First order sealing and hydrocarbon migration processes, Gippsland Basin, Australia: implications for CO_2 geosequestration

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Abstract

The petroleum systems of the Gippsland Basin have been evaluated to provide insights into how hydrocarbons have migrated and accumulated and how injected CO_2 could migrate and be either retained or lost from the system. This study has provided both new insights into the petroleum systems in this mature basin and a regional framework for assessing the viability of the Gippsland Basin for large-scale Carbon Capture and Storage (CCS) in relation to containment and migration.

New data on the palaeo-charge history suggest that the initial hydrocarbon charge into many of the existing giant gas and oil accumulations was actually oil and that significant oil columns were present in the Neogene. Subsequently, increased maturation and gas expulsion from a gas-prone, upper coastal plain source kitchen located south of Barracouta caused the partial to complete displacement of the oil columns in what are now giant gas fields.

Thickness, distribution and MICP capacity data for the Lakes Entrance Formation suggest that the base top-seal within the Central Deep has excellent containment characteristics, with the capacity to withhold hundreds of metres of gas or CO_2. The Central Deep represents an ideal setting for large-scale CO_2 injection. CO_2 injected either east or west of Halibut should, because of the connectedness of the traps, eventually migrate into Halibut and then progressively fill and spill through Kingfish, Bream and Barracouta. Further north, there is an analogous fill-spill chain associated with Marlin, Snapper and Barracouta. The very high integrity of the Lakes Entrance Formation seal and the porous nature of the Latrobe Group sandstones suggest that the storage capacity of the Central Deep is very large. The flanking Northern and Southern terraces appear to have lesser, but still adequate containment, with the potential to withhold 50-100 m gas being proven on parts of the Northern Terrace. In contrast, the Northern and Southern platforms have very poor sealing characteristics; sealing capacity decreases to only 5 m of gas and 13 m of CO_2 at Groper-2. Onshore, the top-seal is relatively thick and offers good containment within the Lake Wellington and Seaspray depressions. However, outside these areas, the Lakes Entrance Formation onshore has generally poor MICP characteristics and it is likely that containment is inadequate.

Keywords: Gippsland Basin, geosequestration, seal capacity, MICP, charge history, migration

Introduction

The Gippsland Basin, one of Australia's most prolific hydrocarbon provinces, is situated in southeastern Australia and is located about 200 km east of the city of Melbourne, Victoria (Fig. 1). The basin, which has both onshore and offshore elements, has proven to be a world-class hydrocarbon province and contains several giant oil and gas fields (Fig. 2). The vast majority of the discoveries are reservoired within the siliciclastics of the Late Cretaceous to Paleogene Latrobe Group (Fig. 3) and almost all of the currently producing fields are located offshore in shallow water.

In spite of the Gippsland Basin's prolific exploration and production history over the last 40 plus years, relatively little work has been published regarding key elements of the petroleum systems. This is becoming increasingly important for a number of reasons.

Firstly, high energy prices and the combination of the basin's existing quality infrastructure and its undiscovered resource potential, probably in the realm of 250–600 million barrels (MMbbl) of oil and 0.6–2 Tcf of gas (unpublished data, Department of Primary Industries, Victoria), make the region an attractive exploration destination. As a result, exploration activity continues at a high level, with an increasing emphasis on exploration within the older and deeper section. Consequently, whilst hydrocarbon production, especially oil production, from known fields is decreasing, it is likely that discoveries made during the latest exploration upsurge will ensure that the basin remains a significant hydrocarbon producer for many years to come.

Secondly, the pressing need to introduce large-scale CO_2 geosequestration to reduce carbon emissions means that, within a decade, the Gippsland Basin is likely to be a hub for CO_2 injection. For example, the new Monash Energy coal-to-liquids project plans to produce 60–70,000 barrels of diesel a day from brown coal in the Latrobe Valley. Attendant with this production will be the annual sequestration of 10–15 million tonnes (MMt) of CO_2 (Monash Energy 2008). In addition, the ongoing exploitation of Victoria's massive brown coal resources, which are currently mostly used

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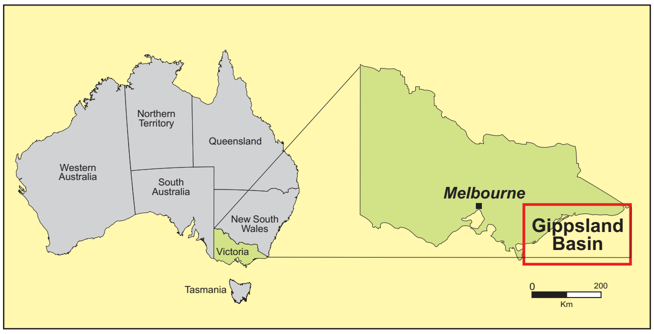

Figure 1. Location map of the Gippsland Basin.

for electricity generation, will be at least partly contingent upon emissions reduction via carbon capture and storage (CCS).

The Gippsland Basin, with its high quality Late Cretaceous and Cenozoic siliciclastic reservoirs, provides a potentially viable location for CCS, especially given its proximity to the current and future emissions sources in the Latrobe Valley. CO_2 geosequestration within the Gippsland Basin would, however, effectively turn the basin's pore space into a multiple use zone. Management of potential conflicts between hydrocarbon producers and explorers and the needs of CO_2 emitters and the wider society to reduce emissions to meet mandated targets will provide significant challenges into the future.

The approach adopted in this study was to assess the key aspects of fluid and gas migration and retention in the Gippsland Basin, using these insights to predict how injected CO_2 might behave in the sub-surface. The existing petroleum systems have been investigated, because the nature, distribution and volumes of the hydrocarbon inventory within a sedimentary basin provide a robust, empirical overview of how fluids behave and have moved through the system. Overall, the primary goal of this work is to develop a technical understanding of the basin which is sufficiently detailed to mitigate the potential adverse impacts of CCS.

GeoScience Victoria is currently assessing the CCS potential of the area under three technical themes, namely; Containment, Injectivity-Capacity and Impacts. This paper specifically addresses the containment and impacts themes for the Gippsland Basin.

The containment theme deals principally with key aspects of the integrity of the regional top-seal, the Lakes Entrance Formation, which spans the offshore and parts of the onshore basin. The key objective of this work was to determine where the Lakes Entrance Formation provided an effective top-seal for oil, gas and (any injected) CO_2 and where it did not. From a CCS viewpoint, the simple question is: 'If the CO_2 is put in, will it stay in?' Our initial investigations on the thickness and seal capacity of this formation are presented, as is a simple facies framework. New results include Mercury Injection Capillary Pressure (MICP) data from 15 wells in the Gippsland Basin, which have allowed a regional quantitative assessment of the sealing capacity of the Lakes Entrance Formation to be made. In addition, a secondary part of the containment theme is a brief consideration of the importance of intra-Latrobe sealing units within the basin. In this paper, the intra-Latrobe sealing facies are considered to be a very important controller of hydrocarbon (and hence CO_2) migration.

The impacts assessment was undertaken to provide a first-order understanding of the Gippsland Basin's connectivity or plumbing. The key consideration for a CCS viewpoint was: 'If the CO_2 is injected, where will it go?' In this section, a series of simple, regional observations were made regarding the distribution and composition of hydrocarbon accumulations across and around the Gippsland Basin. In particular, the overall molecular composition of hydrocarbon gases is considered, as are the distribution of more CO_2-rich gases within the basin. Having established the

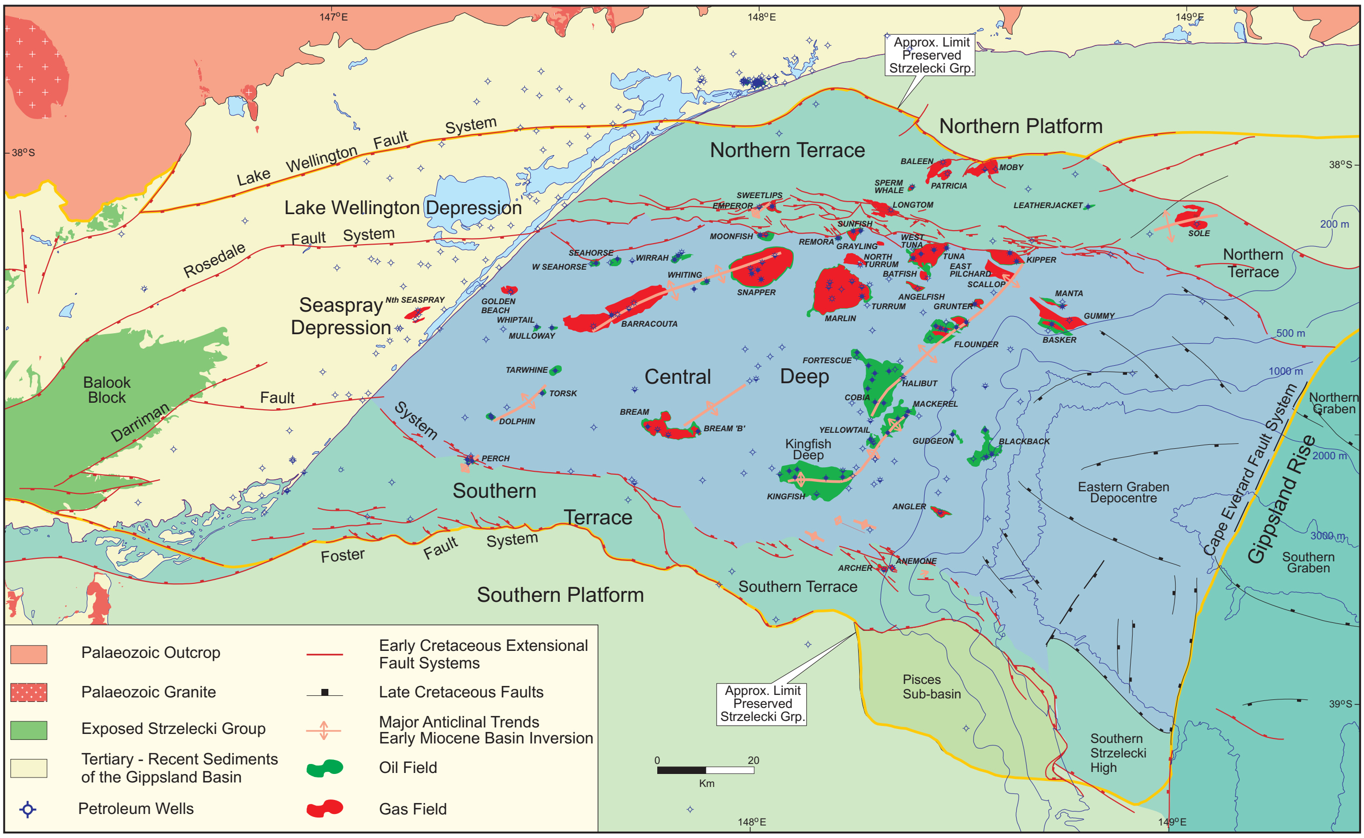

Figure 2. Structural elements map of the Gippsland Basin, showing distribution of oil and gas fields.

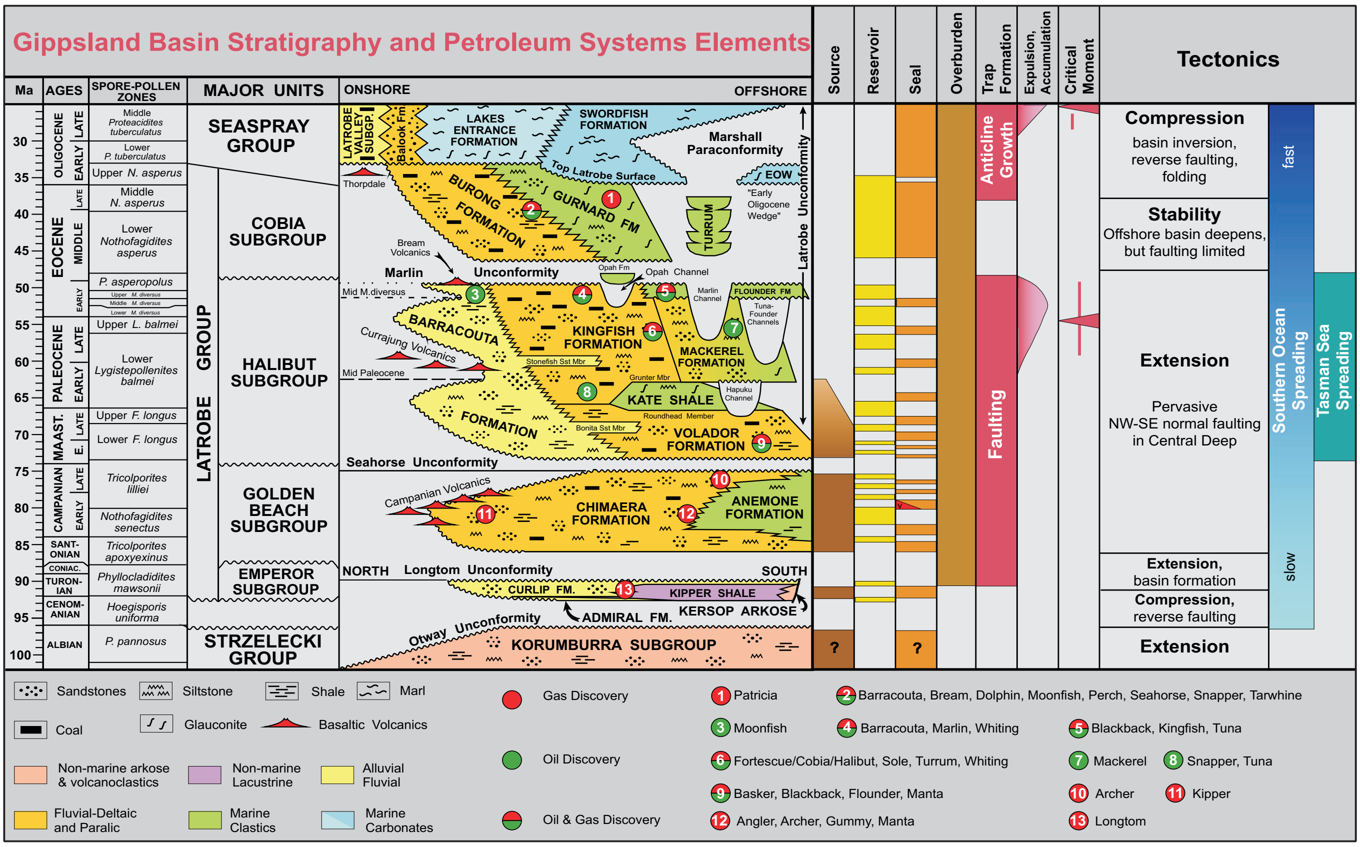

Figure 3 Stratigraphic column for the Gippsland Basin, showing petroleum system elements and tectonic evolution (after Bernecker & Partridge 2001).

distribution of the present day charge within the basin, new data on the palaeo-charge history are considered. These palaeo-charge data can also potentially provide important independent insights into the seal integrity within the basin. For example, could the large oil fields located in the Central Deep actually lack gas caps because of poorer seal integrity? If such a scenario were correct, then the charge history work should reveal that the initial hydrocarbon charge into such fields was actually gas, rather than oil, and hence the gas has subsequently leaked off. Such a scenario could potentially be consistent with the reported gas chimneys above the Kingfish field (Cowley & O'Brien 2000). Following the establishment of scenarios for both the present day and palaeo-charge inventories within the Gippsland Basin, the results of some simple 3D migration PetroMod models are presented that test some potential scenarios.

Petroleum geology and petroleum systems

Petroleum geology

The Gippsland Basin contains several giant oil and gas fields (Figure 2), with almost all of the currently producing fields located in shallow water on the western and northern margins and flanks of the basin. The gas fields are distributed primarily on the northern flank of the basin, whereas oil fields dominate within the Central Deep to the southeast. According to Bishop (2000), this strong spatial compartmentalisation may be the result of the combined effects of subsidence and variable heat-flow through time across the basin. Some simple models have been proposed which suggest that the source rocks are overmature and generating gas to the north, whereas in other regions, such as the Central Deep, they are now thermally mature and are generating oil (Mebberson 1989; Rahmanian et al. 1990; Moore et al. 1992). The distribution of the gas and oil fields is further complicated by variations in source rock type and quality across the basin and the presence of relatively complex migration pathways (Moore et al. 1992).

There are three broad, principal stratigraphic intervals (Fig. 3) that have been actively explored in the onshore and offshore Gippsland Basin (Bishop 2000).

1. The top-Latrobe Group;
2. The intra-Latrobe Group; and
3. The pre-Latrobe Early Cretaceous Strzelecki Group.

The early exploration phase in the Gippsland Basin focussed on the obvious, large, compressional anticlinal traps which developed at, and from, approximately 50 Ma (Duff et al. 1991). Compressionally-driven trap formation continued sporadically through the late Miocene; some faults on the Northern Terrace currently have a significant expression at sea floor. During the uplift associated with basin inversion, the Latrobe Group was eroded to varying extents. The eroded surface is known as the 'top-Latrobe Unconformity' (Duff et al. 1991; Gross 1993), over which the high-quality sealing facies of the marine Lakes Entrance Formation was deposited. Reservoirs beneath the top-Latrobe Unconformity vary in age from Late Cretaceous to Eocene (Gross 1993).

Bishop (2000), quoting Petroconsultants (1996), states that approximately 85% of the total discovered reserves in the Gippsland Basin are located in top-Latrobe Group reservoirs. Approximately 15% of the discovered reserves in the Gippsland Basin are reservoired within the deeper 'intra-Latrobe' levels and within the Golden Beach Subgroup. It is likely that future exploration successes will come from the exploration within the deeper horizons in the Golden Beach and Emperor subgroups and Strzelecki Group.

Petroleum systems

Remarkably little has been published about the basin's petroleum systems, especially the nature of the source rocks and their maturation histories, given that hydrocarbons have been produced from the onshore Gippsland Basin for over 80 years and the first major field was discovered offshore over 40 years ago.

The source rocks in a prolific, oil-rich basin such as the Gippsland Basin were considered traditionally to be of marine origin. However, Brooks and Smith (1969) proposed, somewhat controversially, that the coal measures of the non-marine Latrobe Group had generated the majority of the oil within the basin. More recent work (Burns et al. 1987; Moore et al. 1992; Philp 1994) demonstrated that the oils in the Gippsland Basin were principally generated from within the lower coastal plain facies, where coals, coaly shales and carbonaceous mudstones are abundant. This facies extends beneath the giant Kingfish oil field and across the basin to the north, whereas the gas-prone, upper coastal plain sediments are located shoreward, to the northwest (Burns et al. 1987; Rahmanian et al. 1990; Moore et al. 1992).

Some workers, such as Sloan et al. (1992), have proposed that parts of the Golden Beach Subgroup can have good source rock characteristics. In addition, it may be that the Strzelecki Group, which has long been considered to be economic basement, can contain good quality gas-prone source rocks. The equivalent-aged Eumeralla Formation in the Otway Basin is a prolific gas source.

Peak generation and primary migration in the Gippsland Basin (Clark & Thomas 1988) occur at depths of 4–5 km for oil and 5–6 km for gas. Clark and Thomas (1988) consider that peak hydrocarbon generation within the Latrobe Group source rocks takes place at an R_o between 0.92–1.0 %, which agrees well with the findings of Burns et al. (1987), whose maturity data (Methylphenanthrene index of Radke & Welte 1983) indicated that most Gippsland Basin oils were generated in a R_V range between 0.9–1.16%. Moore et al. (1992), using maturity data calculated from source-rock extracts, proposed that the reservoired oils were generated at maturity levels of R_o 1.15–1.30 %, whereas the gas was generated from the overmature section at maturity levels of R_o 1.25–2.0 %. Using gas isotope data, Burns et al. (1987) estimated that many of the oils in the Central Deep, such as those in West Halibut-1 and the Kingfish field, were generated at depths of approximately 3,900 m, which corresponded to a R_o of approximately 1.0–1.1%.

The rapid progradation and attendant subsidence associated with the deposition of the Gippsland Limestone in the Miocene and Pliocene pushed the Latrobe Group source rocks rapidly into the oil and gas window, with the result that maximum temperatures have been reached at present day (Duddy & Green 1992).

The hydrocarbons reservoired in the western Gippsland Basin have undergone some biodegradation and water washing (Burns et al. 1987) as a result of the invasion of the fresh-water wedge in the late Cenozoic (Kuttan et al. 1986).

CO_2 Containment

The primary focus of the containment study was to better understand the seal integrity of the regional top-seal, the Lakes Entrance Formation. This is presented first, followed by a brief overview of the intra-Latrobe sealing units.

