BUREAU OF MINERAL RESOURCES, GEOLOGY AND GEOPHYSICS, AUSTRALIA.

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SOUTHEAST GIPPSLAND BASIN HYDROCARBON PROSPECTIVITY PACKAGE.

BY

A.E. Stephenson, T.U Maung, J.R. Conolly,
S. Miyazaki, S.J. Cadman, J.B. Willcox, J.B. Colwell,
V. Vuckovic, E. Nicholas, P.E. Williamson, &
H.M.J. Stagg.

Bureau of Mineral Resources, Australia.

In collaboration with Maher Megallaa.

Petroleum Resources Branch, Department of
Manufacturing and Industry Development, Victoria.

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Contributions from the Victorian Department of Manufacturing and Industry Development, Petroleum Resources Branch are identified by [VDMID].

Acknowledgements

The Southeast Gippsland Basin Hydrocarbon Prospectivity Package owes much to many people. Authorship of text is labelled throughout, but any errors in editing or compilation are the responsibility of the senior author. Numerous people contributed to the accompanying Plates, particularly John Conolly, Tun Maung, Maher Megallaa, Steve Cadman, Jim Colwell and myself. Howard Stagg contributed the detailed shotpoint maps of each area, and John Ashworth (VDMID, Petroleum Resources Branch) contributed the basin-wide seismic line map. Technical assistance with the Plates was ably provided by David van der Straaten, Sue Howarth, and Paul Jung.

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Tony Stephenson
Project Leader

2 May 1991

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1. INTRODUCTION

The offshore Gippsland Basin is Australia's major producing hydrocarbon province. Acreage has historically been tightly held, and opportunities for new players in this highly prospective basin have been limited. However, recent relinquishments have allowed the Australian Federal and Victorian State Governments to offer three potential permits to petroleum exploration companies and consortia (Fig. 1).

The Bureau of Mineral Resources' Petroleum Group, in collaboration with the Victorian Department of Manufacturing and Industry Development's Petroleum Branch, has produced a hydrocarbon prospectivity package for the Southeast Gippsland Basin, with particular emphasis on the three areas to be released. The package takes the form of this BMR Record 1991/9.

The package covers regional geology, geophysics, palaeogeography, and hydrocarbon play concepts, together with a new structural interpretation for the Gippsland Basin developed at BMR. In addition, for each release area the package covers previous exploration, local geology and play concepts, reservoir geology and engineering, and geohistory. Prospects and leads are described in detail, and the text is complemented by some 80 Plates and Figures.

This Record should prove invaluable for explorationists interested in acquiring petroleum acreage in this highly prospective basin.

Tony Stephenson
Project Leader

May 1991

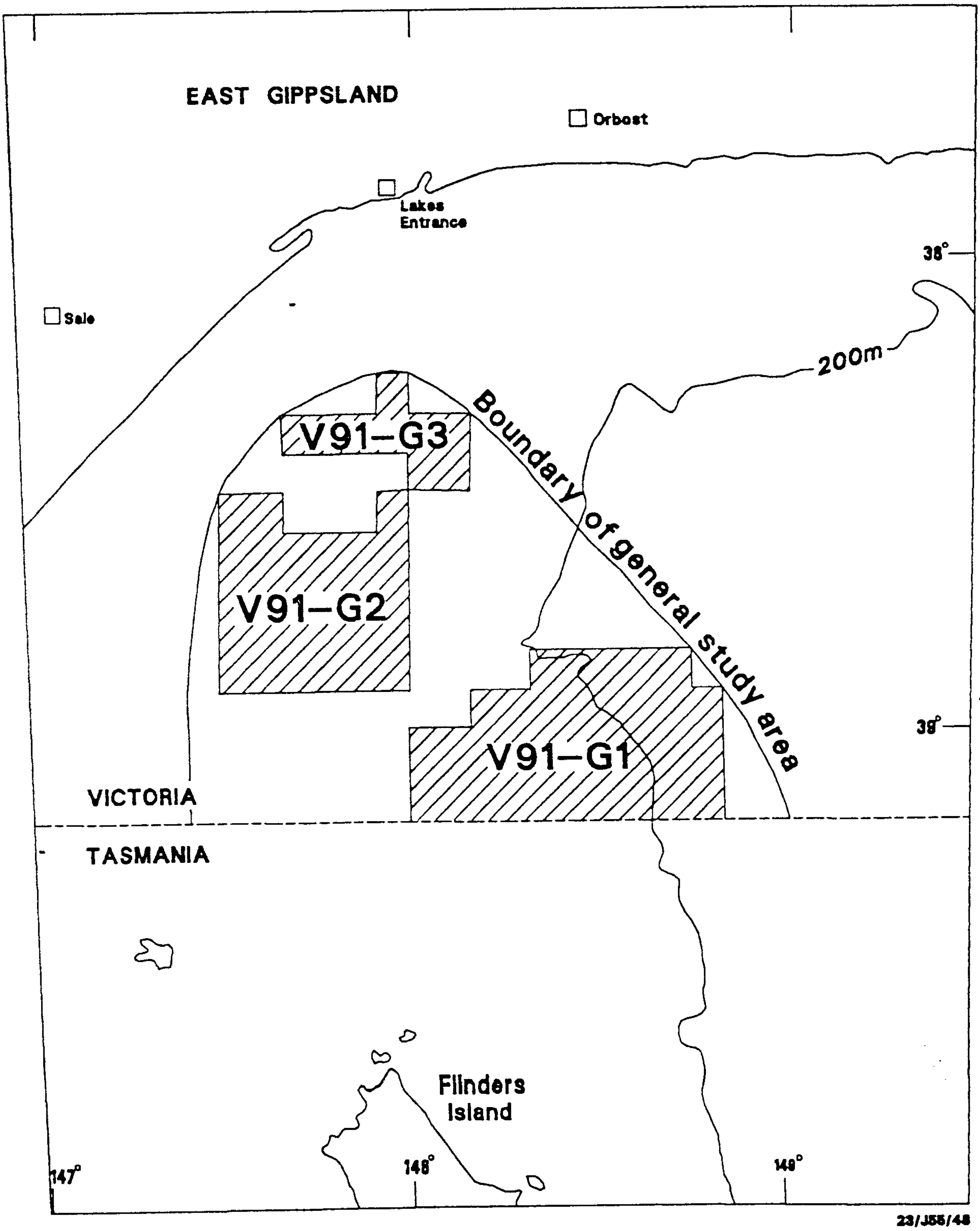


Figure 1. Location of study area, and vacant areas V91–G1, V91–G2, and V91–G3.

2. REGIONAL GEOLOGY

[by A.E. Stephenson & E. Nicholas, BMR Petroleum Resource Assessment Branch.]

2.1 BACKGROUND.

2.1.1 Basin setting

The Gippsland Basin is a late Mesozoic/Tertiary basin located mainly offshore in the northeastern part of Bass Strait between the mainland of Australia and Tasmania (Fig. 2). The northern boundary is an unconformable contact between basin sediments and Palaeozoic rocks of the Tasman Fold Belt. The Selwyn Fault on Mornington Peninsula forms the northwestern boundary with the Otway Basin. The Gippsland Basin is separated from the Bass Basin to the southwest by a southeast-trending basement ridge, the Bassian Rise. Preliminary analysis of BMR seismic data (Colwell & others, 1987) confirms earlier interpretations (Willcox, 1984) that the eastern margin is marked by a large, approximately north-northeast trending structural high at the base of the continental slope, which is coincident with the interpreted boundary between the Australian continental lithosphere and oceanic lithosphere of the Tasman Sea.

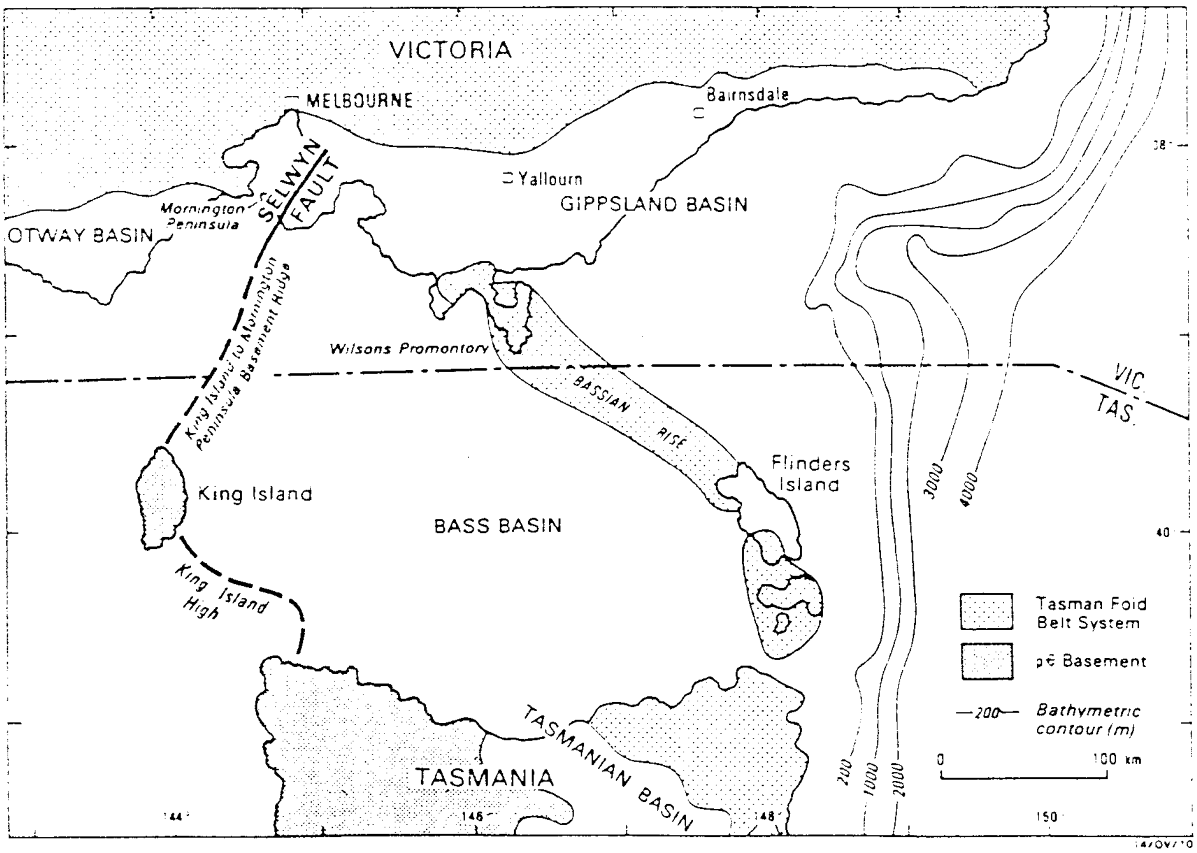


Figure 2. Gippsland Basin setting (modified after Robertson & others, 1978)

2.1.2 Earlier work.

The stratigraphy of the basin and major tectonic events (after Esso, 1988; Rahmanian & others, 1990) is shown in Fig. 3. The Cretaceous spore pollen-zones shown in Fig. 3, and associated dinoflagellate zones, are described in a study of the palynological zonation of the Australian Mesozoic by Helby & others (1987).

The evolution and stratigraphy of the Gippsland Basin have been described by James & Evans (1971), Hocking (1976), Partridge (1976), Threlfall & others (1976), and more recently by Davidson (1980), Davidson & others (1984), Stainforth (1984), Veevers (1984; 1986), Etheridge & others (1985), Bodard & others (1986a,b), B.R. Brown (1986), Evans (1986), Hegarty & others (1986), Thompson (1986), Lowry (1987, 1988), Esso (1988), Mebberson (1989), Rahmanian & others (1990), and Maung & Nicholas (1991). The following discussion is derived mainly from the more recent literature. Earlier work is reviewed in Robertson & others (1978).

2.2 BASIN FORMATION, TECTONICS AND STRUCTURE.

The Gippsland Basin evolved as a passive continental margin basin during the breakup of Gondwanaland and the separation of Australia from Antarctica and from Lord Howe Rise-New Zealand. Fig. 3 shows current datings for the onset of seafloor spreading in the Southern Ocean and in the Tasman Sea. The Early Cretaceous date for the opening of the Southern Ocean as represents a revision of earlier interpretations (Le Pichon & Heirtzler, 1968; Weissel & Hayes, 1972) of an Eocene age for this event, based on a revised identification of magnetic anomalies (Cande & Mutter, 1982).

The concepts of lithospheric extension (McKenzie, 1978; Jarvis & McKenzie, 1980), and rotational normal faulting (Bally & others 1981), have gained acceptance as a basis for modelling the tectonic and thermal history of extensional passive margin basins. Applying these concepts in a study of the Bass, Gippsland, and Otway Basins, Etheridge & others (1985) concluded that they were 'initiated by north-northeast to south-southwest lithospheric extension, largely during the Early Cretaceous'.

The following description of the evolution of the Gippsland Basin is based on recent discussions by Mebberson (1989), and Rahmanian & others (1990), unless otherwise indicated.

The Gippsland Basin originated as part of an extensive rift system which developed in the late Mesozoic along the present southern margin of mainland Australia prior to continental breakup. The Early Cretaceous rift is now largely represented in the Gippsland Basin, by the Central Deep and the flanking Strzelecki Terraces (named by Rahmanian & others, 1990; Plate 13). Cande & Mutter (1982) estimated the breakup between Australia and Antarctica at between 110 and 90 Ma. Veevers' (1986) estimate of 95 plus or minus 5 Ma has been adopted in Fig. 3. Continent separation did not extend into the Bass and Gippsland Basin areas, where uplift and erosion on the margins of the rift produced the major basement ridges which separate these basins from each other and from the Otway Basin.

In the Gippsland Basin there was a renewal of rifting in the early-to-middle Late Cretaceous, when the basin is interpreted to have constituted an arm of a rift system associated with the breakup of Australia and Lord Howe Rise-New Zealand, and the development of Australia's eastern margin. The Late Cretaceous rift was oriented roughly parallel to the Early Cretaceous depression, and its northern and southern margins correspond to the basinward margins of the Strzelecki Terraces. Subsidence was controlled by a series of northwest-trending normal faults resulting from northeast-southwest extension, with the degree of downfaulting greater on the northern than on the southern margin. In addition to these long-recognised fault systems, Etheridge & others (1985) identified major basement-related Early Cretaceous structural lineaments traversing the basin at right angles to the normal fault systems, and interpreted these as being transfer faults (analogous to oceanic transform faults).

Rahmanian & others (1990) have constructed tectonic subsidence curves for the Gippsland Basin from the onset of Latrobe Group deposition, which indicate rapid fault controlled subsidence in the Late Cretaceous, followed by a progressive decrease in sedimentation rates and subsidence from the Paleocene to Recent. This pattern, which is attributed to heating of the lithosphere during rifting followed by thermal cooling during post-rift subsidence, is typical of passive margin basins. These authors applied the lithospheric extension model of McKenzie (1978) to account for the increased heat flow during rifting, and consider that the high subsidence rates observed of about 15 Ma, in the centre of the graben are indicative of a short rifting phase during Latrobe Group deposition ending with the opening of the Tasman Sea at 80 Ma.

As a result of the opening of the Tasman Sea, the basin was left as a 'failed rift', which evolved through the latest Cretaceous to Paleocene from a fault controlled depression to a marginal sag. Continuing fault controlled subsidence in many areas was accompanied by high sedimentation rates, which progressively declined as sea floor spreading continued. The extensional structures were overprinted by compressional tectonism from the Late Eocene to the Middle Miocene, producing the major northeast-trending anticlinal trends with which the major top Latrobe Group hydrocarbon traps are associated. Compression against the northern and southern margins of the basin caused partial inversion of the east-west trending faults, resulting in compressional rolls along the marginal fault zones.

Subsidence has continued in the offshore Gippsland Basin to the present day due to thermal sag, with the greatest subsidence rates occurring in the Central Deep. In the Volador area in the northeast of the basin, over 1500 m of sediment have accumulated since the Pliocene (Maung, 1989).

2.3 STRATIGRAPHY.

2.3.1 Basement.

Palaeozoic basement rocks of the Tasman Fold Belt System are exposed as islands along the Bassian Rise (Fig. 2), and have been penetrated in a number of onshore wells including East Nowa No.1 and East Lake Tyers No.1, but in only four offshore wells, Groper Nos.1 & 2, Mullet No.1 and Bluebone No.1. Groper No.1, Mullet No.1 and Bluebone No.1 terminated in granite, and Groper No.2 encountered red siltstone of presumed Devonian to Carboniferous age.

2.3.2 Strzelecki Group.

The Early Cretaceous Strzelecki Group is well known onshore, where the basal units are thick polymictic conglomerates deposited by alluvial fans (Smith, 1988), which pass upwards into alluvial to fluvial conglomerates, muddy sandstones, and silty mudstones with thin coals. The basaL units are followed by a thick sequence of alluvial floodplain mudstones, thin sandstones, rare conglomerate and thin coals (Smith, 1988).

Offshore the Strzelecki Group has been intersected only in wells on the Strzelecki Terraces, where it consists of interbedded fluvial volcanoclastic sandstones, siltstones, and minor coal. The sandstones have poor reservoir quality due to abundant chloritic and clay matrix, and the unit has generally been regarded by explorationists as economic basement. The boundary with the overlying Latrobe Group is unconformable where intersected, but deposition may have been continuous in the Central Deep, where a thick sequence of Strzelecki Group sediments is thought to occur [see section 4].

2.3.3 Latrobe Group.

The Late Cretaceous to Eocene Latrobe Group contains all the significant petroleum discoveries made to date in the offshore Gippsland Basin, and continues to be the section of principal interest to explorationists. The sequence reaches a thickness of more than 5000 m in the Central Deep, about 400 to 500 m on the Strzelecki Terraces, but is generally very thin or absent in the platform areas, except where it occurs in basement grabens on the Southern Platform. The sediments comprise sandstones, siltstones, carbonaceous mudstones, coals, and volcanics (locally). They were deposited in continental to marine environments during two major depositional phases - the first during the Late Cretaceous rifting, the second during post breakup subsidence, under increasing marine influence due to the incursion of the Tasman Sea from the southeast in the latest Cretaceous to Eocene.

A diachronous regional unconformity on which the hiatus increases eastwards, separates the Latrobe Group from the overlying Lakes Entrance Formation. The primary petroleum reservoir section, which occurs at or near the top Latrobe Group, is informally referred to as the 'top Latrobe coarse clastics'. The thin Gurnard Formation which overlies the 'coarse clastics' over much of the basin, and the Flounder and Turrum Formations which infill major channels incised into the top Latrobe Group in the eastern area, are the only formal stratigraphic subdivisions of the Group to be widely used. However, with the current changing emphasis of exploration from top to intra-Latrobe Group targets, more detailed stratigraphic studies, such as proposed by Thompson (1986) and Bodard & others (1986a, b), may receive more attention. In a departure from more conventional lithostratigraphic techniques, Rahmanian & others (1990) have used sequence stratigraphic analysis to construct a detailed model of the stratigraphy and facies architecture of the Latrobe Group, as a basis for delineating the perceived higher risk exploration targets remaining in the Gipplsand Basin, including stratigraphic traps.

The Late Cretaceous rift-fill sediments have been intersected only on the flanks of the Central Deep and in Pisces No.1 well in a graben on the Southern Platform. In the most marginal areas they consist of sandstones and conglomerates of braided stream and alluvial fan origin, with finer grained fluvial sediments and lacustrine units present in more basinward locations. Aggradational stacking of the depositional sequences indicates that the high rate of subsidence in the Late Cretaceous rift was matched by a high rate of sediment supply (Bodard & others, 1986a; Rahmanian & others, 1990).

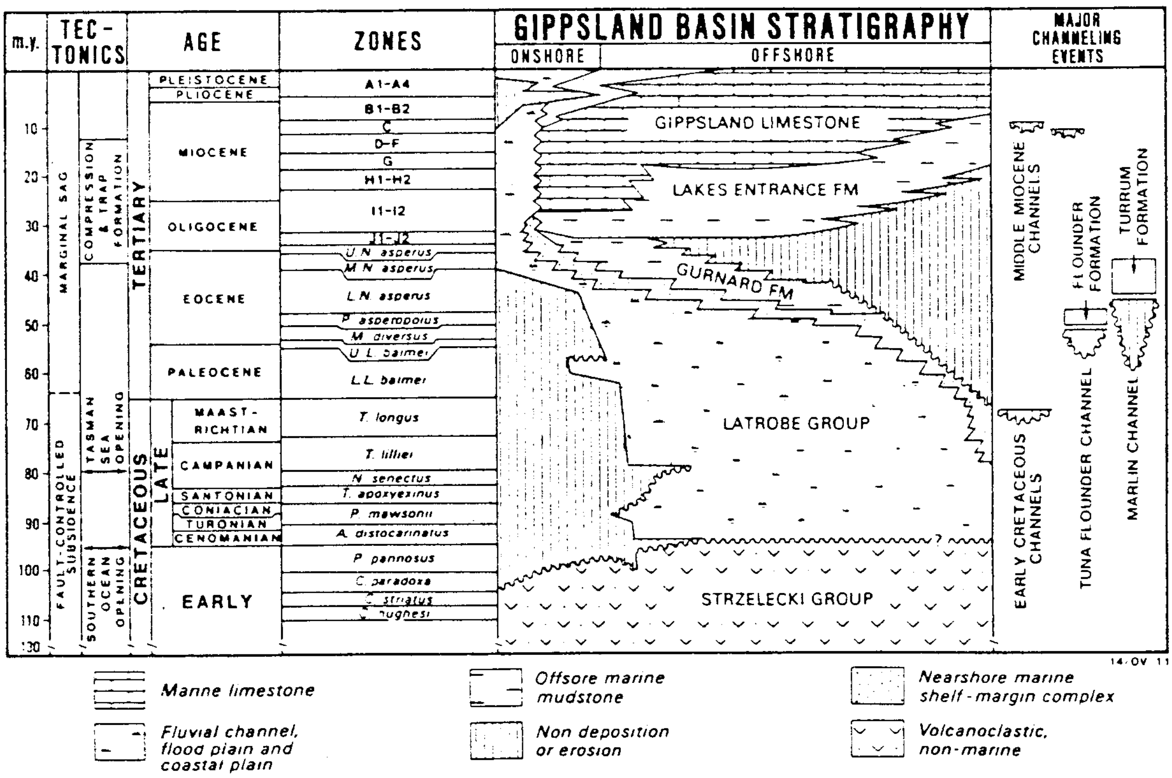


Figure 3. Gippsland Basin stratigraphy and tectonics (modified after Esso, 1988; Rahmanian & others, 1990)

An unconformity within the Campanian N. senectus spore-pollen zone (Fig. 3) in wells located on the margins of the Central Deep, has been interpreted as the breakup unconformity (Lowry, 1987, 1988; Rahmanian & others, 1990). The recognition of a Late Cretaceous unconformity, and the identification of it with the opening of the Tasman Sea, is a significant departure from the long-standing interpretation of only one Cretaceous unconformity, developed at the end of the Early Cretaceous and separating the Strzelecki Group from the overlying Latrobe Group.

In presenting the concept of two Cretaceous unconformities, Lowry (1987, 1988) concluded that palynological evidence from wells on the northwestern and southeastern flanks of the deep basin, combined with evidence from dipmeter logs and seismic sections, indicated that an angular unconformity previously interpreted as the Latrobe/Strzelecki Group boundary, should be interpreted as marking the Late Cretaceous intra-Latrobe Group (N. senectus zone) unconformity. A new sub-unconformity play was suggested for the Gippsland Basin, based on this identification of 'additional' potentially prospective Latrobe Group section previously identified as unprospective Strzelecki Group. Lowry (1987, 1988) applied the name 'Golden Beach Formation' to the sub-unconformity Late Cretaceous section, a stratigraphic term originally proposed by Haskell (1972) for a Late Cretaceous sequence intersected by the offshore well Golden Beach No.1A and several onshore wells at the western end of the basin. The term 'Golden Beach Group' has been informally used in some company reports to describe this section, but as no constituent formations of this 'Group' have been formally described, the term 'Golden Beach Formation' is preferred in this report.

Rahmanian & others (1990) interpreted a "mild unconformity and a peak in volcanism ... best illustrated by well and seismic data in the northeast of the basin ...", as a record of the Late Cretaceous breakup event. Although equating the unconformity with that recorded by Lowry (1987, 1988) in the northwest, these authors make no comment on Lowry's revised interpretation of the angular unconformity. Evans (1986) interpreted an intra-Campanian unconformity to the east of the basin centre on the basis of a distinctive change from fluvial floodplain to shoreface lithofacies, but saw no obvious evidence of regional erosion of the fluvial section, and Stainforth (1984) related a thick intra-Campanian sequence of volcanics with interbedded alluvial sediments encountered in the Basker No.1 well in the northeastern part of the Central Deep, to the Tasman Sea opening.

The earliest known indication of the development of marine conditions in the basin is provided by a Late Cretaceous (Santonian) dinoflagellate assemblage recorded in the Kipper No.1 and Tuna No.4 wells on the northern flank of the Central Deep, and in dredge samples from the Bass Canyon on the outer continental slope (Marshall, 1988).

Deposition of the latest Cretaceous to Eocene upper Latrobe Group sequence during the continuing overall marine transgression was punctuated by multiple transgressive-regressive episodes related to major and minor sea level fluctuations, variations in sediment supply, and the tectonic influences previously discussed. The following generalised summary of the resulting complex lithostratigraphy is based on regional descriptions in the detailed sequence stratigraphic study by Rahmanian & others (1990) and in Mebberson (1989), unless otherwise indicated.

The sediments were deposited typically along wave-dominated shorelines in a suite of transgressive environments ranging from alluvial and coastal plain, through beach, foreshore, shoreface, to offshore. The central and eastern areas of the basin were starved of siliclastic sediments in the Middle and Late Eocene as the shoreline transgressed to the west and northwest. In the central area, this interval is represented by the Gurnard Formation, a condensed, time-transgressive sequence of glauconitic sandy mudstones at the top Latrobe Group (Fig. 3), which reaches a thickness of 50 m and constitutes a seal for several 'top Latrobe Group' petroleum accumulations.

In the eastern area of the Gippsland Basin, the Latrobe Group was deeply eroded during several periods of major channelling or submarine canyon formation (Fig. 3). The Eocene channel systems are shown in Fig. 4. A major channel system associated with sea level falls at the end of the Cretaceous (68-71 Ma) has also been identified on limited data in the southeastern area.

Cutting of the Tuna-Flounder channel complex began south of the Flounder field during the Early Eocene 53 Ma lowstand, and extended northwards, mainly by headward erosion, during subsequent Eocene (53-50 Ma) sea-level falls. In the Flounder field (Sloan, 1987), the channel is eroded down into early Paleocene coastal plain deposits. The Flounder Formation which fills the channel, consists of a predominantly lower sandy section overlain by a thick marine shale. The sequence contains dinoflagellates and rare foraminifera indicative of an early Eocene age of deposition (Marshall & Partridge, 1988).

The most extensive period of submarine channelling occurred during a series of sea level falls in the mid-Eocene and associated tectonic uplift. The resulting Marlin Channel system (Fig. 4) ranges from 5 to 30 km in width, and is more than 75 km long and up to 700 m deep. On its northeastern flank it overlies, and has partly eroded the channel fill of the Tuna-Flounder Channel.

The Marlin Channel (Marshall & Partridge, 1988) continued to be a major bathymetric feature into the early Miocene. The mainly middle Eocene Turrum Formation, consisting predominantly of siltstones and shales, fills less than one quarter of the channel which was eventually buried by prograding shelf carbonates in the early and middle Miocene. The Opah Channel, between the Kingfish and Halibut fields, is infilled by a thin unnamed clay-choked sandstone. The use of successive first occurrences of species of the Eocene acritarch Tritonites, in addition to spore-pollen and dinoflagellate zones, has provided additional control for the correlation and dating of the marine channel infill deposits. Although age control is still limited, Marshall & Partridge (1988) favour the correlation of the initiation of the Marlin and Opah Channels with a sea level fall near the end of the early Eocene (49.5 Ma).

