Petroleum Systems of the Taranaki, East Coast, and Great South Basins: Some Key Elements

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Abstract

The presence of hydrocarbon seeps and shows provides ample evidence of petroleum generation in many of New Zealand's Cretaceous to Cenozoic basins, although modern commercial production has only come from the Taranaki Basin to date. Some known fundamentals of the Taranaki petroleum system include: (1) source rocks are primarily terrestrial Type III with a variable contribution from marine Type II kerogen; (2) produced oils can be broadly correlated to Late Cretaceous, Paleocene, and Eocene source intervals; (3) proven reservoirs have a wide range of chronostratigraphic ages and depositional settings; (4) all main accumulations occur in structural traps formed in the Neogene; (5) oil expulsion maturity was reached locally during the Eocene, but mainly in the Late Neogene. In some ways the success of the Taranaki petroleum system can be related to the main phases of basin development, specifically the deposition of source rocks during an early rift phase, deposition of source rocks, pre-eminent reservoir tracts, and cap rocks during a subsequent passive margin phase, and the formation of structures and deposition of seal rocks and thick overburden during the latest active margin phase. The petroleum systems of the East Coast and Great South basins share several similarities to the Taranaki system, but also contain many differences. The relatively distal paleogeographic position of the East Coast through the Paleogene passive margin phase in particular resulted in deposition of primarily marine Type II source rocks, and comparatively few pre-Neogene coarse-grained potential reservoir intervals. Neogene active margin deformation produced a highly complex array of structural traps, and wide-ranging but variably-distributed potential reservoir facies. Prior to their offset along the Alpine Fault, the Taranaki and Great South basins were comparatively close neighbours, on opposite-facing margins of the proto-New Zealand landmass. Late Cretaceous to Paleogene facies belts in the Great South Basin are laterally equivalent to, and closely resemble, those in Taranaki, including the highly prolific Eocene transgressive shoreline system. In contrast to the other two basins, the Neogene in the Great South Basin was relatively quiescent, with little structural development or clastic sedimentation.

Introduction

As defined by Magoon and Dow (1994), a petroleum system encompasses a volume of active (or once-active) source rock and all oil and gas accumulations derived from that source rock, together with the geological elements and processes required for the formation of those accumulations. The geological factors, which must eventuate in timely order, include organic-rich source rock, reservoir rock, trap formation, overburden rock, seal rock, and hydrocarbon generation-migration-retention.

Applied research within the Institute of Geological and Nuclear Sciences Limited (IGNS) is increasingly embracing an integrated 'dynamic petroleum' systems' approach to understanding the occurrence of hydrocarbons in New Zealand's sedimentary basins. This review paper summarises some results of recently published syntheses and ongoing research into the petroleum systems of the Taranaki Basin (TB), East Coast Basin (ECB), and Great South Basin (GSB), with supplementary information gained from stratigraphic correlations and tectonic reconstructions nationwide; only a few key references are cited, although these contain more comprehensive reference lists. In Magoon and Dow's (1994) classification, each source rock-reservoir pairing within a basin is named as a separate petroleum system. Although we are now able to make some general correlations between produced oils and their source rock age (eg Killops et al 1994; King and Thrasher 1996), for simplicity the systems concept is applied here to collectively encompass all known or inferred oil and gas habitats within an individual basin. Moreover, each region is generally referred to here as a single entity, although each in fact comprises a number of smaller sub-basins of varying history and morphology. We briefly review some of the known parameters within the Taranaki petroleum system, and then compare and contrast these with inferred petroleum systems in the frontier ECB and GSB (summarised in Figure 1). The development of the various systems is discussed in the context of sediment facies distribution (Figures 2, 3), and paleogeographic and tectonic setting (Figure 4a-e). The relationship between basin evolution and petroleum generation is generalised in Figure 5.

Taranaki Basin

Taranaki is a composite basin, with a complex evolution involving several depositional cycles and tectonic phases. The main phases of basin development include Late Cretaceous to early-Paleocene rifting (Figure 4a), Late Paleocene to Eocene passive margin (Figure 4b), and middle-Eocene to present active margin (Figure 4c, d, e). The overall geologic setting was favourable for the generation and entrapment of hydrocarbons, especially within the Eastern Mobile Belt (King and Thrasher 1996), where all proven hydrocarbon accumulations occur. Although commercial hydrocarbons have yet to be discovered on the Western Stable Platform, parts of this region remain prospective (see Wood et al this volume; Matthews et al this volume).

Taranaki Basin is an oil, gas and condensate province. The main hydrocarbon accumulations have a wide-ranging size distribution, typical of provinces with highly contrasting and diverse structural and/or stratigraphic conditions. The nine largest fields exhibit four different structural trapping styles, and have hydrocarbons reservoired in no fewer than eight different formations. Paleogene-aged reservoirs variously contain gas-condensate or oil, whereas proven Neogene reservoirs are all primarily oil accumulations.