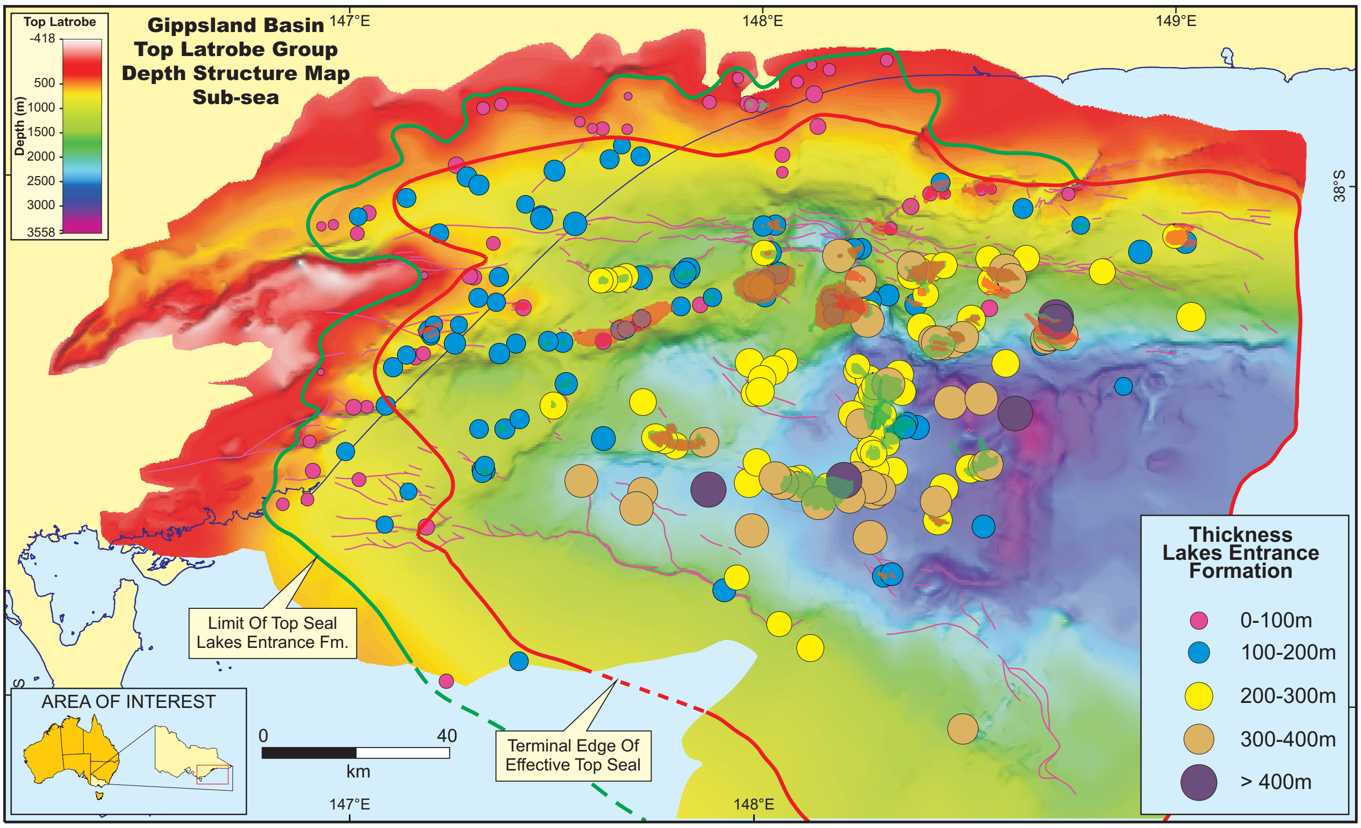

Figure 4. Lakes Entrance Formation thicknesses and top of Latrobe Group depth structure map.

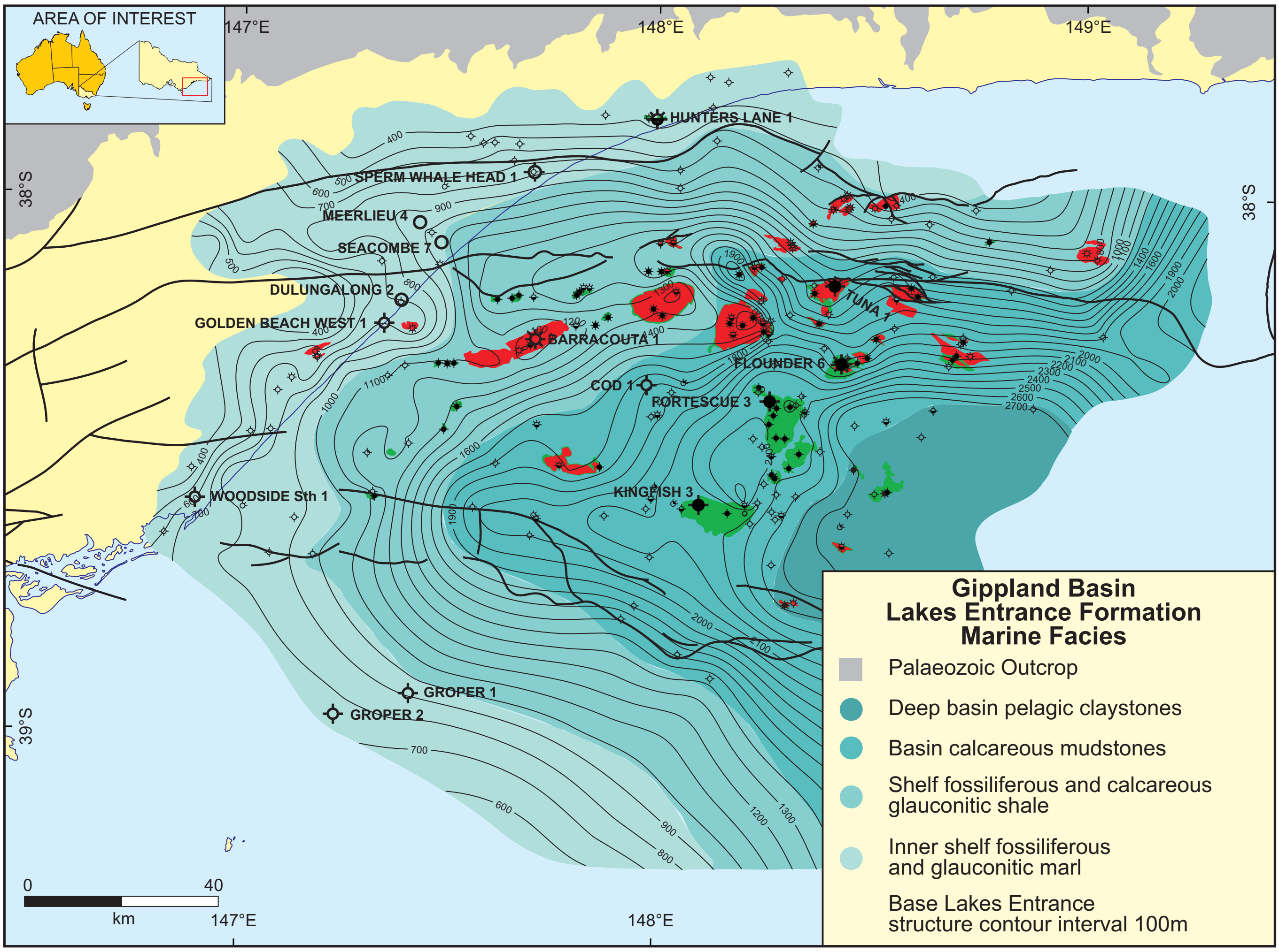

Figure 5. Basal sedimentary facies identified within the Lakes Entrance Formation marine sequence. Locations of wells sampled for MICP analysis are also highlighted.

Regional seal – Lakes Entrance Formation

The basal sections of the Oligocene Lakes Entrance Formation are comprised of calcareous mudstones and shales (Fig. 3) and provide the basinwide, high quality regional top-seal to the top-Latrobe Group reservoirs over much of the Gippsland Basin.

Stratigraphy

The Lakes Entrance Formation is the lowermost unit of the Oligocene to Recent Seaspray Group (Fig. 3) and is composed predominantly of calcareous mudstones, with some variation in composition across the basin. The recognition of major lateral facies changes has allowed the formation to be sub-divided into separate onshore and offshore components.

Onshore, the Cunningham Greenstone Member, Giffard Sandstone Member, Colquhoun Sandstone Member, Seacombe Marl and the Metung Marl are identified as constituent units of the Lakes Entrance Formation (Hocking 1976). The constituent formations of the onshore Seaspray Group have been divided into nine sequence stratigraphic units based on microfossil evidence (Holdgate & Gallagher 1997).

Offshore, four distinct units within the Seaspray Group are identified (Bernecker et al. 1997) according to well-log character, lithological composition and depositional facies. ‘Unit I’, a hemipelagic fossiliferous mudstone, is equivalent to the onshore marly Lakes Entrance Formation (Bernecker et al. 1997) and part of the offshore Lakes Entrance Formation (T. Bernecker pers. comm. Geoscience Australia 2007). ‘Unit I’ of the Seaspray Group was formalised by establishing a new formation name, the Swordfish Formation (Partridge 1999).

The boundary between Units I and II is not well-defined and is based on a subtle increase in carbonate content. Over large parts of the basin, however, a seismic reflector has been identified at the top of the Lakes Entrance Formation which is known as the ‘Mid-Miocene Marker’. Above this horizon, an interval of anomalous seismic velocity, the ‘High Velocity Zone’, produces distinctive two-way time pull-ups which in the past had significantly deleterious effects on the depth mapping and definition target intervals within the Latrobe Group (Feary & Loutit 1998).

Seal thickness and geometry

The thickness of the regional seal generally increases from the onshore to the offshore portion of the Gippsland Basin (Fig. 4). Onshore, the thickness of the Lakes Entrance Formation ranges between 23 and 176 m; it is thickest in the Lake Wellington and Seaspray depressions (Fig. 2). The average thickness of the Lakes Entrance Formation increases in the nearshore and on the southern and northern platforms offshore. The formation attains its greatest

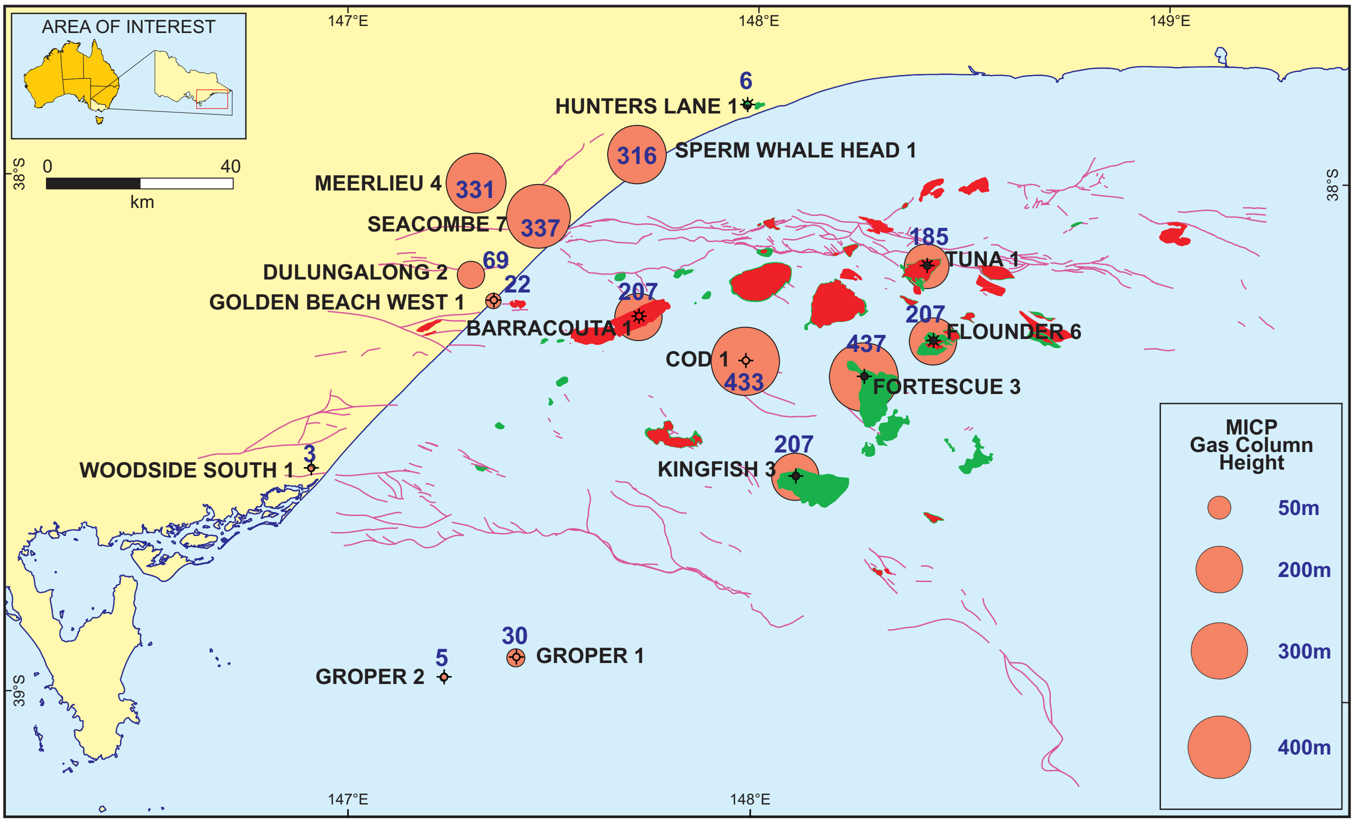

Figure 6a. Retention capacity of the Lakes Entrance Formation for gas.

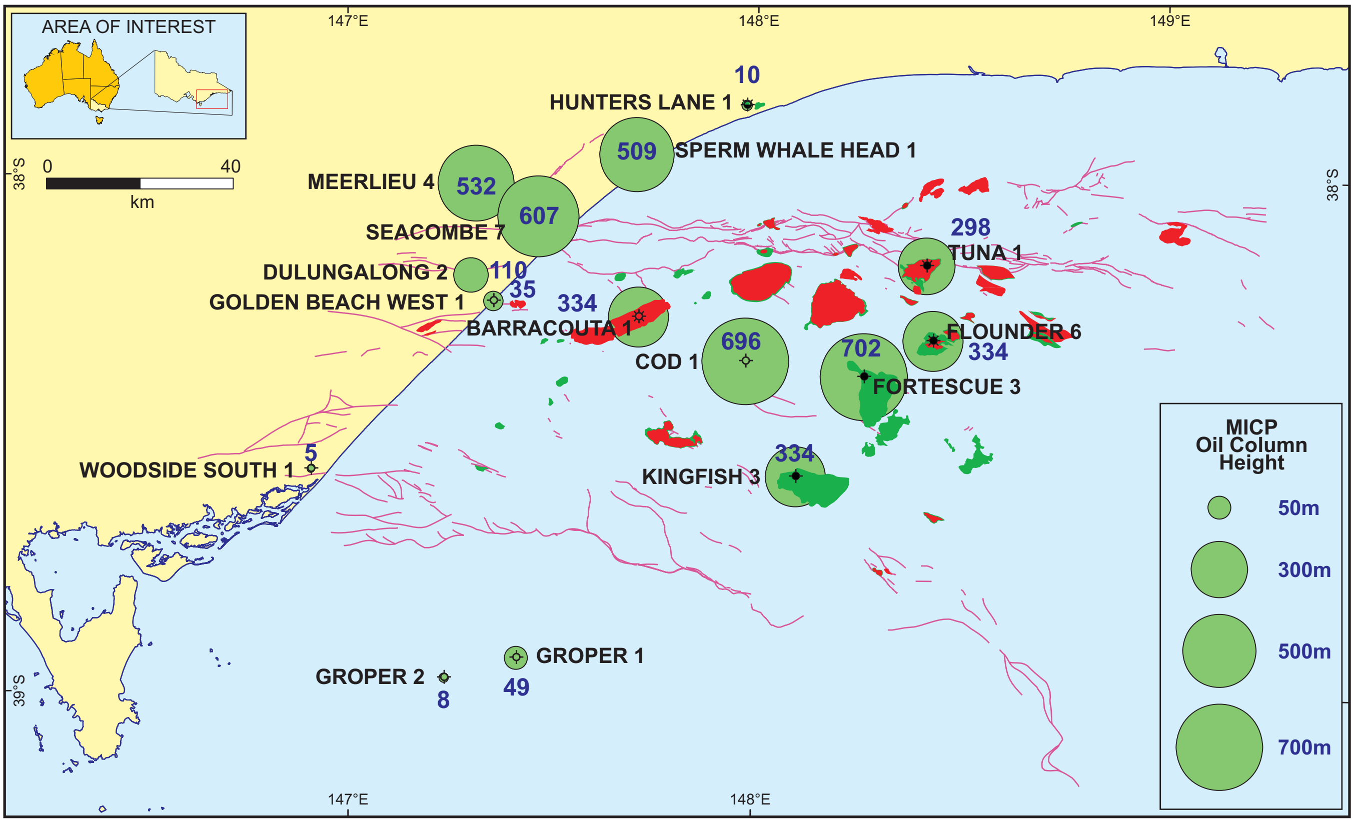

Figure 6b. Retention capacity of the Lakes Entrance Formation for oil.

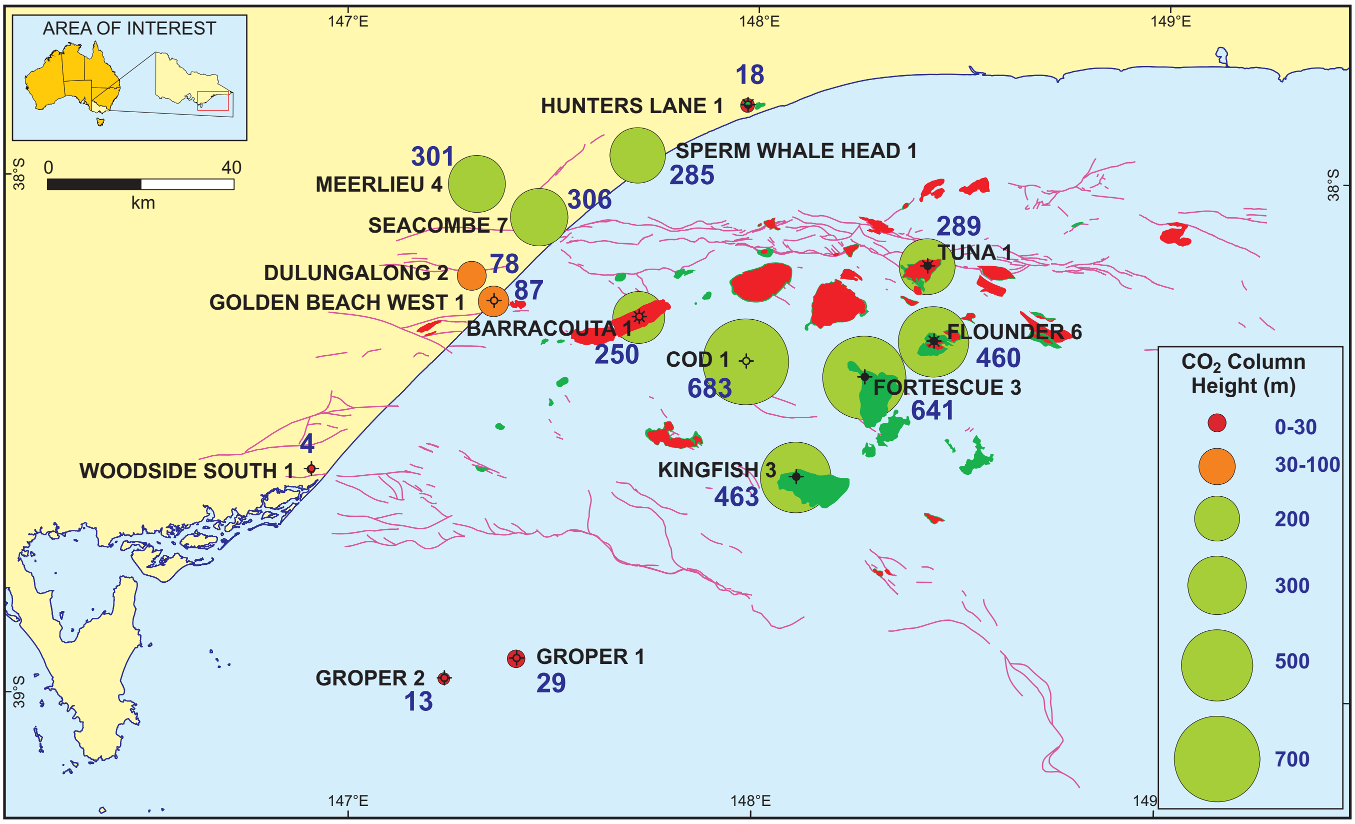

Figure 6c. Retention capacity of the Lakes Entrance Formation for CO_2.

thickness in the Central Deep, reaching a maximum of 430 m; it is thinner on the flanking Southern and Northern terraces. In general, the Lakes Entrance Formation is between 100 to 200 m thick over the north-western gas fields (i.e. Barracouta, Snapper and Turrum) and 200 to 300 m thick over both the eastern fields (i.e. Tuna, East Pilchard, Basker and Gummy) and the south-eastern oil fields (i.e. Kingfish, Fortescue, Cobia, Halibut and Blackback).