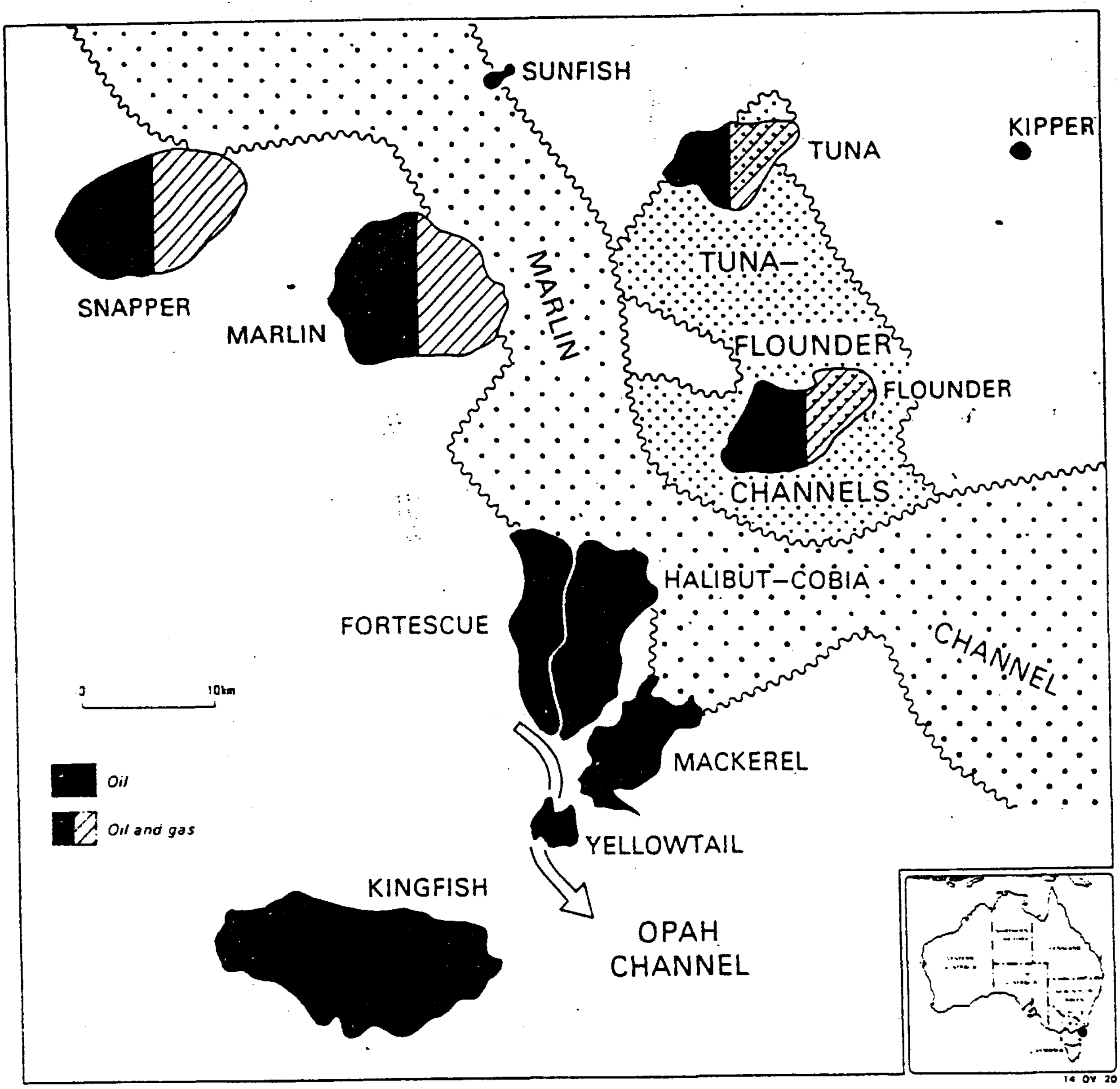


Figure 4. Location of major Eocene channels, and petroleum accumulations within or adjacent to the channels (after Rahmanian & others, 1990; Maung & Nicholas, 1990)

2.3.4 Seaspray Group.

During the Oligocene to Miocene, the Latrobe Group was succeeded by a southeasterly prograding continental shelf sequence, the Seaspray Group (Hocking, 1972). The basal unit is the mainly Oligocene Lakes Entrance Formation, a sequence of shale and marl which forms a regional seal for the top Latrobe Group reservoirs. The Miocene section exhibits a transition from the shales and marls of the Lakes Entrance Formation to the marls and limestones of the Gippsland Limestone. Structural movements and eustatic sea level fluctuations resulted in complex submarine channelling (Fig. 5) of the Miocene sequence (Threlfall & others 1976). The heads of the channels are filled with a coarse mixture of skeletal fragments and sand grains, and the middle and distal portions, mainly by micritic limestones with low porosity. The micritic limestone presents problems (discussed in detail in Section 3) for the seismic mapping of underlying strata, because of its very high velocity compared to that of the surrounding rocks.

The change from clastic to carbonate deposition has been attributed to a reduction in the supply of clastic sediment, combined with a change in oceanic current direction and increasing basin subsidence. Upwelling of nutrient-rich cold water via submarine canyons on the continental shelf also probably aided carbonate formation. Progradation of carbonate deposits continued through the Plio-Pleistocene, extending the shelf to its present position (Mebberson, 1989; Rahmanian & others, 1990).

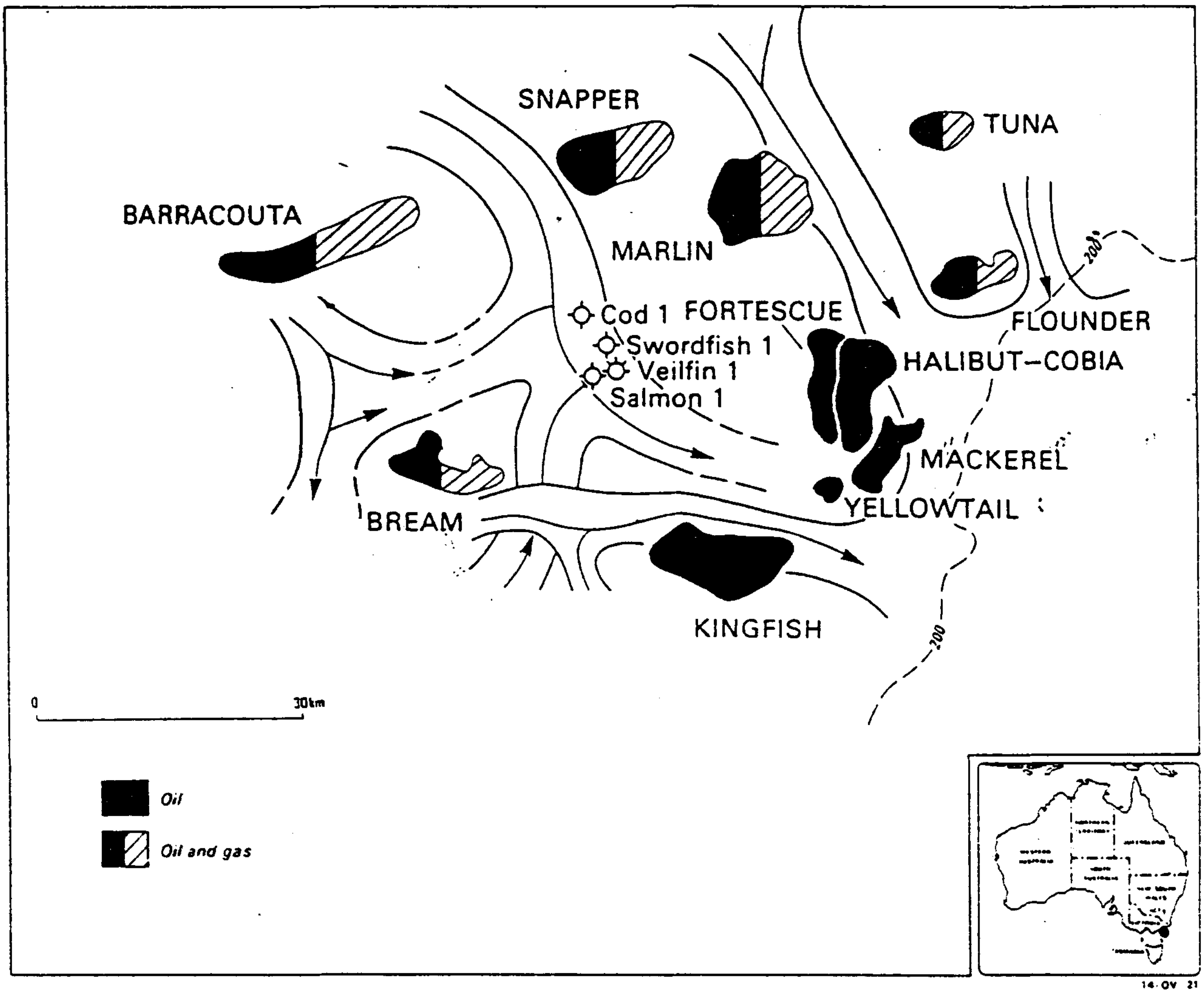


Figure 5. Location of major Miocene channels and adjacent petroleum accumulations (after Birmingham & others, 1985; Maung & Nicholas, 1990)

2.4 KNOWN HYDROCARBONS.

2.4.1 Exploration and distribution.

Oil and gas were first discovered in the Gippsland Basin onshore in 1924 by Lake Bunga No.1, a water well near Lakes Entrance (Robertson & others, 1978). Subsequent drilling of some 130 onshore wells has resulted in the discovery of only one subeconomic and five uneconomic hydrocarbon accumulations (Ozimic & others, 1987). Most of the petroleum discovered in the Gippsland Basin has been found offshore in structural or combined structural/stratigraphic traps at the top Latrobe Group 'coarse clastics' level, with the largest fields being discovered early in the exploration of the basin. B.R. Brown (1986) documented the exploration history of the offshore Gippsland Basin to that time, and Ozimic & others (1987) published a comprehensive account of known hydrocarbon accumulations. An updated list of known accumulations is given in Table 1. Well locations are shown on Plate 1 - it is noticeable that nearly all hydrocarbon accumulations are within the Central Deep of the Gippsland Basin, with the exception of some small discoveries on the North Strzelecki Terrace, and the Perch and Archer fields on the South Strzelecki Terrace.

Table 1. Known hydrocarbon accumulations in the Gippsland Basin.

[Economic status implies developed unless otherwise indicated.]

Accumulation	Hydrocarbons	Current Status
Anemone	Gas/condensate	Subeconomic
Angler	Gas	Subeconomic
Archer	Oil & gas	Subeconomic
Angelfish	Oil & gas	Subeconomic
Baleen	Gas	Subeconomic
Barracouta	Oil & gas	Economic
Basker	Oil & gas	Subeconomic
Batfish	Gas	Subeconomic
Bignose	Gas	Uneconomic
Bream	Oil & gas	Economic
Dolphin	Oil	Economic
Emperor	Oil & gas	Subeconomic
Flathead	Oil & gas	Subeconomic
Flounder	Oil & gas	Economic
Fortescue	Oil	Economic
Golden Beach	Gas	Economic [development pending]
Grunter	Oil & gas	Subeconomic
Gummy	Gas	Subeconomic
Halibit-Cobia	Oil	Economic
Hapuku-Blackback	Oil	Subeconomic
Hermes	Gas	Uneconomic
Judith	Gas	Uneconomic
Kingfish	Oil	Economic
Kipper	Oil & gas	Subeconomic
Lakes Entrance	Oil	Subeconomic
Leatherjacket	Oil & gas	Subeconomic

Table 1 (continued).

Accumulation	Hydrocarbons	Current Status
Luderick	Oil & gas	Subeconomic
Mackerel	Oil	Economic
Manta	Oil & gas	Subeconomic
Marlin	Oil & gas	Economic
Mulloway	Oil	Subeconomic
North Seaspray	Gas	Uneconomic
Omeo	Gas/condensate	Subeconomic
Pelican Point	OIl & gas	Uneconomic
Perch	Oil	Economic
Seahorse	Oil	Economic [development pending]
Selene	Gas	Uneconomic
Snapper	Oil & gas	Economic
Sole	Gas	Subeconomic
Sperm Whale	Oil	Subeconomic
Stonefish	Oil & gas	Uneconomic
Sunday Island	Oil	Uneconomic
Sunfish	Oil & gas	Subeconomic
Sweetlips	Oil & gas	Subeconomic
Tarwhine	Oil & gas	Economic [development pending]
Terakihi	Oil	Subeconomic
Torsk	Oil	Subeconomic
Trumpeter	Gas	Uneconomic
Tuna	Oil & gas	Economic
Veilfin	Gas	Uneconomic
Volador	Oil & gas	Uneconomic
Wellington Park	Oil	Uneconomic
West Seahorse	Oil & gas	Subeconomic
Whiptail	Oil	Subeconomic
Whiting	Oil & gas	Subeconomic
Wirrah	Oil & gas	Subeconomic
Woodside 1	Oil & gas	Uneconomic
Woodside 2	Oil & gas	Uneconomic
Yellowtail	Oil	Subeconomic

2.4.2 Petroleum types.

Oils and condensates found within the Gippsland Basin are paraffinic to naphthenic in composition, have a high wax content, and are characterised by high pristane to phytane ratios (Powell & McKirdy, 1976). High wax content and high pristane to phytane ratios are indicative of a terrestrial plant source (Ozimic & others, 1987).

Gippsland Basin oils are generally light, with gravities ranging from 40^{o}API to 60^{o}API (Fig. 6). Some heavier oils, discovered at shallow depths, have gravities of 14.6^{o}API to 26.5^{o}API, and are thought to have been biodegraded. The gravity of Gippsland Basin condensates ranges from 48^{o}API to 63^{o}API (Ozimic & others, 1987).

In general, oils from terrestrial sources are classified as high wax oils (Hedberg, 1968), although a wide range of compositions can occur. In the Gippsland Basin some oils have condensate-like compositions with API gravities in excess of 50°, no wax content, and virtually no compounds heavier than about C_{22}. Other Gippsland oils have an API gravity of 35°, are extremely waxy, and are composed of molecules heavier than C_{20}. In between these two extremes are many combinations and variations in such properties (Ozimic & others, 1987). Burns & others (1984) suggested that such compositional variations can be explained by the oils having been generated at different maturity levels, and possibly by separation migration. Bacterial degradation, which ranges from mild to severe, has complicated current oil composition and had varying effects on quality.

The composition of Gippsland Basin natural gases also varies, but not as markedly as that of oil. Most accumulations have low condensate yields, and high carbon dioxide contents are locally present. Fuller details of hydrocarbon compositions in various Gippsland Basin accumulations are given by Ozimic & others (1987).

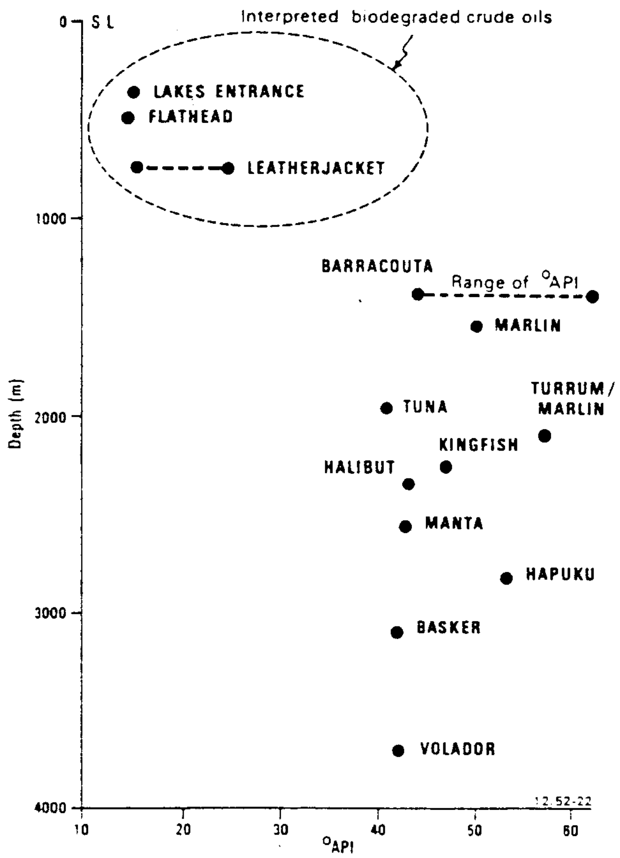


Figure 6. Plot of crude oil gravity (API) versus depth of selected Gippsland Basin oils (after Ozimic & others, 1987)

2.4.3 Source and maturation.

Potential source rocks can be found in the Strzelecki, Latrobe and Seaspray Groups, although the Latrobe Group is recognised as containing the greatest proportion of organic-rich sediments buried within the accepted rank range for hydrocarbon generation (Smith, 1988).

The Strzelecki Group contains thin coals and dispersed non-marine organic matter where it is known on the basin margins, and minor hydrocarbon shows have been recorded from Strzelecki Group sediments in the Woodside Nos. 1 & 2, and Flathead No.1 wells. The Strzelecki Group has not been intersected by drilling in the Central Deep, but it is reasonable to assume that early rift phase sediments in this area may have included organic-rich fluvio-lacustrine deposits. Although the Central Deep Strzelecki section is now overmature for all but dry gas generation, geohistory studies (Smith, 1988; Williamson, this Record) suggest that liquid hydrocarbon generation could have taken place between 110 Ma and about 20 Ma. There could thus have been some overlap between generation from Strzelecki sources and the onset of major trap formation in the Gippsland Basin, and the Central Deep Strzelecki section should not be totally discounted as a possible source of some of the basin's accumulated hydrocarbons.

Undoubtedly, the lower Latrobe Group is considered by most Gippsland Basin workers to be the primary source of the basin's petroleum. The Latrobe Group contains vast quantities of non-marine to marginal marine sourced organic matter, deposited in a variety of environments. Not all facies represented have source potential - for example, alluvial sandstones and upper coastal plain point bars and clays probably contain little organic material, coastal barrier bar and littoral sands even less. The best source rocks in the Latrobe Group are likely to have been deposited in lower coastal plain fluvio-lacustrine environments, with some potential from coal swamps, lakes, and back-barrier lagoons. Shallow marine shales are not thought to be a significant source, as hydrocarbon chemistry in the Gippsland Basin points to land plants being the major organic precursors.

The main hydrocarbon source in the lower Latrobe Group is thought to be that part of the sequence currently at depths of 4 km (Ozimic & others, 1987). In most of the Central Deep, this corresponds to rocks of pre-Campanian age (> 80 Ma). Some Gippsland Basin rocks reach a vitrinite reflectance of 0.7, and hence the top of the oil window, at depths as shallow as 3 km (Fig. 7). However, evidence from known oil fields in the basin suggests that oil is only expelled from Latrobe Group source rocks at maturity levels equivalent to a vitrinite reflectances of 0.8 to 1.0. Oil generation is attributed to thermal breakdown of exinite, and gas generation to thermal cracking of vitrinite and some exinite (Ozimic & others, 1987).

Although upper Latrobe Group sediments contain sedimentary facies which are potential sources, these sediments are thermally immature. Similarly, the entire Latrobe Group is are thought to be immature over most of the Strzelecki Terraces and the Platforms, although some potential for local generation exists in features such as the Pisces Graben.

Post-Latrobe Group sediments are immature throughout the Gippsland Basin, although suitable source facies do occur within the Lakes Entrance Formation.

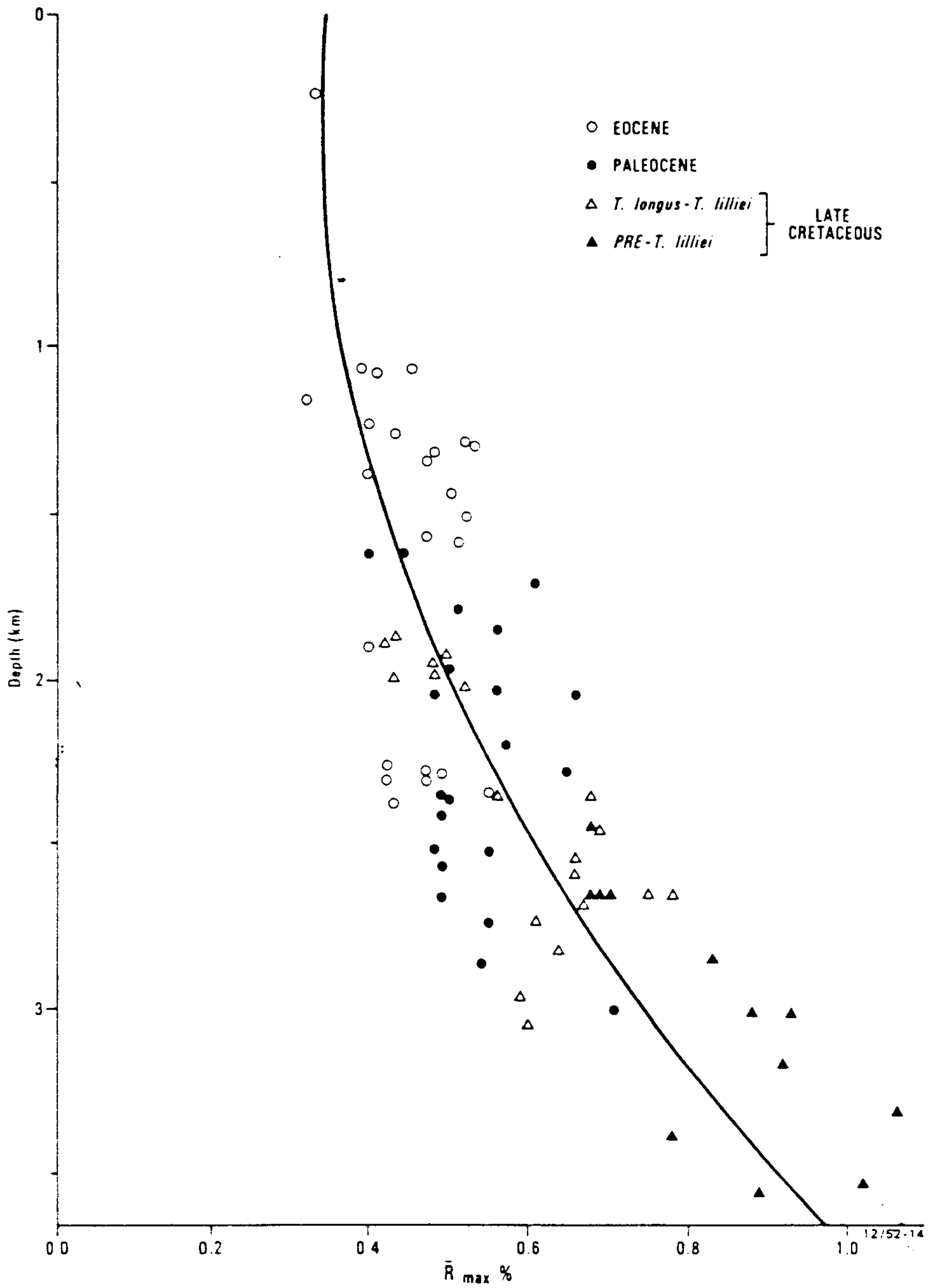


Figure 7. Plot of mean maximum vitrinite reflectance (Rv max per cent) versus depth, Gippsland Basin (after Smith & Cook, 1984)

2.4.4 Reservoirs and seals.

Nearly all known reservoirs in the Gippsland Basin are within or at the top Latrobe Group. Latrobe Group reservoirs comprise siliciclastic sediments deposited in four major environments: alluvial valley, progradational coastal plain, coastal barrier, and near-shore marine (Ozimic & others, 1987). The Eocene top Latrobe Group 'coarse clastic' reservoirs which host most of the basin's major known petroleum accumulations consist of friable to unconsolidated sands with minor scattered zones of dolomitisation. The porosity of these reservoirs ranges from 15-30%, while permeabilities frequently exceed 1 Darcy. The Late Cretaceous to Palaeocene intra-Latrobe Group reservoirs are more compacted, with porosities of from 5-15% and permeabilities of up to 1000 millidarcies.

Cap rocks to the Latrobe Group reservoirs are impervious sandstone, siltstone, shale, calcilutite, and coal. Lateral seal is frequently provided by fault seal against such lithologies, stratigraphic pinchout, and/or juxtaposition against impervious channel-fill sediments.

The Eocene-Oligocene Gurnard Formation normally acts as a cap rock over the Top Latrobe petroleum accumulations, but may locally act as a reservoir (as at Snapper and Kingfish) or more commonly as a thief zone. Similarly, channel-fill sediments can occasionally form reservoirs, as is the case with four Flounder Formation sands at Flounder.

Intra-Strzelecki Group reservoirs have been encountered by several wells on the Northern Platform. Golden Beach No.1A and North Seaspray No.1 encountered gas within the Strzelecki Group; shows in Wellington Park No.1 and Woodside Nos. 1 & 2 wells are more problematical. Flathead No.1 encountered oil at three separate stratigraphic levels - Strzelecki Group, Latrobe Group, and Lakes Entrance Formation - although none of the pools was economic. The Lakes Entrance Formation also contains the P-1 gas reservoir at Bream, and the Greensand Member at Lakes Entrance, which hosts heavy tarry oil (15.7^{o} API) in a poor quality reservoir. The only known reservoir in the Gippsland Limestone was encountered by Pelican Point No.1, where an oil and gas show was recorded in sandy limestone of Miocene age.

2.4.5 Migration and entrapment.

Although most Gippsland Basin hydrocarbons are believed to have been sourced in the Central Deep at depths greater than 4 km, variations in organic facies, combined with different maturity levels at the time of primary migration, and differing secondary migration pathways, lead to considerable range in the compositions of the entrapped hydrocarbons. Compositional variation is further complicated by widespread but variable biodegradation, and ongoing geochemical changes caused by heatflow differentials at the varying stratigraphic levels of the traps. Some oils are thought to have migrated updip through a succession of traps, resulting in mixing of multiple-sourced hydrocarbons.

Hydrocarbon play types are detailed later in this report, but some generalisations can be made here. Two main structural elements are recognised in the Gippsland Basin: northwest trending normal fault structures developed during a tensional tectonic regime operative from the Early Cretaceous to the Paleocene (Fig. 8), and northeasterly to easterly trending anticlines and associated wrench faults, a result of compressional tectonics during the Late Eocene to Miocene (Fig. 9). In addition, Etheridge & others (1985) identified major Early Cretaceous structural lineaments which traverse the basin at right angles to the trend of the normal fault system, and interpreted these as transfer faults. This interpretation remains controversial, but Etheridge & others (1985) postulated that reactivation of the transfer faults, and of the normal faults, was a major controlling factor in the development of the younger compressional structure.

The largest petroleum accumulations in the Gippsland Basin are present in the Central Deep, immediately below the unconformity at the top Latrobe Group, in traps located along the axes of major anticlinal trends (Fig. 9). The traps are primarily structural or combined structural and stratigraphic in origin, with vertical seal provided by overlying marine shales and calcilutites. Migration of hydrocarbons to the top Latrobe Group was facilitated by a westerly regional dip of the sequence from the basin centre, and vertical pathways provided by normal faults (Ozimic & others, 1987). Petroleum is also trapped in sandstone reservoirs within the Latrobe Group, intra-formationally sealed by shales. The trapping mechanism is either stratigraphic, resulting from pinchout of the reservoir sands; structural, where sands are sealed across fault planes by the shale units; or by a combination of both trap types.

In the Lakes Entrance accumulation, the only significant onshore discovery, oil is trapped stratigraphically within a glauconitic sandstone (the Greensand Member) of the Oligocene Lakes Entrance Formation (Ozimic & others, 1987). Offshore, gas in the small Lakes Entrance Formation P-1 unit at Bream is trapped structurally, as is the small accumulation at Flathead. The trapping mechanism for the small Gippsland Limestone oil and gas discovery at Pelican Point is not known (Ozimic & others, 1987).

Traps within the Gurnard Formation can be either stratigraphic, as at Kingfish, or structural, as at Snapper. All four Flounder Formation (channel fill) traps at Flounder are stratigraphic.

All Strzelecki Group hydrocarbon accumulations discovered to date, where the trapping mechanism is known, have occurred in structural traps (Ozimic & others, 1987).