Produced oils in Taranaki have a mainly terrestrial origin, judging from their carbon isotopic compositions, paraffinic and waxy nature, low sulphur contents, and various biomarker criteria (Killops et al 1994, King and Thrasher 1996). On the basis of organic carbon content, hydrogen-richness, and maturity, coals and interbedded carbonaceous shales deposited within Late Cretaceous to early-Paleocene syn-rift sub-basins (Rakopi and Farewell formations), and on the Eocene post-drift passive margin (Kaimiro and Mangahewa formations) constitute the main petroleum source rocks in Taranaki. Taranaki coals and coaly sediments have hydrogen indices of ca 250-400 g HC/kg C_{org} (at maturity levels roughly equivalent to the onset of oil expulsion) and oxygen indices of less than 50, indicative of mixed oil and gas potential. The oil potential of the coals appears to be related to the abundance of vitrinite in the form of the hydrogen-rich maceral desmocollinite (Killops et al 1994). All Taranaki oils exhibit some evidence of a marine contribution as judged by differences between their terrestrial/marine biomarker indices, and those of Taranaki coals. This suggests that marine shales deposited during periodic inundation of the coastal plain have contributed to hydrocarbon generation (Killops et al 1994). Oil from Kora-1 in the north of the basin exhibits a predominantly marine phytoplankton signature in both biomarker distribution and carbon isotopic data, and is sourced primarily from marine rocks (Reed 1992; Killops et al 1994). A source of this oil may be a lateral equivalent of the Waipawa (Black Shale) Formation, a distinctive potential source rock in the East Coast and Great South basins, and elsewhere (Killops et al 1996). Similarly, oil stains in Tangaroa-1 and Pukearuhe-1 have a significant marine contribution, probably also from a facies equivalent of the Waipawa Formation (Killops 1996).

Produced oils in Taranaki can be related to source rocks of a particular age from their respective biomarker distributions. In particular, an index of the relative proportion of angiosperm and gymnosperm component biomarkers (AGI) allows the distinction of three 'families' of oils; the Maui family (Maui Field-Moki Field-Maui-4 trend) of oils are derived from Late Cretaceous source rocks, the Kapuni family (Kapuni and Kupe fields, and probably Waihapa Field) from Paleocene or mixed Late Cretaceous to Eocene sources, and the McKee family (northern peninsula) from an Eocene source (Killops et al 1994, King and Thrasher 1996). For most reservoirs where the AGI of produced oils has been determined, a suitably thick and mature source sequence of

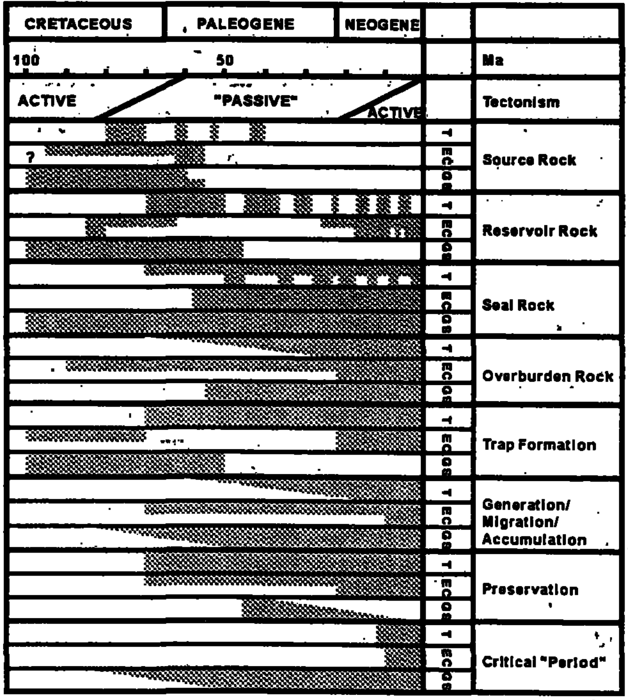

Figure 1. Chart comparing the chronological evolution of key petroleum system parameters in Taranaki (TB), East Coast (ECB), and Great South (GSB) basins.