The depth to the base of the Lakes Entrance Formation increases from the onshore to the offshore (see Fig. 4 for top Latrobe Group structure map and Fig. 5 for base Lakes Entrance Formation contours). In the Central Deep, the base Lakes Entrance Formation occurs at approximately 2,000–3,500 m subsea, whereas towards the margins of the Gippsland Basin, depths of 500–1,000 m are typical. Onshore, where the Lakes Entrance Formation is thinnest, the depths decrease to less than 400 m.

In the current study, the marine facies present at the level of the basal Lakes Entrance Formation were identified from well completion reports. A simple representation of the basal Lakes Entrance Formation facies identified is presented in Figure 5. Overall, these facies are broadly similar to those proposed by Bernecker et al. (1997) and Gibson-Poole and Svendsen (2005).

Seal capacity

Seal capacity is the maximum hydrocarbon column height that can be contained by a seal and is an important factor in the evaluation of seal potential for the geosequestration of carbon dioxide (Kaldi & Atkinson 1997). Previous investigations of the capacity of local Latrobe Group intraformational seals and the regional top seal, the Lakes Entrance Formation, were undertaken on a limited number of wells by Daniel (2005) and Root (2005). The samples analysed in the current study were obtained from different wells to those presented by Daniel (2005), Root (2005) and Gibson-Poole et al. (2008).

The present study is focused on obtaining an understanding of the sealing capacity of the regional top seal Lakes Entrance Formation, as it is this formation that must ultimately provide containment to any injected CO_2. In some areas, the underlying Gurnard Formation can also be locally important as a seal, although it is the Lakes Entrance Formation that provides regional containment. In total, 15 core samples from the Lakes Entrance Formation and one from the Gurnard Formation were submitted to ACS Laboratories (Perth) for Mercury Injection Capillary Pressure (MICP) analysis. Maximum column retention capacities for oil and gas were determined (see Daniel 2005) using standard ACS methodologies. CO_2 retention capacity was determined using the method outlined in Daniel (2005).

The wells sampled are listed in Table 1, along with details such as sample depth, lithology and comments regarding the relative stratigraphic position and its relationship to the live hydrocarbon column. The wells from which MICP samples were taken are highlighted on Figures 6a-c. It is not routine for exploration companies to acquire conventional cores within sealing lithologies such as the Lakes Entrance Formation and hence the number of suitable core samples was limited. Samples were chosen close to the base of the formation; otherwise, samples were selected as near as possible to the base of the available cored interval.

From the MICP results presented in Table 1 and Figures 6a-c, it is clear that the Lakes Entrance Formation can withhold the greatest column heights in the central offshore Gippsland Basin, a result consistent with the results of Daniel (2005). Samples taken from near the base of the Lakes Entrance Formation in Flounder-6 and Fortescue-3 have large hydrocarbon and CO_2 column retention heights, as do samples analysed from slightly shallower depths

WELL	SAMPLE DEPTH (m)	LAKES ENTRANCE FM THICKNESS (m)	LOCATION	LITHOLOGY	COMMENT	COLUMN HEIGHT (m)		
						GAS	OIL	CO_2
Barracouta-1	1021.95	114	Offshore Central Deep	Calcareous shale, fossiliferous, glauconitic, indurated	33 m above gas column	207	334	250
Cod-1	1711.89	285	Offshore Central Deep	Fossiliferous calcareous shale, fissile and brittle	171 m above base of LEF	433	696	683
Dulungalong-2	478.1	85	Onshore, Seaspray Depression	Fossiliferous marl, friable to indurated	47 m above base of LEF	69	110	78
Flounder-6	1929.38	394	Offshore Central Deep	Calcareous mudstone, indurated	Sidewall Core 3 m above gas	207	334	460
Fortescue-3	2411.50	252	Offshore Central Deep	Calcareous mudstone, well indurated	1 m above base of LEF	437	702	641
Golden Beach West-1	667.68	119	Onshore, Seaspray Depression	Fossiliferous silty marl, slightly glauconitic, friable to indurated	27 m above base of LEF	22	35	87
Groper-1	926.10	123	Offshore Southern Platform	Glauconitic mudstone, calcareous, fossiliferous, friable	5 m above base LEF	30	49	29
Groper-1*	932.00	-	Offshore Southern Platform	Glauconitic sandstone, indurated	Gurnard Formation 1 m below base LEF	19	30	24
Groper-2	747.86	73	Offshore Southern Platform	Glauconitic mudstone, calcareous, fossiliferous, friable to indurated	13 m above base of LEF	5	8	13
Hunters Lane-1	377.00	76	Onshore Northern Platform	Fossiliferous bioturbated mudstone, glauconitic, micaceous, friable	34 m above granodiorite basement	6	10	18
Kingfish-3	2143.05	264	Offshore Central Deep	Calcareous mudstone, indurated	101 m above base of LEF	207	334	463
Meerlieu-4	769	141	Onshore Northern Terrace, Lake Wellington Depression	Marl, friable to indurated	56 m above base of LEF	331	532	301
Seacombe-7	947.6	176	Onshore Northern Terrace, Lake Wellington Depression	Marl, friable to indurated	91 m above base of LEF	377	607	306
Sperm Whale Head-1	718.1	127	Onshore Northern Terrace, Lake Wellington Depression	Marl, friable to indurated	51 m above base of LEF	316	509	285
Tuna-1	1160.00	259	Offshore Central Deep	Calcareous mudstone, indurated	151 m above gas column	185	298	289
Woodside South-1	522.12	80	Onshore Southern Terrace	Fossiliferous marl, soft and friable	70 m above base of LEF; 10 m from top of LEF	3	5	6

Table 1. Supportable column heights for Gippsland Basin samples, based upon MICP results.

within the Lakes Entrance Formation in Barracouta-1, Cod-1, Kingfish-3 and Tuna-1.

The Lakes Entrance Formation within the Central Deep has a retention capacity of several hundred metres of oil and CO_2 and approximately 200–400 m of gas (see Figs 6a-c). There are, however, variations in the retention capacities within the Central Deep, which could be due to subtle variations in facies and lithologies. For example, equivalent intervals at Fortescue-3 can contain 641 m of CO_2 whereas at Kingfish-3 and Flounder-6, the retention capacities are 463 m and 460 m respectively.

Both of the Lakes Entrance Formation samples from the Groper-1 and Groper-2 wells in the offshore Southern Platform have low potential column retention heights for both gas and CO_2 (Table 1). At Groper-1, which is located in a slightly more basinward position, the top-seal could retain 30 m of gas and 29 m of CO_2. At Groper-2, the Lakes Entrance Formation could withhold only 5 m of gas and 13 m of CO_2. At both locations, the samples analysed were friable, fossiliferous and glauconitic and appear representative of the interpreted marine inner shelf facies of the Lakes Entrance Formation across the region. These MICP data suggest that the sealing capacity of the Lakes Entrance Formation decreases rapidly south of the Foster Fault System and is very poor compared to the Central Deep (Figs 6a-c). Moreover, there appears to be a decrease in seal capacity between Groper-1 towards Groper-2, suggesting a further decrease in capacity to the southwest. These data indicate that the regional top-seal across the Southern Platform has relatively poor to no retention capacity for either gas or CO_2, at least at or to the southwest of Groper-2. Based upon the MICP data, the Groper-2 location would appear to represent the approximate terminal edge of the effective top-seal for gas and CO_2 through this area. The sealing capacity of the Gurnard Formation also appears to be poor on the Southern Platform (Table 1).

Further west, the Lakes Entrance Formation thins significantly and the seal capacities show corresponding decreases into the onshore areas.

In the Seaspray Depression, the regional top-seal at Golden Beach West-1 can potentially contain 87 m of CO_2, 35 m of oil and 22 m of gas. Dulungalong-2, located 2 km from Golden Beach West-1, can potentially contain 78 m of CO_2, similar to that seen at Golden Beach West-1. Whilst still representing an effective seal, at least for CO_2, the retention capacities in the Seaspray Depression appear to be significantly less than those present in the Central Deep.

Three cores from the Lake Wellington Depression yielded significantly greater retention heights than those from the Seaspray Depression located to the southwest. MICP data from friable to indurated marls from Meerlieu-4, Sperm Whale Head-1 and Seacombe-7 indicate that the seal through this area can retain

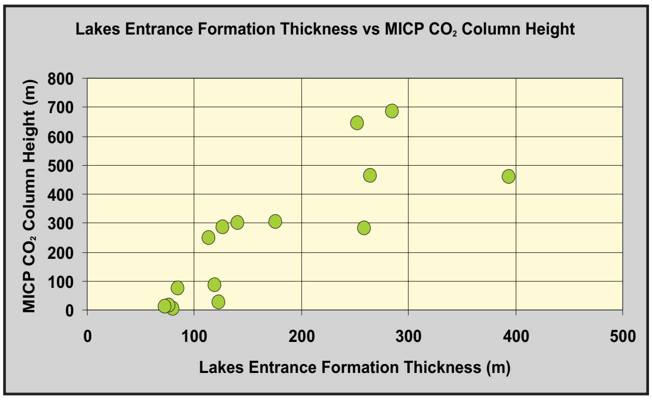

Figure 7a. Relationship between the thickness of the Lakes Entrance Formation and its MICP retention capacity.

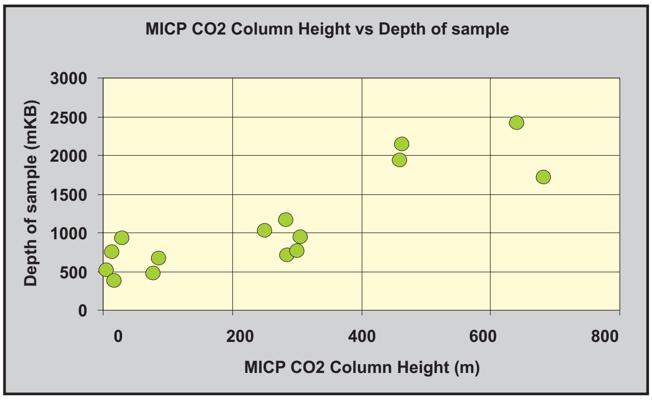

Figure 7b. Relationship between the depth of the Lakes Entrance Formation and its MICP retention capacity.

a gas column height between 316–377 m and a CO_2 column height between 285–306 m.

Two samples were available from wells located on the onshore extensions of the Northern (Hunters Lane-1) and Southern (Woodside South-1) platforms. Both samples yielded very low column retention heights. The Lakes Entrance Formation at Hunters Lane-1 could retain a gas column height of only 6 m and a CO_2 column height of 18 m, similar to the retention capacities measured at Groper-2. The top seal capacity at Woodside South-1 was even poorer, 3 m for gas and 6 m for CO_2. Both of these samples were fossiliferous, with the sample from Hunters Lane-1 also being glauconitic (see Table 1).

In summary, onshore, the top-seal capacity appears to be good within the Lake Wellington Depression, where retention capacity appears similar to the western parts of the Central Deep. The top-seal capacity in the Seaspray Depression appears to be less than in the Lake Wellington Depression, but may be still adequate for CO_2. The available sample database is currently too limited to draw any definitive conclusions about top-seal integrity across the wider onshore area. The data from Hunters Lane-1 and Woodside South-1 suggest that containment for gas and CO_2 is inadequate on the flanking platforms. The lack of any significant hydrocarbon accumulations at the top-Latrobe horizon onshore could be an indication that the Lakes Entrance Formation top-seal is ineffective over significant parts of the onshore Gippsland Basin region, at least at geological timeframes.

The relationships between the MICP capacity of the Lakes Entrance Formation and its thickness and MICP capacity and the depth of the Lakes Entrance Formation are presented in Figures 7a and 7b, respectively. There is a strong positive relationship between potential column height and the thickness of the regional seal. Further offshore, where the seal is thicker its retention capacity is high. In contrast, in more marginal parts of the basin,

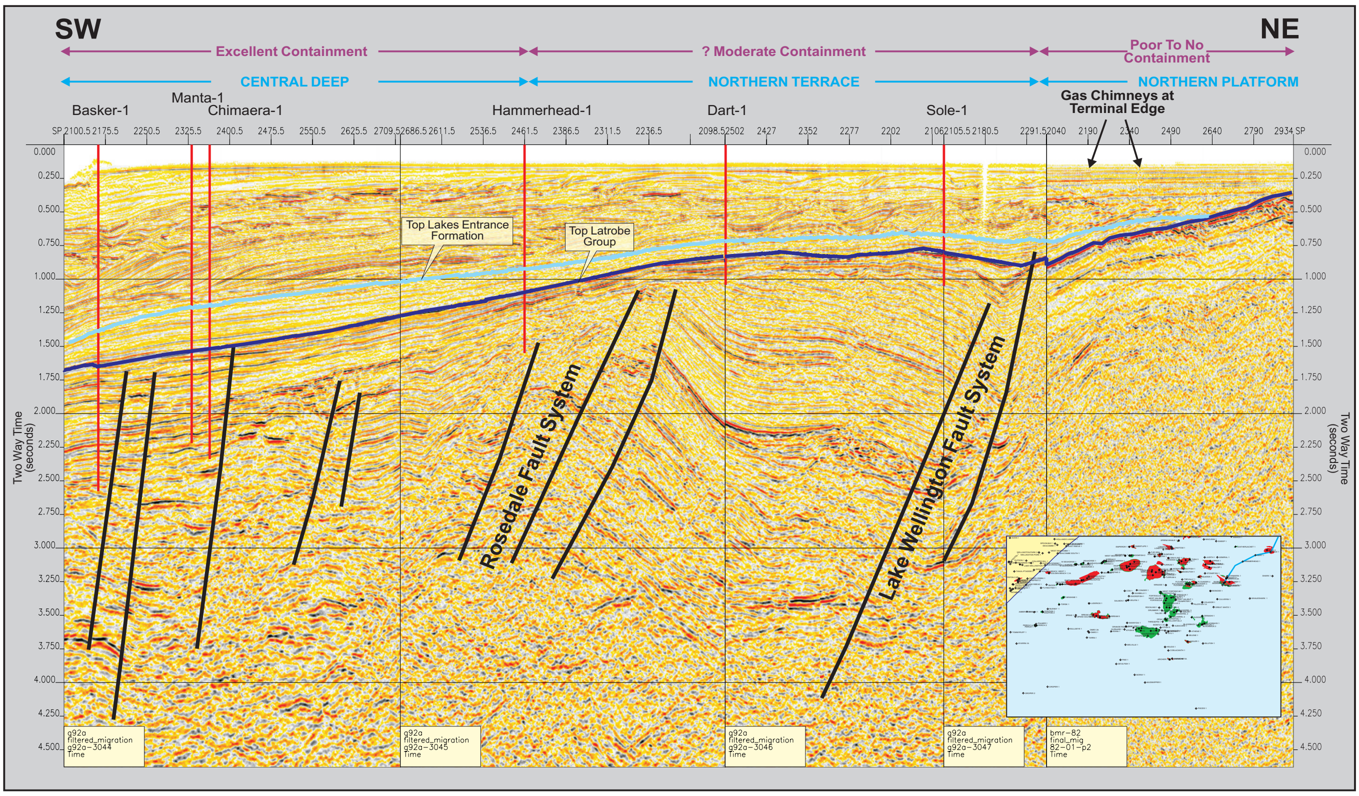

Figure 8a. Seismic line (NW-SE from Basker-1 to Northright-1) showing broad relationships between seismic facies and architecture and derived MICP retention capacities.

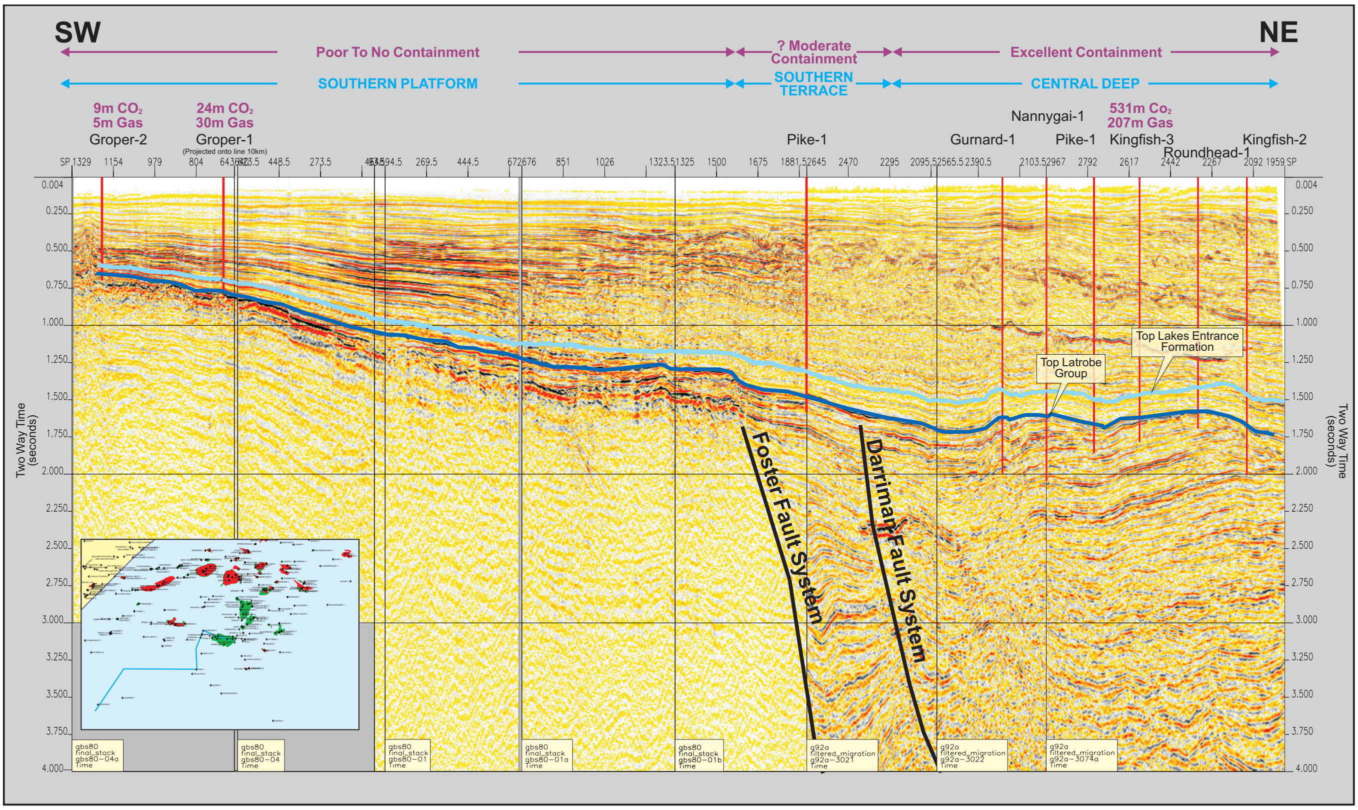

Figure 8b. Seismic line (NW-SE from Groper-2 to Roundhead-1) showing broad relationships between seismic facies and architecture and derived MICP retention capacities.

either on the Southern Platform or onshore, the Lakes Entrance Formation is thin and has a poor retention capacity. The positive relationship between depth and retention capacity (Fig. 7b) is probably due to the fact that the Lakes Entrance Formation was deposited in an early postrift setting, where it progressively filled the palaeo-topographic lows. The strong relationship between the thickness of the Lakes Entrance Formation and the depth of the top-Latrobe surface is evident from Figure 4.

The overall relationships between the derived MICP retention capacities and the basin architecture for the northern and southern parts of the Gippsland Basin are summarised in Figures 8a and 8b respectively. The regional top-seal thins rapidly across the Rosedale Fault and then pinches out north of the Lake Wellington Fault (Fig. 8a). To the south (Fig. 8b), the seal thins across the Darriman and Foster faults in the south; it also shows a significant change in seismic character immediately southwest of the Foster Fault.

Latrobe Group seals

In the Gippsland Basin, a number of oil and gas accumulations are locally sealed by Latrobe Group units, rather than by the early Oligocene Lakes Entrance Formation. Regionally, these intra-Latrobe seals typically have poor top-seal integrity and are largely ineffective at preventing migration of hydrocarbons to the base of the regional seal. Consequently, the majority of hydrocarbons regionally are sealed by the Lakes Entrance Formation.

