SOURCE ROCK AND RESERVOIR POTENTIAL OF THE NORTHERN EAST COAST BASIN, NORTH ISLAND, NEW ZEALAND

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Petroleum exploration north of Gisborne has been going on for more than one hundred years encouraged by the more than 80 oil and gas seeps throughout the region and especially those at Waitangi, Totangi and Rotokautuku.

Existing rock data is strongly biased toward those intervals traditionally considered to be good source rocks. The Waipawa *blackshale* Formation of Paleocene age, and interbeds within the Late Cretaceous Karekare Formation, have TOCs consistently exceeding 4%. Most maturation data collected indicates that potential source rocks are immature, or marginally mature, however, negligible data is available for those parts of the basin where depths of burial are greatest. Attempts to *type* oil from the main surface seeps, especially those at Waitangi, seem to indicate that the Waitangi oil was not derived from the Waipawa *blackshale*.

Numerous potential sandstone reservoir intervals can be recognised through the stratigraphic sequence. Those with the best potential are sandstone units of Early Cretaceous age (Koranga and Te Wera Formations), Late Cretaceous age (Karekare *intraformational sandstones*, Tahora and Moanui Formations), Oligocene (Weber Formation) and Miocene age (*intraformational* sandstones). The reservoir potential of Oligocene sandstones is indicated by a maximum poroperm value of 21.5%/4md from outcrop, and the Gisborne-2 well, which gave strong gas shows and traces of oil from Oligocene greensands. Intense deformation resulting from a phase of Late Oligocene-Early Miocene allochthonous emplacement, has enhanced reservoir potential in numerous areas. Fracture porosities of up to 30% have been recorded within a sequence of Eocene mudstones/ siltstones within the Te Horo-1 well.

INTRODUCTION

The East Coast Basin commonly refers to that area along the eastern margin of the North Island, and includes all that area from Palliser Bay in the south, to East Cape in the north (Fig. 1). Basement rocks of Jurassic/Early Cretaceous age define the basin's western extremity. Drilling and seismic evidence indicates that the basin extends a considerable distance offshore. The East Coast Basin is arbitrarily divided into northern and southern regions by a line passing through central Hawkes Bay. The northern region was examined during the course of the first years work requirements for PPL 38312 (operator Asia Pacific) and PPL 38314 (operator Ocean Resources). The work programme included detailed photogeologic interpretation, several field familiarisation visits, and general data assimilation.

Petroleum exploration has been going on in the East Coast Basin for more than 100 years encouraged by the more than 80 recorded oil and gas seeps which occur throughout the region. These occurrences are direct evidence that petroleum source rocks exist in the area and that they have at some stage, matured and undergone hydrocarbon generation and explusion. The best evidence for oil generation occurs in the northern part of the basin, specifically, three areas north of Gisborne; at Totangi, Waitangi and Rotokautuku. In these areas, active oil seeps and oil shows in shallow wells, provided the initial impetus for oil exploration (1870s-1920s). Later efforts (1930s-1986) continued to test the same oil seeps but also included areas away from the known hydrocarbon indications.

Existing source rock data for the East Coast Basin is biased towards those intervals traditionally considered to be good source rocks. As a result of this, some formations have not yet been adequately tested. It is worth noting that none of the rocks so far tested appear to be the source of oil from the Waitangi and Totangi seeps. This lack of geochemical correlation, together with a general lack of Cretaceous/Early Tertiary outcrop, suggests that the source for the Waitangi and Totangi oils is a formation or member not yet recognised. This apparent lack of oil-source rock correlation doesn't discount the possibility that one or more of the potential source rocks so far analysed may have sourced other hydrocarbon accumulations.

The existing reservoir potential database is not particularly extensive or encouraging for it suggests that there is a preponderance of fine grained sandstones with high clay matrix, and a lack of widespread, clean sandstone reservoirs. Because of a lack of regional outcrop for most

