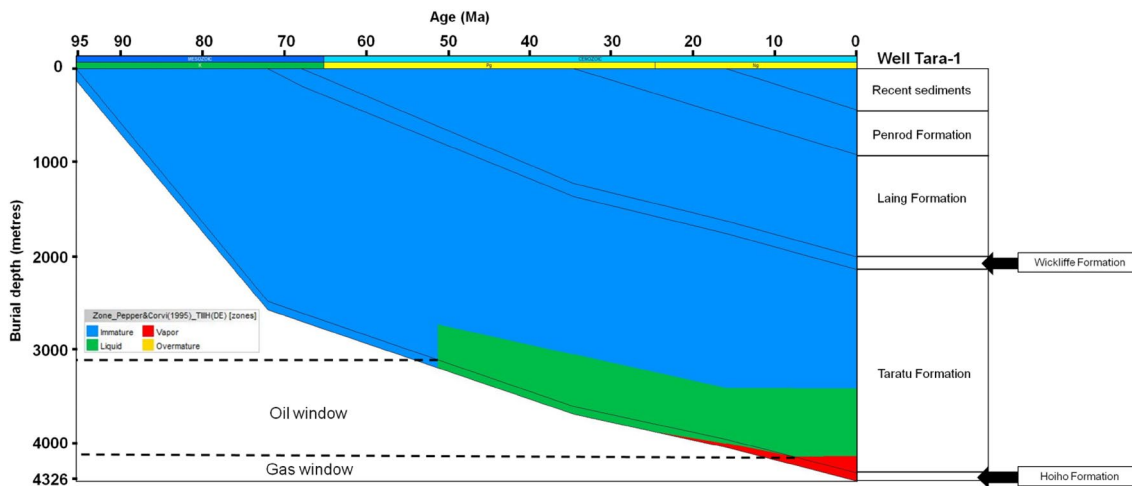
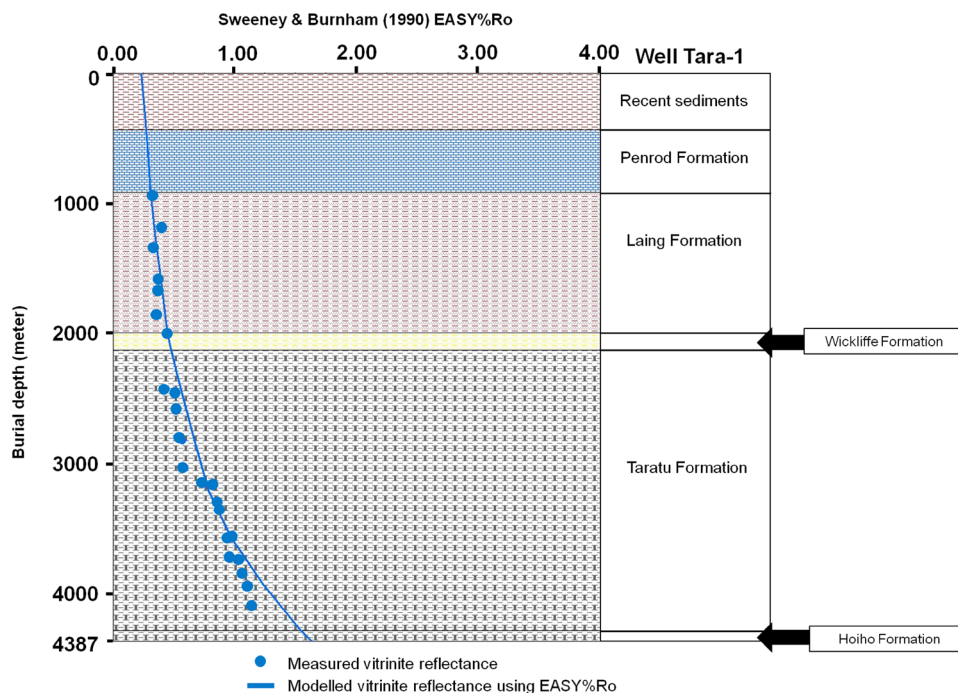
**Fig. 14** Correlation between sulfur and %  $R_o$  to show the relationship between both parameters

(Fig. 17). During the same time interval, gaseous hydrocarbon generation also simultaneously occurred with a present concentration of 12 mg HC/g TOC. However, as of present, generation of liquid and gaseous hydrocarbon has not reached their peaks.

**Conclusion**

The Taratu Formation in the Great South Basin of New Zealand is proven to be an excellent source rock in this study. The studied source rock samples collected from Tara-1 Well has two different ages: Paleocene and Cretaceous. Rock-Eval pyrolysis executed on these samples shows that higher readings of TOC and  $S_2$  are detected in coal samples of both Paleocene and Late Cretaceous age relative to the mudstone samples. Regardless, the Taratu

**Fig. 15** Calibration of measured and modeled vitrinite reflectance values for Tara-1 well

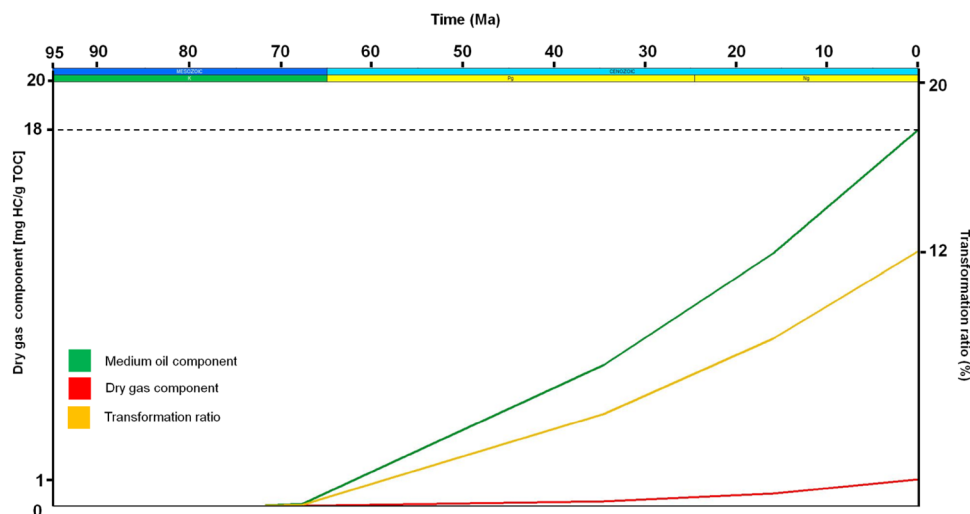


**Fig. 16** Hydrocarbon generation model indicating oil, gas, and overmaturation windows for Tara-1 well

Formation is still considered a source rock of high quality and quantity, which generates kerogen type II–III and gas-prone kerogen type III. Varying thermal maturity stages of the Taratu source rock is recorded; Paleocene source rocks located at relatively shallower depths are thermally immature based on the  $T_{max}$ , VR, and PI values. In turn, source rock belonging to the Late Cretaceous is thermally mature

due to its relatively older age and greater depth of burial. One-dimensional basin modeling of Tara-1 well allowed the understanding of burial and thermal histories of the Taratu Formation. An excellent fit between measured and modeled values for subsurface temperature and vitrinite reflectance are obtained after making the necessary adjustments, indicating a good data quality is used in this study.

**Fig. 17** Hydrocarbon multi-component and transformation ratios for Tara-1 well



Top of oil and gas generative windows for the Formation are encountered at 51 and 8 Ma, respectively. In this study, all results are parallel and in agreement with each other.

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