The Gurnard Formation underlies the Lakes Entrance Formation in some areas and acts as a top-seal for several giant fields. It can be a good seal locally, as MICP data from the Gurnard Formation in Kingfish-9 demonstrate (723 m CO_2 retention column height; Daniel 2005). The sealing capacity of the Gurnard Formation is very variable, however, as indicated by the low CO_2 retention column heights measured in Bream-2 and Fortescue-2 (0.19 m and 40 m respectively; Daniel 2005) and also in Groper-1 on the Southern Platform (Table 1). The thickness and distribution of the Gurnard Formation are also highly variable. Partridge (1999) noted that 'The (Gurnard) Formation is generally not present or very thin over most of the eroded topographic highs of Blackback/Terakihi, Kingfish, Mackerel, Halibut/Cobia/Fortescue and Marlin'.

There are several intra-formational sealing units within the deeper Latrobe Group, which include floodplain sediments deposited in upper and lower coastal plain environments, as well as lagoonal to offshore marine shales. These local seals are commonly thin and mostly occur within stacked sandstone/mudstone successions. Other effective seals are formed by several distinct volcanic horizons of Campanian to Paleocene age; these are often less than 50 m thick, although they are known to exceed 100 m at the Kipper field. Excellent Latrobe Group intra-formational seals include the Turonian Kipper Shale and the late Maastrichtian to early Paleocene Kate Shale (Bernecker & Partridge 2001). The Kipper Shale accumulated in shallow to deepwater lacustrine environments and is widespread in its distribution. It covers the offshore portion of the basin between the basin-bounding faults and its thickness exceeds 500 m in Kipper-1 (Bernecker & Partridge 2001). In contrast, the shelfal marine Kate Shale is limited in extent (Fig. 9), with its principal depocentre located around the Halibut and Flounder fields (Bernecker & Partridge 2005). The Kate Shale reaches its maximum thickness around and underneath the oil fields which dominate the Central Deep. The thickest intersection of the sequence is at Trumpeter-1, where its thickness reaches 120 m.

Daniel (2005) and Gibson-Poole et al. (2008) have demonstrated that these intra-formational seals can locally hold back hundreds of metres of CO_2. However, whilst their seal capacities can be

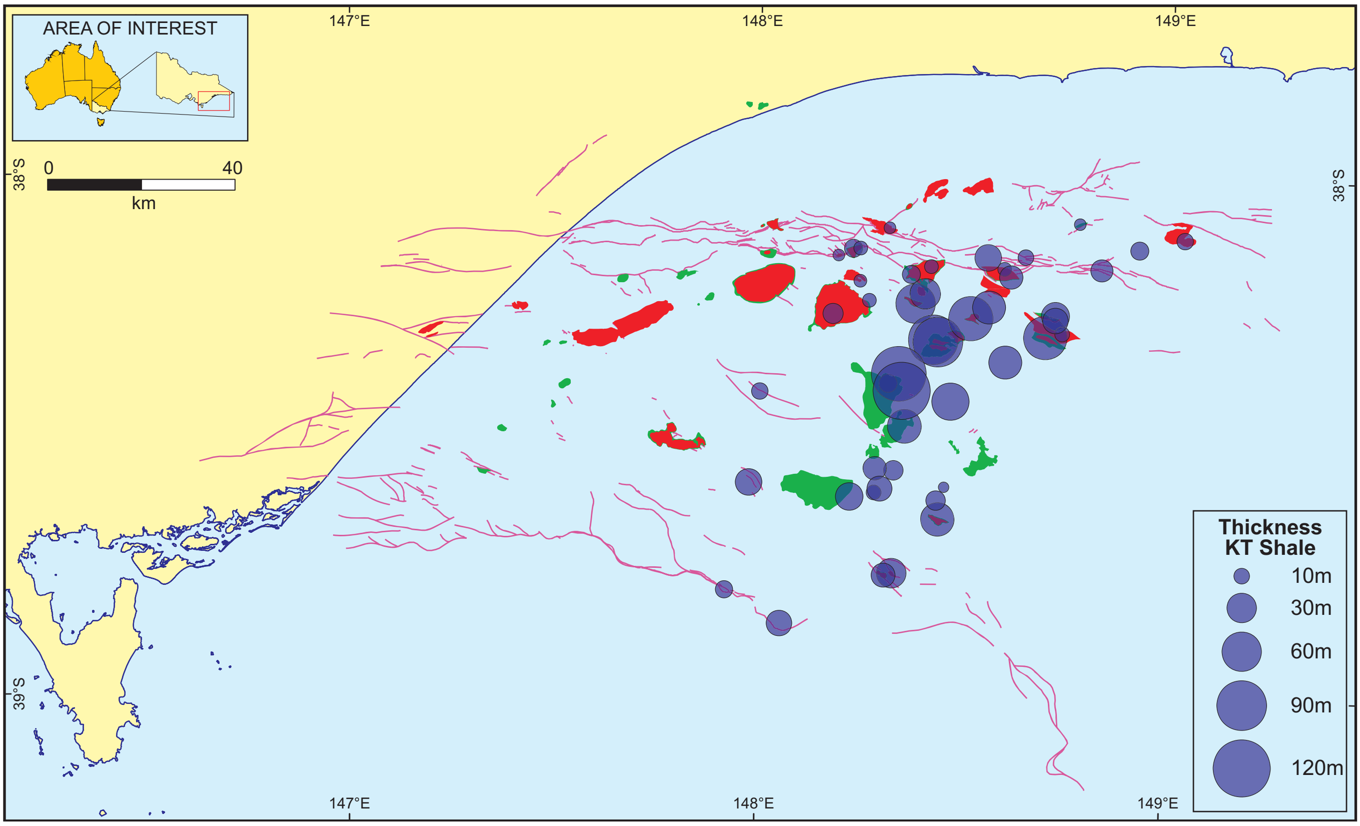

Figure 9. Thickness of the Kate Shale (as derived from well data).

high, the laterally discontinuous nature of these intra-Latrobe seals probably produces a substantial decrease in their seal integrity at a regional scale. The predominance of hydrocarbon discoveries at the base of the regional seal testifies to the overall ineffectiveness of the intra-Latrobe sealing system. Similarly, the combination of the variation in the seal capacity and the patchy geographic distribution of the Gurnard Formation suggests that the Lakes Entrance Formation will provide the ultimate regional barrier to the migration of hydrocarbons or injected fluids such as CO_2.

Impacts

The Impacts assessment has been sub-divided into three sub-sections, namely;

- Present day charge
- Palaeo-charge
- Migration

The present day charge section represents a simple assessment of the distribution and composition of the existing hydrocarbon resources within the basin. The palaeo-charge assessment was undertaken in collaboration with CSIRO Petroleum using fluid inclusion analyses of key fields within the Gippsland Basin. The migration assessment was undertaken at the Australian School of Petroleum and at GeoScience Victoria using the PetroMod 10 3D basin modelling software.

Present day charge

Most workers agree that the dominant hydrocarbon inventory within the Gippsland Basin has been sourced from the Latrobe Group (Moore et al. 1992). There have, however, been modifications to the original charge, principally related to the influx of meteoric water, namely the 'fresh water wedge' of Kuttan et al. (1986), and attendant biodegradation (Burns et al. 1987). The purpose of the present discussion is to provide a simple, regional framework for examining the principal composition of hydrocarbon gases within the Gippsland Basin, to understand what may be modifying the gases, determine where natural CO_2 is currently present within the basin and assess how the above may help to better understand the potential of the region for Carbon Capture and Storage (CCS).

For the purposes of this investigation, Geoscience Australia's OrgChem gas database was used to produce a representative subset of the hydrocarbon gas compositions from the offshore and onshore Gippsland Basin. In total, this database consists of 410 individual analyses from approximately 40 different wells.

Hydrocarbon cases

A simple measure of gas composition is the ratio, $C_1/(C_2+C_3)$, which provides an estimate of how geochemically wet a gas is. The $C_1/(C_2+C_3)$ ratio for the Gippsland Basin is presented in Figure 10. Also included in this figure are the principal fault systems through the region and the location and thickness of the interpreted freshwater wedge (from Kuttan et al. 1986).

Most gases within the Central Deep have relatively low $C_1/(C_2+C_3)$ ratios; typically less than 15. Such values are consistent with either condensates or gases associated with oil legs. In contrast, significantly drier gases are found in the western part of the Gippsland Basin, within the area influenced by the fresh water wedge. There, the ratio is typically between 15–30, with some fields containing quite dry gases ($C_1/(C_2+C_3) > 30$). Around the flanks of the basin, dry gases are found at the Sole field on the Northern Terrace, with extremely dry gases ($C_1/(C_2+C_3) >800$)

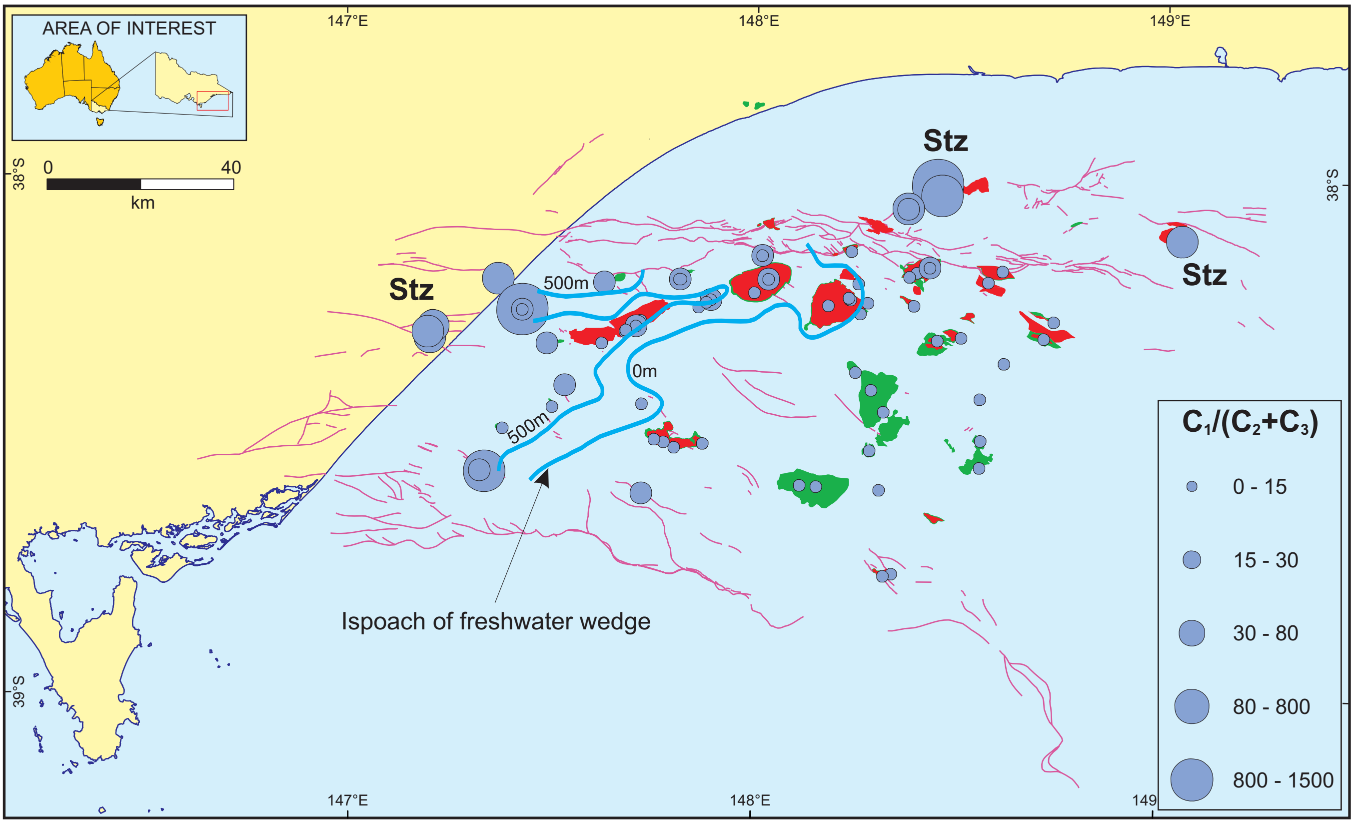

Figure 10. Map showing the $C_1/(C_2+C_3)$ ratios of hydrocarbon gases in the Gippsland Basin. Gases probably sourced from the Albian-Aptian Strzelecki Group are marked with 'Stz'.

present in the Patricia-Baleen and Golden Beach fields, as well as onshore.

The relationships between the $C_1/(C_2+C_3)$ and iC_4/nC_4 ratios and depth are presented in Figures 11a and 11b respectively. These plots reveal that the gases located at depths shallower than approximately 1,500 m within the Gippsland Basin are often, though not always, biodegraded. This maximum depth threshold is consistent with biodegradation levels in natural gas from other Australian basins (Boreham et al., 2001). Based upon the distribution of the $C_1/(C_2+C_3)$ in Figure 10, it seems that the gases directly affected by Kuttan et al.'s (1986) freshwater wedge and those located around the very periphery of the basin, such as the Northern Terrace, are often biodegraded, sometimes severely, as is the case for the Patricia-Baleen and Golden Beach fields.

An exception to this is the gas in the small fields located onshore, North Seaspray, Trifon and Gangell. The gases in these fields are reservoired in tight sandstones within the Strzelecki Group and none of the gas appears to be biodegraded, in spite of its often relatively shallow depth. These onshore gases appear to be mostly produced from fractures (rather than from the matrix). Moreover, based upon their location within the sedimentary section, it is likely that all of these gases were sourced from within the Albian-Aptian Strzelecki Group, rather than from the Latrobe Group. It appears likely that the permeability within

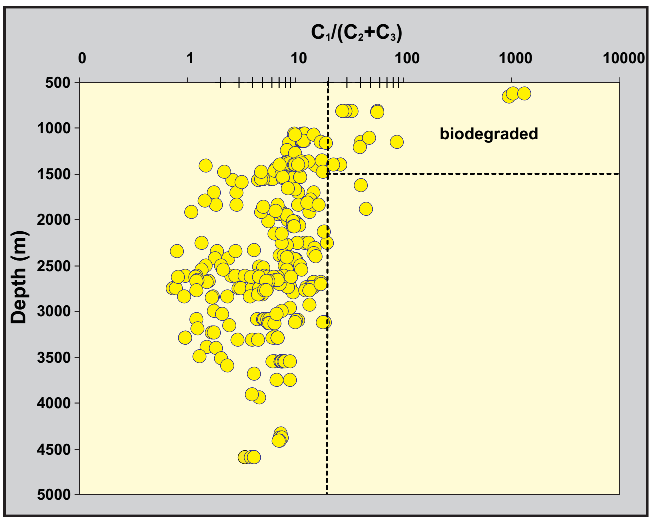

Figure 11a. Relationship between C1/(C2+C3) and depth in the Gippsland Basin.

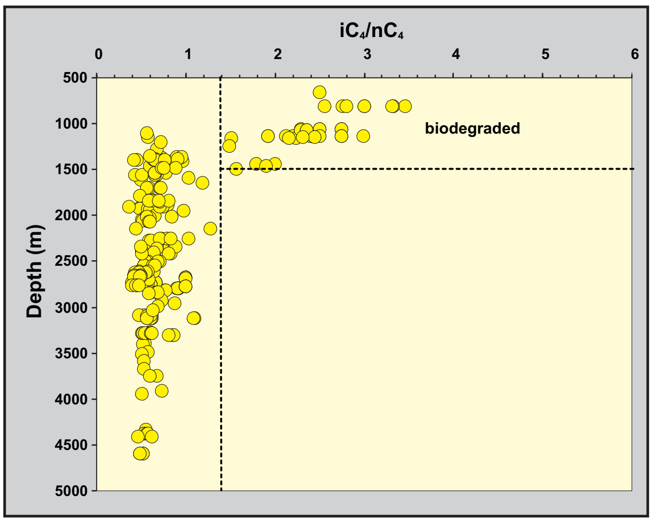

Figure 11b. Relationship between iC4/nC4 (biodegradation indicator) and depth in the Gippsland Basin.

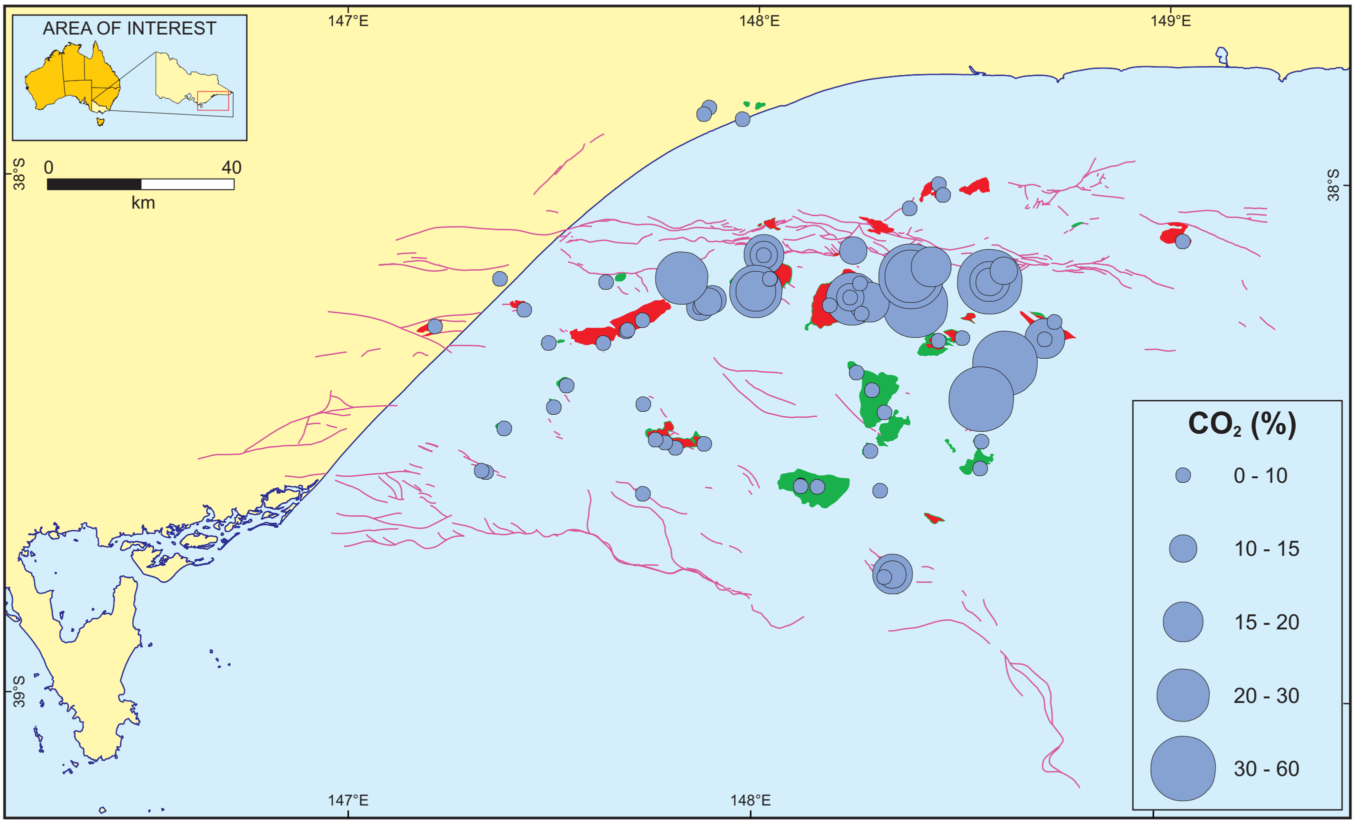

Figure 12. Map showing the CO_2 concentrations in natural hydrocarbon gases in the Gippsland Basin. Note that this bubble map display emphasises the maximum CO_2 contents of gases found in any one field.

these Strzelecki Group sandstones is laterally discontinuous, which has effectively prevented the influx of fresh water into the reservoirs and the subsequent biodegradation of the gases. These observations suggest that the onshore Strzelecki Group probably has poor injectivity characteristics and hence its geosequestration potential may be limited.

The gas compositional data indicate that all of the gases reservoired south of the Rosedale Fault and north of the Darriman Fault (i.e. in the Central Deep) were sourced from the Latrobe Group, in agreement with previous work (Burns et al. 1987; Rahmanian et al. 1990; Moore et al. 1992). The data in Figures 10 and 11 indicate that virtually all of these Latrobe Group gases are geochemically wet, with the drier gases located further west being biodegraded, but still of Latrobe Group origin. The gases in the shallow (approximately 633 mSS) Latrobe Group reservoirs in the Golden Beach field are extremely biodegraded ($C_1/(C_2+C_3)$ > 1,000) and now consist almost entirely of methane. The gases in the small fields onshore were almost certainly generated within the Strzelecki Group, where the gases migrated short distances into adjacent tight sandstones. The origin of the reservoir gases on the Northern Platform is, however, less clear.