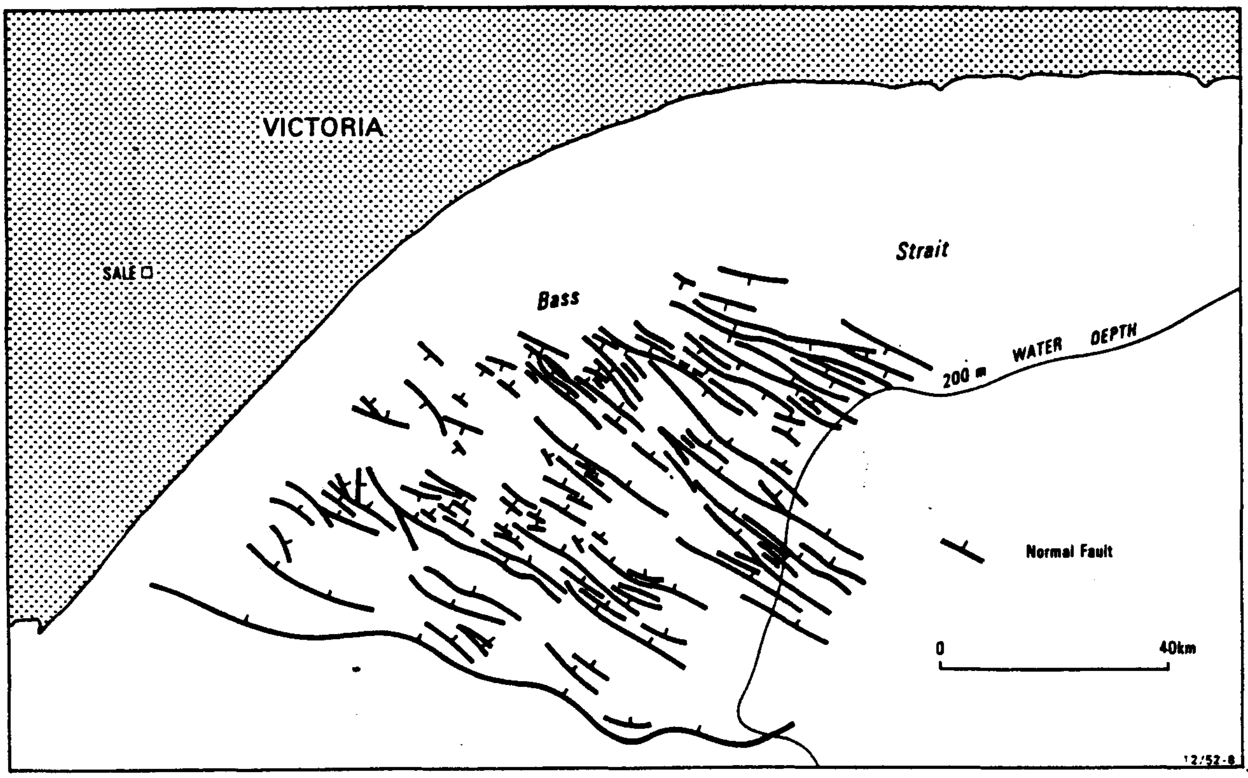


Figure 8. Early Cretaceous to Paleocene basin-forming normal faults, Gippsland Basin
(after Threlfall & others, 1976; Ozimic & others, 1987)

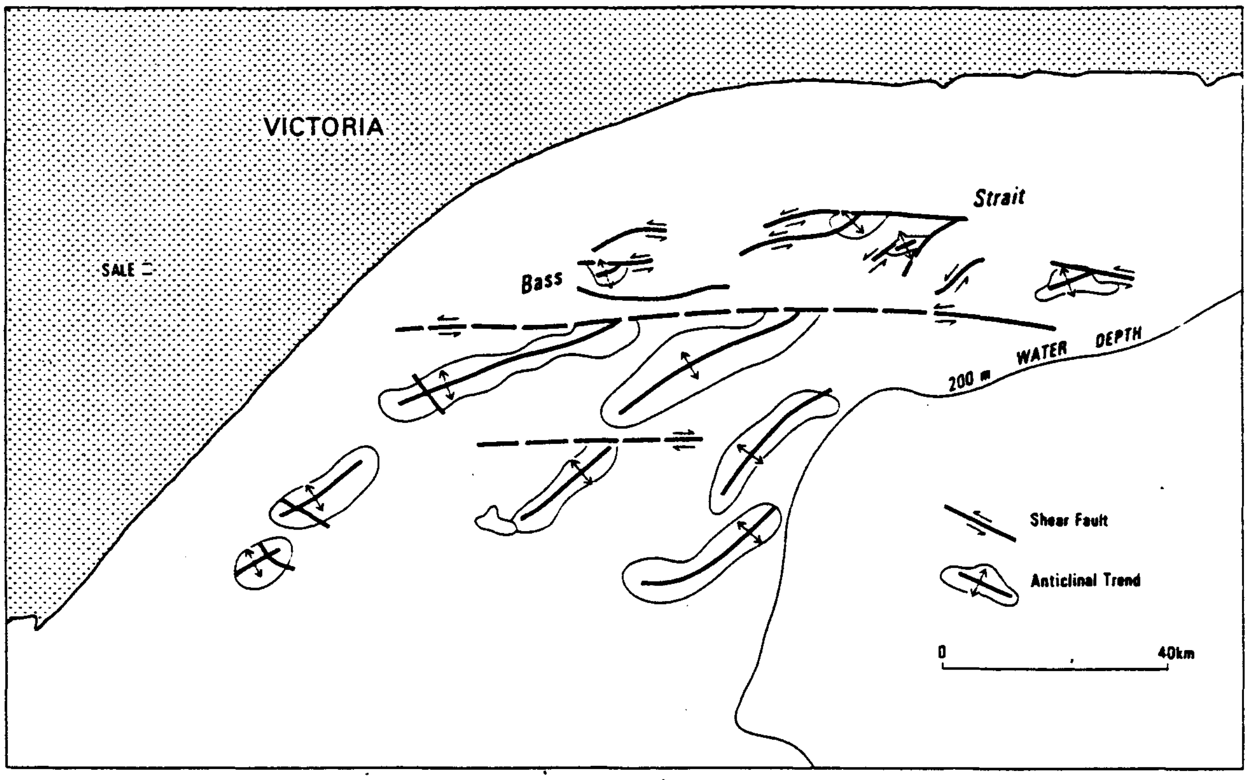


Figure 9. Late Eocene–Early Oligocene and Late Miocene anticlines and shear faults, Gippsland Basin
(after Threlfall & others, 1976; Ozimic & others, 1987)

3. REGIONAL GEOPHYSICS

[by Tun U Maung, Petroleum Resource Assessment Branch.]

3.1 SEISMIC DATA AVAILABILITY.

The first reconnaissance marine seismic survey was undertaken in 1962 by Arco Ltd in a narrow near-shore strip parallel to the Ninety Mile Beach. The objectives were to test for offshore extensions of known structural trends, and determine sediment thickness. These objectives were realised.

However, the first extensive reconnaissance marine seismic survey was carried out in 1963 for Haematite Exploration Oil (now BHP Petroleum) in 1963. Several structures with considerable area and vertical closure were mapped. Following its farm-in agreement with Haematite, Esso carried out the Gippsland Shelf seismic survey in the central part of the offshore Gippsland Basin in 1964. Good results from this 6-fold coverage, together with some onshore well control, led to a basic understanding of the nature of the potential hydrocarbon traps in the area. Several structures were mapped and a notable result of this survey was the detection of the palaeocanyon trending southeast from Lakes Entrance (Eocene Marlin Channel) which was subsequently found to be a critical element in trap formation (Fig. 4).

Following the discovery of the Barracouta field in 1965 (Roder & Sloan, 1986 and Esso, 1988), a second survey, the Eastern Bass Strait seismic survey, was undertaken by Esso in 1966. Rapid lateral facies changes associated with channel filling (Miocene channels, Fig. 5) were interpreted as the cause of complex velocity variations. All these surveys used explosives as energy source. The next survey in 1967 (EC-67) used digital recording and computer processing technology to obtain 6-fold coverage still using explosives as the energy source. An alternative energy source to explosives (aquapulse) was subsequently added to the new digital technology during the 1968 (EH-68) and 1969 (G69) surveys to obtain 12-fold coverage. The limit of the Latrobe Group to the southwest was precisely defined by the results of these surveys. Additional surveys were carried out by Esso, Shell, Magellan, N.S.W Oil, Endeavour and BMR. Seismic surveys carried out between 1962 and 1974 are listed in Appendix 1 Seismic surveys carried out between 1976 and 1989 are listed in Appendix 2.

Seismic coverage of the offshore Gippsland Basin, between 1976 and 1985, is shown in Plates 1A and 1B. Additional surveys carried out in 1988 and 1989 were added on Plate 1A and shown in Plate 14. Seismic data quality varies greatly in different parts of the basin.

Major advances in data acquisition, processing, and interpretation technology during the past 15 years have resulted in a significant improvement in seismic data quality. Good seismic data quality and better stratigraphic and velocity control, due to availability of more well data, have enabled better identification and mapping of deeper horizons than was previously possible, and contributed to more accurate mapping of horizons already identified.

In the aquisition phase, the increase in coverage from 24-fold to 75-fold by the use of more hydrophone channels (96 to 300), longer streamer cable (from 2400 m up to 3750 m) and the introduction of larger volume airgun arrays, have achieved higher resolution. The introduction in 1983 of digital streamer cables (for GUT83A and GUT83P marine seismic surveys), using fibre optic technology for data transmission, offered improved signal quality by virtually eliminating the effects of leakage and cross-feed interference between channels (Laster, 1985).

In the processing phase, the introduction of wavelet processing techniques has made a particularly useful contribution to the resolution of the seismic section, and the use of 3D displays, such as time-slice sections and 3D wave equation migration, has helped to resolve complex events and correlation problems across fault blocks (Denham, 1982; Horvath, 1985; Schultz, 1985; A.R. Brown, 1986).

In seismic interpretation, the development of the interactive seismic interpretation systems has facilitated the rapid construction of accurate structure contour and isopach maps.

The development of new depth conversion methods (Denham, 1980; Birmingham & others, 1985; Blackburn, 1986), together with the improvements in seismic processing techniques, and the additional well control, have helped to overcome the time-depth conversion problems associated with the presence of high-velocity material in Miocene channels. The severity of the problems was initially recognised after the discovery of the Kingfish field by the Kingfish No.1 well in 1967. The well, which was drilled on a time high, was subsequently found to have been located about 3500 m east of the crest of the structure and only 1300 m from the edge of the field (Bein & others, 1973; McQuillin & others, 1984; B.R. Brown, 1986).

3.2 REGIONAL SEISMIC INTERPRETATION.

Regional seismic depth contour maps and regional geological cross-sections presented here have been compiled, synthesised and constructed by Petroleum Resource Assessment Branch of BMR primarily from interpretive data supplied by companies under the terms of the Petroleum (Submerged Lands) Act 1967, and also from data provided specially for the project resulting in the BMR Report 297 (Maung & Nicholas, 1990). The majority of the interpretive data is based on seismic survey and well data acquired by companies between 1976 and 1987.

Seismic-line locations are shown in Plates 1A and 1B. Seismic depth contours for interpreted top of Strzelecki Group/basement, intra-Latrobe Group (several horizons), and top Latrobe Group are shown in Plates 2A and 2B, 3A and 3B and 4A and 4B respectively. Regional cross-sections are presented in Plates 5 to 8, and bathymetry, petroleum accumulations, major tectonic sub-divisions and cross-section line locations are presented in Plate 9A and 9B.

The principal mapped seismic horizons are described below. Further information can be found in Maung (1989) and Maung & Nicholas (1990).

3.2.1 Top of Strzelecki Group/Basement.

Plates 2A and 2B show seismic depth contours mapped on the unconformity at the top of the Early Cretaceous Strzelecki Group (Fig. 3) and on interpreted Palaeozoic basement. The mapping outlines the regional structural framework of the Gippsland Basin established during the Early Cretaceous rifting phase of continent separation, when Strzelecki Group sediments were deposited in an east-west trending graben, now largely represented by the Central Deep and the flanking Strzelecki Terraces. The terraces are the only areas where the top of the Strzelecki Group horizon can be mapped. The Golden Beach No.1A well located at the nearshore northwestern part of the Central Deep, penetrated the Strzelecki Group at 2376 m (Plate 7), indicating a relatively shallow Strzelecki Group in that part of the Central Deep. On the Northern Terrace, the horizon increases in depth from less than 500 m in the north up to 2800 m adjacent to the Rosedale Fault System. On the Southern Terrace, the horizon deepens northeastwards from 1900 m at Moray No.1 well, to over 3400 m near the Darriman Fault System. This horizon was re-interpreted as intra-Late Cretaceous Latrobe Group by Lowry (1987, 1988). Wells drilled to depths in excess of 4000 m in the Central Deep (e.g. Volador No.1, Plate 6, and Hermes No.1, Plate 8) terminated in Late Cretaceous sediments.

The mapping delineates the major Early Cretaceous basin-forming fault systems bounding the basinward and outer margins of the Strzelecki Terraces. The literature varies with respect to the naming of these features. This report follows Hocking (1976) in the use of the 'Rosedale Fault System' and the 'Foster Fault System', and Stainforth (1984) in interpreting an offshore extension of the onshore Lake Wellington Fault. The name 'Darriman Fault System' was introduced by Maung (1989) and Maung & Nicholas (1990) for the fault forming the northern boundary of the southern Strzelecki Terrace as the fault system appears to be related to the Darriman Monocline mapped in the adjacent onshore area.

The Strzelecki Group is absent due to either erosion or non-deposition on the Northern and Southern Platforms. The well-developed, mainly northwest-trending down-to-basement normal faulting at the eastern end of the Southern Platform, interpreted as Late Cretaceous in age, is discussed further in the following section. A Latrobe Group prospect associated with one of these basement structures was tested by the Pisces No.1 well (Plate 6).

3.2.2 Intra-Latrobe Group Horizons.

Plates 3A and 3B show seismic depth contours on a Paleocene, Lower L. balmei seismic marker for the northwestern and central parts. Thompson (1986) has mapped the onshore parts of Strzelecki Group/ Basement and top of Latrobe Group of the basin. Three Late Cretaceous horizons (near top of Maastrichtian, near top of

Campanian, and intra-Campanian) are mapped in the southwestern, southeastern, and northeastern areas respectively. The northwest-trending normal faulting, seen on each of the mapped horizons (and on the Southern Platform, Plates 2A and 2B), is a prominent feature of the intra-Latrobe Group mapping. The initial movement on these faults during the early Late Cretaceous has been related to the breakup between Australia and Lord Howe Rise-New Zealand at about 80 Ma (Fig. 3). Activity on the northwest-trending faults continued into the early Tertiary during post-breakup subsidence. Very thick Late Cretaceous sequences are interpreted in the Central Deep and in basement grabens on the Southern Platform (Plates 5 to 8). The mapping on the near-top-of-Campanian horizon is indicative of some Late Cretaceous activity on the Foster Fault System. The timing and character of the intra-Latrobe Group structures is discussed by B.R. Brown (1986).

3.2.3 Top Latrobe Group.

Plates 4A and 4B show seismic depth contours mapped on the unconformity at the top Latrobe Group. Although the Gurnard, Turrum or Flounder Formations occur at the top Latrobe Group (Plates 5 to 8), the mapped horizon is most likely to represent the top of the 'Top Latrobe coarse clastics' section. It is undoubtedly the most important horizon pertaining to petroleum occurrences and is the only horizon that has been mapped over nearly the whole of the offshore Gippsland Basin.

The time-transgressive nature of this horizon on which the hiatus decreases from east to west can be seen by comparing Plates 5 and 6. The mapping shows anticlinal closures resulting from the compressive tectonism previously discussed, the largest of which contains Australia's major producing fields (Plate 9A). The northwest-trending faults are less numerous than those seen on the intra-Latrobe Group horizons, but still quite prominent at the top Latrobe Group in several areas (e.g. Mackeral, Cobia, Snapper, Dolphin) transecting the anticlinal structures. Reverse movement on Early Cretaceous faults in the northwestern area is seen on both the top of Strzelecki Group and top Latrobe Group horizons. The origins and style of structures developed at the top Latrobe Group is also discussed by B.R. Brown (1986).

4. NEW IDEAS ON GIPPSLAND REGIONAL TECTONICS

[by J.B. Willcox & J.B. Colwell, BMR Marine Geoscience & Petroleum Geology Division.]

4.1 INTRODUCTION.

The Gippsland Basin is the easternmost of a string of Southern Margin basins which are associated with the fragmentation of Gondwana. Although Gondwana breakup/seafloor spreading in the Australian region was a protracted event, extending from about 155 Ma (Callovian) in the northwest of Australia to 55 Ma (Paleocene) in the northeast, the rift-phase which preceeded it may have been older and more synchronous than has been indicated in most literature.

On Australia's western margin, the rift-onset can be recognised by faulting and tilting of Permian sediments; for example, in the Carnarvon and Perth Basins. On the southern margin, dating of the rift-onset is far from certain, since the 'basin forming' tilt-blocks visible on some seismic sections, and the synrift sediments immediately overlying them, have rarely been penetrated by drilling. However, in two widely separated basins - the Eyre Sub-basin and the Bass Basin - there are wells which shed some light on the situation.

In the Jerboa No.1 exploration well in the Eyre Sub-basin, a basal Valanginian section was penetrated which appears to have a synrift relationship to underlying Precambrian (pre-rift) tilt-blocks. Since a relatively thick and older synrift section is probably present downdip of the well-site, in the flanking half-graben, the commencement of rifting must have occured, at youngest, in the Valanginian, but probably considerably before that time (Willcox & Stagg, 1990; Stagg & others, 1990). The lithospheric extension in the Eyre Sub-basin has been calculated at about 300 km and has been related to a detachment model in which an upper crustal Antarctic Plate separated from a lower crustal Australian Plate (Etheridge & others, in press). The dip of the tilt-blocks and the trend of transfer faults and accommodation zones indicate that extension was on a northwest-southeast azimuth. It has been inferred that this extensional system extends along the entire southern margin (Willcox, 1990): similar basin-margin trends and deep-seated tilt-blocks of uncertain age being observed in parts of the Great Australian Bight Basin, Otway Basin, Strahan Sub-basin (Sorell Basin), and South Tasman Rise basins. For the eastern basins, particularly the Otway and Sorell Basins, the extensional geometry suggests that their early development was predominantly strike-slip or very oblique and transtensional.

It would seem logical that the Bass Strait region was also structured by this same stress field. If this were so, then the Bass Basin, and probably Gippsland Basin, would also have been primarily strike-slip at their inception. However, such a scenario is at odds with Etheridge & others (1985) who, on the basis of detailed mapping of basement offsets along the flanks of those basins, concluded that the rifting was of Early Cretaceous age and on an azimuth of 027 degrees: that is, almost orthogonal to that in the Great Australian Bight region. Several north-northeast striking transfer faults (Gibbs, 1984) were postulated to divide the basins into extensional compartments. A major transfer fault or accommodation zone near the western end of the offshore Gippsland Basin was considered to link the Gippsland extensional system to an associated system in the Bass Basin.

4.2 BMR DEEP SEISMIC PROFILES (Plates 10 & 11).

A research program into the deep structure of the Gippsland/Bass region is underway within BMR. To date this has involved the acquisition of a 1600 km grid of deep (14 second) seismic data in the Gippsland Basin, a 1100 km grid in the Boobyalla Sub-basin (Bass Basin), and two transects of the Bass Basin proper. The processed, unmigrated seismic sections are available for purchase from BMR.

A preliminary interpretation of the data has revealed the following:

- the basin has developed by movements of the Palaeozoic basement on a major detachment complex ranging in depth from about 10-15 km. The complex extends beneath the Bassian Rise and links the Gippsland to the Bass Basin.

- on both the 'dip' and 'strike' lines, the basin-bounding faults are listric, and are overlain by blocks of tilted Strzelecki and (?)pre-Strzelecki sediments. The data on the NNE-SSW orientated lines shows that there is no progressive increase in dip of the blocks towards the basin centre (the Central Deep); in fact, in many areas the adjacent blocks have discordant dips, from which we infer that there has been substantial movement parallel to the basin axis (that is, from WNW-ESE, or vice versa).

- the faults basinward of the basin boundaries are generally steep-dipping and in many instances comprise branching 'flower-like' structures, several of which extend to the top Latrobe unconformity.

- the northern margin fault system appears to have been active until top Strzelecki time (end of the Early Cretaceous), whereas the southern margin fault system was particularly active through the Late Cretaceous.

- a major erosional event took place during the latest Cretaceous, probably terminating with a peneplaned basement/basin surface in the Maastrichtian (Horizon B).

- the thermal sag phase of basin evolution appears to have commenced in the Campanian.

4.3 PROPOSED TECTONIC HISTORY OF THE GIPPSLAND BASIN.

- strike-slip or highly oblique opening of the Palaeozoic basement in both the Gippsland and Bass Basin areas on a common detachment complex. The movement would have been largely in a WNW-ESE or NW-SE orientation, and was in response to the lithospheric extension and Gondwana fragmentation which affected the entire Southern Margin of Australia. We presume that its age was pre-Valanginian and that the sense of movement was most likely left-lateral.

- syn-basinal sedimentation of possible Early Mesozoic age (Sequence F-G), followed by block-faulting. The Horizon G unconformity could possibly be of Neocomian age since it has some of the characteristics of the Neocomian unconformity/ decollement in the Bight region. If so, it would probably be the product of western margin breakup.

- deposition of the Early Cretaceous, continental, Strzelecki Group (Sequence E-F). Part of the sediment was derived from a major north-south trending, partially volcanic, ridge which lay along the eastern margin of the basin, and which now underlies the continental rise. On some sections, sediments in the form of alluvial fans, seem to have been derived from high-standing blocks along the northern margin of the basin. The presence of the Strzelecki Group is only proven by drilling on the Northern and Southern Strzelecki Terraces; however, seismic characteristics indicate that its equivalent probably occurs throughout the 'Central Deep'. It is essentially a 'synrift deposit' within the oblique- to strike-slip basin.

- at the end of Strzelecki time (?Cenomanian), when the initial slow spreading phase commenced on the southern margin, a major episode of transpressional and wrench-related faulting took place in the Gippsland Basin (Horizon E). Blocks of Strzelecki Group sediments moved laterally on shallow-dipping detachment surfaces. These movements presumably reflect continued activity on sinuous basin-bounding fault systems.

- through much of the Late Cretaceous, at least till earliest Campanian time (Sequence D-E), the focus of sedimentation was adjacent to the southern bounding fault system. This system was then highly active, unlike the northern boundary which behaved as a hinge. A huge wedge of sediment was deposited within what was essentially a basin-wide half-graben; up to 3 seconds (say 5 km) in the southeast.

- from Campanian to Maastrichtian time (Sequences C-D & B-C), the area seems to have undergone relatively simple sag-phase subsidence in association with the spreading of the Tasman Sea Basin. Continued structuring of the sediment pile by compaction drape and growth of the wrench-related faults, particularly in the main depocentre.

- final peneplanation of the basin margins in the Maastrichtian (Horizon B).

- from latest Cretaceous to early Tertiary time, continued deposition of the upper Latrobe Group aluvial-plain to shoreline sediments, development of the top Latrobe unconformity (Horizon A) and stuctures due largely to (?) transpression, and the deposition of shales and marls of the Oligocene Lakes Entrance Formation under open marine conditions.

4.4 TECTONIC SUMMARY.

In summary, our preliminary interpretation suggests that the Gippsland Basin is <u>not</u> a product a simple NNE-SSW orientated extension as in the model proposed by Etheridge & others (1984). It appears to be of strike-slip to transtensional origin, with early movements sub-parallel to the basin axis. It is probably related to other Southern Margin basins and originated in the earliest Mesozoic. The seismic megasequences and their bounding unconformities can be interpreted in terms of the rifting and breakup history of the Western and Southern margins of the continent and the Tasman Sea Basin.

It is a poly-history basin, with structuring occurring in several stages since its inception. Generation of the traditionally prospective anticlines has taken place through much of the Late Cretaceous and Eocene, and is thought to be caused by transpression of the thick sediment pile when periodic movements on the sinuous north and south-bounding fault systems created restraint in the sediment fill. Thus the anticlines are essentially wrench induced structures.

4.5 COMMENTS ON PETROLEUM PROSPECTIVITY.

The regional data lead us to the following conclusions in regard to petroleum potential:

- the apparently complex structural and stratigraphic history of the basin suggests that, theoretically, there may have been several phases of petroleum generation and migration.

- there appear to be several potential traps below the top of Latrobe unconformity, and in many cases structures near the 'top Strzelecki' and in the 'lower Latrobe' are not reflected in the structure of the top Latrobe unconformity.

- on the basis of the seismic stratigraphy a Strzelecki Group equivalent appears to be present in the Central Deep, however, it has not been drilled.

- in places along the northern flank of the basin, blocks of (?)pre-Strzelecki sediments appear to have shed alluvial fan deposits (possibly with associated fluvial-lacustrine deposits) into the Central Deep. These may be worth investigating for potential traps.

- in post-Strzelecki time, the axis of deposition shifted to the south and was adjacent to the southern bounding fault system.

- potential petroleum source rocks within the largely unknown post-Strzelecki (D-E) sequence could, in the latest Cretaceous, have expelled petroleum updip into compaction/drape structures of similar age, and/or along conduits created by the southern fault system which was active to the (?)Maastrichtian.

- the nature of the rocks incorporated in parts of the Southern Platform needs to be further considered.

5. PALAEOGEOGRAPHY

[by A.E. Stephenson.]

The palaeogeography of the Gippsland Basin could be the subject of a data package the size of this Record in its own right. The basin has been subject to a complex interplay between tectonics, eustacy, sediment supply, and climate throughout most of its existence - a 'stable' palaeogeography has existed only sporadically and for short periods during the last 150 million years or so. This brief section is designed to give the 'flavour' of the Gippsland Basin's palaeogeography - a detailed study is beyond the scope of this petroleum prospectivity package.

5.1 EARLY CRETACEOUS.

Early Cretaceous palaeogeography can be interpreted only from the Strzelecki Group sediments around the Gippsland Basin margins. As described earlier, the known Strzelecki Group consists entirely of terrigenous sediments. Although Strzelecki Group equivalents are believed to exist at depth in the Central Deep, they have yet to be intersected by the drill, and their nature is unknown.

Onshore, Early Cretaceous sediments indicate initial alluvial and/or colluvial fan deposition succeeded by alluvial to upper coastal plain environments. These environments in turn were succeeded by lower coastal plain riverine and coal swamp environments towards the end of the epoch. Evidence from drillholes on the Strzelecki Terraces is consistent with this interpretation. Widespread volcanoclastic sediments probably indicate considerable volcanism around the basin's margins, although evidence from the Eromanga Basin shows that volcanolithics such as shards can be deposited many hundreds of kilometres from their source. It is not impossible that marine incursions into the present Central Deep area took place; very likely at least local lacustrine conditions (associated with initial rifting) prevailed at times, but no supporting data are available.

5.2 LATE CRETACEOUS.

Latrobe Group sedimentation began in the early Late Cretaceous, but as for the Strzelecki Group, evidence is restricted to the non-Central Deep parts of the Gippsland Basin until the Campanian. Drilling has simply not reached rocks of older age in the centre of the basin. Logic suggests that marine incursions should have occurred in at least the east of the basin throughout the epoch, as the Gippsland Rift developed in association with the opening of the Tasman Sea. The earliest evidence of a marine incursion is found at Kipper and Tuna, in the northeast of the basin, where Santonian dinoflagellate assemblages have been recorded. Around the basin margins, early Late Cretaceous sediments indicate braided stream and alluvial fan environments. On the Strzelecki Terraces, pre-middle Campanian sediments are referred to the Golden Beach Formation, which is separated from the rest of the Latrobe Group by a major regional unconformity (Lowry, 1987, 1988). Pre-unconformity sediments appear to have been mainly deposited in fluvial flood plain environments (Evans, 1986), although a thick sequence of volcanics with interbedded alluvial sediments occurs at Basker (Stainforth, 1984).

By the Late Campanian, the main Latrobe Group depositional style was dominated by an overall marine transgression punctuated by shorter-term eustatic transgression - regression episodes. Sediments were deposited typically along wave-dominated shorelines in a suite of environments ranging from lower shoreface, through littoral, coastal barrier and back barrier lagoon, to lower and upper coastal plain, with fluvial deposition around the basin margins (Plate 12). The transgression was primarily driven by thermal subsidence, but the overprint of eustacy has enabled several sequences or sedimentary packages to be identified (as by Rahmanian & others, 1990). Nonetheless, by the Late Maastrichtian a significant nett westerly migration of all palaeofacies is evident (Plate 12).

5.3 PALAEOGENE.

The complex interplay between gradual subsidence and changes in sealevel was also overprinted by variable climate in the Palaeogene, which affected sediment supply. Australia completed its breakup with Antarctica during this epoch, and began moving further north. Overall, regional transgression continued, with the depositional succession gradually moving further west (Plate 12). Evidence from elsewhere in southeastern Australia shows that this part of the continent entered a particularly wet climatic phase during the Eocene (Stephenson & Brown, 1989), with development of widespread coal swamps, including those of the Gippsland Basin.

Offshore, eustatic falls in sealevel led to two major channelling and erosive events in the Eocene (Fig. 4), which was probably exacerbated by higher river streamflows. The first episode led to the development of the Tuna and Flounder Channels, backfilling of which saw deposition of the Flounder Formation. The next eustatic fall caused even greater erosion, and formation of the Marlin Channel (Figs. 3, 4), which was subsequently backfilled by the Turrum Formation.