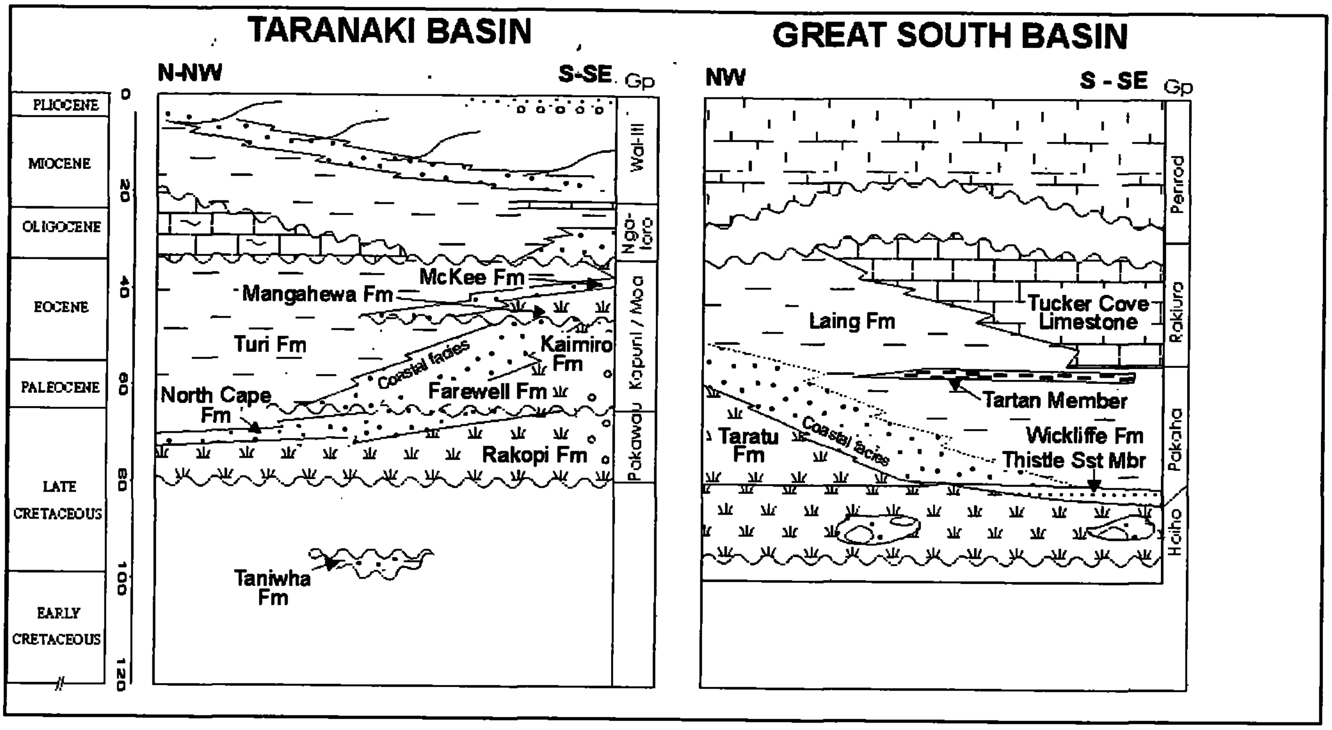

Figure 2. Generalised stratigraphy of Taranaki and Great South basins. Sequences of Cretaceous-Paleogene age are lateral correlatives; key units are named.

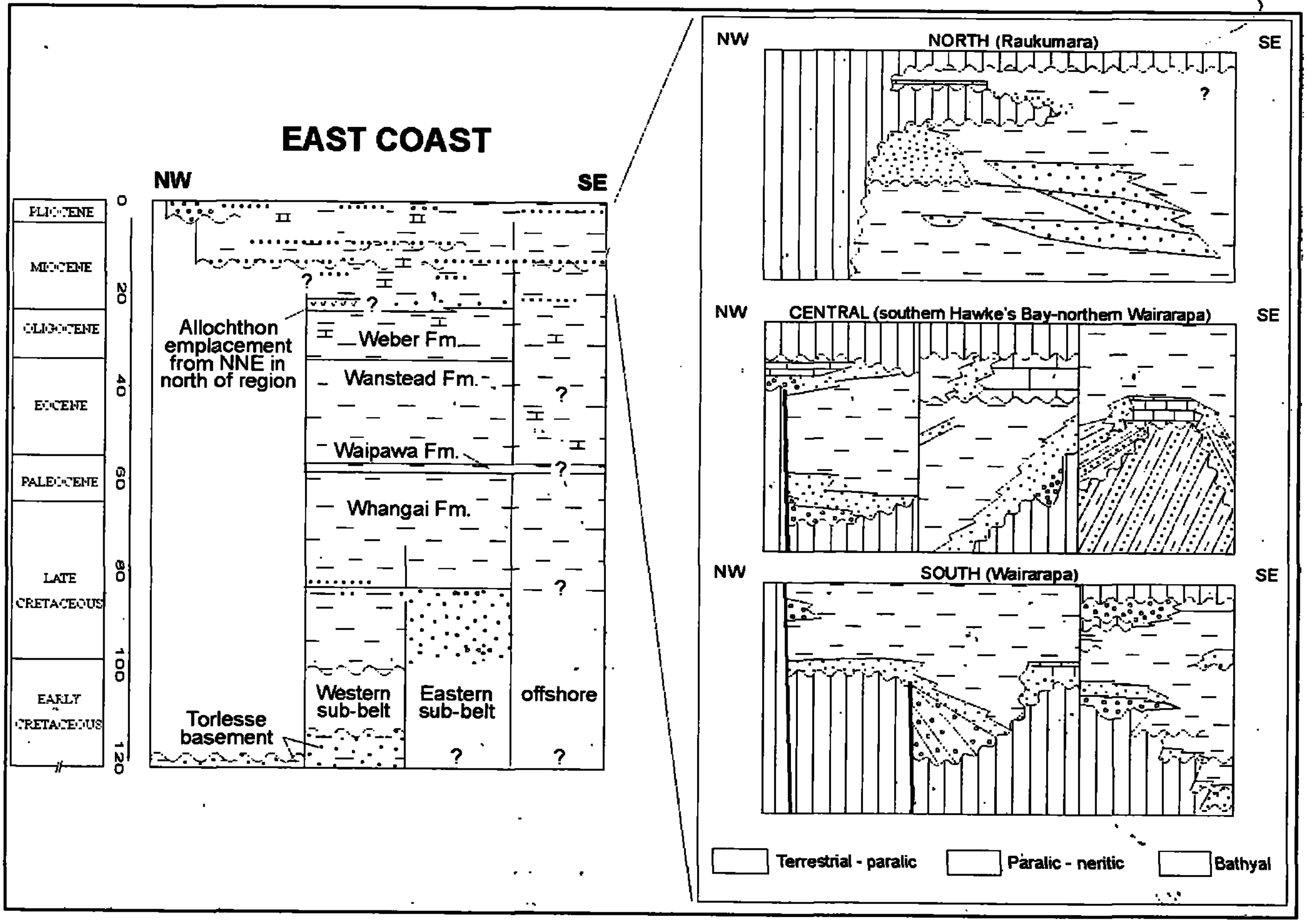

Figure 3. Generalised stratigraphy of the East Coast region. Expanded inset shows Neogene stratigraphic complexity (not to scale).