The gases in the Patricia-Baleen field are strongly biodegraded and are very dry whereas the gases at Sole appear to be less biodegraded and are significantly wetter. An important question is whether the gases on the Northern Terrace are definitely of Latrobe Group origin or whether they could be, as in the onshore part of the basin, of more local Strzelecki Group origin. A Latrobe Group source for these fields would require that the gases have migrated significant distances across the Rosedale Fault and Northern Terrace. This would mean that the Rosedale Fault was not sealing for gas, which would have significant implications for CO_2 containment and migration. In contrast, a Strzelecki Group origin for these fields would allow a scenario where the Rosedale Fault was largely sealing for gas (and CO_2) at the top-Latrobe level.

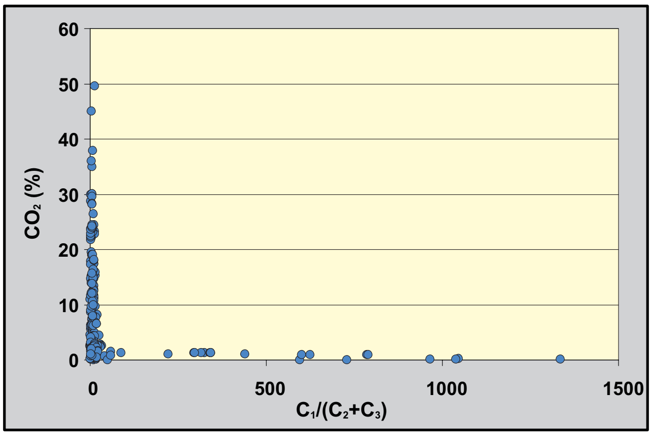

Figure 13. Relationship between CO_2 contents and $C_1/(C_2+C_3)$ ratios in gases from the Gippsland Basin.

The biodegradation of the Patricia-Baleen gases makes their characterisation difficult and no samples were available from the Sole gas field for analysis. Recent analysis of *neo*-pentane, a gas component that is unaffected by biodegradation, reveals significant similarities between the carbon isotopes of *neo*-pentane in gases from the Patricia-Baleen Field and the Albian-Aptian (Eumeralla Formation) sourced gases from the Otway Basin (Minerva, Casino) (Boreham & Edwards, 2008). No samples were available from the Sole gas field for neo-pentane analysis, although there are strong molecular compositional similarities between the gases from the

Sole field and those from unequivocally Eumeralla Formation sources in the eastern Otway Basin (O'Brien & Thomas 2007). At this stage, however, it is not possible to determine unequivocally whether the gases in fields on the Northern Platform were generated locally within the Strzelecki Group and migrated a short distance, mostly vertically, up into the top-Latrobe reservoirs, or whether the gas in Patricia-Baleen and Sole was generated in the Central Deep and migrated significant distances across the Rosedale Fault. Distinguishing between these two alternatives is critical, as important inferences could be drawn on the sealing versus non-sealing nature of the Rosedale Fault through this area.

Natural CO_2 distribution in the Gippsland Basin

The regional distribution of natural CO_2 across the Gippsland Basin was investigated as part of the present study. It was hoped to better define the amount of natural CO_2 present and its geographic distribution and the first-order controls on its concentration and distribution. Understanding the natural CO_2 in the Gippsland Basin is also an important first step in characterising the potential impacts of any injected CO_2 on existing infrastructure, in other words, has the existing infrastructure been engineered to cope with naturally elevated levels of CO_2?

The percentage of natural CO_2 measured in hydrocarbon gases within the Gippsland Basin is expressed in bubble-map form in Figure 12. It should be noted that this form of display emphasises the maximum amount of CO_2 measured at any one well location (this appears as the biggest bubble), rather than providing an impression of the average CO_2 concentrations within any one field. There is a very strong geographic control on the concentrations of natural CO_2, with the majority of high CO_2 gases (some exceeding 30%) closely distributed along or immediately south of, that is in the hanging wall of, the Rosedale Fault. There is also some tendency for the concentrations of CO_2 to increase from west to east. Almost all of the gases located a significant distance from the Rosedale Fault have low CO_2 concentrations. Figure 13 presents the relationship between the CO_2 content and the $C_1/(C_2+C_3)$ ratios in the gases shown on Figure 12. All of the gases with higher CO_2 are geochemically wet; all elevated CO_2 contents were restricted to gases which had a $C_1/(C_2+C_3)$ ratio of less than 15, typical of Latrobe Group sourced gases. All of the biodegraded and the interpreted Strzelecki Group-sourced gases have low CO_2 concentrations.

It is likely, based on the carbon isotopes of CO_2 in Geoscience Australia's geochemical database, that almost all of the CO_2 in gases with significant (>5%) CO_2 concentrations is of magmatic origin (Boreham et al. 2001). If this is true then some correlation between indicators of magmatic processes, such as the presence of volcanics, and CO_2 concentrations might be expected.

In the present study, the work of McPhail (2000) was used to provide insights into the age and distribution of volcanics within the Gippsland Basin. Our analysis of his data indicates that the volcanics within the Gippsland Basin have a strong asymmetric distribution in terms of thickness and perhaps age. Along the Rosedale Fault, the volcanics are thick (their thickness exceeds 100 m in the Kipper field) and they appear to be mostly Campanian in age, although younger intervals are present (Fig. 14). Further south, within the Central Deep, and along the southern margin of the basin, they are much thinner (<40 m thick) than along the Rosedale Fault. Moreover, whilst definitive age control is lacking, it appears that the older, namely Campanian, volcanics are either more poorly developed or absent.

The relationship between the distribution and the interpreted age of volcanics in the Gippsland Basin is shown in Figure 14. There is a strong spatial relationship between the presence of high

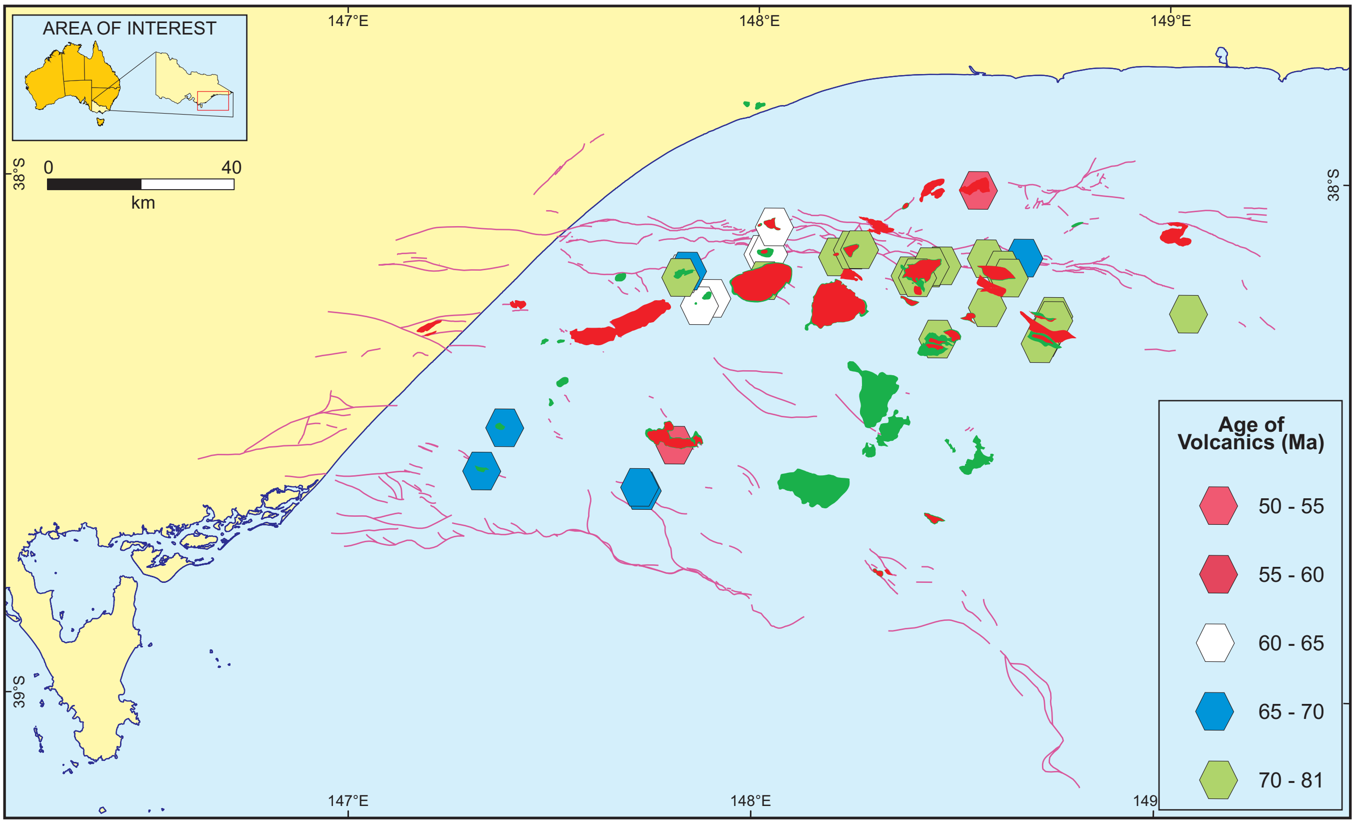

Figure 14. Relationships between distribution and the interpreted approximate age (in Ma) of volcanics in the Gippsland Basin. Based on work by McPhail (2000).

CSIRO No	Well Name	Depth (m)	Sample type	Size (mm)	Weight (g)	QGF Index	QGF Ratio	λ (nm)	Δλ (nm)	QGF	QGF-E (pc)	λ (nm)	Current & Residual Contacts	Palaeo OWC	Comments
132311	Marlin-1	1388.4	Cuttings	180-425	1.2	15.9	2.6	420	154	16	11.1	364			Multiple POWC due to
132312	Marlin-1	1391.4	Cuttings	180-425	0.8	11.3	2.4	429	159	16	3.8	397			intra-formational capillary
132314	Marlin-1	1393.9	Core	180-425	1.1	6.2	2.2	417	152	16	20.5	363		POWC	barriers with some current day
132313	Marlin-1	1414.0	Core	180-425	0.9	27.9	2.9	421	144	16	4.2	368			Residual oil zones present as
132315	Marlin-1	1454.2	Core	180-425	0.7	5.3	2.1	406	117	16	6.3	373		POWC	indicated by elevated QGF-E
132316	Marlin-1	1493.8	Core	180-425	1.1	7.4	2.3	432	169	16	6.8	380			intensities
132317	Marlin-1	1501.1	Cuttings	180-425	0.9	16.8	3.4	442	175	16	50.0	373	Residual		
132318	Marlin-1	1540.5	Core	180-425	1.2	8.7	2.3	407	128	16	15.5	370		POWC	
132319	Marlin-1	1546.9	Core	180-425	0.3	7.5	2.2	452	198	14	38.2	371			
132320	Marlin-1	1562.4	Core	180-425	0.9	7.9	2.3	439	195	16	15.4	371			
132321	Marlin-1	1567.0	Core	180-425	1.3	30.7	2.5	419	149	16	9.3	369			
132322	Marlin-1	1578.3	Core	180-425	1.1	20.9	2.2	406	140	16	3.0	368	**OWC**		
132323	Marlin-1	1601.7	Cuttings	180-425	0.7	49.3	3.5	434	157	16	158.6	373	Residual		
132324	Marlin-1	1647.4	Cuttings	180-425	1.0	19.4	2.9	439	171	16	43.2	371			Palaeo OWC is below the
														POWC	deepest sample investigated
132253	Bream-3	1902.0	Core	180-425	1.17	18.6	2.1	403	130	16	3.9	310	GOC		A gas cap is present
132254	Bream-3	1926.3	Core	180-425	0.6	13.1	2.2	409	144	16	121.1	372			
132255	Bream-3	1930.9	Core	180-425	1.05	10.8	2.7	411	143	16	444.5	383			Palaeo OWC is the same as
132256	Bream-3	1934.9	Core	180-425	1.04	8.3	2.4	403	119	16	253.9	384			the present OWC but residual
132257	Bream-3	1938.8	Core	180-425	1.18	9.2	2.5	413	136	16	263.5	374			oils are present below the
132258	Bream-3	1949.5	Core	180-425	0.95	7.4	2.2	407	132	16	218.7	370	**OWC**		present OWC as indicated
132259	Bream-3	1950.7	Core	180-425	1.26	6.8	2.2	403	139	16	111.8	374	OWC	POWC	by relatively high QGF-E
132260	Bream-3	1951.6	Core	180-425	0.96	7.0	2.3	406	135	16	177.2	371	Residual		intensities
132261	Halibut-1	2302.2	Core	180-425	1.33	17.4	3.1	432	172	16	413.2	367			
132262	Halibut-1	2310.7	Core	180-425	0.96	26.8	3.9	423	149	16	859.0	368			
132263	Halibut-1	2342.1	Core	180-425	0.75	12.6	2.6	404	140	16	690.1	369			
132264	Halibut-1	2349.1	Core	180-425	1.37	14.7	3.1	408	135	16	327.5	366			
132265	Halibut-1	2375.3	Core	180-425	0.88	10.0	2.5	430	187	16	1013.8	371			Both the residual OWC and
132266	Halibut-1	2412.5	Core	180-425	1.5	7.9	2.4	414	163	16	296.9	376	**OWC**		Palaeo OWC appear to be
132267	Halibut-1	2417.1	Core	180-425	1.41	9.2	2.3	407	139	16	271.0	383			below the deepest samples
													OWC	POWC	investigated
132268	Kingfish-2	2252.5	Core	180-425	1.5	16.7	2.8	415	146	16	64.8	375			
132269	Kingfish-2	2255.8	Core	180-425	1.25	16.3	2.9	404	116	16	335.9	368			The QGF Index profile indicated
132270	Kingfish-2	2256.7	Core	180-425	1.16	15.9	2.8	405	112	16	327.3	372			the presence of two Palaeo
132271	Kingfish-2	2259.8	Core	180-425	0.68	13.9	2.7	405	123	16	555.1	367			OWCs, possibly related to the
132272	Kingfish-2	2271.4	Core	180-425	0.68	13.6	2.7	407	115	16	689.3	368			presence of an intraformational
132273	Kingfish-2	2279.3	Core	180-425	0.68	11.9	2.5	408	117	16	845.0	370		POWC	capillary barrier around 2300 m
7501ft	Kingfish-2	2286.3	Core	180-425	0.89	11.0	2.9	405	115	16	673.5	372			Residual oils are present below
132274	Kingfish-2	2308.6	Core	180-425	0.61	16.3	2.7	402	111	16	353.8	368			the current OWC and the
132275	Kingfish-2	2316.2	Core	180-425	0.86	15.5	3.0	406	113	16	49.1	365	**OWC**		Palaeo OWC is below the
132276	Kingfish-2	2319.2	Core	180-425	0.9	17.0	3.0	408	122	16	495.6	370	Residual		deepest sample investigated
														POWC	
132238	Barracouta-2	1048.5	Core	180-425	0.46	18.6	2.1	404	116	12	972.0	367			
132239	Barracouta-2	1054.9	Core	180-425	1.13	11.4	2.4	418	145	16	684.2	366			QGF-E intensities indicate the
132240	Barracouta-2	1063.8	Core	180-425	0.81	18.9	2.3	408	129	16	241.1	367	?Residual		presence of an ?oil or a
132241	Barracouta-2	1069.8	Core	180-425	1.22	15.5	2.3	414	145	16	23.3	367	?OWC		?residual oil zone between
132242	Barracouta-2	1075.9	Core	180-425	1.56	16.5	2.4	419	158	16	19.9	367			1048.5 and 1066.8 m
132243	Barracouta-2	1082.0	Core	180-425	0.84	19.0	2.5	415	146	16	15.6	360			
132244	Barracouta-2	1088.1	Core	180-425	0.6	9.5	2.2	408	156	16	380.3	371	Residual		Multiple residual oils appear to
132245	Barracouta-2	1091.5	Core	180-425	0.83	11.2	2.9	409	134	16	347.7	370	oil		be associated with intraform-
132246	Barracouta-2	1097.3	Core	180-425	1.28	12.7	2.2	405	130	16	6.1	373			ational capillary barriers
132247	Barracouta-2	1109.5	Core	180-425	1.07	13.5	2.4	409	136	16	8.4	368			
132248	Barracouta-2	1121.7	Core	180-425	1.45	16.1	2.4	411	138	16	5.1	374			
132249	Barracouta-2	1133.9	Core	180-425	0.81	17.8	2.6	408	127	16	124.3	364	Residual		
132250	Barracouta-2	1146.0	Core	180-425	1.33	13.7	2.2	407	132	16	5.7	373			
132251	Barracouta-2	1158.2	Core	180-425	1.42	10.6	2.4	407	148	16	26.0	372	GWC		
132252	Barracouta-2	1170.4	Core	180-425	1.35	14.4	2.2	409	148	16	3.7	309			Palaeo OWC is below the
														POWC	deepest sample investigated.
132325	Snapper-1	1231	Cuttings	180-425	1.2	14.6	2.6	411	143	16	8.8	380			
132326	Snapper-1	1241	Cuttings	180-425	1.03	16.7	3.0	402	122	16	122.2	367			
132327	Snapper-1	1248	Core	63-425	0.9	9.2	2.4	403	116	16	181.8	376			
132328	Snapper-1	1250	Core	180-425	1.11	8.7	2.3	406	128	16	63.8	373			
132329	Snapper-1	1257	Core	180-425	0.82	6.6	2.4	415	153	16	448.5	370			
132330	Snapper-1	1264	Core	63-425	0.88	8.1	2.8	409	148	16	113.0	376			
132331	Snapper-1	1304	Core	180-425	1.17	6.6	2.3	407	133	16	51.1	375	Residual	POWC	Residual oil and palaeo oil
132332	Snapper-1	1317	Core	180-425	1.09	6.0	1.8	405	133	16	3.4	378	OWC		OWCs are the same
132333	Snapper-1	1341	Core	180-425	1.28	6.8	1.9	433	199	16	3.0	377			
132334	Snapper-1	1362	Core	180-425	1.26	3.3	1.4	404	164	16	5.3	372			
132335	Snapper-1	1388	Core	180-425	1.16	5.5	1.9	407	141	16	25.2	373			
132336	Snapper-1	1391	Core	180-425	1.23	5.4	1.7	402	138	16	76.6	373			
132337	Snapper-1	1399	Core	180-425	1.12	11.1	2.3	425	196	16	170.2	369	**OWC**		
132338	Snapper1	1406	Core	180-425	1.02	5.4	1.8	426	180	16	14.6	371	OWC	POWC	Current, residual and Palaeo oil
132339	Snapper-1	1419	Core	180-425	1.17	6.6	2.1	430	182	16	48.2	374			water contacts are the same
132340	Snapper-1	1449	Cuttings	180-425	0.63	14.5	2.5	403	125	16	61.5	389	OMP	OMP/ POIL	Oil migration path or Palaeo-oil

Table 2. Charge history data and location of interpreted residual oil and current and palaeo-hydrocarbon contacts.