The regional transgression gained pace rapidly following these two major regressive episodes, and the retreating coastal sand complex which was later to become the top Latrobe Group 'coarse clastics' series of petroleum reservoirs was deposited. Facies migration to the west saw these coastal sands overlapped by nearshore marine clastics of the Gurnard Formation, which forms the major semiregional seal for the top Latrobe hydrocarbon fields. By the end of the Eocene the transgression was at a maximum, with Latrobe Group continental sediments being deposited only in what is now the onshore Gippsland Basin. The modern coastline's broad ouline had been established, and further subsidence throughout the Oligocene saw steadily increasing water depths, and some migration of the nearshore Gurnard Formation facies to the west. The world wide mid-Oligocene sealevel fall seems to have had very little effect in the Gippsland Basin, although it is readily recognisable in the nearby Murray Basin (Brown & Stephenson, 1990).

5.4 NEOGENE.

Steady but gradual increase in water depth led to deposition of first the shallow marine Lakes Entrance Formation, then the shelf carbonates of the Gippsland Limestone. The boundary between the two units is diachronous. The only major event occurred in the middle Miocene, when a series of major submarine channels developed (Fig. 5) probably related to the major compressional tectonic event which affected the Gippsland Basin during the Miocene. Alternatively, southeastern Australia was influenced by a major eustatic sealevel drop in the late Middle Miocene (Brown & Stephenson, 1990), with resulting channelling. A combination of both factors is considered likely. At the northern edge of the basin, a minor regression has been occurring since the Pliocene, as sediment influx from the southeastern Australian highlands exceeds subsidence.

6. HYDROCARBON PLAY CONCEPTS

[by A.E. Stephenson]

Hydrocarbon play concepts in the Gippsland Basin have traditionally fallen into two categories: top of Latrobe Group and intra-Latrobe Group. Examples of both are discussed below, as are other possible play concepts.

6.1 TOP OF LATROBE GROUP PLAYS.

6.1.1 Structural plays.

Top Latrobe Group structural plays have provided about 80% of the hydrocarbons discovered to date in the Gippsland Basin. The now classic top Latrobe play is an association of excellent quality sands of the 'coarse clastics' with anticlinal or faulted anticlinal structures. Major fields such as Kingfish, Barracouta and Marlin are examples. Several sand units with a common oil-water contact may be involved, as at Kingfish. Often separate culminations lie on a larger anticlinal structure, such as Perch, Dolphin, and Tarwhine. Traps formed by convergent faults occasionally form at top Latrobe Group level, as at Sunfish. Several fields are partly bounded by Eocene or Miocene channels, which commonly act as lateral seals - Halibut and Flounder are examples. Although commonest in the Central Deep, top Latrobe structural plays occur across the entire offshore Gippsland Basin, and hence the play type is relevant to all three vacant areas.

6.1.2 Stranded beach-barrier play.

Stranded beach-barrier sediments often form the reservoir sands in top Latrobe structural traps. The potential exists for such beach-barrier complexes to form purely stratigraphic traps, enclosed by shallow marine and backbarrier shales and mudstones. This play type has been tested by drilling in the west of the basin (by Tommyruff No.1), but no producing fields fit into this play category. Combined structural and stratigraphic traps contain hydrocarbon accumulations (such as some reservoirs at Tuna), but successful discovery of purely stratigraphic traps requires rigorous facies mapping and palaeogeographic interpretation. Stratigraphic top Latrobe plays are possible in all three vacant areas.

6.1.3 Taranaki analogue play.

This play was suggested by the senior author to APIRA sponsors of BMR's Palaeogeographic Maps Project in 1989, as part of a comparison between the Gippsland Basin and New Zealand's major hydrocarbon-producing basin, the Taranaki. The play involves looking for analogues of the Taranaki's Maui Field, where deep-sourced hydrocarbons have migrated upward along a major graben-bounding fault to a reservoir on the adjacent shallow shelf.

The southern Gippsland Basin is thought to be analogous to the Taranaki in structure, source, and probable migration paths, and seal should also be present at the top Latrobe Group level. Indeed, the Perch Field, immediately south of the Darriman Fault, may be a representative of this play. The Taranaki analogue play is particularly relevant to area V91-G2 (Plate 35), although it is also relevant to the north-eastern part of area V91-G1, adjacent to the Foster Fault Zone (Plate 20).

6.1.4 Brazilian analogue play.

The Brazilian analogue play was proposed by Dr M.V. Dauzacker, formerly of Petrobras and currently based in Perth. The play is modelled upon the Campos and other Brazilian passive margin basins, and relies upon deep migration of hydrocarbons along extensional fault systems to an edge of basin frontal block, where synthetic and antithetic faults create a horst-like structure. This play type has not been tested in the Gippsland Basin, but was tested in the nearby Otway Basin by Cultus in 1990 with their Copa No.1 well, which was dry. The Brazilian analogue play was championed by Cultus in VIC/P23, but would be relevant only to area V91-G1 in this release.

6.1.5 Gurnard sand play.

The Gurnard Formation is generally regarded as a sealing unit over the 'coarse clastics', but does host hydrocarbon accumulations in some locations, such as at West Kingfish and Flounder. Gurnard hydrocarbons can be expected in stratigraphic traps, where porous sandy intervals are encased by the more typical glauconitic mudstones which make up most of the formation. Gurnard Formation stratigraphic traps may well be upgraded if reinforced by local structuring. Discovering stratigraphic traps within the Gurnard Formation will require high resolution seismic data and a thorough understanding of the local impact of palaeogeography and sequence stratigraphy. This play type will be of most interest in Area V91-G3.

6.2 INTRA-LATROBE GROUP PLAYS.

6.2.1 Structural plays.

Intra-Latrobe Group structural plays include anticlines, faulted anticlines, and fault traps. top Latrobe Group anticlines are often paralelled at intra-Latrobe horizons, such as at Snapper and Tuna, but reservoir quality decreases at depth. Anticlines occur at intra-Latrobe level which have no closure at top Latrobe, such as at Hermes and Selene. Similarly, intra-Latrobe faulted anticlines can parallel top Latrobe structures, as at Flounder, or form unrelated traps at depth, as at Manta and Basker. The degree of faulting increases with depth in the Latrobe Group, and faulted anticlines are in fact the dominant trap type at intra-Latrobe levels. Pure fault traps are rare - even when convergent faults are involved; as at Archer, an anticlinal component is important. Intra-Latrobe Group structural plays are relevant to all three release areas, but particularly so for Area V91-G3.

6.2.2 Stratigraphic pinchout plays.

Intra-Latrobe Group depositional systems were highly variable, both spatially and temporally (Plate 12), with considerable variability in sedimentary facies. Intra-Latrobe stratigraphic pinchout plays are difficult to detect seismically, but can be highly productive - as at Fortescue. Recently, sequence stratigraphic analysis has been applied to the Latrobe Group (e.g. Fittall & Cvetanovic, 1991) in an attempt to delineate stratigraphic pinchout plays. Several types of stratigraphic pinchout plays are possible:

Beach-barrier plays, similar to those for the top Latrobe, except that top seal is more problematical in the absence of the Gurnard and/or Lakes Entrance Formations. Such beach-barrier complexes have been encountered at intra-Latrobe levels - the Late Cretaceous 'Selene Sandstone' being one example. These beach-barrier complexes have the upside potential to be giant fields, but the extensive faulting typical of the intra-Latrobe significantly increases seal risk, downgrading such prospects. Reservoir quality is also lower than at top Latrobe level, mainly due to diagenesis. This play is pertinent to area V91-G3, and to the north of V91-G2.

The fluvial **point bar play** is the classic intra-Latrobe stratigraphic pinch-out play. Unfortunately, whilst these contain much of the intra-Latrobe oil discovered below top Latrobe accumulations, they are frequently difficult to recognise on seismic. Most 'deeper pools' have been discovered by appraisal or development drilling continued in the hope of intersecting deeper pay zones. This play is important in all three areas, but particularly in area V91-G3.

Sequence boundary plays are the flavour of the month in some companies, and rely upon sequence boundaries for top or bottom seal, and intra-sequence facies changes for lateral seal. This play type has great potential, and has barely been tested in the Gippsland Basin. The **lowstand wedge play** is a subset of the sequence boundary play, and invokes transgressive marine shales to overlie lowstand sand wedges. Sand wedges are certainly present in numbers in the Gippsland Basin, but marine shales were conspicuous by their absence in the only well drilled to date in this play. An extremely rigorous and detailed approach and an open mind will be required to discover hydrocarbons in sequence boundary plays, which can potentially be found in all three vacant areas. In particular, local tectonic, climatic, and sediment supply factors need to be taken into consideration.

6.2.3 Basin margin fan plays.

Two types of basin margin fan play are possible. The **deep fan play** invokes turbiditic sands on the continental slope as potential reservoirs. This play has proven very productive on the Brazilian continental margin, but has not been tested in the Gippsland Basin, mainly because of prohibitive water depths. Improving technology and economics of deep water drilling and production will make this an attractive medium to long term play in the Gippsland Basin. Area V91-G1 is most prospective for this play type.

The **colluvial fan play** relies upon coarse grained outwash sediments adjacent to the basin margin or to major palaeotopographic highs forming reservoirs. The major risk for this play is hydrocarbon charge, as long migration paths must frequently be invoked; seal is also problematical. This high-risk play is relevant in both Areas V91-G1 and V91-G2.

6.2.4 Volcanic seal play.

Volcanics and sills are quite common within the Latrobe Group, and can act as top seal, as at Kipper. Lateral seal would be by dip and/or fault closure. Potential exists in all three areas for hydrocarbon prospects top-sealed by igneous rocks.

6.2.5 Golden Beach Formation play.

The Golden Beach Formation play was first described by Lowry (1987), following the discovery of the Kipper field in the northeastern Gippsland Basin. As described earlier, Lowry (1987, 1988) concluded that an angular unconformity previously thought to represent the Latrobe/Strzelecki Group boundary was actually an intra-Latrobe unconformity. He suggested a new sub-unconformity play for the Gippsland Basin, based on this identification of 'additional' prospective Latrobe Group section, the Golden Beach Formation. Although Kipper proved to be a substantial oil and gas discovery, subsequent wells targeted on the Golden Beach Formation play have been disappointing, in part because of poor reservoir quality caused by diagenesis. Lowry (1987) was unsure whether the Golden Beach Formation occurred in the southern Gippsland Basin, and drilling results so far are inconclusive. If the Golden Beach Formation is present in the southern Gippsland Basin, this play type would be relevant in the north of Area V91-G2 and the northeast of Area V91-G1.

6.3 OTHER PLAYS.

Although the Latrobe Group is by far the most prospective sequence in the Gippsland Basin, hydrocarbons have been recovered from other units, as previously described. Two additional plays have been identified in the southeast Gippsland Basin.

6.3.1 Strzelecki fault block play.

Large, tilted fault blocks of Strzelecki Group sediments occur along the Southern Strzelecki Terrace. Potential traps have been identified at top Strzelecki level (Plate 35), fault conduits exist for migrating hydrocarbons, and the Strzelecki Group sediments are thermally mature at depth within the blocks. As described in section 2.4, the Strzelecki Group has been historically underrated as a potential source, and this play type remains almost untested. It is particularly relevant to Area V91-G2.

6.3.2 Lakes Entrance Formation sand play.

The Lakes Entrance Formation contains hydrocarbons at Bream and Lakes Entrance, and has the potential to form stratigraphic traps in the southeast Gippsland Basin also. These traps would be of Oligo-Miocene age, and require significant lateral and/or vertical migration of hydrocarbons. Several such potential traps have been delineated in Area V91-G1 (Plate 20).

7. AREA V91-G1

Area V91-G1 comprises 43 graticular blocks in the far southeast of the Gippsland Basin (Plate 13). Authorship is specified under each subsection.

7.1 PREVIOUS EXPLORATION.

[by Tun U Maung & A.E. Stephenson.]

Area V91-G1 includes parts of three previous permits: VIC/P12, operated by Union Texas, VIC/P18, operated by Phillips, and most recently VIC/P23, operated by Cultus.

7.1.1 Drilling.

Pisces No.1.

Only one well, Pisces No.1, has been drilled in Area V91-G1. Pisces No.1 was drilled by Union Texas in April-May 1982, and discovered a structural feature within the Gippsland Basin's Southern Platform which has been variously called the 'Pisces Graben' or the 'Pisces Sub-basin' - the former usage is preferred in this report.

The Latrobe Group target proved to be of Late Cretaceous age, not Early Tertiary as predicted (Figure 10); the pre-drill interpretation of a deltaic marginal marine sequence was correct, although it contained less coal than anticipated. Union Texas concluded that the Pisces Graben section was distinctively different, on both lithological and palynological grounds, from Latrobe Group sections elsewhere in the basin.

No hydrocarbons were encountered by Pisces No.1, which may be attributable to either lack of seal or lack of charge. The Latrobe Group is overlain by sheet estuarine sands of the Gurnard Formation, which are in turn overlain by prodelta sheet sands correlated with the lower Lakes Entrance Formation - top seal is thus absent below the uppermost Lakes Entrance Formation, which consists of Early Miocene, prograding shelf siltstones and mudstones. Hydrocarbon charge would involve either local generation in the Pisces Graben, or long-distance migration from the basin's main hydrocarbon kitchen to the north. Both charge scenarios are high-risk.

7.1.2 Geophysics.

Area V91-G1 is covered by six different vintages of seismic data: GC80, GP81, GC81A, 1982 BMR, GUT83A and GC89A (Appendix 2). The seismic coverage consists of over 3300 line-km with the general grid spacings of 1.0 x 1.0 km to 4.0 x 8.0 km (Plates 1A and 14). The seismic data from the eastern part of the Area is of poor quality due to the varying water depths and the presence of deep canyons in the sea floor (Plates 13A & 13B); these features also

PISCES 1

Latitude : 39°03'37.05"S
Longitude : 148°30'41.27"E

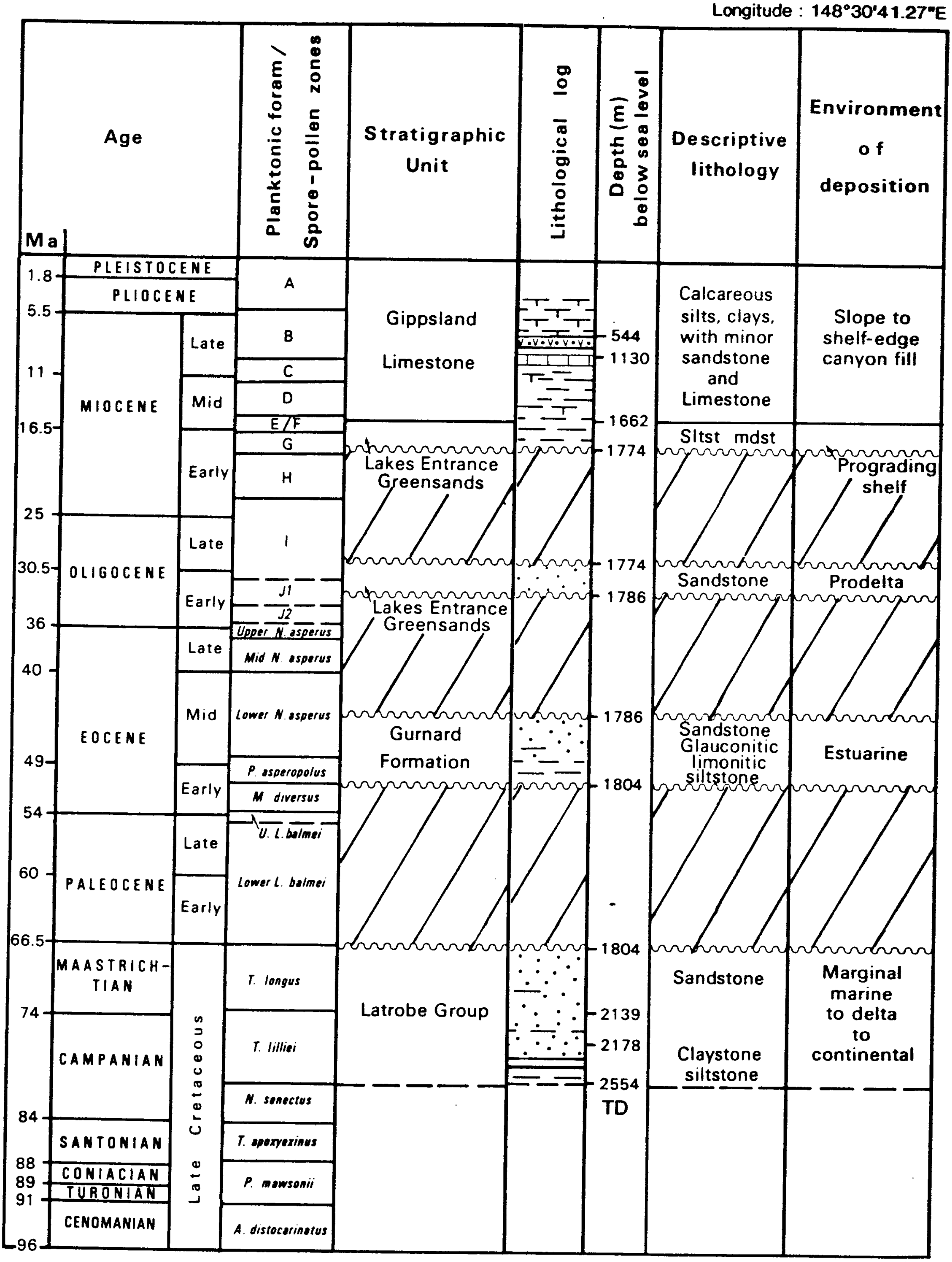


Figure 10 Pisces 1 well (after Moore, 1989)

produce velocity anomalies. In the remaining part of the Area, the seismic data quality is fair to good. During the GUT83A seismic survey, magnetic data were acquired concurrently with the seismic data. A total magnetic intensity map was constructed, and magnetic and seismic modelling of the intra-Latrobe Group features were carried out from this data by Union Texas Petroleum.

All seismic surveys previous to GC89A used different acqusition and processing parameters, and therefore cannot be used for detailed seismic correlation because they do not tie properly, but they can be used to draw a broad structural picture of the area. As there are difficulties in tying-in the data from different surveys, a total of 3000 line-km of 1981 to 1983 data were reprocessed by Cultus Petroleum N.L. in 1988, and the sections were produced at zero phase. The GC89A survey, carried out by Cultus in 1989, consists of 15 lines comprising 301 line-km. The final stacked and migrated sections were produced at zero phase and were displayed at a scale of 1;25 000 at 10 cm/sec to facilitate integration with the existing reprocessed data.

In the eastern part of the area, where irregular or steeply dipping sea floor exists, the time variations introduced when the water depth changes rapidly relative to the cable length will not be static but dynamic. The conventional replacement static corrections cannot be used directly on marine seismic data recorded over these areas of irregular sea floor as fictitious time shifts with consequent time and velocity errors are introduced. They are dynamic, because they differ for different event times of a single seismic trace. To compensate for these dynamic time variations, a ray-trace modelling program is used to calculate the travel times to several depths, and these results are used to shift the samples on all seismic traces to the time they would have had if the sea floor had been even (Dent, 1983).

The area of steeply dipping and irregular sea floor is also crossed by three major submarine canyons (Plates 13A & 13B). Portions of seismic lines over these canyons, had water replacement statics applied and these data were then merged into the conventionally processed data away from the channels (Berryhill, 1979 and Blackburn, 1981). The events beneath the channels showed significant improvements.

The increasing water depths across the Area and associated marked lateral velocity variation distorts the 'time' section greatly to produce an entirely false impression of the dip in time. Depth conversion of all the seismic data was necessary to remove the 'push-down' effect of the increasing water depth. The 'layer cake' method of depth conversion was used, whereby the thickness of the water layer was added to the thickness of the layer from the sea floor to the top Latrobe Group reflector (Hubral & Krey, 1980, Cordier, 1985, Hughes, 1985, Carter, 1989, Marsden, 1989, and Sherwood, 1989). The depth conversion was carried out by using interval velocities calculated from stacking velocities using Dix equation (1955) for a single interval from the sea floor to the top Latrobe Group reflector. These calculated interval velocities were tied to the well velocity for the particular interval by applying a conversion factor of 0.95 to obtain values close to the true interval velocities. This conversion factor was obtained by comparison of well velocity data and the stacking velocities. The velocity used for the water layer was 1480 m per second. Depth conversion to the top of intra-Campanian Unconformity reflector was also carried out by the same process using appropriate interval velocities.

7.2 LOCAL GEOLOGY AND RELEVANT PLAY CONCEPTS.

[by A.E. Stephenson]

Vacant Area V91-G1 is located in the southeastern extremity of the Gippsland Basin (Plate 13). The area contains three main structural features: the Southern Platform, the Southern Strzelecki Terrace, and the Pisces Graben (the latter lying within the Southern Platform).

7.2.1 Southern Platform.

The Southern Platform consists of shallow basement (1.5 - 2.0 km subsea) overlain by very thin Cretaceous Latrobe Group sediments (100 - 300 m thick), in turn covered by Lakes Entrance Formation and Gippsland Limestone (Plate 6). Only two hydrocarbon plays have been recognised on the Southern Platform; both rely upon long migration paths, and thus are high risk. The first is the Lakes Entrance Formation sand play (6.3.2), mapped as the Z Lead Trend on Plate 20. The second possibility is the Taranaki analogue play (6.1.3), which could occur south of the Foster Fault Zone - Lead E on Plate 20 is an example.

7.2.2 Southern Strzelecki Terrace.

A small portion of the Southern Strzelecki Terrace lies within the northernmost blocks of Area V91-G1, immediately north of the Foster Fault Zone (Plate 20). In this area a series of Strzelecki Group fault blocks step downwards towards the Central Deep (Plate 6), and are draped by Latrobe Group sediments. The latter range from about 300m thick near the edge of the Southern Platform, up to 1 km thick at the extreme northern limits of V91-G1, and are draped in turn by 1.5 km to 2 km respectively of Lakes Entrance Formation and Gippsland Limestone sediments. As on the Southern Platform, the Latrobe Group here is immature for the generation of hydrocarbons, and a Central Deep or Strzelecki source must be invoked; migration paths are however much shorter than for potential Southern Platform plays. At the top Latrobe level, three plays are possible: structural (6.1.1), stranded beach barrier (6.1.2), and Brazilian analogue (6.1.4). The Gurnard sand play (6.1.5) is possible but considered to be unlikely. At intra-Latrobe levels, possible play types include all five listed in section 6.2, with particular emphasis on structural and fan plays. The Strzelecki Fault Block play (6.3.1) is also possible if rollover against faults can be demonstrated.

7.2.3 Pisces Graben.

The Pisces Graben lies within the Southern Platform, and contains up to 2 km of Latrobe Group sediments, overlain by 1.5 km of Lakes Entrance Formation and Gippsland Limestone (Plate 6). Local generation of hydrocarbons is possible but unproven; alternative sourcing from the Central Deep would require lateral migration of in excess of 50 km, with all the associated risks. All known prospects and leads occur in structures beneath the Top-of-Latrobe unconformity, except the Z Lead trend, which targets the Lakes Entrance sands play (6.3.2). Prospects and leads are described in detail in section 7.6, and shown on Plates 19 & 20.

7.3 RESERVOIR GEOLOGY.

[by Shige Miyazaki, BMR Petroleum Resource Assessment Branch]

7.3.1 Pisces No.1.

Pisces No.1 was drilled by Union Texas in 1982. Fine-grained sandstones in drill cuttings from 510 to 520 mKB gave minor fluorescence and cuts. Traces of fluorescence were also recorded on drill cuttings from 1674 to 1760 mKB within the Lakes Entrance Formation.

The well was designed to test a top Latrobe closure situated on the down-thrown side of the boundary normalfault between the Central Deep and the Southern Platform. The well intersected the top Latrobe 'coarse clastics', of the T. longus zone, at 1826 mKB, but sandstones in this zone turned out to be water-wet.

Upper Cretaceous siltstones, of the T. lillei zone, gave some hydrocarbon shows. Sidewall core siltstone samples from 2357 and 2377 mKB showed weak fluorescence, and drill cuttings from 2358 to 2458 mKB exhibited patchy fluorescence and produced weak cuts.

Siltstones dominate the Upper Cretaceous section of this well. The interval from 2482 to 2486 mKB is a rare example of the occurrence of clean sandstones. The sandstones have a log porosity of 12% but are water-wet.

The well was terminated at 2574 mKB within the T. lillei zone. No conventional core was cut, and no RFT survey was run in this well.

7.4 DRILLING ENGINEERING.

[by Vel Vuckovic, BMR Petroleum Resource Assessment Branch]

7.4.1 Pore Pressure and Fracture Pressure Evaluation.

Pore pressure gradients and fracture pressure gradients are essential parameters for safe and economical well design. The actual field data from the wells drilled in an area are indispensable for accurate pore pressures and fracture gradients prediction.

Pore pressure and fracture pressure date from sixteen wells drilled to date in Area V91-1, Area V91-2 and Area V91-3 were available for review.

Pore pressures in each well were evaluated on the basis of various parameters measured during drilling and logging such as "d" exponent, trip gas and connection gas readings, shale densities, temperatures, shape and size of cuttings and direct measurement of formation pressures by DST and RFT tools. The estimation of pore pressures using indirect methods is considered subjective; however, it provides close enough definition of pore pressure regime in an area to allow safe drilling.

All sixteen wells studied showed normal pore pressure regime of between 0.99 to 1.10 S.G. Normal pore pressure regime is defined as the hydrostatic pressure exerted by the column of water from any depth to surface. Hydrostatic pressure is a function of formation water density and could be only maintained if a permeable pathway to surface exists.

The formation fracture gradient is a function of several variables and equations used to calculate it are complex in some cases. However, one of the most important variables required to calculate the approximate pressure at which a formation will fracture is the pore pressure within that formation. As established previously, pore pressures in all three release areas appear to be hydrostatic. The formation fracture gradients can therefore be approximated using Eaton's correlation chart.

The brief overview of each surveyed well is summarised below, and in sections 8.4 and 9.4 of this Record. Where available drill data plots and pressure gradients analysis plots are attached.

7.4.2 Pisces No.1.

Operator: Union Texas Australia Inc.

Co-ordinates: 38° 03' 35.919" S.
148° 30' 42.474" E.

Elevations: KB: 22 m.
GL: - 122 m.

Dates: 15.04.82 to 15.05.82.

Status: Plugged and abandoned.

Open hole sections:

36" to 190 m.
26" to 368 m.
17.5" to 1071 m.
12.25" to 2580 m.

Casings:

30"	shoe at	184 m.
20"	shoe at	353 m.
13.375"	shoe at	1056 m.

Pore pressures: During the drilling of Pisces No.1 no overpressuring was recorded. Sharp peaks in the curve to the left of the normal DCS trend were recorded in sands below 1821 m. Such peaks were representative of porous formations rather than of overpressured shales and allowed calculation of porosities

The loss of a cone close to T.D., together with other junk in the hole, caused the drilling rate to slow considerably. Under such circumstances the DCS exponent is not representative.

Formation integrity tests:

377 m	1.48 S.G.	leak off.
1087 m	1.55 S.G.	leak off.