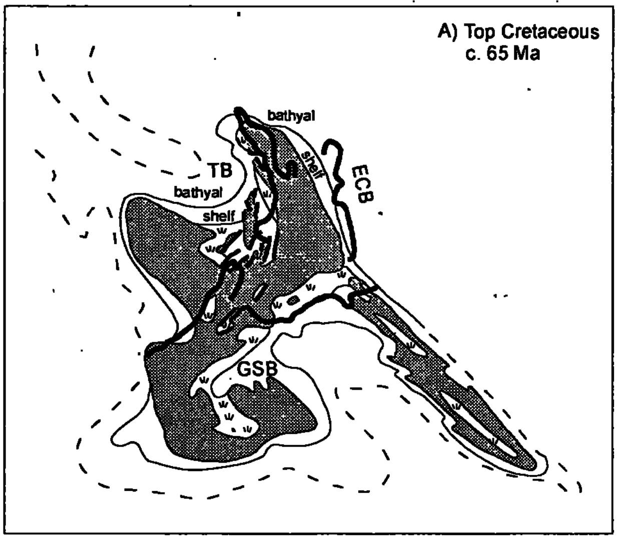

Figure 4a. Top Cretaceous: rift transform zone through Taranaki.

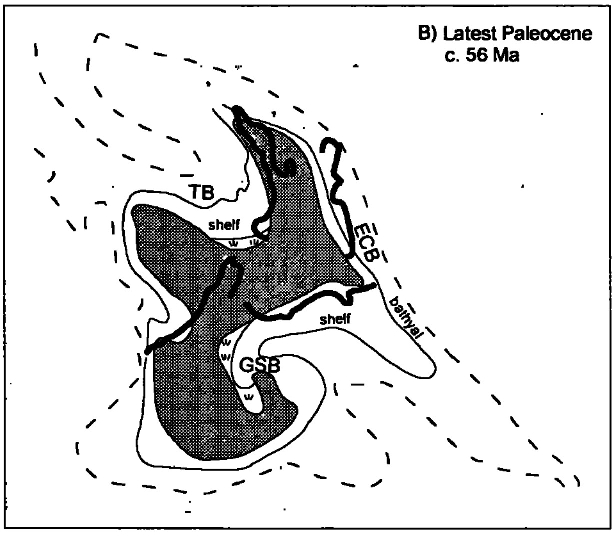

Figure 4b. 56 Ma: passive margin, and setting for Waipawa (Black Shale) Formation deposition roughly at shelf/slope break.

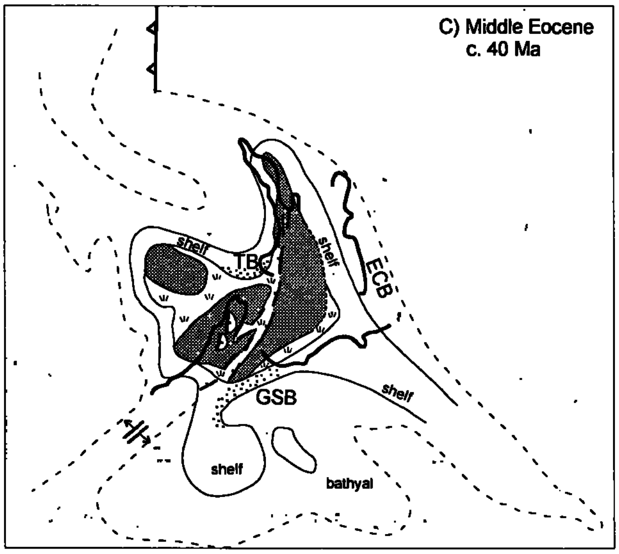

Figure 4c. 40 Ma: Moonlight aulocogen propagating into southern New Zealand, passive margin elsewhere.

Figure 4 - Figures 4a-4e are based on the palinspastic reconstructions of New Zealand (after King in prep.) referenced to present-day coastlines (in bold) and 2,000 m isobath (dashed lines).

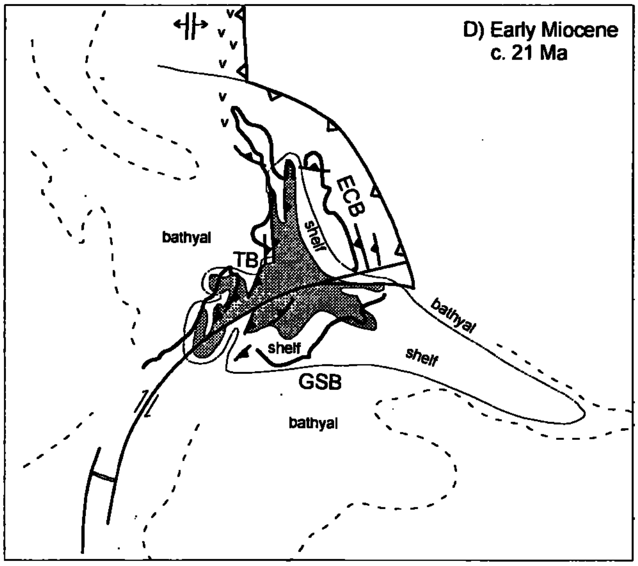

Figure 4d. 22 Ma: inception of Alpine Fault as small circle about Pacific/Australian plate rotation pole (located south of map area), convergent tectonics in north.