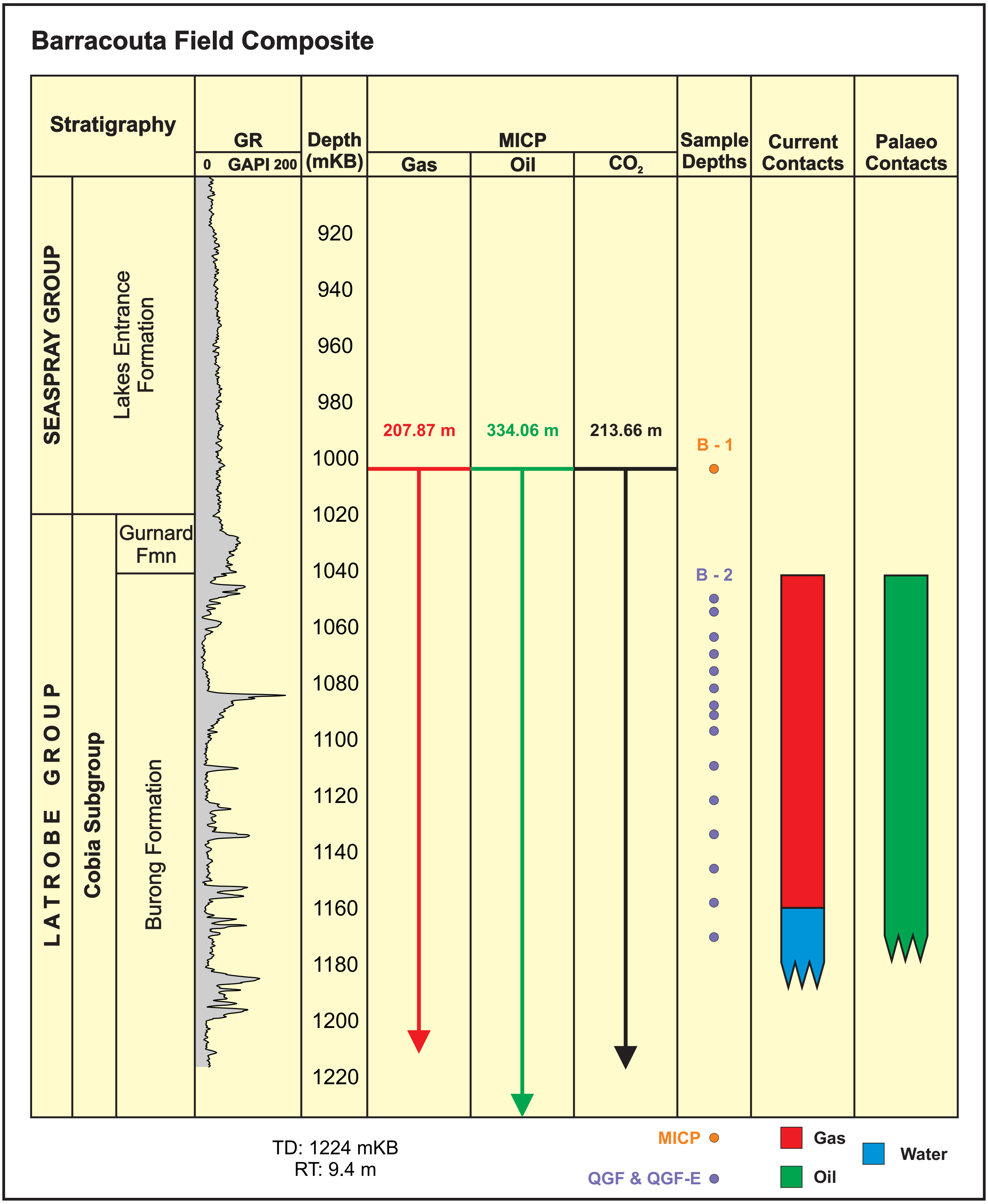

Figure 15a. Composite well summary of the Barracouta Field. The Gamma Ray (GR) Log shown here is from the Barracouta-2 well. MICP analysis was undertaken on core from the Lakes Entrance Formation in the Barracouta-1 well at a depth of 1021.95 m, which correlates with a depth of approximately 1,005 m at Barracouta-2. Fifteen reservoir samples from the Barracouta-2 well, over the interval 1,048.50–1170.43 m in the Burong Formation of the Latrobe Group, were analysed using the quantitative fluorescence techniques QGF and QGF-E.

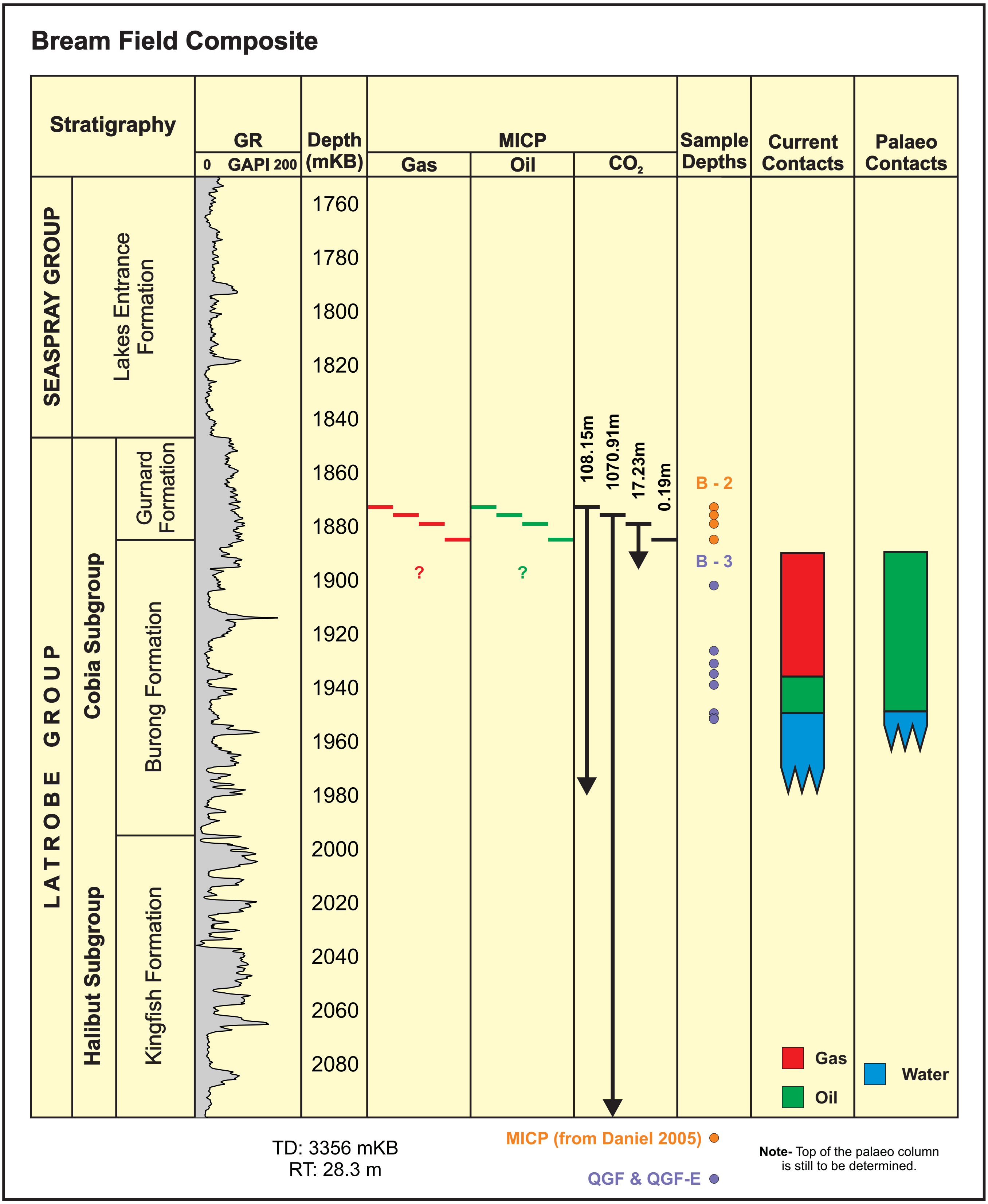

Figure 15b. Composite well summary of the Bream Field. The Gamma Ray (GR) Log shown here is from the Bream-3 well. Four samples were analysed by MICP (Daniel 2005) at depths of 1852.73 m, 1,855.93 m, 1,859.23 m and 1,864.88 m from the Bream-2 well. The first three samples listed were interpreted as Lakes Entrance Formation by Daniel (2005), however log interpretations by Wong & Bernecker (2001) suggest that all four samples are from the Gurnard Formation of the Latrobe Group. The sample depths from Bream-2 correlate with estimated depths of 1,872 m, 1,875 m, 1,879 m, and 1,885 m respectively in Bream-3. Note that only the CO_2 retention heights were published in the report. QGF and QGF-E was conducted on eight reservoir samples over the interval 1,901.95 m–1,951.63 m from the Bream-3 well within the Burong Formation of the Latrobe Group.

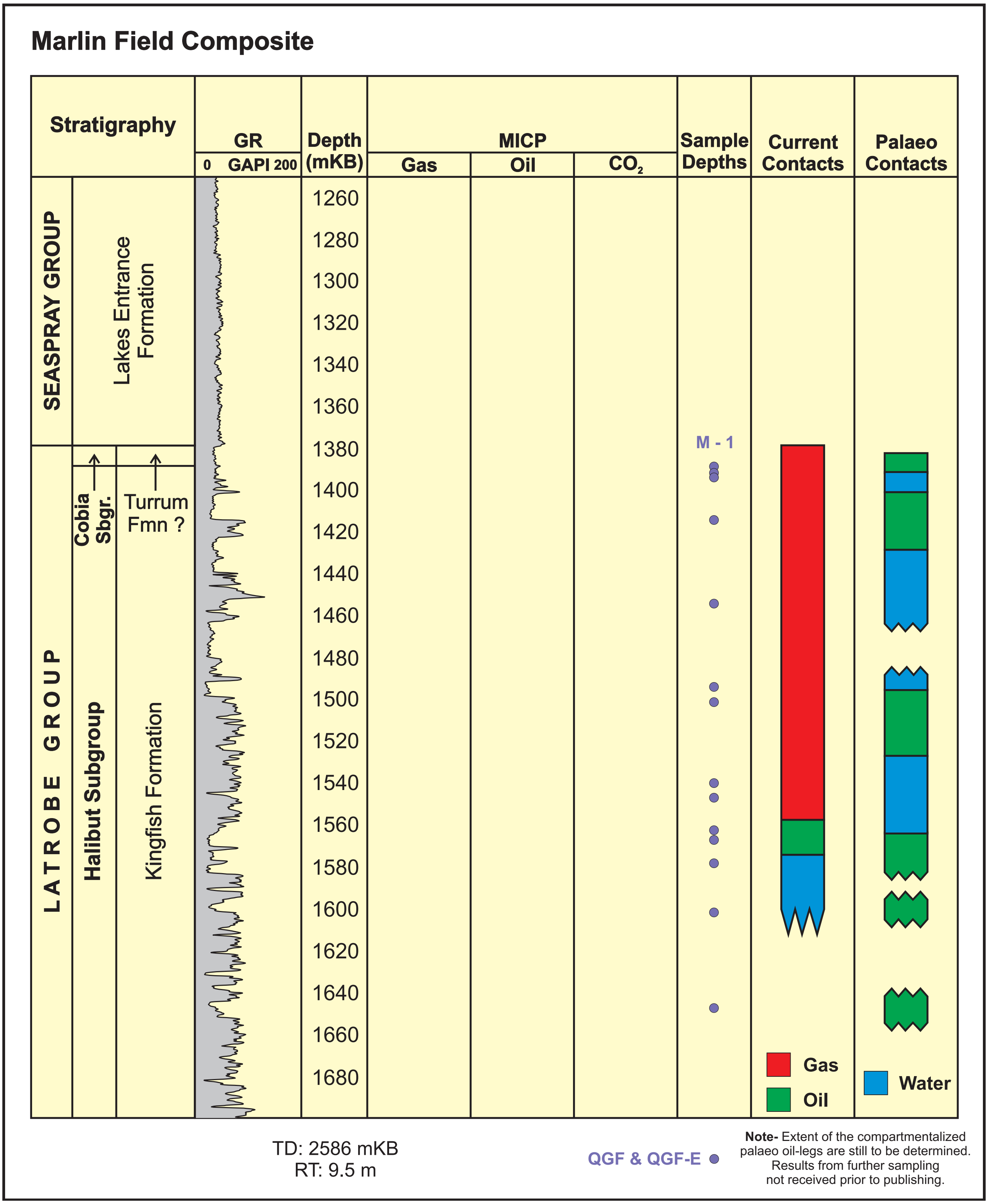

Figure 15c. Composite well summary of the Marlin Field. The Gamma Ray (GR) Log and the 14 reservoir samples (depths ranging from 1,388.36 m–1,647.44 m) are from the Marlin-1 well. No MICP Analysis has been conducted on core samples from the Marlin Field.

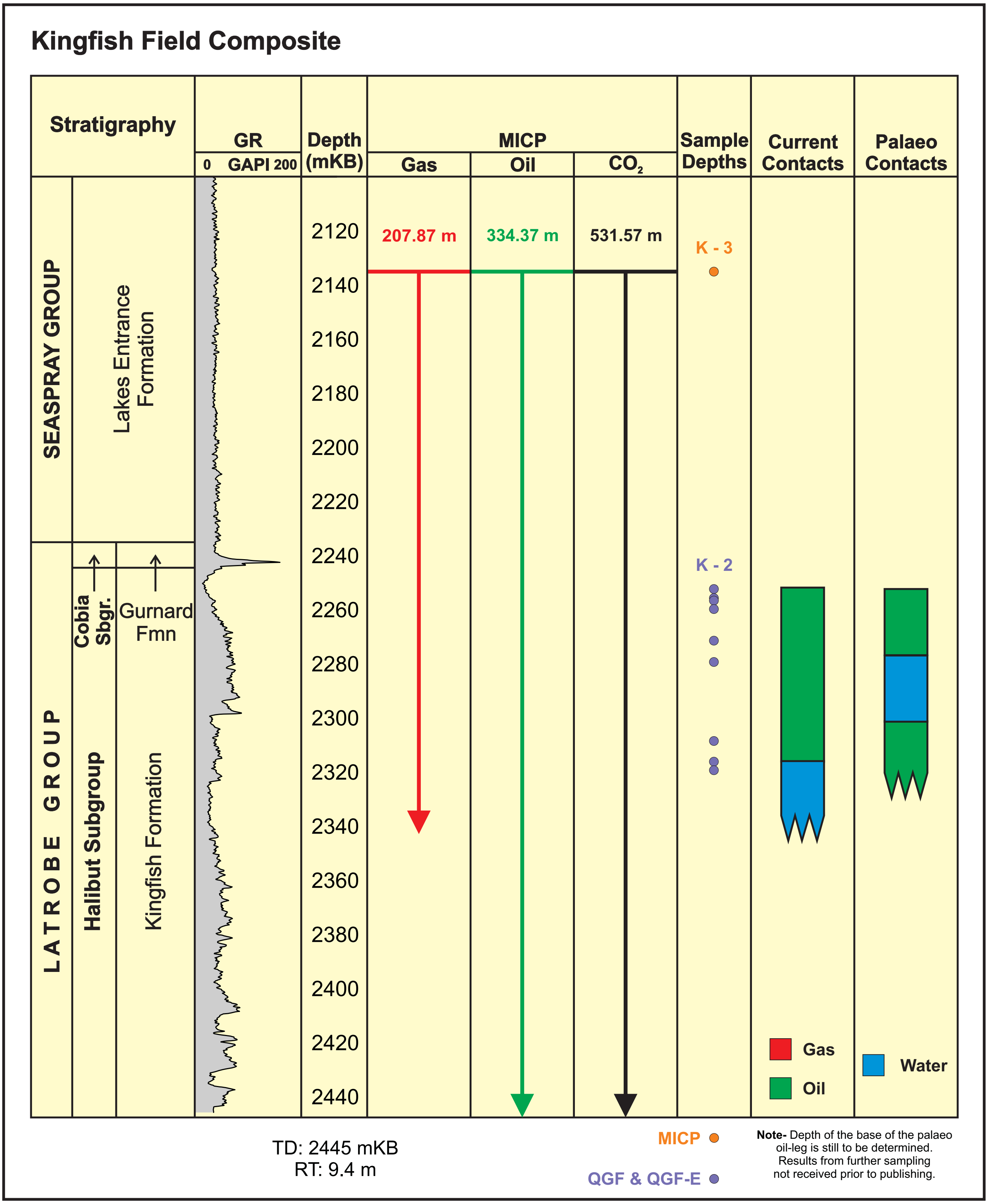

Figure 15d. Composite well summary of the Kingfish Field. The Gamma Ray (GR) Log shown here is from the Kingfish-2 well. MICP Analysis was conducted on core from the Lakes Entrance Formation in the Kingfish-3 well at a depth of 2,143.05 m, which correlates with a depth of approximately 2,135 m at Kingfish-2. Nine reservoir samples were collected from within the Kingfish Formation over a depth range 2,252.47 m–2,319.22 m in the Kingfish-2 well.

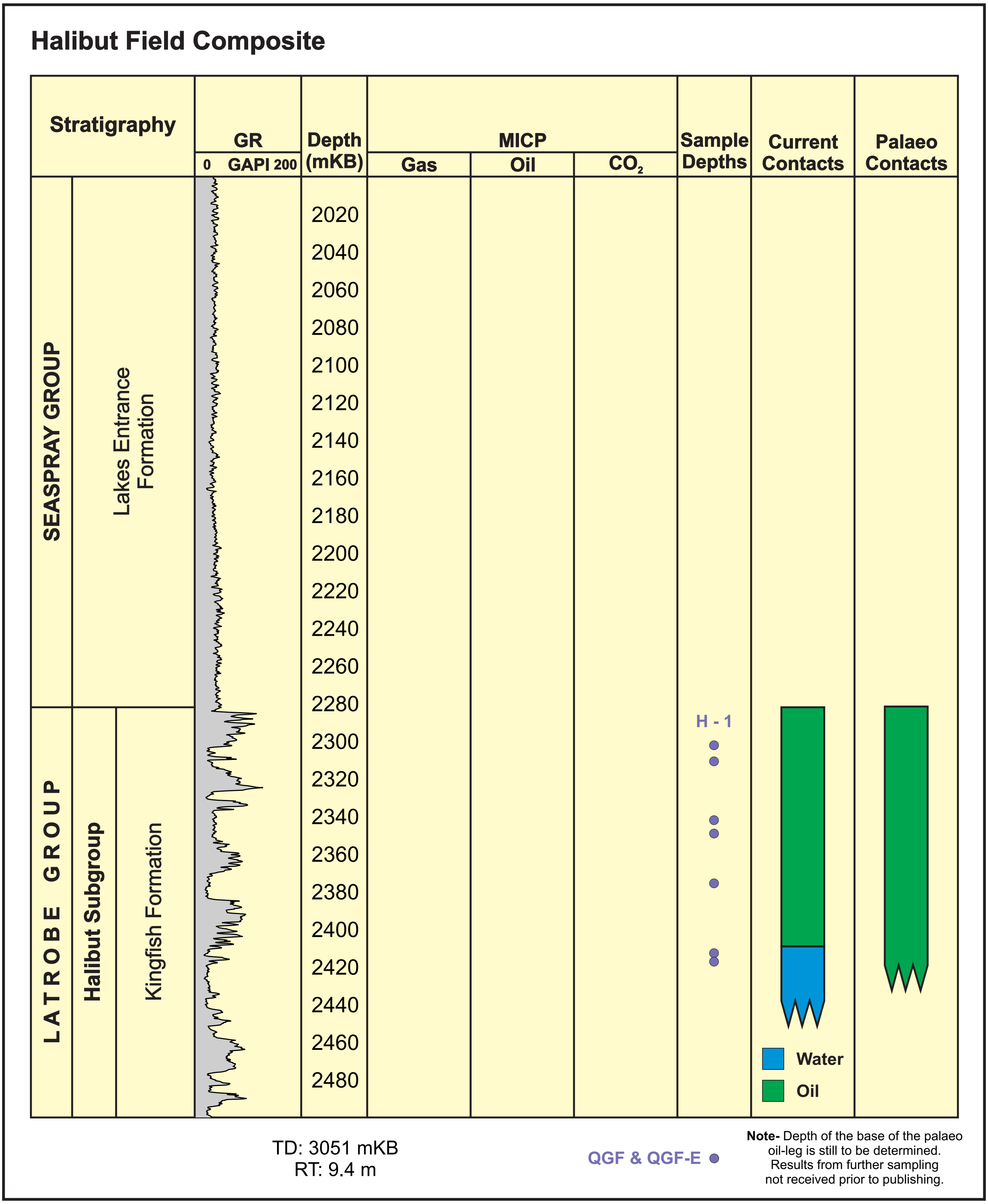

Figure 15e. Composite well summary of the Halibut Field. The Gamma Ray (GR) Log and the seven reservoir samples (depths ranging from 2,302.15 m–2,417.06 m) are from the Halibut-1 well. No MICP Analysis has been conducted on core samples from the Halibut Field.

CO_2 concentrations along the Rosedale Fault (Fig. 12) and the distribution of thick volcanics (Fig. 14; McPhail 2000). In contrast, the CO_2 concentrations in gases from the Central Deep further south are typically low. Consequently, it appears that natural CO_2 concentrations in the Gippsland Basin are greater in areas where there is a greater abundance of volcanics and it is possible, but not confirmed, that this correlation may relate more particularly to the abundance of early rift-related (i.e. Campanian), as opposed to younger, volcanics.

The data in Figures 12 and 14 show that the gases in accumulations that are not strongly associated with major fault systems, such as Barracouta and Bream, have low CO_2 contents. Consequently, it may be that the key control on natural CO_2 concentrations in the Gippsland Basin is not necessarily the presence of volcanics *per se*, but rather the proximity to major, crustal-scale fault systems which have provided the conduits for magmatic or mantle-derived CO_2 to migrate from very deep levels up into Latrobe Group reservoirs. These faults, and the wider extensional processes, have in turn controlled the distribution of the volcanics. In this scenario, the Rosedale Fault would represent the headwall of the rift system, under which crustal extension and magmatic activity have been focussed. The through-going faults provided a conduit for the magmatic-mantle derived CO_2, both in the rift phase and subsequently during postrift reactivation. The increasing CO_2 contents evident to the east in Figure 12 may also be reflecting relative proximity to the Tasman Sea spreading centre.