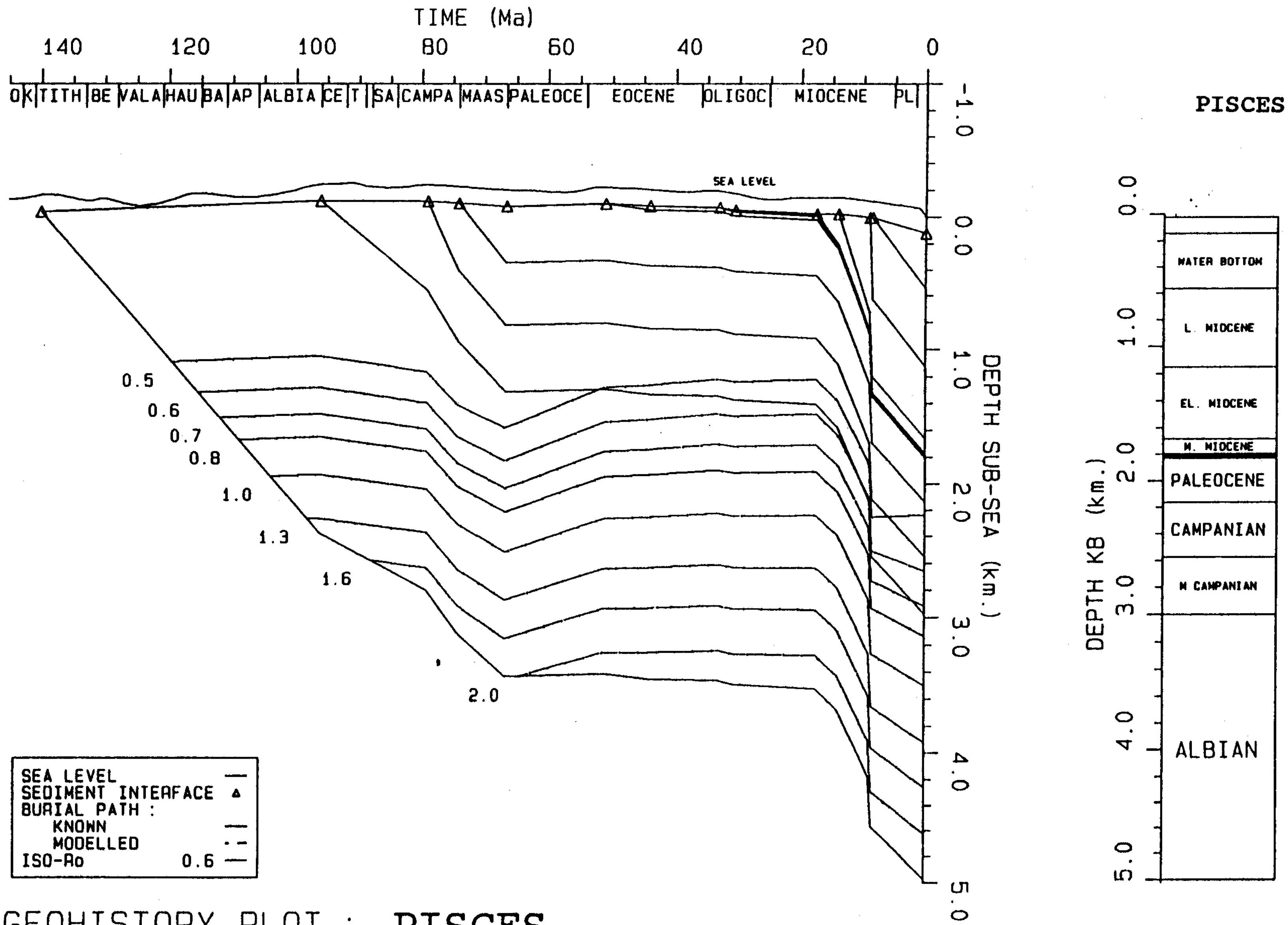
7.5 GEOHISTORY - Pisces No.1.

[by Paul E. Williamson, BMR Petroleum Resource Assessment Branch]

Modelling of the timing of source rock maturity for Pisces No.1 was included in the geohistory study (Figure 11). The maturity for the onset of oil generation for the type of terrestrial source rocks in the Gippsland Basin is considered to correspond to a vitrinite reflectance of 0.7%, maximum oil generation to a vitrinite reflectance of 1.0% and the onset of thermal gas generation at 1.3%. On that basis, present day maturity for oil generation at the Pisces No.1 location would occur in the Strzelecki Group and possibly in the lowest Latrobe Group at depths greater than 3.0 km. At the time of the Miocene compressional event which contributed to trap formation at top Latrobe Group level the upper Strzelecki Group was immature for oil generation. Since that time maturity has moved shallower in the section with subsequent burial and increased temperatures in the sediments. The thermal gas window now occurs in the interpreted lower Strzelecki Group at a depth of approximately 4.1 km.

No vitrinite reflectance data were available for the Pisces No.1 well, but the thermal history used corresponds to that which produces calculated vitrinite reflectance values which match observed values in the region.

The inferences from the geohistory study are that hydrocarbons in the region have been sourced probably from the Strzelecki Group with a possible contribution from the lowest Latrobe Group. Hydrocarbons now occur at levels immature for oil generation. These hydrocarbons have thus migrated vertically into traps set in their present form by seal facies overlying structures associated with Miocene compression and erosion of the top Latrobe Group reservoirs. Since migration of existing oil at that time would have resulted in loss, it can be inferred that hydrocarbons have also been produced from strata subsequently within the oil window and that the oil hydrocarbons have been released by rapid burial since the Miocene compressional event.



GEOHISTORY PLOT : **PISCES**

Figure 11.

7.6 INTERPRETATION PROBLEMS.

[by Maher Megallaa, VDMID, Petroleum Resources Branch.]

7.6.1. Background.

Block V91-G1 was previously granted as Permit Vic/P12, operated by Union Texas, and then as Permit Vic/P23, operated by Cultus Pacific. The information cited here is partly based on company analyses and studies, and presented in this publication with the permission of Cultus Pacific. A number of problems were encountered by the operators during the mapping of the V91-G1 area. Some of these problems, and their solutions are summarised below.

7.6.2 Problems.

A) Misties. Prior to the Cultus 1989 GC89A seismic survey, five different surveys of the area existed: GC80; GP81; GC81A; BMR 1982; and GUT83A. Tying the data between these different surveys was difficult.

B) Irregularity of the Seabed. The seafloor in the eastern portion of V91-G1 slopes steeply, and is incised by two major submarine canyons. This introduces static, lateral velocity, and diffraction problems. When the water depth changes rapidly relative to the seismic cable length, time variation is introduced which results in time shift variation down any individual seismic trace. Also, the time shift associated with any particular shot varies with offset, which produces static correction problems.

C) Lateral Velocity Changes. Large lateral velocity changes associated with these seafloor canyons can severely distort seismic stack sections, pulling time horizons down so they appear with a dipping orientation. Conventional replacement statics can partially correct for regular steeply dipping seafloor, but it is inadequate when this seafloor is crossed by canyons or other irregularly steeply dipping water bottom features.

D) Insufficient Velocity Control. Only one well (Pisces No.1) was drilled in this area. The sparsity of reliable velocity analyses data makes the time to depth conversion difficult. This matter will be discussed in detail in section 7.7.

7.6.3 Partial Solutions.

The problems mentioned above were partially resolved by:

A) Cultus reprocessed 3000 line-kms of pre-GC89A survey data in 1988. Of the total reprocessed lines, about 1500 kms were reprocessed from field tapes, and the remainder reprocessed post-stack only.

B) To compensate for the dynamic timing variations associated with the canyons and steep seafloor topographies, a two-stage technique was utilised in the 1988 reprocessing. Firstly, a ray-trace modelling program was used to calculate travel time to several depths, and secondly, model results were used to shift samples on all seismic traces to the time they would have had if the seafloor had been even. This method is known as REVEAL (of Digital Exploration). Away from the steep seafloor topographies, the remainder of each seismic line has been conventionally processed.

C) To obtain a more accurate picture of the seafloor in areas of deep canyons or irregular topographies in the eastern part of V91-G1, Cultus digitised the water bottom reflection times from migrated near trace displays. The one-way water bottom reflection times are multiplied by 1480 m/s velocity to obtain depth values.

D) To obtain additional well control, the seismic grid in V91-G1 can be tied into a large number of recent open file survey data acquired by Phillips, BHP, Shell, Petrofina, and Esso. BMR's 1982 regional seismic grid, which is tied to 11 wells, provides additional control for regional interpretation.

7.6.4 Seismic characters.

Union Texas and Ampol carried out detailed mapping of prominent seismic markers in the V91-G1 area. The origin and character of these seismic events are discussed below. They can be taken from the Vertical Seismic Profiling (VSP) and synthetic seismogram available for the Pisces No.1 well.

A) Intra-Lakes Entrance Seismic Marker. This event appears at 1662 mSS, and is characterised by a clear event at 1.39 seconds. It separates Middle Miocene sediments of deep water equivalent (eg. carbonate canyon infilling) from underlying Early Miocene high energy progradational sandstones. The event is variable in amplitude and probably transgresses the Miocene/Oliigocene time interval.

B) Base Lakes Entrance/Top Gurnard Formations (not mapped). This is the highest amplitude event observed on the seismic sections and is generated from two steep reflection coefficients, closely separated, at 1738 and 1748 mSS in Pisces No.1. The composite produces a single wavelet of relatively high amplitude immediately above the top Latrobe 'coarse clastics', which obscures recognition of the top Latrobe unconformity.

C) Top Latrobe Group Unconformity - 'Coarse Clastics'. This event is confined to the area of the Pisces Sub-Basin and is locally absent through erosion on the Southern Platform. It appears to lack readily discernible character at Pisces No.1, but can be recognised by virtue of its irregularity and its variation from angular to disconformable nature. This event is considered to be the top Latrobe Group 'coarse clastics'. At Pisces No.1 it occurs at 1850 mSS, corresponding to 1.390 seconds two-way time (TWT).

D) Intra-Latrobe (Campanian) Seismic Marker. This horizon is also confined to the Pisces Sub-Basin. It is one of several intra-Latrobe Group events, and is attributed to the change of the sediments from a continental section, through an overlying marginal marine, to marine sediments. It occurs at 2400 mSS, corresponding to 1.79 seconds TWT. The lithological transition is not expressed as an amplitude character change. As a result, this horizon is poorly defined in places and its regional definition relies on phantoming.

E) Base of the Latrobe Group. This event was not tested by Pisces No.1, and as a result no immediate control exists. In places, it is interpreted as Top Strzelecki Group and in other places as a phantom of the basement structural form.

7.6.5 Prospect Mapping.

Prospects G1-P-A, G1-P-B, and G1-P-C were recognised by previous permit holders. The prospects were independently mapped by Cultus (1982, 1989), Union Texas (1984), Ampol (1984), and the Victorian Department of Manufacturing (Megallaa, 1984, 1991). One of these prospects came close to being drilled, but that was stopped by the collapse of the oil price in 1986.

The three prospects are illustrated in two montages: Montage A describes Prospect G1-P-B; Montage B describes Prospects G1-P-A and G1-P-C, which are thought to be one entity.

It is of interest to mention here that the G1-P-B prospect was named the Barra Prospect by Cultus and subsequent to its identification, the company acquired the GC89A survey over this prospect. This survey comprised 15 lines, with a total of 302 line-km.

7.6.6 Uncertainty in Depth Conversion.

There is no doubt that the recent reprocessing of the pre-1989 seismic data by Cultus has greatly improved the time mapping of prospects G1-P-A, B and C. However, due to the increasing water depth to the east and the effect of deep sea floor channels on the underlying data, the time structure contour maps over the prospects mimic the seafloor topography, and <u>their viability as economic targets would rely entirely on the accuracy of time to depth conversion.</u>

The velocity maps included in Montages A and B are based on two sources: Union Texas (1984) and Cultus (1990). The produced prospects depth closures are based on these two velocity fields. Map F in both montages provides a comparison of areal closure and vertical relief of the prospects at the Top Latrobe level as mapped, based on these two velocity fields. Map G provides intra-Campanian depth structural contours as mapped by Union Texas.

It is obvious from Map F that the depth conversion has proved difficult because of inadequate velocity control and the sea floor irregularities. However, all interpretations confirm that the structures are present, but there is no confidence in accurately mapping their size. <u>It is therefore essential for interested parties in Area V91-G1 to carry out independent velocity studies</u> (perhaps by using Sierra SIVA/RAY MAP or GEOQUEST AIMS III).

7.6.7 Velocity Maps (Maps C and D in Montages A and B).

A) Union Texas (1984). The velocity determination approach employed by Union Texas (Map D) involved the generation of an average velocity map from sea level to the individual mapped horizons. This was achieved by generating a smooth water-bottom to horizon average velocity field and then combining it with the water column to produce the average velocity from sea level.

The steps used included:

a) converting the digitised and edited NMO velocity field to RMS velocity from sea-bottom for each picked horizon;

b) a second order minimum least-squares polynomial surface fitting routine, within the bounds of a specified radius of influence, was used to grid the data followed by subjective hand smoothing for the horizon's RMS velocity map;

c) the average velocity from the sea floor was calculated from RMS velocity using a simplified mathematical approximation of the ray-tracing approach to velocity conversion.

Using this method, Union Texas "found that the interpreted depth to top Latrobe (1850 m in Pisces-1) overestimates the actual depth by around 44 m. No regional correction was applied to remove this overestimate". Thus, without a regional velocity correction, "many of the structures mapped near the top Latrobe and intra-Campanian level are subject to depth error or up to plus or minus 50 m."

B) Cultus (1990). The 'layer cake' method of depth conversion was used by Cultus [Map C - Montages A and B], where the thickness of the layer from the sea floor to the top Latrobe reflector was added to water depth. No attempt was made to map intra-Latrobe events.

The method involved the calculation of interval velocities from stacking velocities using Dix equation (from the sea floor to the top Latrobe Group seismic reflector). The top Latrobe Group reflection times were those obtained after the removal of the replacement statics. Velocities input to the Dix equation were stacking velocities, where 1480 m/s was used for the water layer. In order to tie this interval velocity to the Pisces No.1 well velocity survey a conversion factor of 0.95 was applied to the calculated velocities.

7.7 PROSPECTS AND LEADS.

[by John Conolly, of J.R. Conolly & Associates, and Maher Megallaa. Authorship is specified throughout.]

7.7.1 General comments. [by John Conolly]

Three prospects (Prospects G1-P-A, G1-P-B, & G1-P-C) and several leads (leads A, B, C, D, E and the Z lead trend) are discussed in this section. Other prospects and leads obviously occur within Area V91-G1, but the prospects & leads discussed here represent a selection of those for which there is sufficient seismic control.

All prospects and leads except those in the Z lead trend occur beneath the top Latrobe unconformity surface; all prospects and leads have been illustrated by maps & seismic sections:

Plate 19 is a map showing the location of all the prospects and leads that occur beneath the top Latrobe unconformity. The three prospects have been mapped by previous permit holders; in particular, Union Texas (1984) mapped several closures at the top Latrobe Level, which were remapped by Cultus in 1989. Subsequently Mr Maher Megalla of the Victorian Department of Maunfacturing has also mapped three of these prospects and his prospect maps are included in this report (Montages A & B).

Leads A, B, C, D & E, like the above 3 prospects all occur in the Pisces Graben. Union Texas (1984) mapped an extra Lakes Entrance Formation wedge of sediment that crosses the central portion of Area V91-G, and showed that this wedge of sediment could contain a series of stratigraphic traps. The updip edge lies to the west and is controlled by a series of lower velocity, probably canyon fill sediments of Miocene age, whilst the downdip edge is controlled by subtle changes in dip reversal back towards the southeast.

The potential trend of Oligo-Miocene stratigraphic traps is shown as lead trend Z on Plate 20, and also illustrated in the schematic stratigraphic diagram over seismic line GC 81A-09 (Plate 25).

The region west of the lead trend Z is believed to be now prospective, at least within Area V91-G1. In this western region of V91-G1 pinchout of Latrobe and older horizons occurs against the southern basement platform. Wells drilled in this style of pinchout play have so far not found any hydrocarbons (Mullet-1, Bluebone-1, Moray-1).

Similarly, significant lateral migration is required to fill the mounded features within the Z lead trend. Here even though a clastic reservoir sector may exist within the mounds, source rocks of the deeper Gippsland Basin still lie 20 to 50 km away.

The leads within the outer rim of the Pisces Sub-basin, however, lie adjacent to thick sequences of source rock within the main Gippsland Basin province. In addition, the horst blocks that make up the outer rim often contain dipping sequences of sediment which is probably of Lower Cretaceous (Stzelecki) age, and may also provide a source for those structures that directly overlie them.

Good reservoir rocks were penetrated by the Pisces No.1 well below the top Latrobe unconformity. Two prospective sequences were penetrated in this well. The upper sequence is Maastrichtian to late Campanian in age and consists of many marginal marine and outer deltaic-plain sands; the lower sequence consists of fluvial and deltaic sediments. A disconformity separating these two sequences can sometimes be seen on seismic sections. This disconformity surface is intra-Campanian in age and probably corresponds to tectonic uplift of the outer rim basin at the time of the opening of the Tasman sea at about 80 Ma.

This also explains why dipmeter readings in Pisces No.1 show that the upper sequence is mainly derived from the southwest, or the southern platform margin, whereas the lower fluvial sequence has dips that indicate that it was derived from the outer rim high to the east. The boundary of the two sequences occurs at about a depth of 2509 m in Pisces No.1. Dips above 2486 m in the Pisces well are towards the northeast, whereas those below 2486 m show progradation towards the southwest.

Vitrinite reflectance values from the upper sequence are in the range of 0.32 to 0.33, whereas the values increase to a range of 0.5 to 0.6 below 2300 m in Pisces No.1. Organic matter is common to abundant in the upper sequence, but even higher organic contents occur in the more continental sequence below 2486 m. It can be concluded that the Campanian and older sediments of the Pisces Sub-basin (the lower sequence discussed above) form a distinct facies which will be mature and could have generated oil.

Additional hydrocarbons (gas and oil) could have been produced from the rift-valley fill sequences seen in some of the horst blocks. Most of this sediment is presumed to be older than 95 to 100 Ma, to have been deposited during the original rifting of the southern margin of Australia in the lower Cretaceous, and hence be equivalent in age to the Strzelecki Group. No wells have penetrated this sequence along the southern margin of the Gippsland Basin, although Omeo-1 drilled in Area V91-G2 did penetrate Strzelecki age sediments which had good hydrocarbon shows. Rçcent discoveries of oil and gas by Petrofina in their Archer No.1 and Anemone No.1 wells are important, since the zones that contain hydrocarbons probably lie beneath the intra-Campanian unconformity and the reservoirs may be equivalent in age and facies to those penetrated beneath 2500 m in Pisces No.1 (or in other words, "lower sequence" in the Pisces well), or may be equivalent also to the Golden Beach Formation.

Lead D in the Pisces Sub-basin lies in fairly shallow water (about 200 m) and sits in a similar tectonic setting to the Archer and Anemone discoveries. It would appear to be the most obvious, potentially commercial lead encountered so far in Area V91-G1. Leads A, B, & C also lie in fairly shallow water, whereas the 3 Prospects and Lead E all lie in deep water areas.

The following sections describe the Prospects and Leads in more detail, referring to specific maps, seismic sections and stratigraphic illustrations.

7.7.2 Prospects.

Area V91-G2 includes three recognised Prospects, two of which may be one entity, if Maher Megallaa is correct. The velocity problems described in the previous section mean that more than one interpretation of these Prospects can be geophysically valid. In this section, interpretations by John Conolly (of J.R. Conolly & Associates) and Maher Megallaa (of VDMID Petroleum Assessment Branch) are included in full.

Prospect G1-P-A. [by John Conolly]

This prospect lies over the outer rim of the Pisces Sub-basin at depths of 600 m (Plate 19). Seismic sections GC 89A-07, and GC 89A-04 are used to illustrate the geology of this prospect (Plates 23 & 29; and 28 & 32 respectively).

Seismic Line GC 89A-07 clearly shows drape and rollover of a Latrobe age sequence over tilted horst blocks that form the outer rim of the Pisces Sub-basin, and seismic line GC89A-04 on the other hand, intersects the Prospect along the strike of the faults controlling the outer rim horst blocks.

The main target horizons occur within Campanian age reservoirs as they thin across the outer rim horsts. Secondary targets are Strzelecki age reservoirs within the horst blocks. A detailed analysis of this prospect is given by Maher Megalla in this report.

Prospects G1-P-A/G1-P-C (probably one entity). [by Maher Megallaa]

A) Location: The two prospects are located on the outer rim of the Pisces Sub-Basin some 15 km northeast of the Pisces No.1 well. Geologically, the features are believed to be one prospect and have always been difficult to map (see previous section). The water depth at its shallowest is 400 m.

B) Structure/Trapping: The structure is formed by drape of the Latrobe group section over high fault-tilted Strzelecki blocks which form part of the outer rim. These fault blocks form a ridge which extends from Prospect G1-P-A/G1-P-C to the southeast where the Foster and Pisces fault systems merge. The structure is well defined by dip closure to the northeast, northwest and southwest. Critical closure is to the southeast along the trend of the horst blocks.

C) Horizontal and Vertical Closures: Optimistically, the areal closure at the top Latrobe is 8 km^2, and has been defined by a 1975 m contour, while the vertical relief is 45 m. The amount of structure existing with depth is such that at the intra-Latrobe Campanian level the relief is about 55 m below the Prospect.

D) Reservoirs: The top Latrobe Group at Pisces No.1 is the Late Campanian/Maastrichtian regressive deltaic sequence, which consists of delta-front sands overlain by delta plain channel sands and overbank shales/siltstones. A similar, but more marine section may be expected at Prospect G1-P-A/C; because the sediments were deposited further from the source area and in a higher energy depositional environment. The sands may become better sorted and cleaner, and may be expected to have an average porosity of 20%.

In the Pisces No.1 well area, the deeper Early Campanian target was found to be a thinly interbedded sand of poor reservoir quality. At G1-P-A/C location, it is expected that these sediments were deposited in a higher energy environment further from the clastic source. Consequently, the petrophysical characteristics of the sands may be more favourable.

E) Seal: The top Latrobe Group 'coarse clastics' would be adequately sealed by the shales and claystones of the overlying Lakes Entrance Formation. The early Campanian reservoirs may add to the potential of the prospect if an adequate intra-Latrobe Group seal is present.

F) Source/Migration: Results from Pisces No.1 cast doubts on the oil-generating potential of the Latrobe Group sediments within the Pisces Sub-Basin. The Late Campanian/Maastrichtian section is very sandy (77%) and the shales contain very little organic matter (average T.O.C. of 0.66%). The Early Campanian continental section contained more organic carbon (average T.O.C. of 1.5%, maximum 4.37%) but much less than the Latrobe Group in the Gippsland Basin proper (average T.O.C. 5.96%). The low levels of T.O.C., together with the humic nature of the kerogen, would limit the capacity for generation of large volumes of oil.

Prospects for oil at G1-P-A/C may be improved by access to migration out of Latrobe Group sediments deposited north and northeast of the outer rim of the Pisces Sub-Basin; ie. from sediments deposited under different environmental constraints to those in the sub-basin.

Prospect G1-P-C. [by John Conolly]

This prospect lies on the western flank of the outer rim of the Pisces Sub-basin at water depths of 400 m. As such it lies in much shallower water than Prospects G1-P-A & G1-P-B. Unfortunately no recent (1989) seismic line crosses this prospect. Because of this it is difficult to know whether the horst blocks which underline this prospect have potential Strzelecki age sediment targets or not. Despite this depth section illustration (Seismic line GC 80-11A; Plate 24) shows potential closure at several levels in the Latrobe sequence at depths of about 2000 to 2400 m. The occurrence of multiple potential pays within the Maastrichtian to Campanian age sands should make this prospect a viable objective despite the moderate (400 m) water depths.

Prospect G1-P-B. [by Maher Megallaa]

The structure is located on the outer rim of the Pisces Sub-Basin, and is similar to the G1-P-A/C prospect. The closure is formed by the drape of the Latrobe sediments over a high-standing Strzelecki fault block near the intersection of the Pisces and Foster fault systems.

The relief of the structure (net sand) at the top Latrobe Group is 40 m, while at the intra-Campanian level the relief is 30 m. Critical closure is to the southwest. As with the G1-P-A/C prospect, the main potential reservoirs in this prospect are the top Latrobe and intra-Campanian sands where moderate porosities and permeabilites may be assumed. Intraformational shales necessary for vertical seal to the Early Campanian reservoirs were abundant in the equivalent section in Pisces No.1, and may be expected at G1-P-B prospect.

The source potential at the prospect must be from within the early Late Cretaceous-Early Campanian section; either from the area of the Pisces Sub-Basin to the west, or beyond the Foster Fault system to the east. The latter source area is more favourable, but organic content, kerogen type, maturity, and volume of potential source rock are unknown.

Since water depth over the structure ranges from 700 m in the west to 950 m in the east, the viability of the prospect depends entirely on the time to depth conversion.

Prospect G1-P-B. [by John Conolly]

This prospect lies above the outer rim of the Pisces Sub-basin at water depths of 700 to 800 m (Plate 19). Three seismic lines (GC 89A-11, GC 89A-13 & GC 89A-04) are used to illustrate the geology of this prospect (Plates 22 & 30; 21; 28 & 32 respectively).

Line GC 89A-11 quite clearly shows Latrobe age sediment thinning over a tilted horst block containing potential Strzelecki secondary targets. The intra-Campanian unconformity surface can also be seen on this seismic line separating the marine and marginal marine "upper sequence" Late Campanian to Maastrichtian age from older suspected fluviatile reservoirs of Early Campanian and older age.

The tilted horst block sediments will provide an excellent secondary target. Within the horst blocks stacked tilted reservoirs could add significantly to the reserve potential of the prospect.

Mr Maher Megalla has made a detailed analysis of the reserves of this Prospect, however this analysis does not include the addition of large reserves from the tilted reservoirs of the horst blocks.

7.7.3 Leads. [by John Conolly]

Leads A and B.

Both these leads are illustrated by seismic line GC 89A-11 (Plates 22 & 30), and occur within the main part of the Pisces Sub-basin. Lead A occurs at water depths of 130 to 150 m and Lead B at Water depths of 300 to 400 m.

Both leads occur as drape over a major tilted horst block and both leads have potential targets on the three sub-Latrobe reservoir sequences namely:

1. Maastrichtian & Upper Campanian age sands;

2. Lower Campanian and older (Golden Beach equivalent) sands; and

3. Strzelecki equivalent (Lower Cretaceous) sands.

Lead B lies in a similar tectonic Setting to Prospect G1-P-C, and at similar water depths while Lead A lies in a similar structural and water depth setting to Leads C and D.

Lead C.

This lead is illustrated on seismic line GC 81A-09 (Plate 25). Like lead A it occurs as a drape across the tilted horst blocks of the rim of the Pisces Sub-basin and has potential targets at least in Latrobe Upper Cretaceous sediment. No 1989 vintage seismic crosses Lead C, so it is not known whether Strzelecki age sediments exist within the underlying fault blocks. However, by analogy, it would appear to be safe to say that they should occur as they do at Leads A & B.

Lead D.

Lead D is illustrated by Seismic Line GC 89A-03 (Plates 27 & 31), and occurs in water depths of about 120 m. A significant rollover can be seen on this seismic line between shotpoints 700 & 600. Sediment within this rollover should be Campanian in age, and the lead has a similar structural setting to the new discoveries at Archer and Anemone, in nearby VIC/P20.

Lead E.

This lead is illustrated by Seismic line GC81A-17 (Plate 26) and occurs in deep water (800 m) on the basin side of the outer rim of the Pisces Sub-basin. As such it certainly lies more directly over the potential source rocks of the deep Gippsland Basin than some of the other leads (A, B). Rollover occurs in several reflecting horizons at depths of 2600 to 3200 m. These horizons correlate with Campanian and older sediments of the Pisces Sub-basin.

Z Lead Zone.

This lead Zone was extensively mapped by Union Texas (1982, 1984) and is illustrated on Plate 20, and seismic line GC 81-09 (Plate 25). Union Texas mapped a broad zone crossing Area V91-G1, of mounded intra-Lakes Entrance sediments. The western edge of the mounded sediment was a pinchout under lower velocity Miocene channels (herein called Canyons) at the eastern edge a dip reversal as the sediments dipped over towards the main Gippsland Basin. The play depends on lateral migration from the deeper source rocks of the Gippsland Basin, and on top and bottom seal by shales over a prognosed sandy Oligo-Miocene sequence, the reservoir. It is obviously a high risk play but one that can be tested in shallow water (less than 100 m) at fairly shallow drilling depths (about 1000 m).

8. AREA V91-G2

Area V91-G2 consists of 27 graticular blocks in the south-central Gippsland Basin (Plate 13). Authorship is specified under each subsection.

8.1 PREVIOUS EXPLORATION.

[by A.E. Stephenson & Tun U Maung.]

8.1.1 Drilling.

Ten wells have been drilled in Area V91-G2, seven in the Gippsland Basin's Central Deep, and three on the South Strzelecki Terrace. Brief details are given in Table 2 - fuller descriptions are contained in sections 8.3 (reservoir geology), 8.4 (reservoir engineering), and 8.6 (prospects & leads).

Table 2: Wells drilled in V91-G2.

Well	Operator	Year	TD (m)	Deep/Terrace	Hydrocarbons
Bullseye 1	Esso	1973	2368	Edge of Deep	Dry hole.
Devilfish 1	Shell	1990	2058	Strz. Terrace	Dry hole.
Edina 1	Aquitaine	1982	2594	Central Deep	Dry hole.
Gurnard 1	Esso	1969	2964	Central Deep	Solution gas.
Nannygai 1	Esso	1972	3019	Central Deep	Dry hole.
Omeo 1	Aquitaine	1983	3379	Edge of Deep	Gas discovery.
Omeo 2A	Aquitaine	1985	3400	Edge of Deep	?New gas pool.
Pike 1	Esso	1973	2134	Strz. Terrace	Dry hole.
Speke 1	Aquitaine	1984	2772	Central Deep	Dry hole.
Tarra 1	Aquitaine	1983	2905	Strz. Terrace	Dry hole.

Wireline and lithological logs for all wells can be found on Plates 15 & 16. A detailed description of the Omeo field is contained in section 8.3.