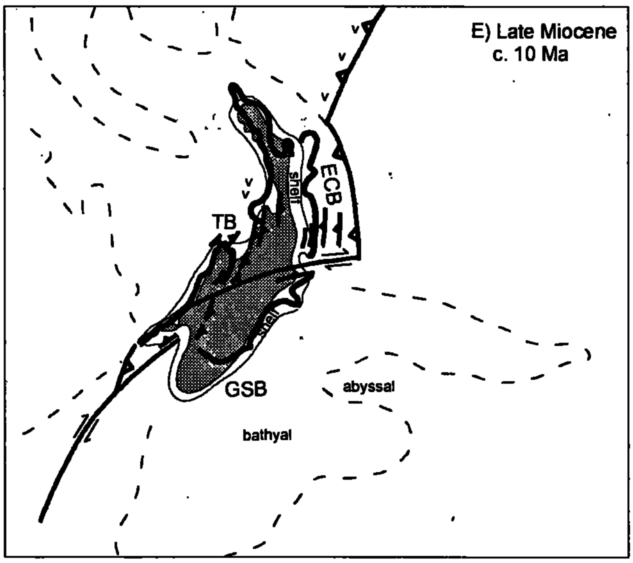

Figure 4e. 10 Ma: rotation of Hikurangi subduction margin east of ECB, and increased convergence throughout central New Zealand.

the appropriate age is located nearby. The oldest known potential source interval in Taranaki, the mid-Cretaceous Taniwha Formation in Te Ranga-1, appears to have sourced oil stains recorded in that well (Killops 1996).

Proven reservoir rocks have been deposited throughout much of the basin's history, although producible hydrocarbons have yet to be discovered in mid-Late Cretaceous sediments. Most known petroleum reserves are reservoired in Paleogene shoreline and coastal plain sandstones, deposited in a late rift or post-rift passive margin setting. Younger reservoir rocks include

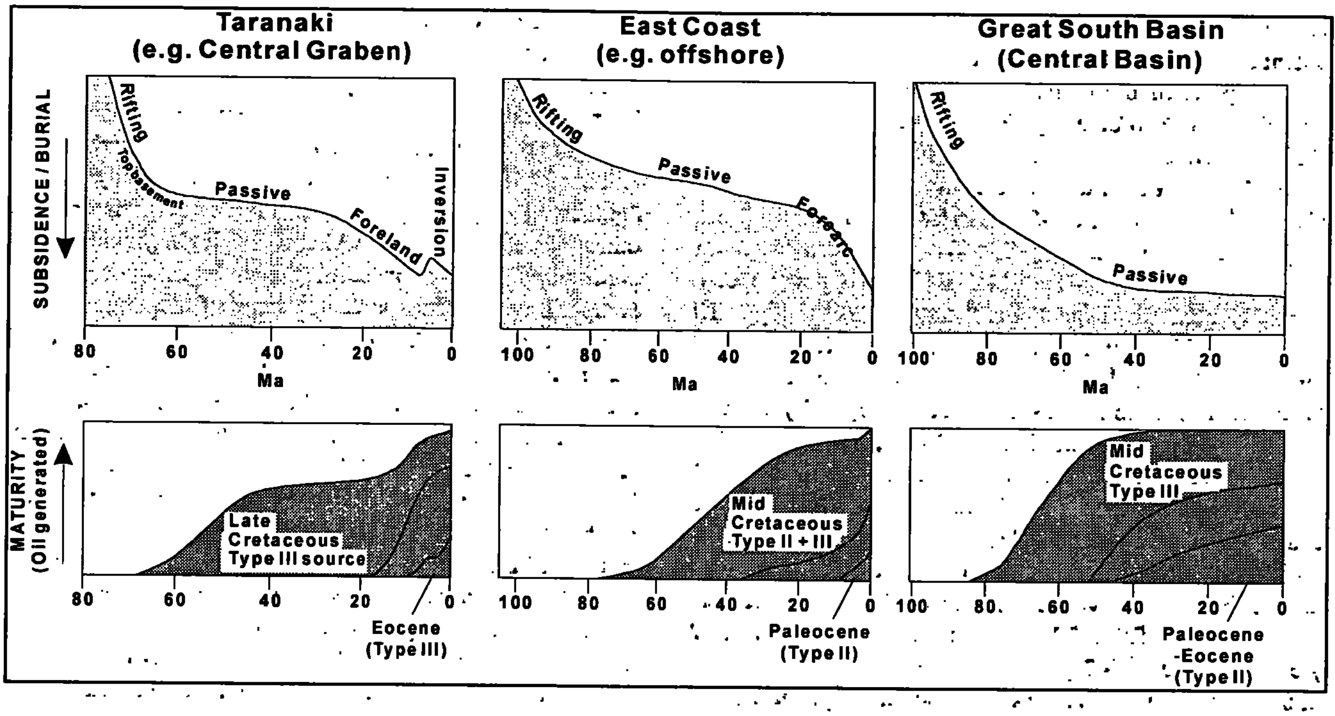

Figure 5. Generalised burial and hydrocarbon generation diagrams, representing typical kitchen areas within the Taranaki, East Coast and Great South basins. The curves in the lower graphs refer to relative proportions of oil generated from available kerogen. Gas would also be generated at upper levels of maturity.

Oligocene foredeep turbidites, earliest Miocene foredeep limestones, Miocene slope and submarine fan sandstones, Miocene volcaniclastics associated with submarine volcanoes, and Pliocene shelf sandstones. Sealing rocks are generally marine mudstones. In the Late Cretaceous and Paleogene these were deposited during periodic marine incursions and eventual transgression over the coastal plain. Terrestrial mudstones may form inter- and intra-reservoir seals in Paleogene successions. Widespread marine mudstones cap Neogene reservoirs.

Phases of convergent tectonics and later subsidence and fill are critical in the development of hydrocarbon accumulations in Taranaki. All major fields involve structural traps formed in the Neogene, with most occurring within the Miocene-aged fold-thrust belt, and in some cases modified by later stage extension. The accumulation of thick Mio-Pliocene sequences within the eastern foredeep and Northern and Central Grabens was instrumental in achieving source rock maturation.