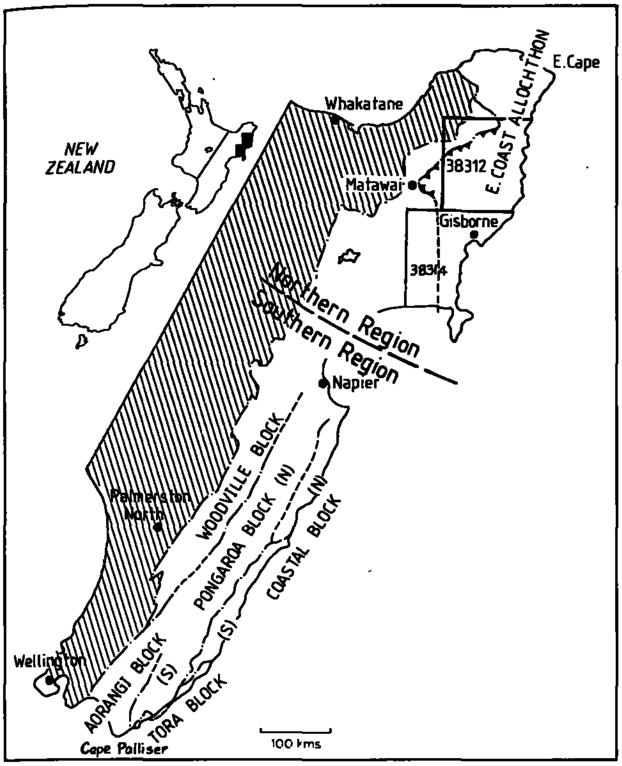

Fig. 1: *Simplified diagram showing extent of East Coast Basin, North Island, New Zealand (after Moore, 1988).*

of the lower units of the stratigraphic sequence, facies distribution is not well understood. Only limited confidence levels can be assigned to existing facies distribution maps. Despite this apparent constraint, hydrocarbon bearing lithologies do occur within the northern region of the East Coast Basin.

REGIONAL STRATIGRAPHY

Basement rocks in the northern region consist of Triassic to Early Cretaceous, Torlesse Supergroup metasediments which accumulated as part of the New Zealand Geosyncline. The Early Cretaceous Rangitata Orogeny intensely deformed these sediments. Deposited over basement, is a marine sequence of Early Cretaceous to Pliocene age. In some areas it has been deduced that this sequence is in excess of 13 000 m thick (Fig. 2).

Basically, the marine sequence records a transgression with minor regressive episodes. The stratigraphic sequence is complicated in the eastern part of the northern region where autochthonous and allochthonous components have been recognised (Black, 1980; Phillips, 1985). Tectonic activity varied from negligible to severe throughout the basin's depositional history. Periods of severe tectonism are well illustrated in outcrop and from limited well information by major formation thickness variations, localised and regional unconformities, and significant lateral facies changes in some areas.

The earliest basin fill sediments of the autochthonous sequence are best exposed near the central western part of the northern region in the Matawai Koranga District (Moore, 1978). Here they comprise shallow marine sandstones, siltstones, breccias and conglomerates of the Koranga and

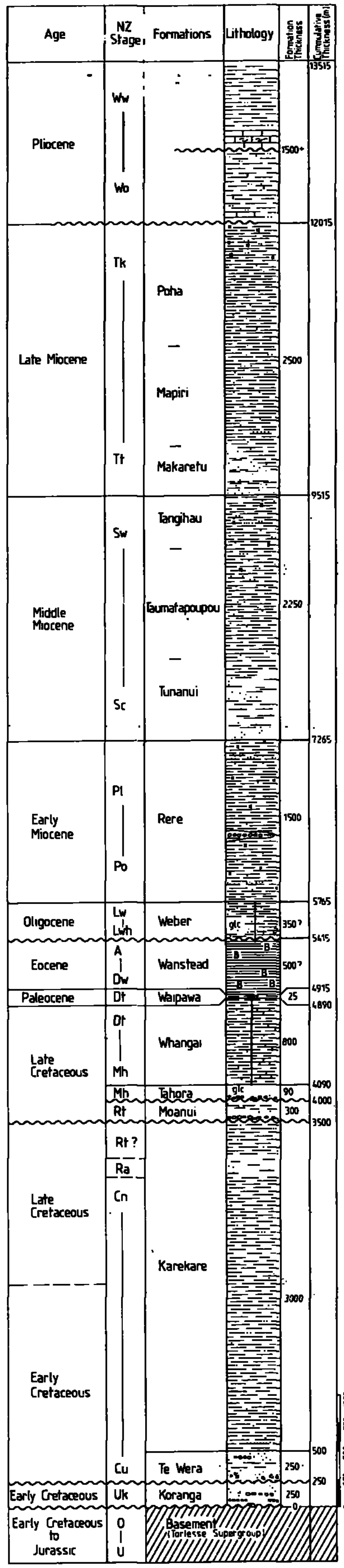

Fig. 2: Generalised stratigraphic column for the Gisborne Region, East Coast, North Island.

Te Wera Formations (Fig. 2). The Koranga and Te Wera Formations which are basal transgressive base levelling units, have highly variable thicknesses. They are conformably overlain by a thick sequence of bathyal flysch deposits comprising mudstones with generally thin sandstone/ siltstone interbeds: the Karekare Formation. Towards the top of the formation, thicker sandstone units do appear (Speden, 1975).

Uplift associated with block faulting during the Late Cretaceous period is indicated by the unconformably overlying Moanui/Tahora Formations which comprise shallow water siltstones and sandstones with conglomeratic and microbreccia interbeds. These formations appear to fine towards the east. Fine grained, fully marine siliceous and calcareous mudstones of the Whangai Formation (Late Cretaceous-Paleocene (part)) overlie these shallow water deposits.