8.1.2 Geophysics.

Area V91-G2 has been explored by Esso, Bass Strait Oil and Gas, and Australian Aquitaine, with seismic vintages ranging from 1969 to 1984 (Plates 33 & 34). The area north of the Foster Fault (Plates 13A & 13B) is mostly covered by Aquitaine seismic data with a generally regular grid spacing of 1.5 x 1.5 km (Plate 14). The data quality in this area is fair to good. On the Southern Platform, the grid spacing is large and the data is generally older vintage (1969, 1970 and 1980) and the data quality in this area is poor to fair. The data quality is generally good enough to delineate the major structural elements and deteriorates below 2.0 seconds two-way time, at depths where the intra-Latrobe play is considered to be best developed. A total of 1138 line-km was reprocessed by Shell in 1988 with significant improvements in data quality, which were achieved by reprocessing through the use of F-K filtering, dip-moveout corrections (DMO) and careful picking of velocities.

Velocities were picked in an horizon consistent manner for later use in depth conversion (Blackburn, 1980 and Cordier, 1985). In 1988, Shell acquired 273 line-km of 75-fold new seismic data in the eastern part of the Area which shows a significant improvement on earlier data. The use of 3750 m digital streamer is responsible for the major improvement. The new data have increased resolution, improved signal to noise ratio and penetration, and have improved multiple suppression.

A set of zero-phase synthetic seismograms was generated for all the wells within the Area (Nannygai No.1, Gurnard No.1, Pike No.1, Tarr a No.1, Omeo Nos.1 and 2A, Bullseye No.1 and Speke No.1), and for other relevant wells (Dolphin No.1, Moray No.1, Bream Nos. 2, 3, and 5, and Kingfish No. 1). These have been used by Shell to tie the wells into various vintages of seismic data. The reprocessed G81A data was chosen by Shell as the reference data set as it provides the most extensive coverage of the Area.

8.2 LOCAL GEOLOGY AND RELEVANT PLAY CONCEPTS.

[by A.E. Stephenson]

Vacant Area V91-G2 is located on the south-central margin of the Gippsland Basin (Plate 13). The area contains three distinct structural elements: the Southern Platform, the Southern Strzelecki Terrace, and the Central Deep.

8.2.1 Southern Platform.

The southern half of V91-G2 lies on the Southern Platform, which is considered to have very limited prospectivity (see section 8.2.7). The Southern Platform consists of shallow basement (1.5 - 2.0 km subsea) overlain by very thin Cretaceous Latrobe Group sediments (100 - 200 m thick), in turn covered by Lakes Entrance Formation and Gippsland Limestone (Plate 5). Only one hydrocarbon play has been recognised on the Southern Platform in Area V91-G2. This is the Taranaki analogue play (6.1.3), which could occur south of the Foster Fault Zone. However, it relies upon long migration paths and must be regarded as very high risk.

8.2.2 Southern Strzelecki Terrace.

Approximately a quarter of Area V91-G2 lies over the South Strzelecki Terrace; and it is regarded as prospective and is so far underexplored. In this area a large Strzelecki Group fault block steps downwards towards the Central Deep between the Foster and Omeo Faults (Plates 5 & 35), and is draped by 300 to 400 m of Latrobe Group sediments. The latter are draped in turn by some 1.5 km of Lakes Entrance Formation and Gippsland Limestone sediments. As for the Southern Platform, the Latrobe Group here is immature for the generation of hydrocarbons, and a Central Deep or Strzelecki source must be invoked; migration paths are however much shorter than for potential Southern Platform plays. At the top Latrobe level, three plays are possible: structural (6.1.1), stranded beach-barrier (6.1.2), and Brazilian analogue (6.1.4).

The Gurnard sand play (6.1.5) is possible but considered to be unlikely. At intra-Latrobe levels, possible play types include all five listed in section 6.2, with particular emphasis on structural and fan plays. The Strzelecki Fault Block play (6.3.1) is particularly relevant in Area V91-G2, as rollover against faults can be demonstrated at that level (see section 8.7).

8.2.3 Central Deep.

The Central Deep portion of V91-G2 is regarded as the most prospective part of any of the three release Areas, as it lies between Bream and the giant Kingfish oilfields. Plays are discussed in detail in section 8.2.7, but broad concepts are given here.

The standard top Latrobe Group structural plays have been examined in the area, but some prospects of this play type remain undrilled (see section 9.7). Stratigraphic plays also exist, and Mr Maher Megallaa of VDMID has recognised a possible Fortescue analogue (Prospect G2-P-A), which relies upon stratigraphic pinchout. The stranded beach-barrier play (6.1.2) and the Gurnard sand play (6.1.5) have yet to be tested in Area V91-G2, so must be given some potential. Intra-Latrobe Group plays also have potential, in particular the intra-Latrobe structural play. As mentioned in section 4 of this Record, recent work in BMR indicates that many intra-Latrobe Group structures have no expression at the top Latrobe level, and may have been easily overlooked. Similarly, intra-Latrobe stratigraphic plays remain totally untested in V91-G2.

8.3 RESERVOIR GEOLOGY.

[by Shige Miyazaki, BMR Petroleum Resource Assessment Branch]

8.3.1 Omeo No.1.

Summary: Omeo No.1 is a gas discovery well. Small quantities of gas were recovered by RFT fluid-sampling from thin intra-Latrobe sandstone units of high water-saturation. Various liquid hydrocarbon shows were recorded in the Strzelecki Group at the bottom of the hole, but drilling problems prevented the operator from testing this interval.

Omeo No.1 was drilled by Australian Aquitaine in 1982-83. The well intersected the top Latrobe 'coarse clastics' (N. asperus zone) at 2347 mKB. (The KB elevation for the well was 30.5 m above mean sea level.) A core was cut over 2348.0 to 2366.0 mKB with a recovery of 14.5 m (80%). Sandstones in the core have porosities of 20.7 to 27.0% and permeabilities of 689 to 6111 millidarcies. The uppermost sandstones of the Latrobe 'coarse clastics' are clean and have a wireline log porosity of 23% and a water saturation of 100%. There is no structural closure at the top Latrobe 'coarse clastics'.

The well intersected an intra-Latrobe massive sandstone unit at 2813 to 2953 mKB (on open-hole logs) within the Paleocene and the upper section of the Upper Cretaceous. (The bottom of this sandstone unit is at 2958 mKB, according to cased-hole logs.) The bulk of the sandstone unit is shaly and has a porosity of 10%. A number of RFT pressure and fluid sampling surveys and a cased-hole DST were carried out for this unit. One of the RFT fluid-sampling operations caused a drilling problem (see Note at the bottom of this section).

Of the many RFT pressure surveys for the massive sandstone unit, pressure data from 2849.8, 2854 and 2858 mKB exhibit an inconclusive gas gradient of 0.2 g/cc. However, dual laterolog data for these depths do not show any strong resistivity anomalies. Apparent resistivity anomalies from 2859 to 2947 mKB are probably a result of the washing-out of the hole.

An RFT fluid sample, taken at 2849.8 mKB in the massive sandstone unit, recovered 5.6 cubic feet of gas, 9 litres of water or filtrate from the 10.4-litre lower chamber, and 30 cubic feet of gas and 5 litres of water or filtrate from the 10.4-litre upper chamber. The bulk of the recovered gas, however, appears to be a solution gas dissolved in formation water. Wireline log data indicate that the formation at 2849.8 mKB consists of clean sandstones having a porosity of 12% but a water saturation of 90%. This log analysis may be pessimistic, but water saturation would not be able to be substantially decreased without the unrealistic assumption of the presence of very salty formation-water.

Another RFT fluid sample, taken at 2952.0 mKB near the bottom of the massive sandstone unit, recovered 9.75 and 9.5 litres of water or filtrate, but no hydrocarbons, from the two 10.4-litre chambers. The sandstones at 2952 mKB have a porosity of 16%.

A cased-hole DST was run over two intervals of 2918 to 2925 mKB and of 2932 to 2939 mKB within the massive sandstone unit. No flow was made to surface during a 4.5-hour plus 50-minute flow test through an 8/64 inch choke, and only muddy water was recovered during reverse circulation. A small amount (18.2 cubic feet) of gas was recovered from the APR chamber in the bottom hole assembly. The formation has an extrapolated pressure of 4100 psig and a temperature of 121^{o}C at a datum depth of 2912 mKB. This pressure does not match an RFT pressure of 4320 psig at 2936.5 mKB.

Wireline log data indicates that the DST-tested formations consist of shaly sandstones containing 30% clay. These sandstones have a porosity of 8% and a water saturation of 90%. The DST pressure build-up curve suggests a formation permeability of 0.8 millidarcies, and the RFT pressure drawdown data suggest a permeability of 0.1 millidarcy.

The second core was cut at 3031.2 to 3040.4 mKB, within the lower section of the Upper Cretaceous, with a recovery of 2.85 m (31%). It consists of sediments of fluvial or alluvial facies, and includes 0.7m thick shaly sandstones having porosities of 11.3 to 16.7% and permeabilities of 3.1 to 100 millidarcies. The core did not exhibit any hydrocarbon shows.

A log analysis has identified a few prospective zones, below the second core interval, within the Upper Cretaceous (see Table 3 for details). These zones consist of fairly clean sandstones with good porosity. However, water saturation is high, and nett pay is thin. One zone (3120.5 to 3128.5 mKB) was identified as gas-bearing by RFT fluid-sampling, and two zones (3073.0 to 3081.5 mKB and 3130.0 to 3136.5 mKB) have been interpreted as gas-bearing by log analysis.

RFT pressure drawdown data, taken from these zones, indicate formation permeabilities of 10 millidarcies at 3077.5 mKB, 100 millidarcies at 3125 mKB and 1 millidarcy at 3126.5 and 3131.5 mKB. An RFT at 3131.5 mKB recorded a formation pressure of 4585.8 psia and a temperature of 113 ^{o}C.

An RFT fluid sampler, taken at 3125 mKB, recovered 0.02 m^3 (at 180 psig) plus 1.5 cubic feet (at surface conditions) of gas, a thin film of condensate and 7.5 litres of water or filtrate from the 10.4-litre lower chamber, and 0.02 m^3 (at 460 psig) plus 6 cubic feet (at surface conditions) of gas, a thick film of condensate and 3.75 litres of water from the 10.4-litre upper chamber. These large amounts of water recovery confirmed the reservoir being highly water-saturated. The gas contains 92% of methane and 4% of ethane. The formation at 3125 mKB consists of clean sandstones with a log porosity of 15%.

The gamma ray log for one of the gas-bearing zones (3120.5 to 3128.5 mKB) shows a smooth bell-shaped pattern. This sandstone zone is overlain by 3 m thick claystones and coals, and underlain by 2 m thick claystones.

Table 3 Log analysis

Depth (mKB)	Gross thickness (m)	Thickness (m) Vclay < 0.4	Thickness (m) Vclay < 0.4 & PHI > 0.1	Net thickness (m) Vclay < 0.4 & PHI > 0.1 & Sw < 0.5	PHI	Sw	Remarks
3073.0 - 3081.5	8.5	7.0	7.0	4.0	0.17	0.45	gas (inferred)
3090.0 - 3099.0	9.0	8.0	6.0	0.0			
3100.0 - 3107.0	7.0	7.0	6.0	0.0			
3120.5 - 3128.5	8.0	7.0	7.0	5.0	0.17	0.40	gas (recovered)
3130.0 - 3136.5	6.5	6.0	6.0	2.0	0.18	0.48	gas (inferred)
3140.5 - 3152.0	11.5	11.0	8.0	0.0			
3154.0 - 3159.5	5.5	5.0	2.0	0.0			washed-out hole
3171.0 - 3176.0	5.0	4.0	3.0	0.0			washed-out hole

A post-drill structure map shows a roll-over closure of 3 km^2 on the down-thrown side of a normal fault for the intra-Latrobe "orange" horizon, which was intersected at 2846 mKB in Omeo No.1. (The drilling result of Omeo No.2A suggests that the size of the areal closure would be much less than 3 km^2.)

Drill cuttings from a claystone/sandstone/siltstone zone over 3354 to 3379 mKB within the Strzelecki Group exhibited dull yellow fluorescence and instant streaming cuts. Mud gas gave a maximum of 30% of methane, 1.5% of ethane, 0.5% of propane, 0.25% of butanes and a trace of pentanes at 3370 mKB near the bottom of the hole (3379 mKB). Following a gas kick at 3379 mKB, mud weight was increased from a specific gravity of 1.13 to 1.28. Liquid hydrocarbon samples in the mud were recovered on a wiper trip at 3379 mKB. The chemical analysis of bottoms-up mud and mud filtrate samples from 3379 mKB confirmed the presence of liquid hydrocarbons with high pristane/phytane ratios of 6.6 to 7.6.

A total of 21 side-wall core bullets were shot for the 6-inch part of the hole, below the 7-inch liner shoe at 2984 mKB, but only three were recovered. Shaly sandstones with poor visible porosity from 3361 and 3365 mKB showed patchy fluorescence and slow cuts, and sandstones of the similar lithology from 3376 mKB showed dull fluorescence but no cut.

Wireline log data, however, indicate that the interval from 3355 to 3376 mKB consists of very shaly sandstones or siltstones with a porosity of 10% and a water saturation of 95%. No RFT was attempted for this zone. The many hydrocarbon shows in the 6-inch slim part of the hole were not fully evaluated because of drilling problems. (A total of 4.6 tons of Soltex was used as a mud additive for the 6-inch part, which might have caused an adverse effect on wireline log response.) There appears to be no moveable oil in this interval, but the hydrocarbon shows suggest the existence of residual oil or a minor gas/condensate accumulation under a high water-saturation condition in this interval within the Strzelecki Group.

<u>Note:</u> The paleontological zonation of the intra-Latrobe and Strzelecki Groups is inconclusive in this well. After wireline logging cable had been cut off in the hole during an RFT fluid-sampling operation at 2936.5 mKB, casing strings were set down to the bottom of the 121/4-inch part (1320 to 2 985 mKB) of the hole. Therefore, no side-wall cores were taken from this part. The operator picked the top of the Lower Cretaceous Strzelecki Group at 3195 mKB on the basis of a lithological change and of inconclusive palynological evidence taken from six sets of drill cuttings at 3174, 3209, 3219, 3237, 3249 and 3351 mKB and two samples from the conventional cores at 2357 and 3036.5 mKB. There remains the possibility that the well was terminated in the Upper Cretaceous within the intra-Latrobe Group.

8.3.2 Omeo No.2A.

Summary: The small gas-bearing sandstone units, identified and interpreted in Omeo No.1, are absent in Omeo No.2A. While the middle section of the Upper Cretaceous was being drilled, the well failed to exhibit any hydrocarbon shows in the similar interval to that for the Omeo No.1 gas reservoirs. The lower section of the Upper Cretaceous, however, has the potential for a different gas accumulation under a high water-saturation condition. The well was plugged and abandoned without running any RFT survey.

Omeo No.2A was drilled by Australian Aquitaine in 1985 to appraise Upper Cretaceous intra-Latrobe sandstones. A small gas pool at 3120.5 to 3128.5 mKB was identified by RFT fluid-sampling in Omeo No.1, and the presence of another two small gas pools at 3073.0 to 3081.5 mKB and 3130.0 to 3136.5 mKB was interpreted with wireline log data. Omeo No.2A was located one kilometre northwest of Omeo No.1.

Omeo No.2A intersected the top Latrobe 'coarse clastics', of the M. diversus zone, at 2347 mKB. (The KB elevation for the well was 22 m above mean sea level.) Drill cuttings from 2346, 2357 and 2368 mKB and a sidewall core sample from 2356 mKB showed moderate fluorescence and a slow streaming cut, but mud gas readings were negligible at these depths. Wireline log data indicate that the Eocene part (2347 to 2448 mKB) of the Latrobe 'coarse clastics' includes a total of 60 m of sandstones. The porosity of these sandstones is good (20 to 23%), but the water saturation is 100%.

Any obvious equivalents of the Omeo No.1 gas reservoirs are absent in the middle part (2964 to 3221 mKB) of the Upper Cretaceous section of the Latrobe Group in Omeo No.2A. This part did not exhibit any reasonable hydrocarbon shows. The gas-bearing sandstones, intersected in Omeo No.1, appear to either pinch out or be faulted-out in Omeo No.2A, and the actual size of the closure would be much smaller than 3 km^2.

Moderately high mud gas readings continued from the depth of 3221 mKB to the bottom of the hole (3403 mKB), and reached a peak of 4.5% at 3384 mKB. Sidewall core samples from 3295 and 3366 mKB and drill cuttings from 3396 mKB showed weak fluorescence and weak cuts. The operator interpreted that all the formations in this well are completely water-wet.

A re-examination of the wireline log data indicates that a total of 90 m of sandstones within 3221 to 3403 mKB have a porosity of 13% and a water saturation of 70%. This calculation is based on a low formation water salinity of 11000 ppm derived from adjacent water-bearing zones. However, formation-water salinity in hydrocarbon-bearing zones is often much higher than that in water-bearing zones in the Gippsland Basin (Kuttan & others, 1986). If this is applicable to Omeo No.2A, then a few m of these sandstones may possibly have a water saturation of as low as 50%. The possible hydrocarbon would be gas rather than oil, however, according to the nature of the hydrocarbon shows.

The formation at the bottom of the hole (3403 mKB) is of Late Cretaceous age, and the well did not penetrate the Strzelecki Group. No RFT survey was attempted in this well.

8.3.3 Gurnard No.1.

Gurnard No.1, located between the Kingfish and Bream oil fields, was drilled by Esso in 1969. The well intersected the top Latrobe 'coarse clastics' at 2223 mKB, consisting of an alternation of sandstones and claystones of the N. goniatus zone. (The KB elevation for the well was 9.8 m above mean sea level.) Wireline log data indicate that sandstones of this zone have a porosity of 22%.

Esso ran two FITs at 2925 and 2944 mKB within the L. balmei zone (or the T. longus zone) near the bottom of the hole (2957 mKB). FIT-2 at 2925 mKB recovered 2 cubic feet of gas, 0.35 litres of water and 0.25 litres of mud from the chamber, and 0.52 litres of water from the segregator. FIT-1 at 2944 mKB recovered 0.05 litres of water and 0.25 litres of mud. The recovered gas appears to be a solution gas dissolved in formation water. Shaly sandstone of this zone has a porosity of 10%. All the formations intersected in this well are completely water-wet. The well was terminated at 2957 mKB within the L. balmei zone.

8.3.4 Nannygai No.1.

Nannygai No.1 was drilled by Esso in 1972. The well was located between the Kingfish and Bream oil fields. Esso picked the top Latrobe 'coarse clastics', of the N. asperus zone, at 2213 mKB. (The KB elevation for the well was 9.8 m above mean sea level.) A core was cut from 2225 to 2235 mKB with a recovery of 8.8 m (88%). Sandstones and siltstones of the core have porosities of 9.2 to 12.7%, horizontal permeabilities of 0.1 to 1.2 millidarcies and vertical permeabilities of 0.1 to 1.4 millidarcies. The core did not display any hydrocarbon shows.

Sidewall core samples, taken from a fining-upward sandstone unit at 2899 to 2920 mKB within the L. balmei zone, exhibited fluorescence and produced a cut. Esso interpreted the top 5 m of this unit as a non-productive oil zone with porosities of 8 to 15% and water saturations of 65 to 80% , but did not test this zone.

The well was terminated at 3019 mKB within the L. balmei zone without running any formation test.

8.3.5 Pike No.1.

Pike No.1 was drilled by Esso in 1973. The well intersected the top Latrobe 'coarse clastics' at 1828 mKB immediately below the Lakes Entrance Formation. (The KB elevation for the well was 9.8 m above mean sea level.) The Gurnard Formation is pinched-out or was completely eroded at the well location. A core was cut from 1834 to 1839 mKB, within 137 m thick sandstones of the Upper Eocene, with a recovery of 2.7 m (60%). The core consists of well-rounded, coarse-grained, well-sorted and unconsolidated quartzose sandstone, and exhibited no hydrocarbon shows. A sandstone plug taken from the core has a porosity of 21% and a permeability of 2402 millidarcies.

A post-drill structure map for the top Latrobe Group indicates that the well was drilled in a tilted fault block closure on the downthrown side of a fault. No hydrocarbon shows were detected, and no formation test was run in this well. The well was terminated, without encountering any hydrocarbon shows, at 2126 mKB within the L. balmei zone.

8.3.6 Edina No.1.

Edina No.1 was drilled by Australian Aquitaine in 1982. A core was cut from 2312.6 to 2320.2 mKB, with a recovery of 7.0 m (92%), within the Gurnard Formation. (The KB elevation for the well was 30.5 m above mean sea level.) The core consists of fine-grained, calcareous, argillaceous and well-cemented sandstones. The core showed traces of fluorescence and very diffuse cuts. The sandstones have fairly good porosities (12.0 to 19.0%), very low permeabilities (0.036 to 3.70 millidarcies) and very high grain-densities (2.69 to 2.89 g/cc). Wireline log data indicate that the Gurnard Formation is saturated with water.

The well intersected the top Latrobe 'coarse clastics', of the P. asperopolus zone, at 2333 mKB. The uppermost sandstones (2333 to 2372 mKB) are a coarsening-upward unit. These sandstones have a porosity of 21% and a water saturation of 100%. An RFT fluid sampling was run at 2335 mKB and recovered water-filled in 3.8- and 10.4-litre chambers. Pressure data from this RFT indicate permeabilities of 3000 and 5500 millidarcies.

The Edina structure is a 4-way dip closure of 10 km^2 transected by a normal fault, according to a pre-drill structure map for the top of the Gurnard Formation. As there are no hydrocarbon shows and no residual oils in the top Latrobe 'coarse clastics', it appears that any substantial quantity of liquid hydrocarbons has never migrated into the structure.

No hydrocarbon shows were detected from the intra-Latrobe Group in Edina No.1. The well was terminated at 2594 mKB within the L. balmei zone.

8.3.7 Tarra No.1.

Tarra-No.1 was drilled by Australian Aquitaine in 1983. The well intersected the top Latrobe 'coarse clastics' at 2244 mRT within the N. asperus zone. (The RT elevation for the well was 30.2 m above mean sea level.) The top sandstones have a porosity of 25% but a water saturation of 100%.

Unlike many other wells in the Gippsland Basin, the Latrobe Group was not the main objective for this well, as no closure had been expected in these formations. The objective was sandstones in the Strzelecki Group in a tilted fault block on the downthrown side of a normal fault. Australian Aquitaine picked the unconformity between the Latrobe and Strzelecki Groups at 2583 mRT in this well.

The first core was cut from 2797 to 2804 mRT with a recovery of 1.5 m (21%). The core consists of lithic, fine-grained and well-cemented sandstones with laminations of claystones and coals. It exhibited no hydrocarbon shows. Two sandstone samples taken from the core have porosities of 10.5 and 8.5% and permeabilities of 1.6 and 4.8 millidarcies.

The other core was cut from 2890 to 2905 mRT, with a recovery of 13.67 m (91%), at the bottom of the hole (2905 mRT). The core consists of lithic, fine-grained and well-cemented sandstone and thin laminations of coals, of the C. striatus zone within the Strzelecki Group. The core exhibited no hydrocarbon shows. Ten sandstone plugs from the core have porosities of 5.9 to 12.3% and permeabilities of 3.6 to 7.6 millidarcies.

No hydrocarbon shows were detected in this well. Diagenesis appears to have caused detrimental effects to the reservoir quality of Strzelecki sandstones. No RFT was run in the well.

8.4 DRILLING ENGINEERING.

[by Vel Vuckovic, BMR Petroleum Resource Assessment Branch]

An overview of Pore Pressure and Fracture Pressure evaluation in the Southeast Gippsland Basin is given at the front of section 7.4 of this Record. This section contains drilling engineering data for Area V91-G2.

8.4.1 Bullseye No.1.

Operator: Esso Australia Ltd.

Co-ordinates: 38° 35′ 29.352" S.
147° 33′ 59.466" E.

Elevations: KB: 9.75 m.
GL: - 58.5 m.

Dates: 22.11.73 to 5.12.73.

Status: Plugged and abandoned - No shows.

Open hole sections:

26" to 193.5 m.
13.75" to 839.0 m.
9.875" to 2367.7 m.

Casings:

20" shoe at 183 m.
10.75" shoe at 831 m.

Pore pressures: All available parameters indicated a normally pressured hole from spud to 2367.7 m.

Formation integrity tests: 831 m 1.61 S.G.

8.4.2 Devilfish No.1.

Operator: Shell Australia Ltd.

Co-ordinates: 38° 47′ 58.21" S.
147° 55′ 10.54" E.

Elevations: KB: 28.4 m.
GL: - 74.0 m.

Dates: 9.04.90 to 1.05.90.

Objectives: 1. Top Latrobe Group.
2. Intra-Latrobe Group.

Status: Plugged and abandoned.

Open hole sections:

36"	to	142 m.
26"	to	400 m.
12.25"	to	1100 m.
8.5"	to	2058 m.

Casings:

30"	to	137.5 m.
20"	to	391.0 m.
9.625"	to	1088.6 m.

Pore pressures: Overpressure indicators were not encountered in Devilfish No.1. The use of PDC bits through zones of potential overpressure precluded the use of the D-exponent indicator. Normalized compaction trends could not be reliably established. Secondary indicators lacked evidence of overpressure.

Mud weights used to drill each interval were as follows:

To 408 m:	Sea water with Hi-Vis Pills.
408 m to 1100 m:	1.04 to 1.09 S.G.
1100 m to 2058 m:	1.09 to 1.13 S.G.

Formation integrity tests:

408 m:	1.31 S.G.
1105 m	1.60 S.G.

8.4.3 Edina No.1.

Operator: Australian Aquitaine Petroleum Pty Ltd.

Co-ordinates: 38° 36′ 22.539" S.
147° 52′ 41.949" E.

Elevations: KB: 30.5 m.
GL: - 68.5 m.

Dates: 26.09.82 to 1.11.82.

Status: Plugged and abandoned.

Open hole sections:

26"	to 224 m.
17.5"	to 1212 m.
12.25"	to 2534 m.

Casings:

20"	shoe at 213 m.
13.375"	shoe at 1201 m.

Pore pressures: All pressure parameters indicated a normally pressured hole from spud to 2594 m.

RFT Pressures:

2298 m:	1.00 S.G.
2335 m:	0.99 S.G.
2351.5 m:	1.00 S.G.
2368.5 m:	0.99 S.G.
2383 m:	0.99 S.G.
2387.5 m:	0.99 S.G.
2410.5 m:	0.99 S.G.
2431 m:	0.99 S.G.
2437.5 m:	0.99 S.G.
2438.5 m:	0.99 S.G.
2530 m:	0.99 S.G.
2545.5 m:	0.99 S.G.
2550.5 m:	0.99 S.G.
2562.5 m:	0.99 S.G.

Formation integrity tests:

231 m:	1.11 S.G.
1224 m:	1.50 S.G.

8.4.4 Gurnard No.1.

Operator: Esso Standard Oil (Aust) Ltd.

Co-ordinates: 38^{o} 35′ 33" S.
147^{o} 58′ 38" S.

Elevations: KB: 9.4 m.
GL: - 68 m.

Dates: 3.10.69 to 30.10.69.

Status: Plugged and abandoned.

Pore pressures: No useful information for pore pressure regime interpretation was available.

8.4.5 Nannygai No.1.

Operator: Esso Australia Ltd.

Co-ordinates: 38° 33′ 10.10" S.
147° 59′ 43.42" E.

Elevations: KB: 9.75 m.
GL: - 68.6 m.

Dates: 9.07.72 to 3.08.72.

Status: Plugged and abandoned - non productive oil show.

Objective: Top Latrobe Group.

Open hole sections:

26" to 242 m.
17.5" to 856 m.
12.25" to 3019 m.

Casings:

20" shoe at 225 m.
13.375" shoe at 841 m.

Pore pressures: All pressure parameters indicated a normally pressured hole from spud to 3019 m.

Formation integrity tests: Not available.

8.4.6 Omeo No.1.

Operator: Australian Aquitaine Petroleum Pty Ltd.

Co-ordinates: 38° 36′ 45.01" S.
147° 43′ 02.24" E.

Elevations: KB: 30.00 m.
GL: - 62.66 m.

Dates: 1.11.82 to 10.02.83.

Status: Plugged and abandoned.

Objectives: 1. Intra-Latrobe: approx. 2670 m.
2. Strzelecki Group: approx. 3630 m.

Open hole sections:

26"	to 220 m.	
17.5"	to 1320 m.	
12.25"	to 2876 m	
8.5"	to 2985 m,	sidetrack at 2674 m.
6"	to 3389 m.	