Thermal modelling and geohistory case studies indicate that over most of Taranaki Basin present-day maturity of source rocks for oil expulsion requires burial depths of greater than about 5 km. In present-day areas of high heat flow, and in the geologic past, the top of the oil expulsion window is (or was) around 4-4.5 km below ground surface. The onset of oil expulsion occurs at around Rank (S) 12.5, which corresponds to peak hydrogen index values in Taranaki coals (King and Thrasher 1996). Corresponding vitrinite reflectance values for the onset of significant oil generation in Taranaki are 0.5-0.6% and for oil expulsion are 0.7-0.8%. Locally thick sequences of Late Cretaceous Pakawau Group source rocks may have started to generate and expel hydrocarbons in the early-Cenozoic, and much of their available kerogen would now be depleted. In these areas most early-formed hydrocarbons have probably been lost from the basin's petroleum system. In other areas Late Cretaceous source rocks began to expel oil in the middle to late-Miocene. Locally, Eocene Kapuni Group source rocks reached the top of the oil expulsion window in the late-Miocene or more recently. Present-day mature kitchen areas occur where there has been substantial sediment burial in the Miocene and/or Pliocene.

In general, hydrocarbon generation and migration appears to have occurred relatively late in the basin's history, as supported by the results of modelling, the geochemical matching of produced oils with inferred present-day kitchen areas nearby, the wide age range of proven reservoir rocks, and especially the fact that late-Miocene and early-Pliocene rocks have been charged. The primary 'critical moment' for establishing most of Taranaki's known hydrocarbon accumulations was evidently not reached until late-Miocene to recent times.

East Coast

The East Coast region has the highest number of surface hydrocarbon seeps in the country, proving that expulsion and secondary migration have taken place. Surface oil and gas seeps are associated with structural highs, faults, and/or unconformities. There are also many localities where exposed porous sandstones or fractured formations exhibit oil staining. The main challenge for making a commercial discovery is in establishing the presence of a complete petroleum system (in the strict sense) from source to sealed trap, for specific areas of the East Coast.

Our understanding of the nature and distribution of potential source and reservoir rocks is limited mainly to onshore parts of the region, as only two wells have been drilled offshore to date (eg Uruski et al this volume). The Waipawa (Black Shale) Formation of late-Paleocene age is generally considered to have the greatest source potential, with TOC contents of c 2-6%, and hydrogen indices in the range 50-500 g HC/kg C_{org}. The Waipawa Formation was probably deposited on the outer shelf to upper slope; it primarily contains Type II kerogen, with some Type III material, and has mixed oil and gas potential (Killops et al 1996, Field and Uruski et al 1997). In outcrop, the Waipawa Formation is no more than marginally mature. The unit thickens eastwards (to c 70 m), but this trend is accompanied by an apparent eastwards decrease in TOC in some areas. Underlying Late Cretaceous formations also contain likely source rocks, especially the Whangai Formation. These Late Cretaceous formations are mainly marine, but contain variable amounts of detrital terrestrial organic matter. Their TOC contents are generally <1%, S2 yields are modest (<2 g HC/kg rock), and HI is generally <300 g HC/kg C_{org}. These formations have primarily gas potential, although some samples exhibit mixed oil and gas potential.

The major oil seeps (Waitangi, Isolation Creek, Rotokautuku, Totangi) appear from a variety of geochemical evidence to have originated from primarily marine source rocks of Late Cretaceous age, possibly deposited in an oxic, neritic environment (Weston et al 1988, Johnston et al 1992, Rogers et al 1994, Murray et al 1994). This indeed substantiates the source potential of Late Cretaceous strata, and probably reflects the relative maturity of kitchen areas nearby. These seeps may all have a Whangai Formation source, although the Rotokautuku oil differs in some respects from the others, and may have a mixed Whangai/Waipawa source. Lateral variations in source facies may account for the differences, and for the fact that as yet no definitive biomarker correlation has been reported between specific Cretaceous source formations and the main seep oils. At least one oil stain in the East Coast region has a mixed marine-terrestrial biomarker signature (somewhat similar to oils in the Maui Field in Taranaki), and is thought to have originated from the Late Cretaceous Karekare Formation (Field and Uruski et al 1997). The Waipawa Formation has very distinctive biomarker characteristics (eg Murray et al 1994), which assists oil-source rock correlations. An oil stain from Te Weraroa Stream in the western part of the East Coast allochthon evidently has a Waipawa Formation source, and several other stains located to the south appear to be derived from relatively immature Waipawa Formation intervals (Field and Uruski et al 1997). Preliminary kinetic studies indicate that Waipawa Formation kerogen may generate oil at relatively low temperatures (Francis and Murray 1997, Funnell et al unpublished results).

Owing to a complex Neogene history of deformation, sedimentation, and erosion, a wide range of present-day surface heat flow (c 40-90 mW m^{-2}) is present across the East Coast region. Thermal modelling reveals a range of maturation scenarios for hypothetical source intervals with hydrocarbon generative potential, from the expulsion of oil from Type II Cretaceous source intervals as early as the Paleocene in some areas, to ongoing immaturity of Late Cretaceous (especially Type III) and Paleocene intervals in other areas (Field and Uruski et al 1997). In general, model predictions for the onset of oil and gas expulsion are compatible with the source rock age of seeps, as inferred from biomarkers. As in Taranaki Basin, significant oil generation is primarily limited to areas with high sedimentation rates in the Mio-Pliocene, although the thermal regime has been depressed due to cooling of the crust associated with subduction processes since 25 Ma. Source rocks evidently have the greatest maturity in the north of the region. In the Raukumara Peninsula, for instance, Paleocene source intervals may have been buried to c 10 km depth following mid-Cenozoic allochthon emplacement and rapid Miocene burial. Modelling for this area suggests that all available kerogen was converted to oil by the end of the Miocene, and gas generation has either continued to the present day or been switched off, depending on the amount of ensuing uplift and erosion in the Late Neogene.