Conformably overlying early Tertiary deposits include dark brown to grey black carbonaceous mudstones of Paleocene age (which are potentially important as a rich source rock), and massive green and blue grey Eocene mudstones which are often bentonitic and occasionally sandy. The carbonaceous mudstones are regionally developed with a typical thickness of 10 to 20 m. At the Makorokoro Stream locality in the northern East Cape area the unit is up to 50 m thick. The bentonic sediments are usually flakey and/or puggy, highly fractured and slickensided. Eocene bentonitic sediments have been recorded as *mud volcanoes* surrounded by younger Tertiary sediments at many localities in the northern region and together with observations from cored sections in some wells (e.g. Morere-1), indicates the extreme *mobility* of this unit.

Late Eocene/Oligocene uplift associated with movements along the Alpine Fault, resulted in the widespread deposition of Oligocene age shelfal greensands, which are succeeded by Late Oligocene calcareous mudstones. Throughout the remainder of the basin's depositional history, sediments mainly accumulated within a rapidly subsiding forearc basin setting. During this period, considerable thicknesses of flysch mudstone and sandstone accumulated (Fig. 2). Turbiditic derived conglomerates occur in localised areas. Towards the eastern and north-eastern part of the northern East Coast Basin area, an autochthonous sequence generally similar to that recorded in the west is noted (Black, 1980; Phillips, 1985).

SOURCE ROCK POTENTIAL

Although little variation in maceral type is evident within the East Coast Basin, total organic content and source rock maturity are more variable as a consequence of the wide range of sedimentary facies and the complex structural setting and history of the area.

Several source rock investigations were undertaken in the northern region during the late 1930s and 1940s but by modern standards these studies were primitive. Later studies on outcrop and well material by Ames (1975) Pearson (1978) Gibbons (1980) Lowe and O'Reilly (1980) Jackson (1982) and Fry (1982) are much more comprehensive and reliable.

Although source rock data is scarce for the Early Miocene sequence, results so far available indicate poor potential with TOC values less than 0.5%. Although vitrinite reflectance values indicate that these samples are immature, care should be taken in assessing the overall generative potential of Early Miocene sediments because the samples analysed do not represent the deepest buried Early Miocene sediments. Similarly limited TOC data is available for the Eocene to Oligocene sequence but the few results available indicate fair to good generative potential.

The Waipawa *blackshale* Formation of Paleocene age is considered to have the best source potential of any rock tested in the East Coast Basin, with values consistently between 4 and 8% TOC (Fig. 3). A maximum value of 12.3% TOC has been reported. Oil generating capacities ranging from 4.1 to 22.21 kg/tonne have been determined. There is a consensus opinion that the Waipawa *blackshale* is mostly Type II kerogen (of highly marine origin) with a minor Type III (terrestrial) component. All outcrop samples that have been analysed are immature and generally occur below the probable lower liquid limit, however, the samples analysed are by no means representative of the regional distribution of this facies. Gas to oil generation indicies (GOGI) mostly indicate that the kerogen content is gas prone, however, one sample examined from the most recent field familiarisation (Analabs, 1988) plotted above the liquid limit, indicating some oil potential.

The Late Cretaceous/Paleocene age Whangai Formation generally has less than 2.0% TOC, with a moderate generative potential of 3 to 6 kg/tonne. GOGIs indicate mixed oil and gas potential. The Late Cretaceous age Karekare Formation has a viable source potential. Mostly it is nil to fair, however, minor interbeds in the upper part of the formation have very good source potential. For these interbeds, the genetic potential range is 1.2 to 44.5 kg/tonne. There is limited analytical data available to assess the Te Wera/Koranga Formations but results indicate nil or very poor source potential.

Selected vitrinite reflectance data shows that outcrop samples investigated range from immature to marginally mature/ mature for oil prone kerogen maturation. VR values for the Whangai Formation increase from about 0.5 to 0.6 (immature) in the west, to a maximum of 1.43 (fully mature) in the east. Although a similar trend is likely for other formations, a lack of regional outcrop has not enabled this observation to be fully tested.

A detailed study of oils from the Totangi, Waitangi and Rotokautuku seeps (Fig. 4) has shown that these oils are derived from source rocks that are mature but which have not reached the phase of maximum oil generation. Attempts have been made to type oils from surface seeps to specific kerogen or source rock types by comparing carbon 13 isotope ratios and *biomarker* distributions (Weston *et. al.*, 1988). Stable carbon isotope ratios from Waitangi and Totangi oil seep samples indicate a marginally marine source, whereas stable carbon isotope ratios of three Waipawa *blackshale* samples (supposedly the most favourable source rock) were markedly heavier indicating an anoxic marine depositional setting. Similarly, other source rocks so far tested show very limited *type* compatibility with the *biomarker* characteristics of the oil seeps.