Further work on the origin of the natural CO_2 in the Gippsland Basin is planned by GeoScience Victoria and Geoscience Australia, especially the characterisation of the helium isotopes in the gases.

Palaeo-charge Analysis

The initial results from a palaeo-charge history study of oil and gas fields in the Gippsland Basin are provided in Table 2, with the derived interpretations presented in Figures 15a-e. The samples analysed were from the Barracouta, Bream, Marlin, Snapper, Kingfish and Halibut fields. One or more key wells were analysed from each field; the displays presented in Figures 15a-e are composite representations which summarise the respective results from five of the analysed fields.

Cuttings and core samples were collected from within the current hydrocarbon columns and water legs in these fields. The data provide information on the type of hydrocarbons produced by the kitchens, as well as trap integrity through time. By constraining hydrocarbon kitchens the data can be used to infer migration pathways through the basin.

The analytical techniques applied to the samples by CSIRO Petroleum were Quantitative Grain Fluorescence Extract (QGF-E) and Quantitative Grain Fluorescence (QGF). Both the techniques rely on the fluorescence behaviour of liquid hydrocarbons when exposed to UV light. QGF-E measures the maximum fluorescence intensity associated with a solvent that has extracted adsorbed oil from the surface of grains and is a useful technique for the recognition of both current and residual oil zones. QGF measures fluorescence from oil inclusions within grains, after removing adsorbed oil from their surface. The data can be used to detect palaeo-oil zones within reservoir intervals which are currently water-wet or contain live gas columns. Low QGF values at the top of present day oil columns can also be used to infer the existence of palaeo-gas columns. Similar approaches have been applied to the North West Shelf and have proven to be very effective at unraveling complex charge histories (O'Brien et al. 1996; Lisk et al. 1997).

In the present study, interpretation was based upon the methods of Liu and Eadington (2005). In general, the presence of palaeo-oil columns has been interpreted through reservoirs within which the QGF index was greater than 10, whereas residual oil zones were interpreted in zones where QGF-E values were greater than 100. The variation of QGF and QGF-E intensities with depth was also used to identify palaeo-oil zones.

Palaeo-charge histories

The palaeo-charge data indicate that all of the large gas fields analysed, such as Barracouta, Bream, Marlin and Snapper (Figs 15a-c) show evidence for the presence of very significant palaeo-oil charge. These palaeo-oil zones appear to range from approximately 60 m at Bream and Snapper, to over 100 m at both Barracouta and Halibut. There remains some uncertainty as to the absolute dimensions and the number of palaeo-columns identified, which is a function of inadequate sample density. However, the

TECTONIC ELEMENT	LAKES ENTRANCE FORMATION THICKNESS (m)		LITHOLOGY	LIKELY CONTAINMENT		
	RANGE	AVERAGE		GAS (m)	CO_2 (m)	COMMENT
Offshore Northern Platform	<60?	<60?	Marl?	<30E	<20E	Poor?
Offshore Northern Terrace	39–205	101	Calcareous claystone and marl, glauconitic and fossiliferous	<20E–100E	<<100E	Poor - Moderate?
Offshore Central Deep	65–430	232	Calcareous mudstone, indurated	185M–437M	250M–683M	Excellent
Offshore Southern Terrace	57–388	178	Calcareous mudstone, indurated	<50E	<100E	Moderate?
Offshore Southern Platform	70–123	88	Glauconitic mudstone, calcareous, fossiliferous, friable	5M–30M	13M–29M	Poor
Onshore Northern Platform	23–97	57	Fossiliferous bioturbated mudstone, glauconitic, micaceous, friable	6M	18M	Poor
Onshore Northern Terrace, Lake Wellington Depression	31–176	109	Calcareous claystone and marl, friable to indurated	316–377M	285–306M	Excellent
Onshore Seaspray Depression	53–140	98	Fossiliferous silty marl, slightly glauconitic, friable to indurated	46M	83M	Poor - Moderate
Onshore Southern Terrace	56–80	64	Fossiliferous marl, soft and friable	3M	6M	Poor

Table 3. Summary table: Gas and CO_2 retention capacity across tectonic provinces of the Gippsland Basin (E = Estimated, M = Measured).

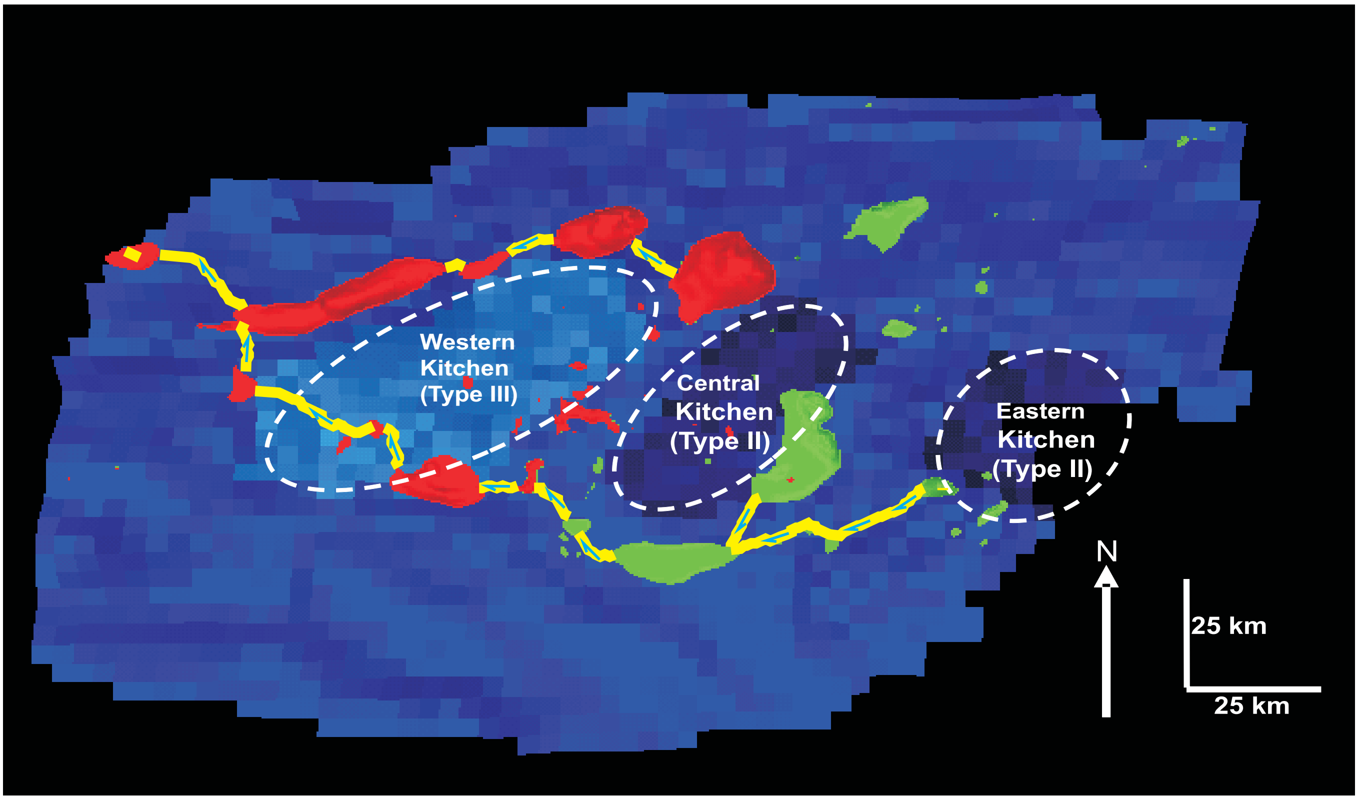

Figure 16. Petromod 10 simulation plan view showing the predicted accumulations, top-lower Paleocene horizon and source kitchens used in the model. Orange arrow indicates north.

data unequivocally support the contention that the first significant hydrocarbon charge into all of these fields was oil, not gas. Prior to gas charge into these fields, there was at least one oil kitchen which was actively expelling large volumes of oil; subsequently, this early oil charge was displaced by a later gas charge. The thin oil rims which are present at the base of the gas legs in these traps at the present day are probably the legacy of this early oil charge.

The QGF and QGF-E analysis of the large oil fields Halibut and Kingfish, has revealed that the charge history of these traps is relatively simple (Figs 15d and 15e). There is no evidence that either of the wells ever had a palaeo-gas cap. Rather, it appears that both fields were filled with an oil charge that has remained in place until the present day.

The data from Halibut and Kingfish are important from a number of viewpoints. Firstly, the data show that the first charge into six of the major fields within the Gippsland Basin was oil and not gas. In the case of the northern gas fields, namely Barracouta, Bream, Marlin and Snapper, subsequent gas charging displaced most, but not all of the oil. Secondly, our interpretation that the first charge into all of these traps was oil, and that in four traps gas subsequently displaced that oil, provides an important constraint on the basin modelling component of this study. There are one or more mature, oil-prone kitchens present within which net gas expulsion was low through their history, or, alternatively, that deeper sealing facies were important in shielding some of the oil-charged traps from the later gas charge. Finally, the combination of the oil-prone charge history for Halibut and Kingfish and the very high top-seal capacities described earlier suggest that the reason that the central oil fields are in fact oil-filled and not gas-charged is simply due to the inherent nature of the charge into the traps, rather than some complex capillary sieving process in which gas is continuously bled out of the trap through leaky top-sealing units.

Migration modelling

In order to better understand the first-order charge and migration history within the basin, 3D migration modelling was undertaken using PetroMod 10. A simple model was constructed based upon GeoScience Victoria's available depth-corrected regional surfaces; sea floor, top-Lakes Entrance Formation, top-Latrobe Group and top-Lower Paleocene. Due to data limitations, the top-Lower Paleocene surface was used as a proxy for the top of the source interval in the basin. The Lakes Entrance Formation was assigned excellent seal properties over the region of interest, partly based on the MICP results and the charge history data. Three kitchens were defined, which were centred upon the depressions within the top-Lower Paleocene surface (Fig. 16), each with somewhat different (PetroMod's standard Laurence Livermore) source rock parameters, namely west (Type III), central (Type II) and east (Type II). The Latrobe Group above the top-Lower Paleocene horizon was assumed to have very good reservoir quality. Thermal conditions were adjusted so that the designated kitchens were heated sufficiently to generate hydrocarbons representative of their kerogen type. In the model any hydrocarbons expelled from the source rocks moved under simple buoyancy up to the regional seal and then migrated laterally. Migration and sealing associated with faults was not considered in the model.

Whilst acknowledging the very simple nature of the model, one feature—namely the linkage of the major traps in the basin along a fill-spill chain and the potential for long distance migration—stands out (Fig 17). The linked nature of the traps is consistent with the results of previous work on migration pathways (Gibson-Poole et al. 2008) and allows the oil in Kingfish and Halibut/Cobia/Fortescue to be sourced from the eastern kitchen or the central kitchen or a combination of both. Once Kingfish was filled to spill,

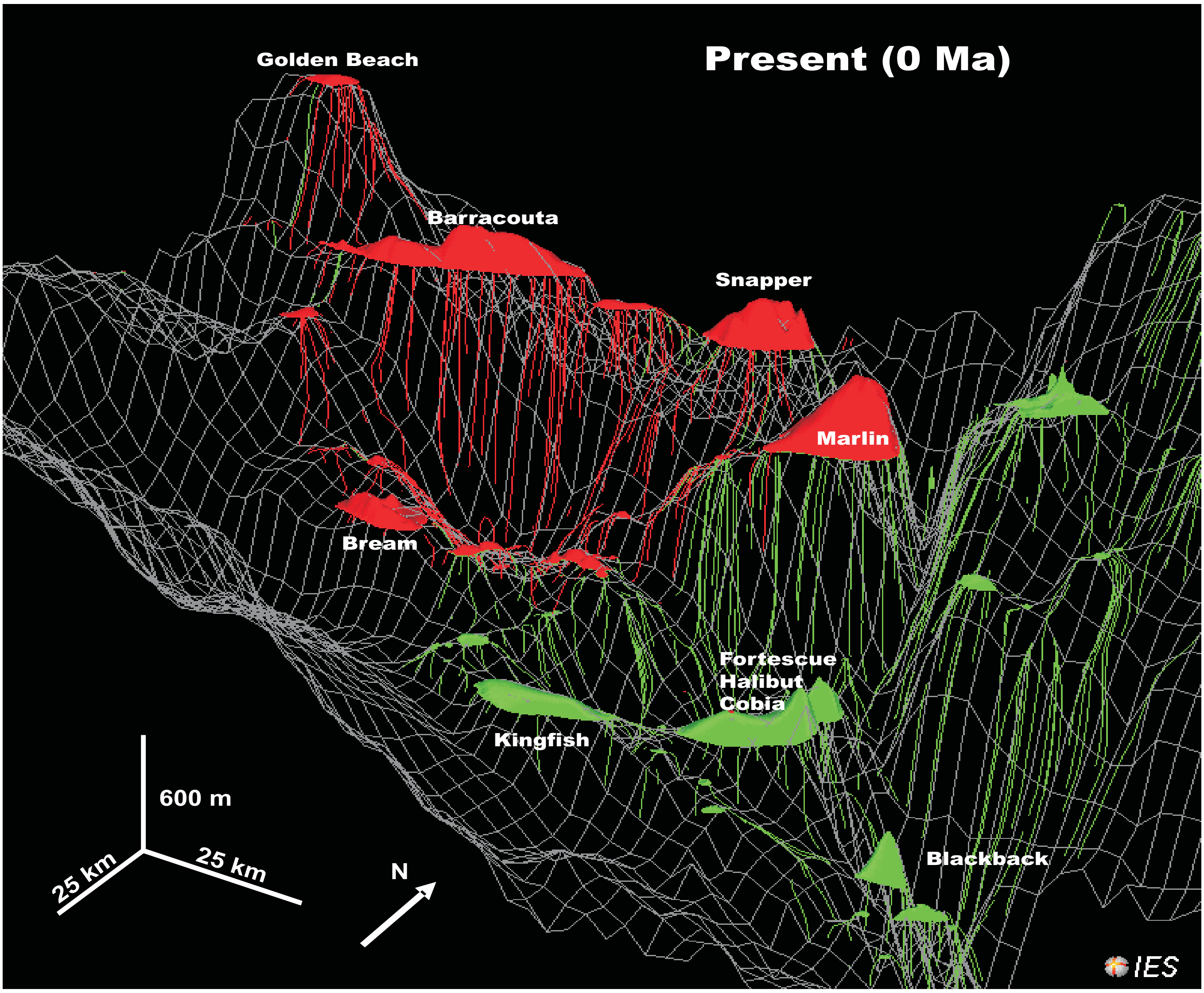

Figure 17. Petromod output showing predicted present day accumulations at Top Latrobe horizon, Gippsland Basin. Note the potential for fill-spill between Halibut/Fortescue/Cobia, Kingfish, Bream and Barracouta fields and Marlin, Snapper and Barracouta fields. Orange arrow indicates north.

the potential existed for oil to spill to Bream and then ultimately to Barracouta. Considering the evidence for early oil charge into the Barracouta, Bream and Marlin fields, the oil charge may be as a result of relatively local sourcing or perhaps more likely, from relatively long distance migration up the fill-spill chain, with the oil originating in lower coastal plain source rocks in the central and eastern kitchens. In the current migration model, both the central and eastern oil kitchens need to be oil-prone to simulate the oil accumulation into the Halibut/Cobia/Fortescue and Kingfish fields. The modelling suggests that the early oil charge detected in the Marlin and Snapper fields has migrated from the central kitchen.

Another possibility is that the top-Latrobe charge history may have been influenced by the seal integrity of intra-Latrobe seals such as the Kate Shale. The relatively thick Kate Shale in the vicinity of the Kingfish and Halibut/Cobia/Fortescue fields could have shielded these fields from hydrocarbons expelled from the central kitchen. In this scenario, the central oil-prone kitchen could actually expel significant gas and still allow the fields to be charged with oil from the easternmost kitchen.

Understanding the fill-spill history in the Gippsland Basin is important for understanding the regional petroleum system and also for validating potential migration pathways for CO_2 injection and sequestration. Further work testing migration pathways (e.g. path sensitive biomarkers) and developing more sophisticated basin models is currently underway.

Integration and discussion

The data acquired in this study have allowed the development of an improved understanding of regional top seal capacity, charge history and migration processes in the Gippsland Basin.

Mapping of the Lakes Entrance Formation's sedimentary facies, thickness and geometry, and the acquisition of new MICP data, have constrained the quantitative capacity of the principal regional top seal in the basin (Tables 1 & 3).

Within the Central Deep, this formation is typically greater than 200 m thick. MICP data reveal that the Lakes Entrance Formation can support CO_2 column heights of between 250 m (Barracouta-1) and 641 m (Fortescue-3), whereas supportable gas columns vary between 207 m and 437 m. In terms of both the thickness and capacity of the regional top-seal, containment characteristics for both hydrocarbons and CO_2 within the Central Deep appear to be excellent.

The thickness of the regional seal decreases rapidly towards the onshore areas and also north and south of the Rosedale and Darriman fault systems respectively. Whilst no MICP data are currently available for the Northern Terrace or Platform offshore, data for the Groper-1 and -2 wells on the Southern Platform suggest that the top-seal capacity through this area is poor, especially for gas and CO_2. This region is unlikely to provide a viable geological setting for either the accumulation of substantial gas or CO_2 columns and based upon our current understanding, gas or CO_2 which migrates as a discrete phase up onto and across the Southern Platform could potentially eventually escape containment, most likely as the top-seal thins and becomes more permeable around, or southwest of, an equivalent geological setting to Groper-2.

The thickness of the Lakes Entrance Formation decreases rapidly towards the present day coastline and thicknesses of less than 100 m are common. At Golden Beach West-1, located onshore in the Seaspray Depression very near the coast, a column height of 87 m of CO_2 and only 22 m of gas can be supported, significantly less than in the nearby Barracouta field to the southeast. Moreover, the adjacent Golden Beach-1A well, drilled just offshore, had a top-Latrobe closure that exceeded 40 m in height, but contained only a 19 m gas column and thus the trap is significantly underfilled. The similarity between the 22 m retention capacity of the seal (at Golden Beach West-1) and the 19 m 'live' gas column in the trap only several kilometres away at Golden Beach-1A, suggests that the hydrocarbons within the Golden Beach-1A trap may well be continuously bleeding through the top-seal, that is, the top-seal is leaking by capillary failure at the present day. Scattered high amplitude zones, visible on the seismic data above Golden Beach-1A are probably due to gas which is leaking through the seal above the trap. The interpretation that the top-seal at Golden Beach-1A is failing supports the contention that this region is located near to the effective edge of the top-seal for gas and CO_2.

Onshore, in the Lake Wellington Depression, the Lakes Entrance Formation is relatively thick (>100 m) and the sealing capacity appears to be good. In the Seaspray Depression further to the southwest, the Lakes Entrance Formation is thinner and sealing capacity is reduced but still appears to be adequate. Across the rest of the onshore Gippsland Basin, however, the Lakes Entrance Formation is thin (typically <100 m) and the MICP data indicate that the regional seal has minimal capacity to retain significant column heights of either gas or CO_2.

The lack of gas accumulations at the top-Latrobe level onshore, when combined with the available MICP data and trends in the data such as the positive relationship between thickness (and depth) of the Lakes Entrance Formation and its MICP capacity, suggest that containment risks onshore at the base of regional seal are probably considerable outside of the Lake Wellington and Seaspray depressions, especially in areas where the Lakes Entrance formation is thinner than 100 m.

Injection into Strzelecki Group sandstones onshore may not be practical, given that the available geochemical data indicate that these sandstones are probably poorly connected and the reservoir data show poor permeability. Based upon our current information, CO_2 injection onshore appears viable within the Lake Wellington and Seaspray depressions, with injection taking place deep within the Latrobe Group, preferably below intra-Latrobe sealing facies. Significant containment issues appear to exist for the retention of even moderate gas or CO_2 column heights across the rest of the onshore Gippsland Basin.

The present day hydrocarbon inventory in the Central Deep is dominated by geochemically wet, Latrobe Group-sourced gases which typically have $C_1/(C_2+C_3)$ ratios of less than 15. In the western part of the basin, the influence of the freshwater wedge has resulted in biodegradation of gases at depths of less than 1,500 m, which has made these gases drier. Gas fields on the flanking Northern Terrace such as Patricia-Baleen and Sole may have been charged quite locally, from mature Strzelecki Group source rocks sub-cropping the traps, rather than from the Latrobe Group in the Central Deep. This is important, as a local source might imply that the Rosedale Fault is an effective seal to gas charge from the Central Deep, at least at the top-Latrobe level. There are no gas accumulations reservoired at the top-Latrobe level present onshore; all of the onshore fields occur within intra-Strzelecki Group sandstones and none rely on the Lakes Entrance Formation for the top-seal.