Casings:

20"	133 lb/ft	x 56	shoe at 210 m.
13.375"	68 lb/ft	K55	shoe at 1310 m.
9.625"	68 lb/ft	N80	shoe at 2606 m.
7"	26 lb/ft	N80	liner shoe at 2984 m.

Pore pressures: Normal pressure gradients of between 1.0 to 1.1 S.G. were experienced throughout the entire well section.

Mud weights used to drill each interval were as follows:

From 91 m to 220 m 1.02 s.g. seawater/lime flocculated gel slugs. Lithology - surface sands, silt and clay. No losses in formation.

From 220 m to 1320 m 1.09 to 1.16 s.g. seawater/Q. mix (prehydrated gel). Lithology - clay/sand/claystone. 8.8 m^3 (55 bbl) lost in formation while drilling this interval.

From 1320 m to 2985 m 1.04 to 1.22 s.g. sea water polymer mud. Lithology - to 2250 m claystone, to 2330 m shale, to 2700 m sandstone/claystone, to 2985 m sandstone/shale.

From 2985 m to 3389 m 1.09 to 1.28 s.g. seawater polymer mud. Lithology - to 2990 m claystone/sandstone, to 3100 m sandstone, to 3200 m sandstone and siltstone, to 3389 m shale/sandstone. 17 m^3 (107 bbl) lost in formation while drilling this section.

RFT pressures:

2349 m:	3300 PSIG	1.00 S.G.
2371.5 m:	3341 PSIG	1.00 S.G.
2387 m:	3352 PSIG	1.00 S.G.
2427 m:	3428 PSIG	1.00 S.G.
2461 m:	3469 PSIG	1.00 S.G.
2590 m:	3646 PSIG	1.00 S.G.
2695 m:	3803 PSIG	1.00 S.G.
2705 m:	3825 PSIG	1.00 S.G.
2725 m:	3856 PSIG	1.00 S.G.
2805 m:	3963 PSIG	1.00 S.G.
2849.8 m:	4101 PSIG	1.02 S.G.
3077.5 m:	4439.6 PSIA	1.02 S.G.
3096.0 m:	4461.7 PSIA	1.02 S.G.
3104.0 m:	4463.8 PSIA	1.02 S.G.
3131.5 m:	4585.8 PSIA	1.04 S.G.
3126.5 m:	4519.6 PSIA	1.02 S.G.
3125.0 m:	4514.7 PSIA	1.02 S.G.

DST test over interval 2918 - 2939 m gave the extrapolated reservoir static pressure of 4100 PSI (0.99 S.G.).

Formation integrity tests:

230 m:	1.08 S.G.	Leak off.
1330 m:	1.74 S.G.	Leak off.
2674 m:	1.44 S.G.	No leak off.
2987 m:	1.75 S.G.	No leak off.

8.4.7 Omeo No.2A.

[Omeo No.2 was abandoned at 284 m because the 20" casing was tilted.]

Operator: Australian Aquitaine Petroleum Pty Ltd.

Co-ordinates: 38° 36′ 21.864" S.
147° 42′ 38.364" E.

Elevations: KB: 22.0 m.
GL: - 62.0 m.

Dates: 10.05.85 to 24.06.85.

Status: Plugged and abandoned.

Objectives: 1. Deep Latrobe sands.
2. Top Cretaceous.
3. Top Latrobe 'coarse clastics'

Open hole sections:

26"	to 265 m.
17.5"	to 1068 m.
12.25"	to 2806 m.
8.5"	to 3400 m.

Casings:

20"	shoe at 249 m.
13.375"	shoe at 1062 m.
9.625"	shoe at 2798 m.

Pore pressures: Normal pore pressure gradients of between 1.0 to 1.1 s.g. were experienced.

Mud weights used to drill each interval were as follows:

84 m to 265 m:	Seawater with Hi-V.S. Pills.
265 m to 1068 m:	1.09 to 1.1 S.G. Seawater - Gel - Native clay.
1068 m to 2806 m:	1.12 S.G. Seawater - Polymer.
2806 m to 3400 m:	1.16 to 1.17 S.G. Seawater - Polymer.

Formation integrity tests: Not available.

8.4.8 Pike No.1.

Operator: Esso Australia Ltd.

Co-ordinates: 38° 46′ 29.054" S.
147° 57′ 00.726" E.

Elevations: KB: 9.75 m.
GL: - 73.75 m.

Dates: 14.07.73 to 25.07.73.

Status: Plugged and abandoned - dry hole.

Open hole sections:

26" to 222.2 m.
13.75" not available.
9.875" to 2133.6 m.

Casings:

20" shoe at 189.7 m.
10.75" shoe at 753.8 m.

Pore pressures: Normal pressure gradients were experienced throughout the well section.

Maximum **mud weight** used was 1.19 S.G.

Formation integrity test:

753.8 m: 1.59 S.G.

8.4.9 Speke No.1.

Operator: Australian Aquitaine Petroleum Pty Ltd.

Co-ordinates: 38° 30′ 34.64" S.
147° 37′ 11.74" E.

Elevations: KB: 22 m.
GL: - 55 m.

Dates: 14.06.84 to 10.07.84.

Status: Plugged and abandoned.

Objectives: top Latrobe and intra-Latrobe reservoirs.

Open hole sections:

26" to 228 m.
17.5" to 1032 m.
12.25" to 1756 m.
8.5" to 2772 m.

Casings:

20" shoe at 218 m.
13.375" shoe at 1020 m.
9.625" shoe at 1744 m.

Pore pressures: All pressure parameters indicated a normally pressured hole from spud to 2772 m.

Mud weights used to drill each interval were as follows:

To 218 m	High viscosity spud mud.
218 m to 1032 m	1.12 S.G. Sea water/gel.
1756 m to 2772 m	1.13 S.G. low solids - polymer.

Formation integrity tests: Not available.

8.4.10 Tarra No.1.

Operator: Australian Aquitaine Petroleum Pty Ltd.

Co-ordinates: 38° 38′ 37.15" S.
147° 42′ 08.20" E.

Elevations: KB: 30.5 m.
GL: - 62.5 m.

Dates: 4.03.83 to 21.04.83.

Status: Plugged and abandoned - dry hole.

Objectives: Strzelecki formations at 2547 m.

Open hole sections:

26" to 219 m.
17.5" to 1010 m.
12.25" to 2580 m.
8.5" to 2905 m.

Casings:

20" shoe at 211 m.
13.375" shoe at 1002 m.
9.625" shoe at 2567 m.

Pore pressures: All pressure parameters indicated a normally pressured hole from spud to 2905 m.

Mud weights used to drill each interval were as follows:

To 219 m	High viscosity spud mud.
219 m to 1010 m	1.1 S.G. Sea water/Q. Mix. Lost circulation problems in upper limestone/calcareous section.
1010 m to 2580 m	1.16 S.G. Seawater - polymer.
2580 m to 2905 m	1.09 S.G. Seawater/gel/polymer.

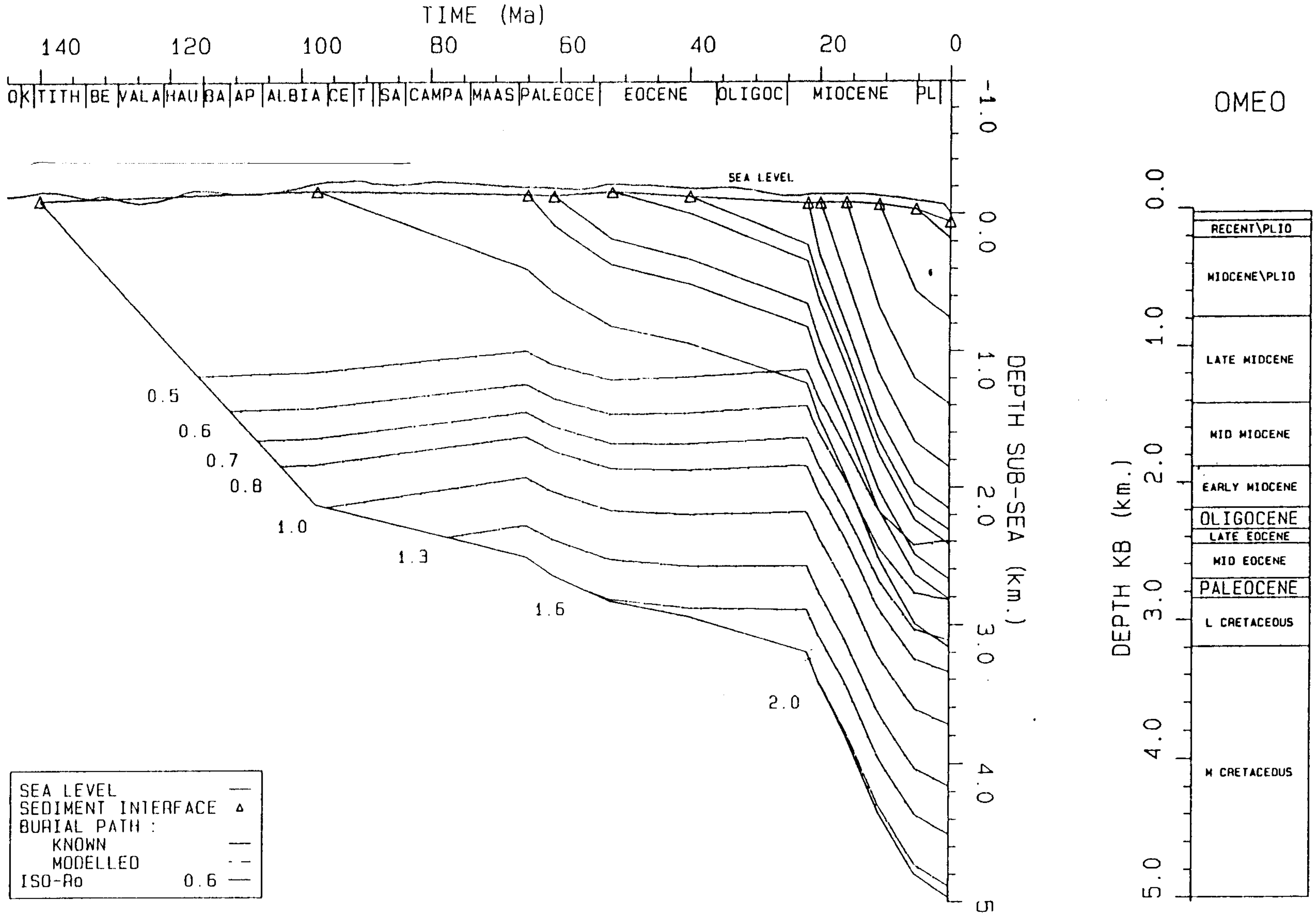
Formation integrity tests: Not available.

8.5 GEOHISTORY - Omeo No.1.

[by Paul E. Williamson, BMR Petroleum Resource Assessment Branch]

Modelling of the timing of source rock maturity for Omeo No.1 was included in the geohistory study (Fig. 12). The maturity for the onset of oil generation for the type of terrestrial source rocks in the Gippsland Basin is considered to correspond to a vitrinite reflectance of 0.7, maximum oil generation to a vitrinite reflectance of 1.0% and the onset of thermal gas generation to 1.3%. On that basis present day maturity for oil generation at the Omeo No.1 well location would occur in the Strzelecki Group and possibly in the lowest Latrobe Group at depths greater than 3.0 km. At the time of the Miocene compressional event which contributed to trap formation at the top of the Latrobe Group, the upper Strzelecki Group was probably immature for oil generation. Since that time maturity has moved shallower in the section with increased burial and consequent increased temperatures for that interval. The thermal gas window now occurs in the interpreted lower Strzelecki Group at a depth of approximately 4.5 km.

The vitrinite reflectance data in the Omeo No.1 well correspond reasonably to the levels of vitrinite reflectance calculated in the geohistory program (Fig. 13). The inferences from the geohistory study are that hydrocarbons in the region have been sourced probably from the Strzelecki Group with a possible contribution from the lowest Latrobe Group. Hydrocarbons now occur at levels immature for oil generation. These hydrocarbons have thus migrated vertically into traps set in their present form by seal facies overlying structures associated with Miocene compression and erosion of the top Latrobe Group reservoirs. Since migration of existing oil at that time would have resulted in loss, it can be inferred that hydrocarbons have been produced from strata subsequently within the oil window and that the oil hydrocarbons have been released by the rapid burial since the Miocene compressional event.



GEOHISTORY PLOT : OMEO

Figure 12.

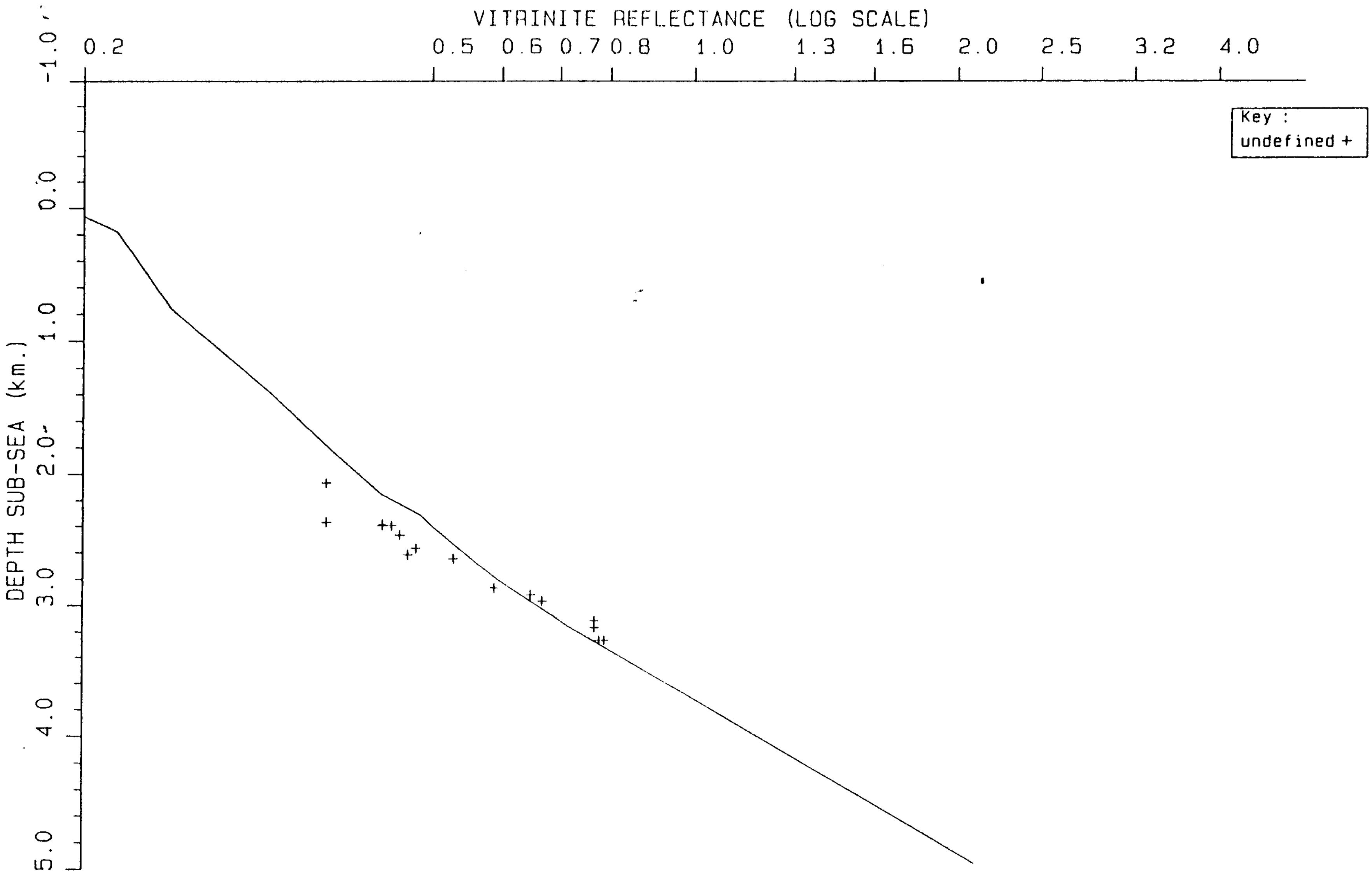


Figure 13.

COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT : OMEO

8.6 INTERPRETATION PROBLEMS.

[by Maher Megallaa.]

With the exception of the area near Gurnard No.1 well (a Miocene channel area) no major time-to-depth conversion problems are expected in Area V91-G2. Adequate velocity control can be obtained from the ten wells drilled in V91-G2, which also has an extensive 1.5 x 1 km grid of modern data covering the area north of the Foster Fault. On the Southern Platform, the grid is coarse and the data are generally of older vintage.

In 1988, Shell reprocessed a large part of the previous grid acquired by Aquitaine. A significant improvement in data quality was achieved by the reprocessing, resulting from the use of F/K filtering, DMO and careful picking of velocities. Velocities were picked in an horizon consistent manner for their later use in depth conversion. Regional interpretation can be completed at two main levels - Top Latrobe Group and Top Golden Beach Formation. The Golden Beach Formation is often recognised as a subtle unconformity and is easily picked in the Pike/Moray area; however, in the north of V91-G2 it is less reliable due to heavy faulting and degradation in data quality.

In the eastern part of Area V91-G2, the top Latrobe Group is marked by the presence of an acoustically 'hard carbonate' streak very near the base of the Lakes Entrance Formation. West of Omeo No.2A, the interval between the 'carbonate' streak and the top Latrobe Group can be picked separately with confidence.

8.7 PROSPECTS AND LEADS.

[by John Conolly, of John Conolly & Associates; with a detailed assessment of Prospect G2-P-A by Maher Megallaa, VDMID Petroleum Resources Branch.]

8.7.1 General comment.

Area V91-G2 can be subdivided into three areas, each with specific structural histories and different hydrocarbon prospectivity. These areas are directly related to the local geology, reflecting those parts of Area V91-G2 overlying the Central Deep, the South Strzelecki Terrace, and the Southern Platform. Each area is described in detail below.

8.7.2 Area A - Central Deep.

Area A lies north of the Darriman Fault Zone, in the southern Central Deep. Here 7 wells have been drilled on a variety of different suspected closures. Two wells were drilled on the Omeo feature, the second well being the follow-up of a series of good hydrocarbon shows from intra-Latrobe and older reservoirs in Omeo No.1.

Area A extends around the southern margins of the Bream field; in fact, the Speke No.1 well drilled a suspected closure that lay directly on trend with the Bream field but located about 10 km west of the Bream field's western limits. Similarly Nannygai No.1 drilled a large "time-high" located only 6 km away and northwest of present production from the western Kingfish field. Gurnard No.1 drilled another "time high" at top Latrobe levels, and this well is located about 8 km west of present day production.

There is little doubt that the use of 3-D seismic and better depth modelling should lead to a refinement of depth structural maps at top Latrobe, intra-Latrobe, and deeper Cretaceous levels. When wells can be located so that they drill structural closures in Area A they should find hydrocarbons, as the geological setting is not substantially different from that of the Bream and Kingfish fields.

It is possible to analyse each wildcat well drilled in Area A and show that so far the depth mapping that was used to locate the new field wildcat wells was at best, only 'State-of-the-Art' for that period, and certainly NOT good enough to properly define real structural closures. This report does not give an in-depth analysis of this kind, but rather points out the obvious problems for each drilled feature, for instance:

Speke No.1 was drilled by Australian Aquitaine Petroleum Pty Limited and its partners, the sixth well in their program, in June and July 1984. The well was designed to test the highest point of a small top Latrobe closure (1.5 km^2). Depth mapping suggested that the closure at top Latrobe was actual larger (up to 5.7 km^2) with a vertical relief of 40 m. The well actually intersected the 'coarse clastics' at the top Latrobe at 1860 mKB which appears to be about 20 to 30 m lower than prognosed. By the time the well reached Aquitaine's purple horizon (intra-Latrobe reflector) the well was 46 m low to prognosis. It is obvious from these results that accurate depth mapping was difficult to achieve and that the Speke No.1 well may well have been drilled off structure. The well had no shows and log interpretation indicated that the main reservoirs at the top Latrobe and intra-Latrobe levels had good reservoir properties but were water saturated.

Omeo No.1 was spudded by the Aquitaine group in Nov 1982 and after some difficulties with drilling and fishing reached a TD of 3379 mRKB on 25 Jan 1983, in early Cretaceous sediments of the Strezlecki Group. No hydrocarbon shows were indicated in the top Latrobe sands at 2188 to 2347 mRKB, RFT's recovered water and gas at 2849 mRKB and 3125 mRKB with a thin film of condensate. Due to testing problems with the 6" hole the lower shows in the well were not properly evaluated. Despite this, it was concluded that Omeo No.1 had a continuous hydrocarbon column from 3073 to 3185 meters (mainly gas, some condensate possible) and another hydrocarbon column extending to 3245 m.

This result encouraged the drilling of **Omeo No.2** northwest of Omeo No.1. Unfortunately, once again the depth mapping was not accurate and Omeo No.2 came in low to prognosis.

It is suggested, 8 years having passed since these wells were drilled, that a good 2D/3D seismic survey is required to remap and reinterpret the entire Omeo-closure trend. The Omeo prospect area remains a region where hydrocarbons have been found and it is concluded that it is still highly prospective. A section describing the reservoirs encountered and subsequent log and DST analysis is given in more detail in section 8.3 of this Report.

Gurnard No.1 and **Nannygai No.1** wells were drilled by ESSO/BHP prior to their relinquishment of acreage in 1980. Both wells drilled large time highs at top Latrobe levels which came in low to prognosis. However, both wells are located on areas where faulting occurs at deeper Upper Cretaceous levels, providing additional trapping mechanisms. The uppermost Miocene sequence contains 500 to 700 m of high velocity channel-fill carbonates in those locations, causing serious velocity pull-up at the Latrobe levels, as it does over the Kingfish field. As it is impossible to properly test the Gunnard-Nannygai region with just two fairly shallow wells it is concluded that several more wells need to be drilled to properly test the main objectives, and that the region located so close to the giant Kingfish oilfield is rated as highly prospective, but technically difficult.

Similar comment can be made about the drilling of the **Edina No.1** well by the Aquitaine group. Here about 600 m of high velocity upper Miocene carbonates has seriously distorted the seismic area sections, and it is concluded that the well was drilled off structure. In addition, Edina No.1 was only drilled to the base of the 'course clastics', and did not penetrate any deeper Upper Cretaceous reservoirs or traps. Several prospects and leads occur in the Central Deep in V91-G2 (Area A), and a brief description of each follows.

Prospect G2-P-C.

The Prospect map drawn at near top Cretaceous level (Plate 35) shows a closure against the Darriman Fault just north of the Bullseye No.1 well, which is Prospect G2-P-C. Seismic Line GA 81-47 intersects this prospect in a NE-SW direction and is illustrated by a line drawing plus a coloured seismic line (Plates 39 & 44 respectively). This Prospect is a region with a potential closure of greater than 10 km^2 and a relief of up to 30 milliseconds. Detailed seismic will be required to map it properly. Reservoirs should occur at intra-Latrobe and deeper Upper Cretaceous (Campanian) levels.

Leads A & B.

These leads are also illustrated on Seismic Line GA 81-47 (Plates 39 & 44). Closure is dependent on rollover into normal faults and once again reservoirs should be quartzose sands of mainly Late Cretaceous age. Some closure could also occur in the 'coarse clastics' at the top Latrobe Group level.

Prospect G2-P-B.

This prospect lies in a similar tectonic setting to the Omeo Prospect region. A prospect montage, modified from work done by Aquitaine (1984) illustrates the key aspects of the prospect (Plate 45). Seismic lines GA 81-27 (Plates 38 & 43), and GA 81-23 (Plates 36 & 41) also cross the prospect and are included in this report. The Prospect montage shows a simplified version of the structural mapping with only one major fault controlling the structure. The Plate showing all the prospects and leads of V91-G2 (Plate 35) shows that at least two separate faults probably run through the prospect region. Closure at intra-Latrobe levels varies from about 2.6 km^2 to 3.9 km^2 as shown on the prospect montage. The predicted well section indicates that over 1000 m of sequence containing potential reservoirs should be intersected if a well was drilled to 3400 m. Prospect G2-P-13 is moreover upgraded because of its proximity to the Omeo No.1 hydrocarbon discovery, located only 5 km to the west.

Prospect G2-P-A Region.

This prospect region is located around the Gunnard No.1 well location and consists of a series of faulted blocks, which form a large time high at upper Cretaceous level (see Plate 35). A more detailed assessment of this Prospect is given below by Mr Maher Megalla. He shows that "Fortescue type" plays exist on the flank of the prospect region. These plays depend on stratigraphic trapping of intra-Latrobe sands on the flank of the structure. The drilling of one well (Gurnard No.1) on the top of the structure would necessarily miss this style of trapping. The prospect area is very large (greater than 20 km^2), and the potential for discovery of a major hydrocarbon accumulation is good.

Prospect G2-P-A. [by Maher Megallaa]

Location: The prospect lies in the extreme northeastern part of V91-G2, some 6 km west of the West Kingfish field and 12 km west of the Kingfish field. It lies in an area immediately west of the Gurnard No.1 well, in a water depth of 70 m.

Trapping: Seismic line GA83A-309 (Plate 45) is aligned northeast-southwest across the G2-P-A prospect and is tied to the Gurnard No.1 and Edina No.1 wells. It illustrates the pinching out of sediments younger than Reflector A west of Gurnard No.1. The evolution of the prospect is schematically illustrated in Plate 46B.

The play concept is directly analogous to that existing across the Fortescue Field and the West Kingfish area. The prospect is defined on the east by the pinchout of Reflector A to the north, and west by the pinchout of Reflector B to the southeast by either structural closure or stratigraphic pinchout, and to the northeast by either fault closure or stratigraphic seal.

Correlation from Salmon No.1 through Nannygai No.1 (Plate 16B) provides further geological evidence of this pinchout in the area west of Gurnard No.1.

Plate 46A is the top Latrobe map upon which the pinchout has been superimposed to show possible configuration of the play type.

Horizontal and Vertical Closures: The prospect covers an area of approximately 39 km^2 and retains a vertical relief of 50 m.

Reservoir: Reworked marginal marine unconsolidated sands of medium to coarse, subrounded, well-sorted, of excellent porosity and permeability similar to the FM 1.3 to FM 1.1 sands in the Fortescue field are believed to represent the primary objective in the G2-P-A prospect. A high potential recovery rate (up to 500 bbl/acre-foot) is expected for this type of reservoir.

Seal: Basal seal will be defined by interbedded coal swamp shales and coals. Lateral seal to the west will be derived from similar deposits, while vertical seal will be provided by the mudstones and shales of the Lakes Entrance Formation. Where closure is structural, either dip-defined as in the southeast or fault-defined as in the northeast, the Lakes Entrance Formation will again provide seal.

Source/Migration: The kitchen area for the West Kingfish area and the Fortescue Field can also offer source potential for this prospect. Migration would have occurred up-dip along westerly and northwesterly dipping palaeoslopes, provided that it occurred prior to faulting along the northeastern margin of the prospect. The depression area west of Prospect G2-P-A (Plates 46A & 46B) is also a potential source area.

Other Leads. [by John Conolly]

Many other leads exist in the region bounded by the Darriman fault system and are dependent on intra-Latrobe and older Upper Cretaceous closures bounded by faults. More extensive mapping and depth modelling at these levels should reveal a number of potential new targets once a reliable depth conversion process has been obtained.

Inspection of the long seismic cross-section across this region (Kingfish No.7 to Bullseye No.1 - Plate 40) shows how high velocity upper Miocene channels have helped "pull-up" the structures at Latrobe level at locations such as Gurnard and Edina. If this is not regarded as insurmountable problem then the region can be seen as highly prospective.

8.7.3 Area B - South Strzelecki Terrace.

Area B lies between the Darriman Fault system (bounding to the north) and the southern bounding fault system (Foster Fault system) to the south. It overlies the South Strzelecki Terrace. Four wells have been drilled in this area: Bullseye No.1, Tarra No.1, Pike No.1, and Devilfish No.1. All of the wells have been dry, however both Bullseye No.1 and Tarra No.1 were drilled off structure, and Pike No.1 appears to have been drilled off structure. The Pike No.1 and Devilfish No.1 wells tested a large potential top Latrobe pinchout which appears to be poorly sealed, and which was dependent on long-range lateral migration for charge. Hence the four wells drilled to date do not appear to have been well positioned.

Area B in V91-G2 will be sourced mainly from the lower Cretaceous (Strzelecki Group) sediments which underlie it. Inspection of the Seismic lines GA 81-27, GA 82B-207, GA 81-23 and GA 81-47 (Plates 38 & 43, 37 & 42, 36 & 41, 39 & 44) quite clearly shows the existence of a very thick (greater than 5000 m) sequence of dipping sediment lying unconformably below an upper Cretaceous unconformity. This older Strzelecki rift-valley fill is faulted down to deeper depths north of the Darriman-Omeo fault system as shown by the deep seismic lines shot by the BMR (Plates 10A & 10B) that cross Area V91-G2.