Acknowledging the constraints of the sampling and analytical database, which is mostly derived from samples taken from the western outcrop margin of the basin, it seems

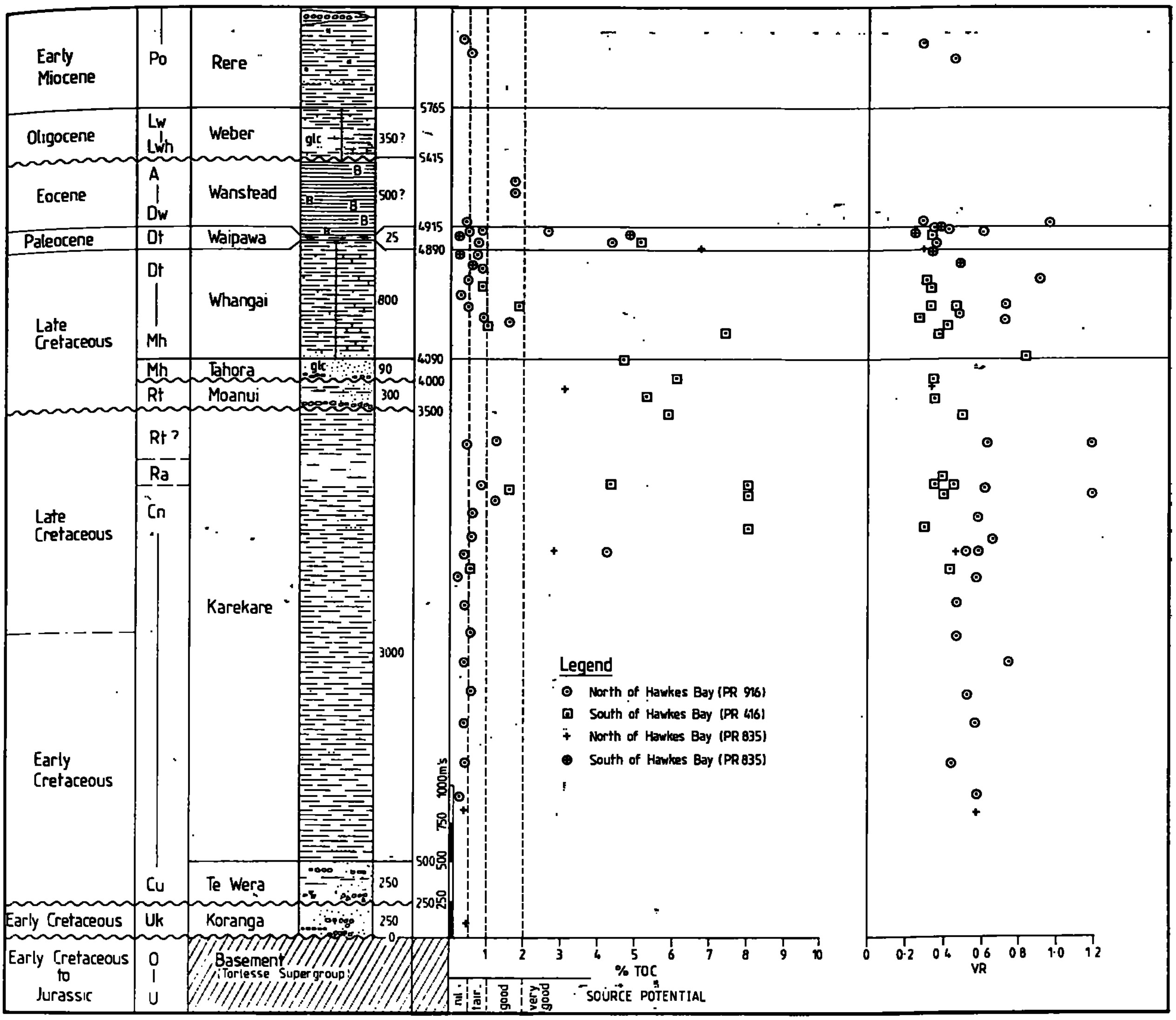

Fig. 3: Total organic carbon and vitrinite reflectance data from a range of potential source rock outcrop samples, East Coast, North Island.

likely that the source for the Waitangi, Totangi and Rotokautuku oil seeps is a formation, autochthonous or allochthonous, not yet recognised, or an easterly lateral equivalent of one of the formations sampled. The greater depth of burial of any potential source rock to the east could place it within the oil maturation zone.

RESERVOIR POTENTIAL

Because of similar source provenance and depositional processes occurring within the East Coast Basin, sandstone characteristics are regionally similar. Potential sandstone reservoirs within the Early Cretaceous to Late Miocene interval are generally fine grained with variable sorting and argillaceous content characteristics. They are distributed throughout the stratigraphic sequence (Fig. 2).