Although East Coast strata include a relatively high proportion of mudstone, potential reservoir intervals of Cretaceous to Pliocene age are present, with depositional facies ranging from alluvial fan to submarine fan (Field and Uruski et al 1997). Cretaceous intervals locally have good poroperm characteristics, but are generally tight. The prime targets are Miocene shelf and deep-water sandstones, and Pliocene shallow-water sandstones and limestones. Oil staining and impregnation has been observed in outcrop in porous or fractured intervals of many formations, generally of Paleocene to Early Miocene age.

There is no shortage of structural traps in the East Coast region. Cretaceous structures are dominantly compressional onshore in the north, and extensional offshore and in the south. There are few structures formed in the Paleogene, reflecting regional tectonic quiescence and passive margin development. The main structural styles and events since the inception of the Hikurangi subduction margin east of the region in the late Paleogene include nappe emplacement (allochthon), thrusting, dextral strike-slip (probably with a compressional component), and some normal faulting. These deformational episodes produced a variety of possible closures, including a large number offshore, some of which appear broader than the giant Maui Field in Taranaki (Field and Uruski et al 1997; Uruski et al, this volume). Thrust-controlled anticlines dominate the potential structural traps identified on seismic reflection profiles. In addition, common lateral facies changes, in part associated with large changes in relative base level, have probably produced numerous stratigraphic traps.

Great South Basin

The petroleum system of the Great South Basin is discussed in Cook et al (this volume), and only a few key points are re-iterated here. The GSB petroleum system is governed by two main phases of basin development, namely rifting with associated crustal thinning and high heat flow in the mid-Cretaceous (c 1100-80 Ma), followed by comparative tectonic quiescence and passive margin foundering to the present day. In the northwest there has been some doming and reverse faulting in the Neogene, although the precise timing is not well constrained. This Neogene deformation is evidently related in some way to development of the 'modern' plate boundary convergent zone and, as in the TB and ECB, has given rise to potential trapping structures. In general however, the main structural traps involve compactional drape of reservoir intervals across former rift horst blocks. The key ingredient in this case is that structures were formed at an early stage, generally prior to or synchronous with source rock maturation.

Potential source rocks are similar to those in Taranaki, being dominated by syn-rift and post-rift terrestrial sediments, specifically coals and carbonaceus mudstones. In addition, Late Cretaceous-Paleocene marine strata are also potential source rocks. The mid-Cretaceous Hoiho Group contains abundant coaly material (of which only a minimal component was derived from woody gymnosperm vegetation), but also exhibits a significant marine influence (Killops 1996; Killops et al 1997). These sediments appear to have mixed oil and gas potential, but in Kawau-1A are more gas prone. The biomarker signatures of these sediments are similar to those in the Taniwha Formation in Taranaki Basin. The Late Cretaceous-Paleocene coals of the Taratu Formation (essentially lateral equivalents of Pakawau Group units and the Farewell Formation in Taranaki) have mixed oil and gas potential, with average HI of 250 g HC/kg C_{org}. Paleogene marine rocks in the GSB are evidently the most oil prone, particularly the Tartan Member (Wickliffe Fm), which is a possible lateral equivalent of the Waipawa Formation, and has an average TOC of 4.5% and HI of c 300 g HC/kg C_{org}.

The presence of hydrocarbon shows in four wells attests to the generation of hydrocarbons in the GSB. All shows were within sandstones of the Pakaha Group, most likely related to an interdigitating coastal facies tract. The best results were from transgressive shoreline sandstones of the Thistle Sandstone Member (Wickliffe Fm), which tested 6.8 MMCFD gas and condensate in Kawau-1A. In addition, surface oil seeps are present in northeastern Stewart Island.

On the basis of isotopic and biomarker characteristics together with maturity considerations, mid-Cretaceous coaly sediments are the most likely sources of oil and condensate recovered in Kawau-1A, as well as the Stewart Island seeps. Biomarker studies have yet to identify any oils generated from marine source rocks (Killops et al 1997).

The present-day surface heat flow in the seven southernmost wells in the GSB is 61±3 mW m^{-2} (Funnell and Allis 1996), which is comparable to the heat flow over large areas of Taranaki Basin (King and Thrasher 1996, their Figure 6.27). Sediments in the GSB reached thermal equilibrium at c 50 Ma, and maturation of source rocks has proceeded slowly since that time. Modelling indicates that in deeper parts of the GSB (Central sub-basin) kerogen conversion to oil from suitable mid-Cretaceous source rocks occurred around 85-50 Ma, and thereafter gas was generated (Cook et al this volume, their Figure 5). Latest Cretaceous terrestrial source intervals in this area are just within the oil expulsion window. Maturity modelling based on Type II kinetics indicates that Paleocene rocks have entered the oil window in the Central sub-basin, but in most areas they are immature. The oil expulsion threshold for a Type II source in the deepest parts of the Central sub-basin is c 2500 m below sea floor. This comparatively shallow threshold is due to the prolonged period that these rocks have remained at or near this depth. Modelling using Type III kinetics indicates that the oil expulsion threshold in Tara-1 is c 2900 m (below sea floor), which is consistent with geochemical evidence (Killops et al this volume).

The main reservoir fairway in the GSB consists of fluvial to mid-shelf sandstones deposited within a broadly transgressive system during Late Cretaceous to Early Eocene times. This reservoir tract is sealed by transgressive shelf mudstones, and is strikingly similar to the Paleogene Kapuni Group coastal facies tract that has long been regarded as the pre-eminent reservoir play in Taranaki Basin. Eocene-aged potential reservoir units are restricted to the western margin of the GSB.