In terms of natural CO_2 within the Gippsland Basin, almost all of the anomalously CO_2-rich gases are restricted to a narrow zone immediately along and south of the Rosedale Fault. It may be that the Rosedale Fault, being the headwall of a large Late Cretaceous extensional system, has provided the conduits for the migration of magmatic-mantle derived CO_2 up into the Latrobe Group reservoirs. This migration could have taken place during either the rift phase or during postrift reactivation events, perhaps when these faults became critically stressed. Fields located on anticlinal axes away from large faults, such as Bream and Barracouta, typically have low CO_2 contents; this lack of CO_2 could be due to the absence of major crustal-scale conduits. If this interpretation is correct, then the Rosedale Fault is behaving in a similar manner to that ascribed to the (similar-aged) Mussel-Tartwaup Fault in the Otway Basin (O'Brien & Thomas 2007), along which the La Bella, Geographe and Thylacine fields all show elevated CO_2 contents of magmatic CO_2.

The apparent localisation of high CO_2 concentrations in essentially the northern gas fields means that it is likely that none of the reservoirs located significantly south of the Rosedale Fault were ever exposed to pore fluids with naturally elevated CO_2. This may potentially be important should injection of CO_2 into these reservoirs take place. Similarly, none of the infrastructure in the central part of the basin is likely to have been specifically engineered for higher-CO_2 gases, unlike fields located along the Rosedale Fault.

The integration of the palaeo-charge history work on the four gas fields (Barracouta, Bream, Marlin and Snapper) and two oil fields (Kingfish and Halibut) with the MICP results allows additional important inferences to be drawn regarding seal capacity. The charge history analysis indicates that the first hydrocarbon charge into all of these traps, including the four giant gas fields, was a significant oil charge; some initial columns were many tens of metres thick. The gas which now dominates the hydrocarbon inventory in these traps entered Barracouta, Bream, Marlin and Snapper subsequent to the oil charge and flushed almost the entire initial oil inventory from the traps, spilling it further up the respective fill-spill chains. The large oil fields within the Central Deep have never had a gas cap, an observation entirely consistent with the retention capacities obtained from the Lakes Entrance Formation over these traps.

The basin modelling has revealed that two principal fill-spill chains are present, a southerly chain comprising Kingfish-Cobia-Halibut-Fortescue-Blackback-Bream-Barracouta-Golden Beach and a northerly chain comprising Marlin-Snapper-Barracouta. Overall, our migration pathways appear similar to those of Gibson-Poole et al. (2008). The basin modelling has revealed the strong degree of connectivity between traps along these respective fill-spill chains. The model allows for many of the palaeo-oil columns detected along the southern fill-spill chain to have

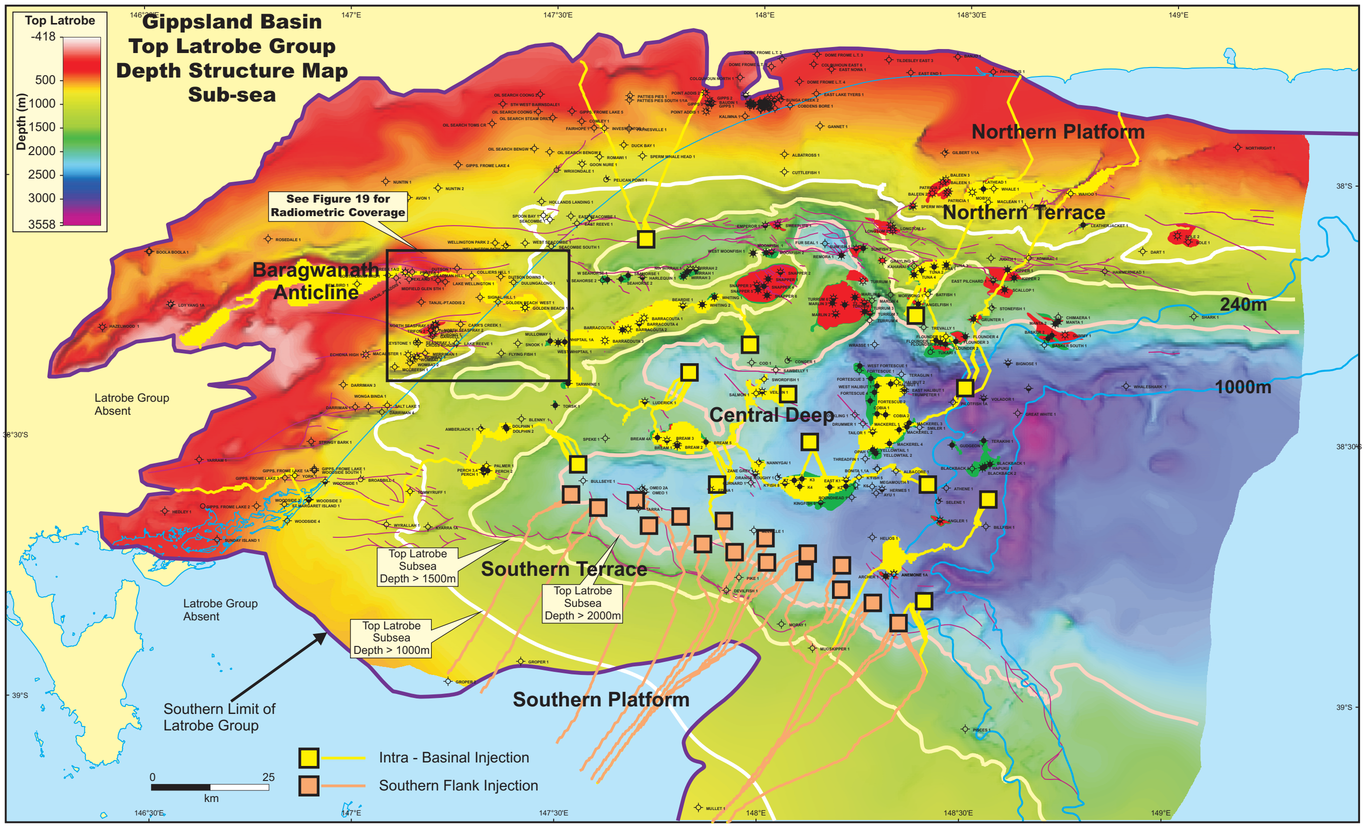

Figure 18. Top Latrobe subsea depth map, Gippsland Basin, showing buoyancy-driven migration vectors for CO_2 injected at assorted hypothetical locations within the Central Deep (yellow) and along the southern flank of the Central Deep (peach). Injected CO_2 within the Central Deep proper (yellow) will migrate into Top Latrobe traps and fill and spill between traps due to highly focused migration pathways. Injected CO_2 in southern Central Deep will migrate towards the Darriman Fault and potentially across Southern Platform.

been originally expelled from an oil source kitchen located well to the east, potentially even as far as Blackback. This oil would then have migrated up the fill-spill chain, filling the traps from east to west. Later maturation and expulsion of gas from more westerly kitchens then flushed the early oil charge completely, or almost completely, out of the traps. In contrast, the early charge into Marlin and Snapper appears to have been generated within the central kitchen and then been progressively spilled towards Barracouta. The observations from the seal capacity work and the very long distance migration pathways (50 to >100 km) evident in the basin modelling data have substantial implications for potential CCS injection in the basin. CO_2 injected into the Central Deep will be geologically contained at the level of the regional top-seal and even very large column heights of CO_2, much greater than the vertical closures of any of the traps present in the basin, would not result in the break-through of CO_2 through the Lakes Entrance Formation seal.

Injection of CO_2 in the Gippsland Basin might be best undertaken at locations which will allow the mimicking of the natural hydrocarbon migration processes. In order to simulate buoyancy-driven CO_2 migration, GeoScience Victoria's depth-converted, top-Latrobe surface was imported into the Geofocus 'Pathways 6.0' migration modelling software package and hypothetical 'injection points' placed at various parts of the basin. The results of this exercise are summarised on Figure 18. On this figure, injection sites and the migration vectors in the Central Deep and northern flanks of the basin are coloured in yellow, whereas sites and migration vectors located in the southern parts of the basin are coloured orange.

Given adequate volumes, CO_2 injected to the east of Cobia-Halibut-Fortescue and west of Blackback would progressively migrate towards and then fill Cobia-Halibut-Fortescue, spill to Kingfish, fill Kingfish and spill to Bream (shown in yellow on Figure 18). Barracouta lies towards the end of this very long, southern fill-spill chain. Providing that any injected CO_2 does not adversely affect the above mentioned traps and hydrocarbon resources and infrastructure during their producing lifetimes, then such a scenario would ensure that the injected CO_2 remains contained within the Central Deep for geological timeframes. Importantly, however, none of the geological systems in this part of the basin appear to have ever been subjected to high CO_2 inventories, the petroleum infrastructure in the Halibut-Kingfish-Bream region of the Central Deep has been engineered in accord with the low CO_2 gases that currently dominate that area. This contrasts with the accumulations along the Rosedale Fault, which contain appreciable natural CO_2. Consequently, the large-scale introduction of CO_2 could potentially have a greater impact on infrastructure in the southern, as opposed to northern, Central Deep.

Injection of CO_2 within parts of the Central Deep will lead to the migration of CO_2 across the Northern Terrace and Northern Platform (Fig. 18), if the volumes are large enough and the Rosedale and Lake Wellington faults do not seal. Uncertainties exist, however, about containment on the Northern Terrace and Platform offshore due to a lack of data. Whilst no direct MICP measurements have been undertaken on samples of the Lakes Entrance Formation from the Northern Platform, other indirect indicators of seal capacity in that region do exist. For example, several apparent gas chimneys are present within 5–10 km north-east of the Lake Wellington Fault, up-dip from the Sole gas field (Fig. 8a). These chimneys may potentially relate to gas spilling from the reservoir at the Sole field and define the edge of the effective seal for gas in this part of the basin. Similarly, data from the VIC/P41 Airborne Laser

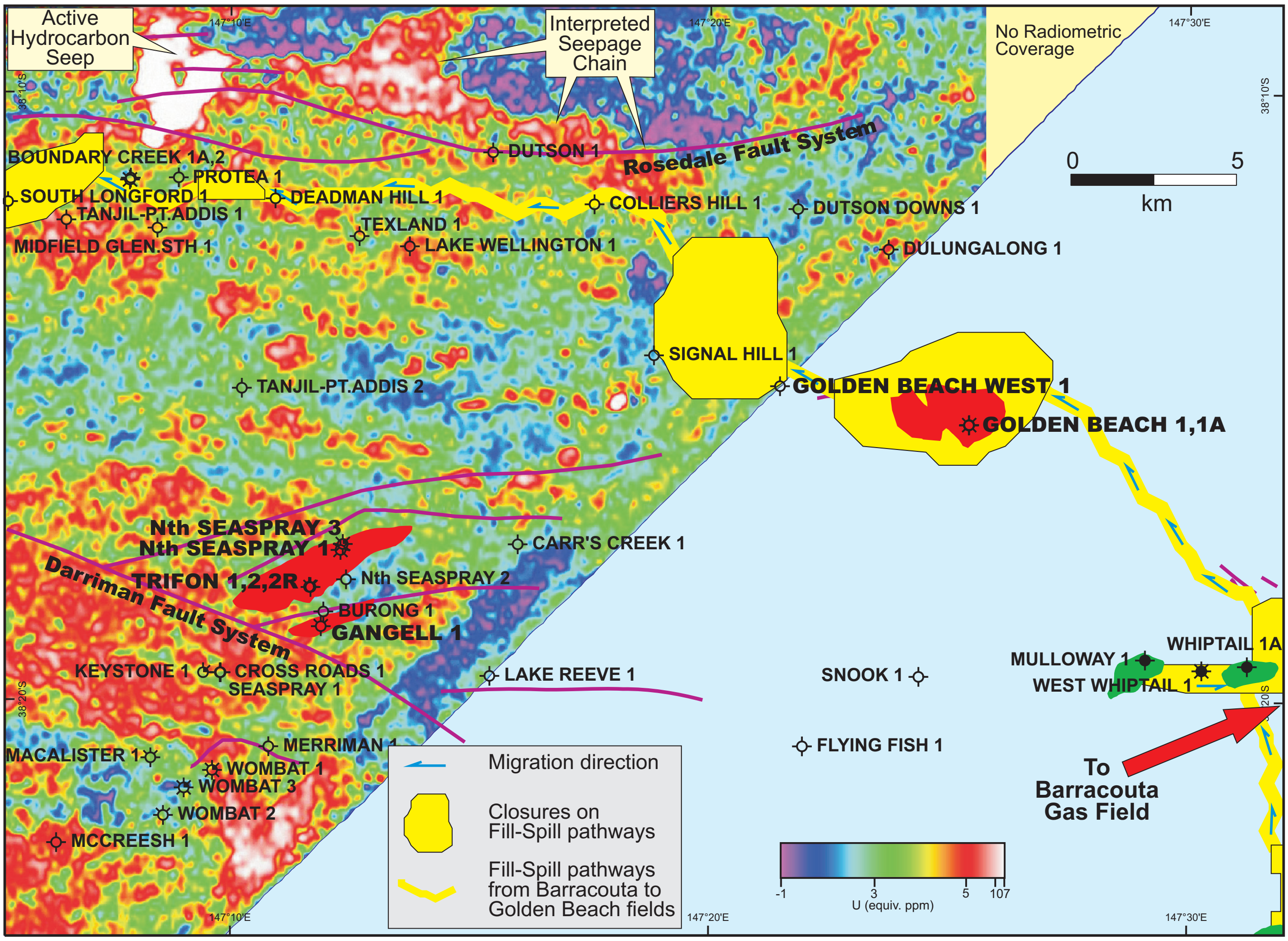

Figure 19. Radiometrics data (uranium) for the onshore Gippsland Basin, along with modelled fill-spill chain from Barracouta. Known and interpreted hydrocarbon seeps correspond to a broadly east-southeast trending zone exhibiting strongly anomalous radiometrics response. Zone of active to significant seepage appears to relate very closely to location of Rosedale Fault; other anomalies may also relate to seepage although this has not yet been confirmed.

Fluorosensor (ALF) survey undertaken by Eagle Bay Resources in 2001 confirm the presence of significant hydrocarbon seepage—based both upon ALF and video data—at the sea surface near the Northright-1 well location.

Overall, the sealing potential of the Lakes Entrance Formation across the Northern Terrace appears to be adequate. Gas columns are contained in fields such as Patricia-Baleen and Sole, reaching thicknesses of 50 m and 75 m respectively, apparently without attendant top-seal failure. These observations suggest that the regional seal across the Northern Terrace can withhold gas columns of at least 50–75 m. However, clear indicators of seal failure on the Northern Terrace are evidenced by the prominent gas chimneys which are located near Flathead-1 and Wahoo-1. Indeed, the chimney near Flathead-1 is currently active and hydrocarbon anomalies (detected during a water column geochemical sniffer survey) are present in the water column directly above the chimney; significant sea floor phase changes also occur associated with this seeping gas (O'Brien, unpublished data). Consequently, the seal capacity across the Northern Terrace appears to be adequate for the retention of modest gas columns, though apparent critical leak points are also present in discrete locations. A much better understanding of this region is required, and will be obtained via a combination of MICP analyses, seismic mapping of leakage and seepage and remote sensing approaches.

Injection of CO_2 on the southern side of the graben south of Kingfish would facilitate migration to the southwest, toward the Darriman Fault (shown in orange on Fig. 18). In this scenario, the fault seal integrity of the Darriman Fault becomes critically important. If this fault does not seal, any CO_2 injected into the southern part of the Central Deep will migrate across the Southern Terrace to the Foster Fault and then onto the Southern Platform. The poor retention capacity evident in the MICP data from Groper-1 and particularly Groper-2 indicate that significant CO_2 columns could not be contained at the base of the Lakes Entrance Formation across much of the Southern Platform. Unlike within the Central Deep, the injection of CO_2 on, or the migration of CO_2 as a separate phase across the Southern Platform, have significant potential attendant uncertainties associated with containment and the development of even minor CO_2 column heights could result in top-seal failure.

The southern and northern fill-spill chains all converge at the Barracouta gas field. To the west, the chain passes through Golden Beach and then up towards the Baragwanath Anticline (Fig. 18). The Lakes Entrance Formation top-seal is absent over the Baragwanath Anticline and top-seal containment has certainly been lost east of the anticline, based upon our MICP capacity and facies work. Our understanding of the fill-spill processes and containment issues allows us to predict where hydrocarbon seeps associated with the offshore fill-spill chains will be located.

An active hydrocarbon seep, located approximately 10 km southeast of Sale, has been confirmed by Lakes Oil (Mulready 2002). The location of this seep is shown in Figure 19, which also shows the fill-spill chain at top-Latrobe level. Also shown on Figure 19 is an image derived from Geoscience Australia's (1999) airborne radiometrics survey data (uranium channel). The uranium counts peak in and around the seep, which is located 1–2.5 km north or northeast of the mapped fill-spill chain (Figure 19). It appears that elevated uranium concentrations, a common feature of hydrocarbon seeps, are causing the anomaly. Moreover, it appears that the trend of enrichment extends in a broad east-southeast direction away from the confirmed seep, where it merges with the fill-spill chain near Signal Hill-1. Whether this seep, or seepage chain, is principally the result of seepage up the Rosedale Fault or seepage along the fill-spill chain, is currently uncertain. Nevertheless, the identification of seepage onshore and the ability to map seeps and seepage indicators using radiometrics data is encouraging and will potentially allow GeoScience Victoria to discriminate between zones of higher and lower seal integrity. In particular, the integration of remote sensing data with the predictions derived from migration modelling and work on top-seal capacity allows a much greater understanding of natural petroleum and anthropogenic fluid migration systems. GeoScience Victoria is currently pursuing these approaches as part of its wider assessment of the Gippsland Basin and other regions.

Conclusions

The majority of the hydrocarbon inventory in the Gippsland Basin is reservoired at the base of the regional seal. This indicates that the intra-Latrobe seals are only locally effective and that regionally, the majority of hydrocarbons (and also injected CO_2) within the Latrobe Group will eventually find their way to the base, or near the base, of the Lakes Entrance Formation. From both the hydrocarbon and CCS viewpoints, an understanding of the viability of regional seal is vital.

An investigation of the thickness, distribution and MICP capacity of the Lakes Entrance Formation in the Gippsland Basin has revealed that the Central Deep has excellent containment characteristics at the base top-seal level, with the capacity to withhold hundreds of metres of gas or CO_2. The flanking Northern and Southern terraces appear to have lesser, but still adequate containment whereas the Southern Platform has very poor to inadequate sealing characteristics. Onshore, the Lake Wellington and Seaspray depressions appear to offer adequate containment at the base of regional seal. However, across the rest of the onshore, the top-seal is thin and has poor MICP characteristics which, combined with the absence of gas accumulations at the top-Latrobe level, implies that containment by the Lakes Entrance Formation is inadequate.

New palaeo-charge history data indicate that the initial hydrocarbon charge into many of the existing giant oil (Kingfish, Halibut) and gas (Bream, Barracouta, Snapper, Marlin) accumulations was oil. In the Neogene, the Halibut, Kingfish, Bream and Barracouta fields all comprised part of a very large, highly interconnected fill-spill chain and contained oil columns which were often tens of metres thick. Subsequent progradation of the carbonates of the Seaspray Group increased the maturation in the gas-prone, upper coastal plain source rock kitchen south of Barracouta; gas migration from this western kitchen caused many of these pre-existing oil columns to be partially to completely displaced by gas.

Our results suggest that the Central Deep represents an ideal setting for large-scale CO_2 injection. Large volumes of CO_2 injected either east or west of Halibut should, because of the connectedness of the southern fill-spill chain, eventually migrate into Halibut and then progressively fill and spill through Kingfish, Bream and Barracouta. The northern fill-spill chain, associated with Marlin, Snapper and Barracouta, is analogous. The quality of the Latrobe Group sandstones combined with the very high seal capacities of the Lakes Entrance Formation, indicate that the CO_2 storage capacity of the Central Deep is very large. The Lakes Entrance Formation across most, if not all, of the platforms north and south of the Lake Wellington and Foster faults appears to have poor to no containment potential. Consequently, migration and accumulation of significant columns of injected CO_2 across these regions should be avoided.

In conclusion, the pressing need to implement large-scale CO_2 storage in southeastern Australia means that developing an improved understanding of the CCS potential of the Gippsland Basin is essential. GeoScience Victoria is currently embarking upon an ambitious research plan to characterise the potential of the Gippsland Basin for CCS, which will involve building a detailed understanding of the 3D architecture of the basin, further characterising its containment potential, assessing injectivity-capacity issues and developing full 3D fluid flow models of the petroleum systems.

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