Early Cretaceous sandstones, breccias and conglomerates sampled from several localities (Liming, 1984) show varied poroperm characteristics with porosities ranging 3 to 15%, and permeabilities generally < 1.5 md. Because of rapid facies changes it is unlikely that the most favourable reservoir characteristics would be maintained over significant distances.

Early/Late Cretaceous *intraformational* sandstones identified from outcrop and well data, generally have porosities less than 10%, with permeabilities < 0.5 md. These sandstone types are generally poorly sorted, fine grained and argillaceous. Detailed studies on such sandstones from the Opoutama-1 well (Smith, 1982) has shown that primary porosity is rapidly reduced during early compaction and that the development of secondary porosity occurs due to clay mineral transformation and feldspar alteration. The latter process is short lived. Their deposition as turbidity currents in a submarine fan environment suggests that there is unlikely to be significant improvement in poroperm characteristics within the area.

Late Cretaceous sandstones which represent the basal unit of a Late Cretaceous/Eocene transgressive cycle, have porosity values consistently between 10 and 15%, and permeabilities < 1.0 md.

The best sandstone reservoir potential so far seen from the northern region occurs within the fine to medium grained glauconitic sandstones of the Oligocene age Weber Formation. This formation has good regional distribution, although it is evident from sampling that poroperm values

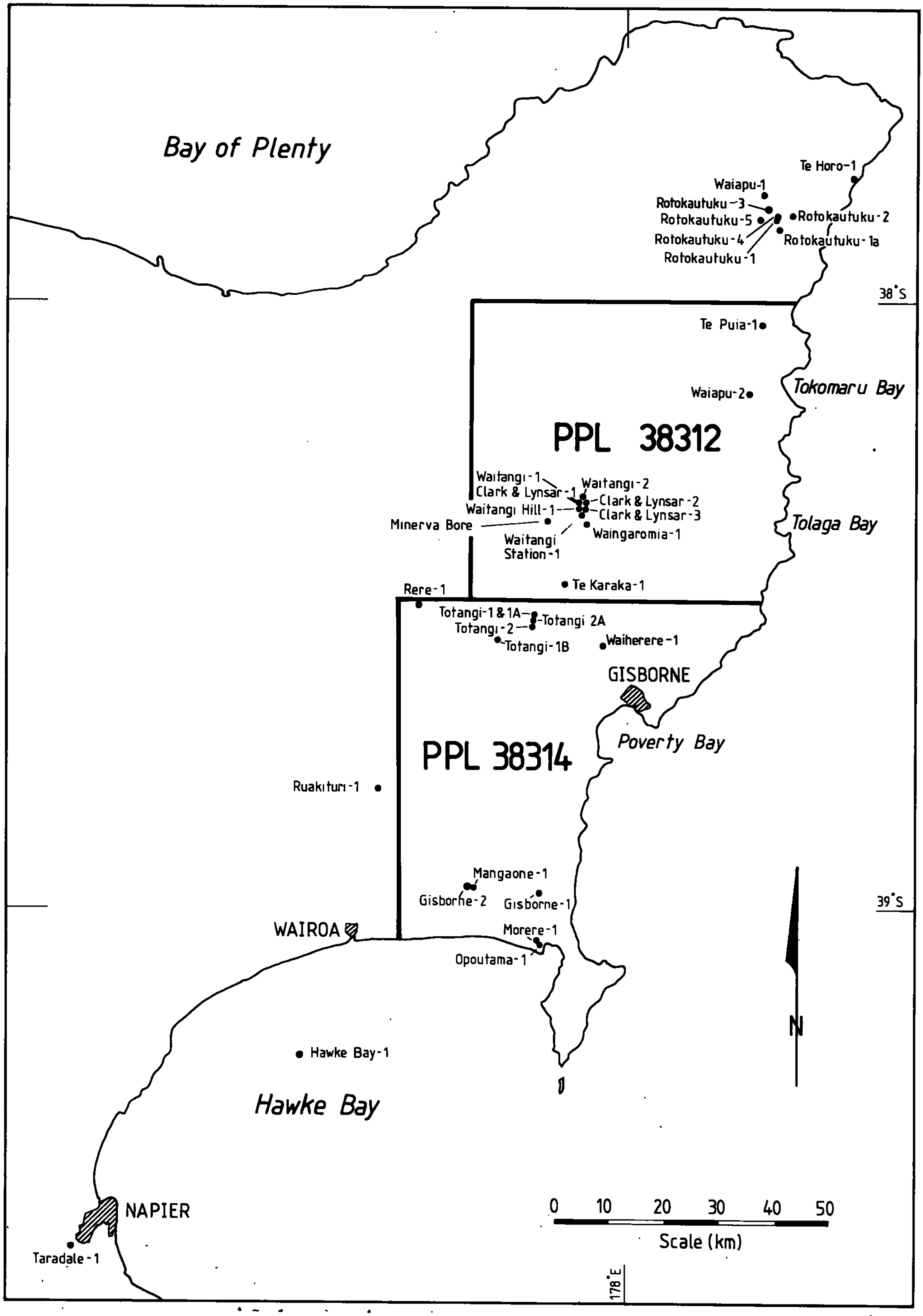

Fig. 4: Drillhole location map for northern region, East Coast Basin.

are quite variable (Fig. 5). A maximum porosity of 21.5%, and permeability of 4 md has been determined from outcrop.