Discussion

As a way of assessing the prospectivity of frontier basins such as the ECB and GSB, it is worthwhile drawing comparisons and contrasts with what we understand to be the successful elements of the Taranaki petroleum system. An initial, obvious comment, however, is that the development of the petroleum systems in any basin is inextricably linked to its geologic history. The three basins discussed here all have broadly similar early histories, with an initial phase of rifting and crustal thinning producing relatively high heat flows, followed by a phase of crustal cooling and passive margin subsidence. In each basin, these tectonic phases allowed the deposition of potential source, reservoir and seal rocks. Rifting began earlier in the ECB and GSB (mid-Cretaceous), and syn-rift sedimentation was more widespread than in Taranaki, where coeval sediments occur only in the far northeast of the basin. The significance of this is that hydrocarbon generation accordingly began earlier in the GSB and ECB than in Taranaki.

Neogene tectonic settings of the three basins were markedly different, reflecting their relative positions with respect to the convergent Pacific-Australian plate boundary. Neogene tectonism influenced sedimentation patterns and structural trapping scenarios in particular, with consequent influence on reservoir/seal development, petroleum generation and fluid migration. 'Behind-arc' and intra-arc extension and compression created all the known major traps in (eastern and southern) Taranaki Basin. The bulk of potential structural traps also formed in the Neogene in the ECB, which was closer to the plate margin and was more affected by subduction-related tectonics. In the north, areas of mature source rocks were alternately increased then reduced following allochthon emplacement and subsequent uplift; in the south and offshore, strike-slip faulting and imbricate thrusting have created a myriad of possible structural traps. Similarly, high Neogene sedimentation rates in both basins have allowed kitchen areas to mature, either simultaneously with, or following, trap formation. Rapid sedimentation caused overpressures to develop beneath regional seals in some areas of Taranaki, whereas strong overpressuring also exists at shallow depths in the ECB, resulting from very high vertical (upward) fluid fluxes and compounded in places by the presence of Eocene-aged, low-permeability smectitic muds. Conversely, the GSB has remained relatively quiescent throughout the Neogene, with structuring limited to its western margin, closest to the plate boundary. In this context, prospectivity of the GSB relies on older rift and compactional drape structures. The Neogene in GSB is characterised by slow sedimentation rates, hydrostatic pressures, and a relatively uniform thermal regime, which has precluded any accelerated maturity of potential source rocks during this period.

Some interesting patterns emerge when considering potential reservoir distribution in the three basins, within which there is a wide range of lithofacies overall. In Taranaki, proven reservoirs occur at virtually all chronostratigraphic levels except the Cretaceous. Curiously, all of the noteworthy hydrocarbon shows observed in the GSB are within Cretaceous strata. The wide age range of clastic reservoirs in Taranaki is in part because major tectonic zones traversed parts of the basin or its nearby hinterland in the Late Cretaceous and in the Late Paleogene, as well as in the Neogene (Figure 4; see King and Thrasher 1996). On the other hand, the ECB was affected by only mid-Cretaceous and Neogene tectonism, and the more distal GSB only by mid-Cretaceous tectonism.

The Late Cretaceous-Paleogene facies belts in the GSB and TB are remarkably similar, reflecting somewhat similar histories. During the post-rift period at least, these two basins were near neighbours (prior to Neogene displacement along the Alpine Fault), on opposite-facing margins of the proto-New Zealand landmass. They shared similar paleogeographic settings within large, gradually deepening marine embayments, wherein transgressive shoreline systems were deposited. In TB this clastic tract constitutes the most prolific reservoir play, and is the prime potential reservoir fairway in the GSB. The various Late Cretaceous-Paleogene facies belts within the two basins are laterally equivalent, and in eastern Otago their correlatives are exposed (eg McMillan and Wilson 1997; see also Browne, G.H.: Appendix to 1998 New Zealand Petroleum Conference field trip to Otago). Ongoing marine transgression restricted the coastal plain/shoreline clastic belt to the northwestern margin of the GSB by the mid-Eocene. In the ECB, which was more distal at the time, a comparable shoreline clastic belt evidently did not develop, except perhaps in now-eroded areas to the west. Instead, irregularly-distributed Neogene sandstones and limestones are the prime targets in the ECB. Neogene reservoir targets are probably not a realistic option in the GSB.

As in Taranaki, oils in GSB and ECB are variably sourced from Cretaceous to Paleogene Type III and Type II kerogens, but in differing proportions that are consistent with the reconstructed paleogeographic settings. In Taranaki, hydrocarbon-bearing structures appear to have been charged from nearby, recently-mature kitchens. The complex geologic history of the East Coast presents a major challenge to understanding petroleum systems in that region, with a range of possible scenarios for reservoir distribution, trap formation and source rock maturation. The dilemma is in finding plays with the appropriate relative timing of these factors. Unlike Taranaki, where there is timely progression in the deposition of key reservoir intervals, followed by trap formation, followed by source rock maturation, the time frame for the evolution of these requisite petroleum system parameters in the ECB was probably more restricted. Our modelling indicates that the main phase of oil generation in ECB was induced by rapid sedimentation in the Late Neogene, variably synchronous with or closely following reservoir deposition and trap formation. Most structures in the GSB were formed early in the basin's history, and oil has probably been generated from various deeper stratigraphic levels from 85 Ma to the present day.

An improved understanding of the intricacies of the TB, ECB and GSB petroleum systems is the aim of ongoing research to characterise and quantify source, reservoir, and seal rock attributes, and to reconstruct scenarios for petroleum migration from source to trap.

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