Early Miocene to Late Miocene *intraformational* sandstones and conglomerates are well distributed throughout the northern region and are well exposed in many outcrops. There is limited analytical data available but field observations suggest that many of these units have good visual porosity/permeability characteristics. In the Ruakituri-1 well (Shell-BP-Todd, 1962), a 400 m thick Late Miocene sandstone unit had measured porosities of between 5.6 and 19%, and permeabilities ranging from 2 to 16.3 md.

In addition to the fair to good intergranular porosity occuring in sandstone reservoirs throughout the region, there is significant potential for Early Cretaceous to Early Miocene fracture porosity within all rocks involved in the *East Coast Allochthon*. Porosities as high as 30% have been measured from wells drilled in the East Cape area (Fig. 6). These porosities, which are inconsistent with the textural characteristics of the cuttings recovered to surface, are thought to relate to fracture porosity resulting from intense deformation associated with allochthonous emplacement during the Oligocene/Early Miocene period (Stoneley, 1968). Field evidence in other areas (e.g. chaotic Eocene marls associated with the Waitangi oil seeps) indicates similarly high fracture porosities.

PETROLEUM OCCURRENCES

The most visible evidence of oil generation within the northern region occurs 35 km north-northwest of Gisborne at Waitangi Station where a 400 to 500 m long line of north-south trending oil pools (the largest of which measures 6 m across) is slowly discharging oil and gas (Fig. 7). Black bitumen and yellow sulphurous accumulations are associated with the oil pools. A photograph of one of these oil pools can be found within the September 1989 issue of *Petroleum Exploration News in New Zealand.* Another smaller less active group of seepages occurs approximately 500 m southeast of the main line of oil seeps. The best drilling results within the immediate area were achieved in 1909-10 when the Gisborne Oil Co. drilled the 450 m deep Waitangi-1 well, several hundred metres northwest of the main oil seeps. Initially, a production rate of 10bbls/day was recorded from 202 m (there is no record of how long this production rate was maintained), and even today, the casing left in this drillhole is emitting small quantities of oil and gas. The various oil and gas shows that have been noted from wells put down in and around the Waitangi oil seeps,

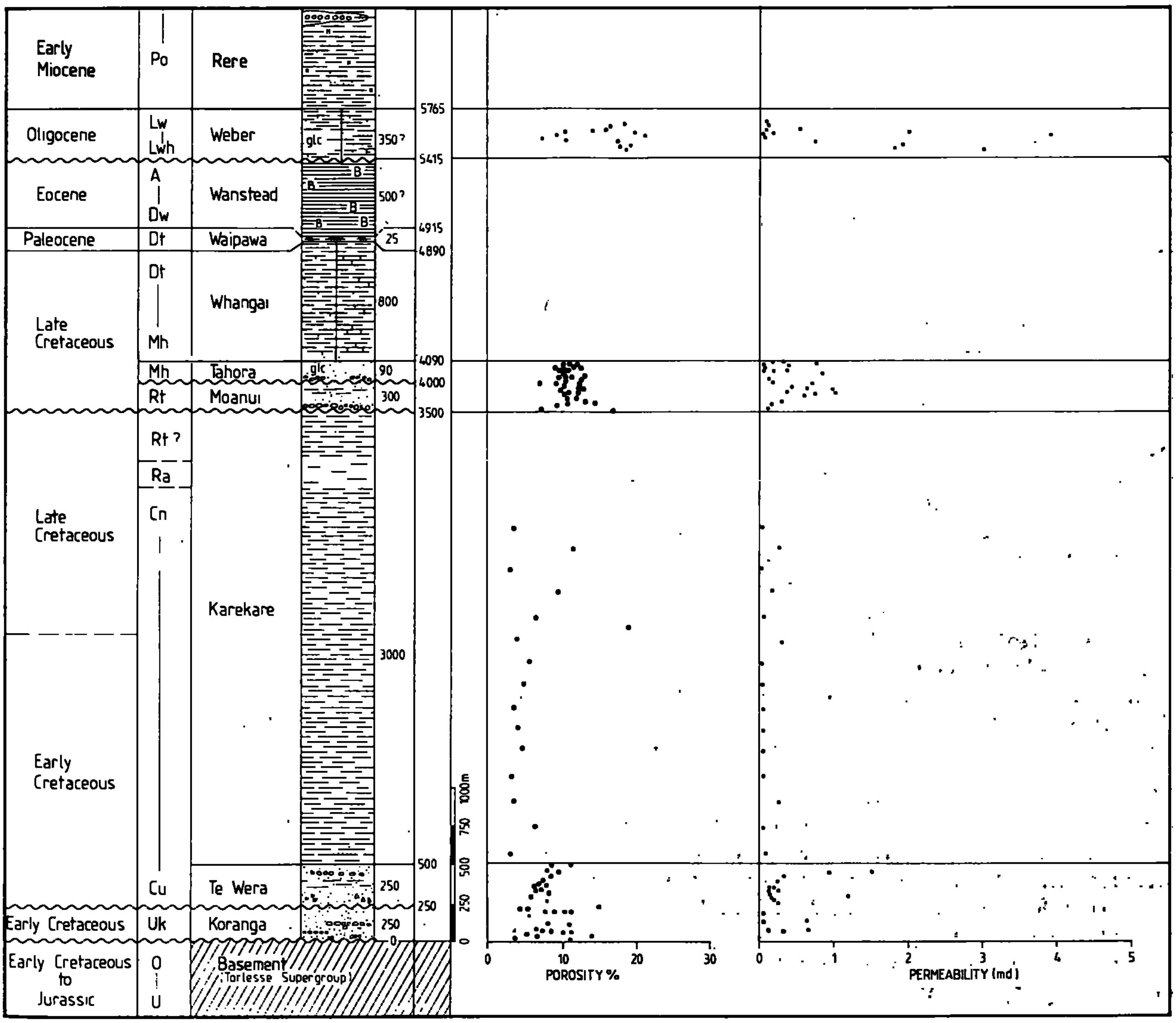

Fig. 5: Porosity and permeability data for potential reservoir outcrop samples, Gisborne Region, East Coast, North Island.

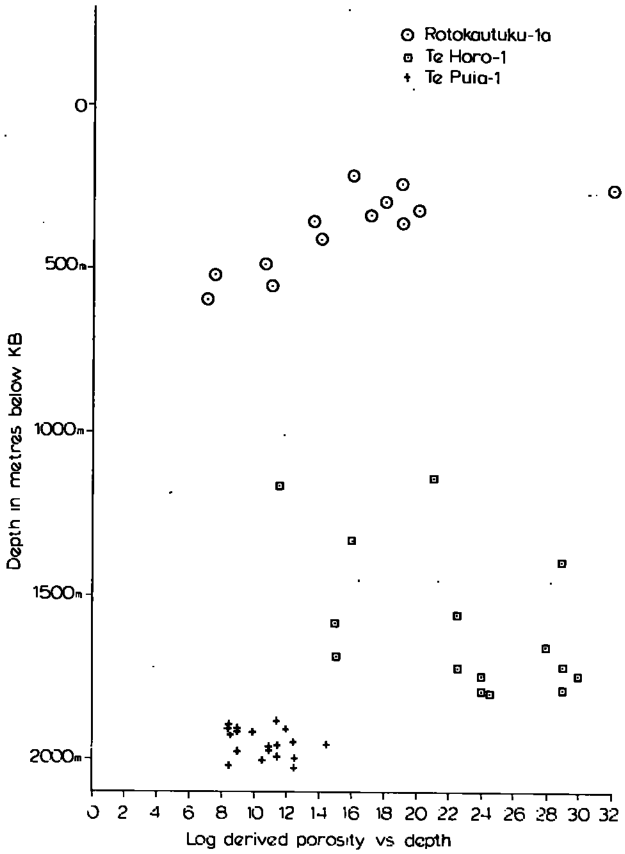

Fig. 6: Log derived porosity values for three wells drilled in the northern East Cape.

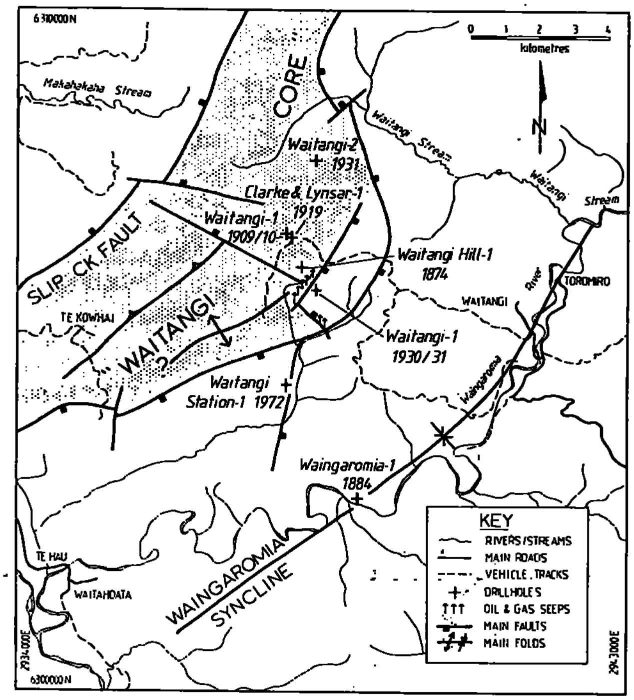

Fig. 7: Main exploration drillholes and simplified structural features of the *Waitangi* oil seeps area (adapted from Stonely, 1958).

emanate from fractured reservoirs within what is thought to be a diapiric core (Stoneley, 1958).

The Waitangi, Totangi and Rotokautuku oil seeps, and oil and gas shows in wells, are derived from sandstone beds with variable intergranular porosity, and/or sandstone - mudstone beds in which nil or poor intergranular porosity has been enhanced by fracture porosity.

Because of the limitations of covering strata thickness (potential Cretaceous sandstone reservoirs are often at undrillable depths), and their better regional distribution and poroperm properties, the best target reservoir rocks within the northern region appear to be Oligocene age greensands of the Weber Formation. In the southeastern part of PPL 38314, two wells had hydrocarbon shows within Oligocene greensands. Gisborne-2, drilled by Taranaki Oilfields in 1929-30, was located 600 m down the western flank of the Mangaone surface anticline (Fig. 4). Mangaone-1 was put down by Shell-BP-Todd in 1960-61 further down the western flank of the same Mangaone anticlinal structure (Fig. 4).

Mangaone-1 produced small volumes of high pressure, gas cut, saline formation water on testing of a 30 m thick interval of Oligocene greensands. The same sands in Gisborne-2 were reported as having strong gas shows with good traces of oil (Fig. 8). In the Gisborne-2 well, Early Miocene turbiditic sandstones also gave weak to strong gas shows. It is worth noting that neither well was actually drilled on the crest of the Mangaone Anticline.

Stratigraphic and hydrocarbon show correlation between Mangaone-1 and Gisborne-2 suggests that better hydrocarbon indications might be found if a well was put down on the crest of the Mangaone Anticline, however, the small area of closure of this particular structure would make it marginally, or non-commercial, even if oil was found.

It is clearly evident that oil has been generated within the northern region of the East Coast Basin and that reservoir rocks of variable quality exist. Numerous exploration targets can be defined within the area, however, the limitations of stratigraphic thickness of covering strata, and drilling difficulties at depth, indicate that shallow plays might have the greatest potential. As such, any favourable structures such as those along the eastern flank of the Wairoa Syncline, a major northeast-southwest trending structure running up the south central part of the northern region, are worthy of continuing investigation.

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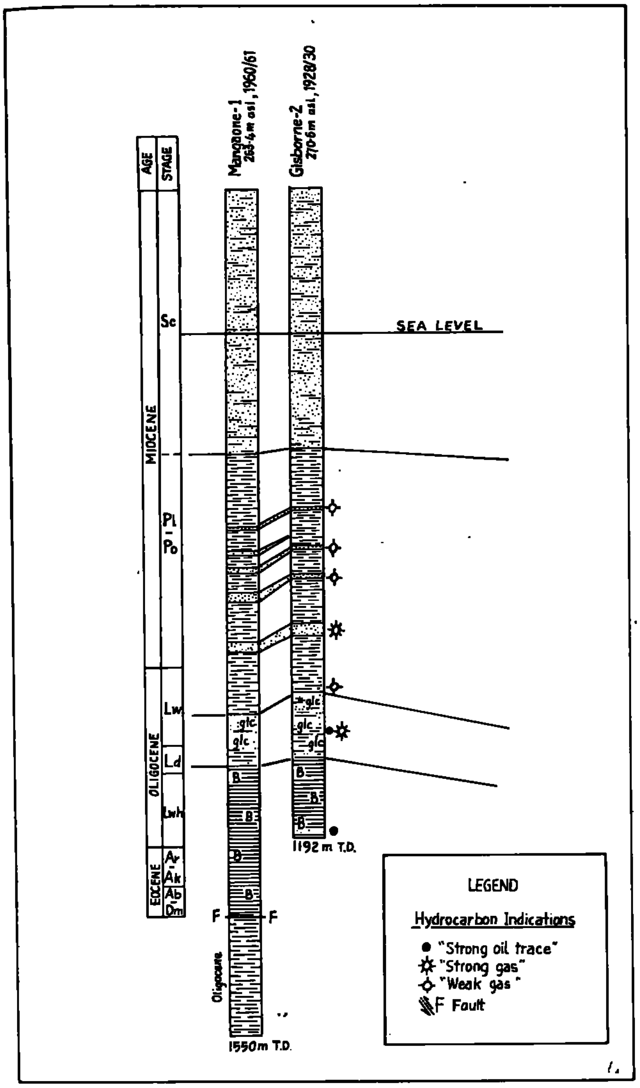

Fig. 8: Stratigraphic correlation and hydrocarbon indications for the Mangaone-1 and Gisborne-2 wells, drilled on the western flank of the Mangaone Anticline.

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