Little is really known about the source potential of this thick pile of Lower Cretaceous sediment. Hydrocarbon shows that occur in the Lower Cretaceous section in Omeo No.1 support the concept that they could produce hydrocarbons. Generally speaking, the reservoirs in these sediments are expected to be less porous than the Latrobe Group quartz sands, however, very few wells have penetrated the sequence to date.

Prospect G2-P-D.

This prospect is a closure mapped at an upper Cretaceous level immediately south of the Omeo Fault about 8 km southeast of the Omeo No.1 well (Plate 35). Seismic lines GA 82B-207 & GA 81-23 (Plates 37 & 42, 36 & 41) illustrate the geology of this prospect. Closure is dependent on rollover on the southern side of the Omeo fault at upper Cretaceous levels. Closure could also exist at higher intra-Latrobe levels, giving this prospect a number of stacked reservoir targets. Reservoirs are expected to be excellent and if the structural trap exists as mapped, then the major risk will be charge, as little as known about the source potential of the upper Cretaceous and lower Cretaceous potential source rocks in this immediate locality.

Prospect G2-P-E.

This prospect is a fault-bounded play along the southern bounding fault of Area B. It is illustrated by a prospect montage (after Aquitaine 1984 - Plate 46), and by the seismic lines GA 81-23 and GA 82 B-207. Closure exists at top Latrobe and intra-Latrobe levels. The most obvious source would require migration from the mature lower Cretaceous sediments adjacent to the prospect. It is a high risk prospect similar in many aspects to that drilled by Devilfish No.1.

8.7.4 Area C - Southern Platform.

Area C is that part of V91-G2 that lies south of the southern bounding fault system, on the Southern Platform. It is underlain by shallow basement and is considered to be of very limited prospectivity. Unlike the Southern Platform portion of V91-G1, no grabens are known within the Southern Platform of V91-G2.

9. AREA V91-G3

Area V91-G3 comprises 9 graticular blocks in the central Gippsland Basin (Plate 13). Authorship is specified under each subsection.

9.1 PREVIOUS EXPLORATION.

[by A.E. Stephenson & Tun U Maung.]

Area V91-G3 was formerly part of the original Gippsland Basin permit: VIC/P1, operated by Esso, until the acreage was dropped as part of the third renewal process for that permit in 1985. Esso immediately took up the acreage again when it became available in 1986, as VIC/P26..

9.1.1 Drilling.

Five wells have been drilled in Area V91-G3, which is located entirely within the Central Deep of the Gippsland Basin. Brief details are given in Table 4 - fuller descriptions are contained in sections 9.3 (reservoir geology), 9.4 (reservoir engineering), and 9.6 (prospects & leads).

Table 4: Wells drilled in V91-G3.

Well	Operator	Year	TD (m)	Hydrocarbons	Target interval
Cod 1	Esso	1965	2907	Dry hole	Top Latrobe
Conger 1	Esso	1989	2970	Mnr gas shows	Intra-Latrobe
Sawbelly 1	Esso	1990	3068	Dry hole	Intra-Latrobe
Swordfish 1	Esso	1977	2469	Dry hole	Top Latrobe
Veilfin 1	Esso	1984	3301	Gas discovery	Top Latrobe

9.1.2 Geophysics.

Area V91-G3 was previously held by Esso/BHP, and is covered by Esso's G74A, G77A,G80A,G81A, G84A and G88A 48-fold seismic survey data (Plates 14 & 47). Seismic survey data earlier than the G74A survey were not utilized by Esso for the past 7 to 8 years as the data quality was significantly poor. The seismic coverage consists of both 2D and 3D data comprising 21,776.5 line-km. The general grid spacing for 2D data is approximately 1.0 x 1.0 km to 2.0 x 2.0 km (Plate 14). The data quality is generally good down to the lower M. diversus seismic marker. Below this level data quality deteriorates dramatically because of the loss of reflection energy to water bottom peg-legs and interbed multiples sourced from thick coals in the shallow part of the Latrobe Group (Mebberson, 1989 and Maung & Nicholas, 1990). Confidence in the deeper interpretation is limited by interference from multiples. Interpretation problems are discussed in detail in section 9.6.

9.2 LOCAL GEOLOGY AND RELEVANT PLAY CONCEPTS.

[by A.E. Stephenson]

Vacant Area V91-G3 is located in the central Gippsland Basin (Plate 13), and is contained entirely within the basin's Central Deep. Play concepts are thus limited to those relevant to this structural feature of the basin.

9.2.1 Central Deep.

The standard top Latrobe Group structural plays have been well examined in the area, but some prospects of this play type remain undrilled (see section 9.7). Stratigraphic plays, such as the stranded beach-barrier play (6.1.2) and the Gurnard sand play (6.1.5) have yet to be tested in Area V91-G3, so must be given some potential. However, intra-Latrobe Group plays may have the best rating. The recent Conger No.1 and Sawbelly No.1 wells tested intra-Latrobe fault dependant structural plays without success, but local sealing factors can be blamed for their lack of producible hydrocarbons. Charge is certainly not a problem in V91-G3, which lies in the heart of the Gippsland Basin's hydrocarbon kitchen. The intra-Latrobe structural play remains valid, particularly as recent work in BMR (section 4) indicates that many intra-Latrobe Group structures have no expression at the top Latrobe level, and may have been easily overlooked because of the velocity and other interpretation problems particular to the area (see section 9.6). Similarly, intra-Latrobe stratigraphic plays remain totally untested in V91-G3. Although palaeogeography shows the beach-barrier play at intra-Latrobe levels to be a long shot, stacked fluvial point bars remain a valid stratigraphic play, although seismically difficult to detect. Other plays discussed in section 6 are unlikely to attract interest in Area V91-G3.

9.3 RESERVOIR GEOLOGY.

[by Shige Miyazaki.]

9.3.1 Veilfin No.1.

Summary: Veilfin No.1 is a gas discovery well. Gas is contained in sandstones in the intra-Latrobe T. longus zone. However, the water saturation of these reservoirs is high, and the porosity and permeability are low. The individual reservoirs are thin, and they appear to be hydraulically separated from each other. The gas flow rate on a production test was insignificant.

Veilfin No.1 was drilled by Esso in 1984. It intersected the top Latrobe 'coarse clastics', at 2025 mKB. (The KB elevation for the well was 21.0m above mean sea level.) The 'coarse clastics' consist of massive 90 thick sandstones, of the Lower N. asperus and P. asperopolus zones, interbedded with 1 m thick coals. These sandstones have a good porosity of 24% but are completely water-wet.

A post-drill structure map for the top Latrobe 'coarse clastics' shows that the well was drilled off structure and that a very small fault-dependent closure of 1 km^2 still exists updip. The closure of the structure expands downwards. The structure has a closure of 14 km^2 on another post-drill structure map for the intra-Latrobe Lower L. balmei seismic marker, and Veilfin No.1 is on the structure. This fault-dependent structure appears to form a closure of 20 km^2 at the top of the T. longus zone.

Sandstones over the interval from 3032 to 3490 mKB in the intra-Latrobe T. longus zone exhibit minor anomalies on resistivity logs. However, the porosity of these sandstones is relatively low (11 to 14%), and the water saturation is high (57 to 80%). The gross thickness of each of these sandstones is in the order of a few metres and tends to decrease downwards. Intra-Latrobe formations are shaly, and the T. longus zone has a sand/shale ratio of 1:4.

Esso attempted a total of 56 RFT pressure seats in intra-Latrobe sandstones, of which only 18 seats gave valid pressure data. These tests failed to obtain information on hydrocarbon-water contacts. However, the pressure data suggest a lack of hydraulic communication between individual sandstone units, and that many of these sandstones have low permeability. All six RFT fluid samplings recovered large amounts of water or filtrate and only minor amounts of gas (See Table 5 for details).

Table 5 RFT fluid-sampling results.

Seat No.	Depth (mKB)	Chamber (litres)	Oil	Gas (m^3)	Filtrate (litres)	ISIP (psia)
6/56	2896.0	10.4		0.009	9.6	
		45.4			36.7	4155
4/54	3149.5	10.4		0.004	9.0	4517
5/55	3149.5	10.4	scum	0.017	9.25	
		45.4	scum	0.067	41.8	4529
4/53	3191.8	45.4		0.017	17.5	4638
2/43	3212.6	10.4		0.02	9.1	
		22.7		0.035	20.3	4696
3/45	3212.6	10.4		0.018	7.75	
		22.7		0.051	19.8	4680

A production test was run over the interval of 3185 to 3194 mKB within the intra-Latrobe T. longus zone. This interval has a porosity of 14 % and a water saturation of 66%. The test recorded an average flow rate of 0.515 million scf/d of gas, through a 24/64-inch choke, with a small amount of water or filtrate. This flow rate is too low to lift water and liquid hydrocarbons from the well and to achieve a stable operation. A 1-litre sample of condensate was recovered from the choke manifold, but no liquid hydrocarbons were recovered during reverse circulation. Therefore, condensate yields are assumed to be negligible.

The maximum recorded temperature during the production test is 121 ^{o}C. Reservoir pressure data for this test are not reliable because of the low permeability of the formation. Two RFT pressure data taken from the production test interval have given a reservoir pressure of 4640 psia at a datum depth of 3189.5 mKB. This pressure value is normal in relation to that for the Gippsland Basin aquifer. The pressure data indicate a formation permeability of 0.14 millidarcies.

A core was cut over the interval of 3453.1 to 3462.8 mKB with a recovery of 9.55m (99%). Siltstones, coals and sandstones comprise the upper half of the core. The lower half consists of sandstones grading upwards to siltstones. Silica and dolomite cements occupy much of the primary porosity. These sandstones showed weak fluorescence, and parts of the sandstones had minor oil stains. The sandstones have porosities less than 9% and permeabilities less than 0.02 millidarcies.

The well was terminated at 3521 mKB within the T. longus zone.

9.3.2 Swordfish No.1.

Swordfish No.1 was drilled by Esso in 1976 to 1977. Esso picked the top Latrobe 'coarse clastics' at 2046 mKB. (The KB elevation for the well was 25.3m above mean sea level.) The Latrobe 'coarse clastics' consist of 169m of massive sandstones interbedded with coals.

Of the five FITs attempted in this well, two were valid tests. FIT-5 was run for the sandstones having a porosity of 27% at 2075.7 mKB within the Latrobe 'coarse clastics', and recovered 22 litres of water in a 22.2-litres chamber. FIT-3 was run for the sandstones having a porosity of 19% at 242 3.2 mKB within the lower M. diversus zone, and recovered 22 litres of water in a 22.2-litre chamber.

The well was supposed to drill into an anticline, but turned out to be drilled off-structure, according to a post-drill structure map. This major revision of seismic interpretation is attributable to high velocity Miocene channel fills. The well was terminated, without exhibiting any hydrocarbon shows, at 2468 mKB within the Upper L. balmei zone.

9.3.3 Conger No.1.

Following a 3-D seismic survey in 1988, Conger No.1 was drilled by Esso in 1989. The well intersected the top Latrobe 'coarse clastics' at 1831 mKB. (The KB elevation for the well was 21 m above mean sea level.) The sandstones of the P. asperopolus zone (and of younger zones) have porosities of 20 to 26% but are completely water-wet. Pre- and post-drill structure maps for the top Latrobe 'coarse clastics' show a monoclinal structure and no closure over Conger No.1.

Moderately high mud-gas readings continued within the intra-Latrobe Group from 2550 mKB to the bottom of the hole (2970.0 mKB). It reached a peak at 2590 mKB with 2.5% of methane, 0.33% of ethane, 0.3% of propane, 0.065% of butanes and 0.01% of pentanes within a shaly sandstones and siltstones zone. Sandstone samples, taken from drill cuttings over 2765 to 2776 mKB, showed bright fluorescence and produced weak cuts.

Following the shows on these drill cuttings, a core was cut from 2776 to 2794.5 mKB with a recovery of 18.23m (98%). The core consists of sandstones with a few laminations of siltstones and coals of the Lower L. balmei zone. These sandstones are overlain by a 45 m thick alternation of siltstones and coals. The sandstones showed weak fluorescence and produced slow streaming cuts and thin ring residues. Esso's log interpretation, however, indicates that these sandstones have a porosity of 14.4% and a water saturation of 98.5%.

A post-drill structure map for the 60 Ma sequence boundary, which was intersected at 2750 mKB in Conger No.1, shows a fault-dependent closure over the well. The fault appears not to form an adequate seal. However, there remains the potential of a small hydrocarbon accumulation updip to the north within the closure, but the areal extent would be less than 1 km^2, and the vertical closure would be less than 50m.

Of the 42 recovered sidewall core samples, two samples from 2790 and 2934 mKB showed weak fluorescence, cuts and ring residues. The well was terminated at 2970.0 mKB within the T. longus zone. No RFT was run in this well.

9.3.4 Salmon No.1.

Although Salmon No.1 is not within V91-63, it is included here because of its proximity to the vacant acreage.

Salmon was drilled by Esso in 1969. Esso picked the top Latrobe 'coarse clastics' at 2030 mRT. (The RT elevation for the well was 30.2m above mean sea level.) The Latrobe 'coarse clastics' consist of clean sandstones interbedded with siltstones, claystones and coals of the N. goniatus zone. The sandstones have a porosity of 26%.

A bottom-hole core was cut from 3000.5 to 3006.9 mRT with a recovery of 6.4m (100%). The core, composed of siltstones and coals, exhibited no hydrocarbon shows. Two siltstone plugs taken from the core have porosities of 3.6 and 7.3% and no permeability, and one coal plug has a porosity of 0.9% and no permeability.

The well was terminated at 3006.9 mRT, within the L. balmei zone, without encountering any hydrocarbon shows. No FIT was run in this well.

9.4 DRILLING ENGINEERING.

[by Vel Vuckovic.]

An introductory section on Pore Pressure and Fracture Pressure evaluation occurs in section 7.4.1.

9.4.1 Conger No.1.

Operator: Esso Australia Inc.

Co-ordinates: 38° 21' 27.74" S.
148° 03' 46.34" E.

Elevations: KB: 21 m.
GL: - 64 m.

Dates: 24.02.89 to 18.03.89.

Status: Plugged and abandoned dry hole.

Open hole sections:

26" to 214 m.
17.5" to 815 m.
12.25" to 2970 m.

Casings:

20" to 209 m.
13.375" to 798 m.

Pore pressures: All the monitored pressure parameters indicated a normally pressured hole from spud to 2530 m. From this depth to 2620 m background gas increased and was slow to fall back after any peaks indicating a possible increase in formation pressure. No connection gas or splintery cavings were seen from this interval, therefore it is unlikely that the formation pressure exceeded the mud hydrostatic at any stage, and the maximum formation pressure was estimated to be 9.0 ppg EMD (1.08 S.G.) at 262 m. From 262 m gas values returned to normal and the section from 2620 m to TD appeared to be normally pressured [see Fig. 14].

Formation integrity tests:

815 m 1.97 G.G. Leak off

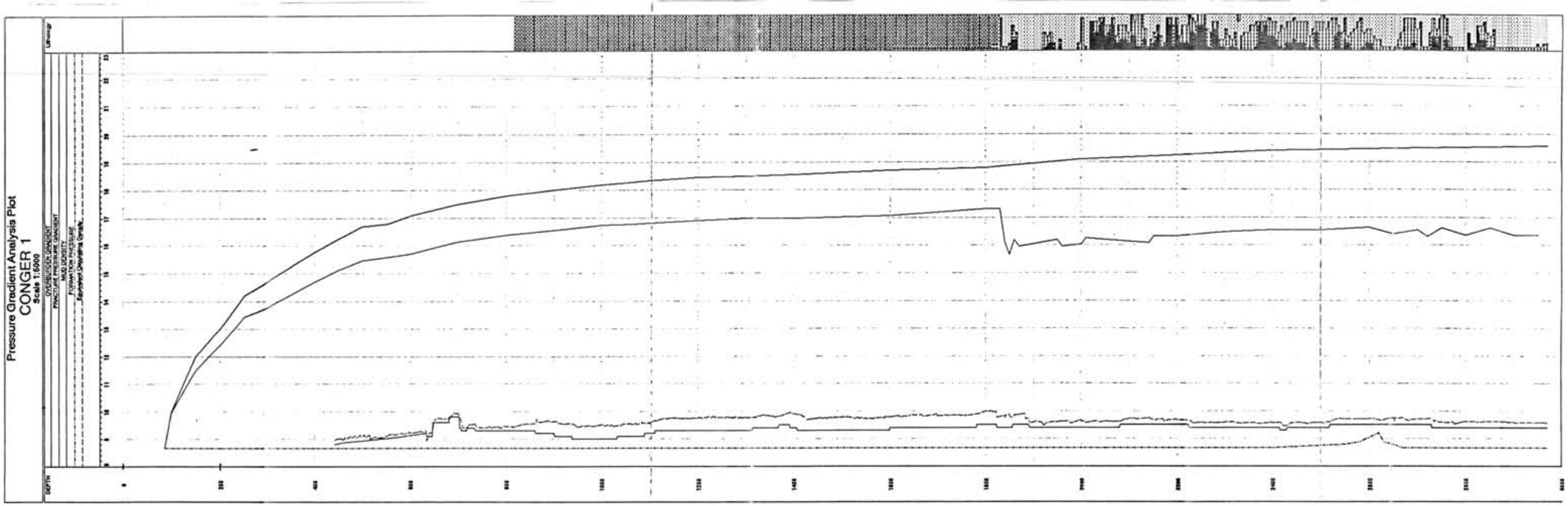

Pressure Gradient Analysis Plot
CONGER 1
Scale 1:5000
OVERBURDEN GRADIENT
FRACTURE PRESSURE GRADIENT
MUD DENSITY
FORMATION PRESSURE
DEPTH

Figure 14.

9.4.2 Salmon No.1.

Salmon No.1 is not within Area V91-G3, lying just outside the boundary of the vacant area.

Operator: Esso Standard Oil (Aust.) Ltd.

Co-ordinates: 38° 25′ 15" S.
147° 59′ 15" E.

Elevations: KB: 28 m.
GL: - 64 m.

Dates: 14.01.69 to 14.02.69.

Status: Suspended - No shows.

Open hole sections:

Bit sizes and depths are not available. TD 3007 m.

Casings:

30"	shoe at	116 m.
20"	shoe at	244 m.
13.375"	shoe at	687 m.
9.625"	shoe at	2983 m.

Pore pressures: Very limited number of pore pressure parameters available indicated a normally pressured hole.

Formation integrity tests: Not available.

9.4.3 Sawbelly No.1.

Operator: Esso Australia Limited.

Co-ordinates: 38° 22′ 31.0" S.
148° 02′ 05.9" E.

Elevations: KB: 21 m.
GL: - 63 m.

Dates: 03.03.90 to 26.03.90.

Status: Plugged and abandoned.

Open hole sections:

26"	to	205 m.
17.5"	to	815 m.
12.25"	to	3068 m.

Casings:

20"	shoe at	198 m.
13.375"	shoe at	800 m.

Pore pressures: The limited amount of pressure parameters available indicated that Sawbelly No.1 was normally pressured from spud to 3068 m.

Formation integrity tests:

818 m 1.59 S.G.

9.4.4 Swordfish No.1.

Operator: Esso Australia Ltd.

Co-ordinates: 38° 23′ 36.063" S.
148° 00′ 24.007" E.

Elevations: KB: 25.30 m.
GL: - 64.92 m.

Dates: 19.12.76 to 20.01.77.

Status: Plugged and abandoned - no shows.

Open hole sections:

26" to 231 m.
17.5" to 920.5 m.
12.25" to 2469 m.

Casings:

20" shoe at 217 m.
13.375" shoe at 908 m.

Pore pressures: All pore pressure parameters indicated that Swordfish No.1 was normally pressured throughout [see Fig. 15].

Formation interval tests:

2423.16 m 0.99 S.G. (H.P. Quartz gauge)
2075.69 m 0.99 S.G. "

Formation integrity tests:

908 m - 1.61 S.G. (No leak off).

9.4.5 Veilfin No.1.

Operator: Esso Australia Inc.

Co-ordinates: 38° 25′ 02.43" S.
148° 00′ 08.38" E.

Elevations: KB: 21 m.
GL: - 65 m.

E S P PRESSURE PLOT

SWORDFISH 1

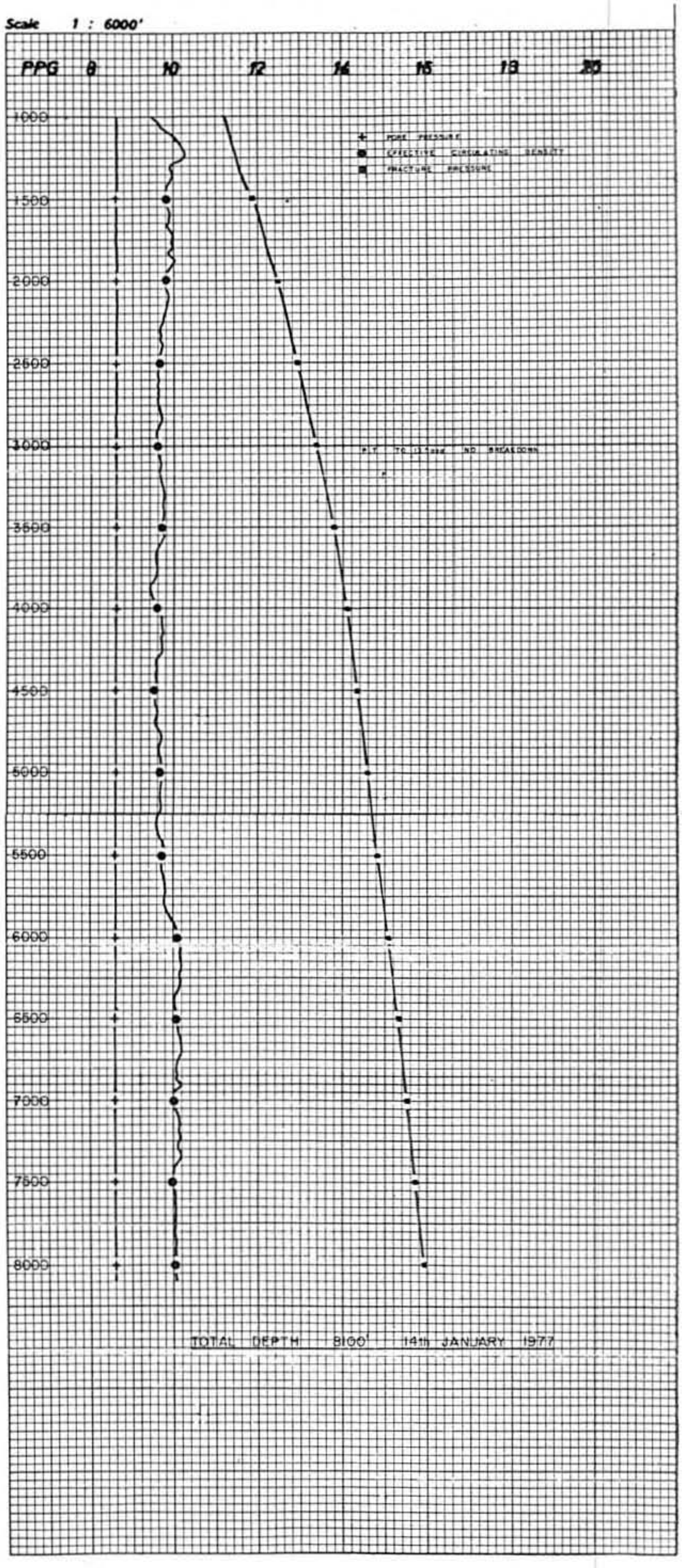


Figure 15.

Dates: 27.02.84 to 14.04.84.

Status: Plugged and abandoned - gas discovery.

Open hole sections:

26" to 225 m.
17.5" to 830 m.
12.25" to 3521 m.

Casings:

20" shoe at 207 m.
13.375" shoe at 815 m.
9.625" shoe at 3301 m.

Pore pressures: The pore pressure gradients of the well was estimated to be 1.01 to 1.03 S.G. throughout [see Fig. 16].

RFT pressures:

3227.5 m	5029.1 PSIA	1.10 S.G.
3212.5 m	4699.7 PSIA	1.03 S.G.
3191.8 m	4642.9 PSIA	1.03 S.G.
3187.5 m	4638.0 PSIA	1.03 S.G.
3149.0 m	4521.4 PSIA	1.02 S.G.
3130.5 m	4529.0 PSIA	1.02 S.G.
3095.5 m	4500.7 PSIA	1.03 S.G.
3081.0 m	4435.0 PSIA	1.02 S.G.
3044.0 m	4309.3 PSIA	1.00 S.G.
3050.0 m	2881.2 PSIA	1.00 S.G.
3212.6 m	4696.4 PSIA	1.03 S.G.
3212.6 m	4679.9 PSIA	1.03 S.G.
3190.0 m	4689.6 PSIA	1.04 S.G.
3189.8 m	4645.1 PSIA	1.03 S.G.
3187.5 m	4639.4 PSIA	1.03 S.G.
3191.8 m	4637.8 PSIA	1.03 S.G.
3149.5 m	4516.5 PSIA	1.01 S.G.
3149.5 m	4528.8 PSIA	1.02 S.G.
2896.0 m	4154.9 PSIA	1.02 S.G.

DST Results:

Interval 3185 - 3194 perforated with $2^{1}/8$" enerjet gas.

Produced fluid: gas.

Production rate: 740 declining to 310 x 10^{3}SCF/D.

Reservoir pressure: 4640 PSI (1.03 S.G.).

Formation Integrity tests:

819 m 1.94 S.G.

Figure 18 is a drill-data plot.

PRESSURE PLOT

VEILFIN 1

SCALE 1:5000

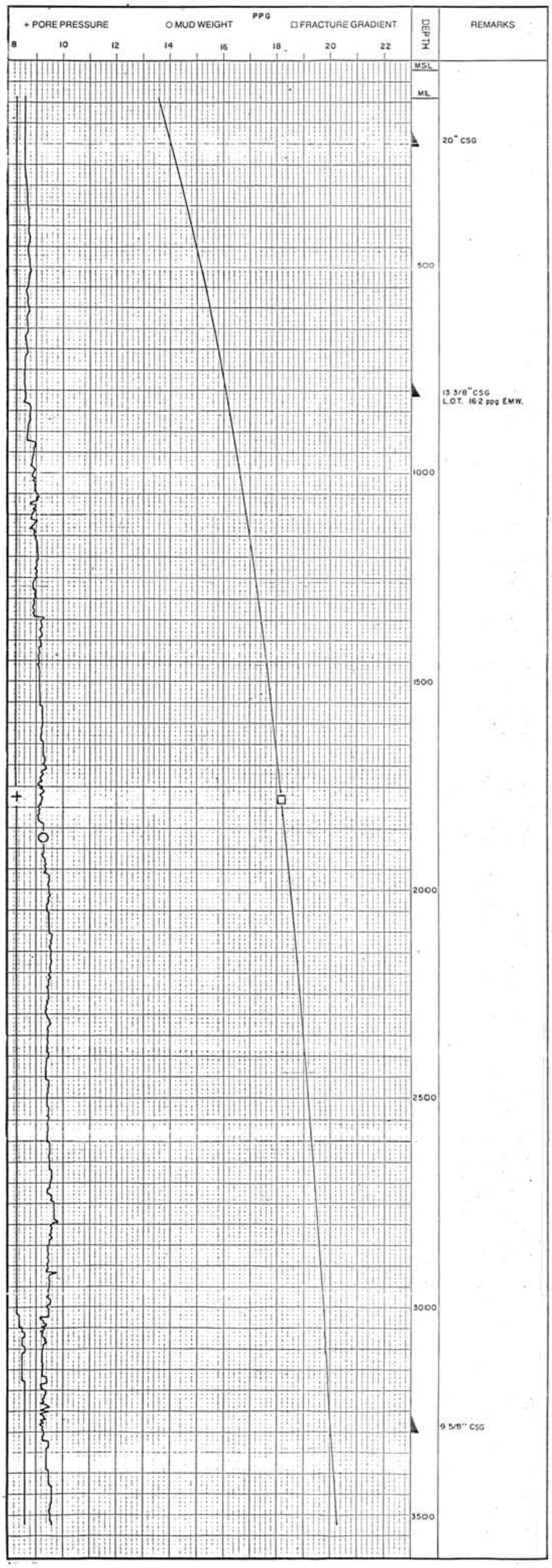


Figure 16.

DRILL DATA PLOT

VEILFIN 1

SCALE 1:5000

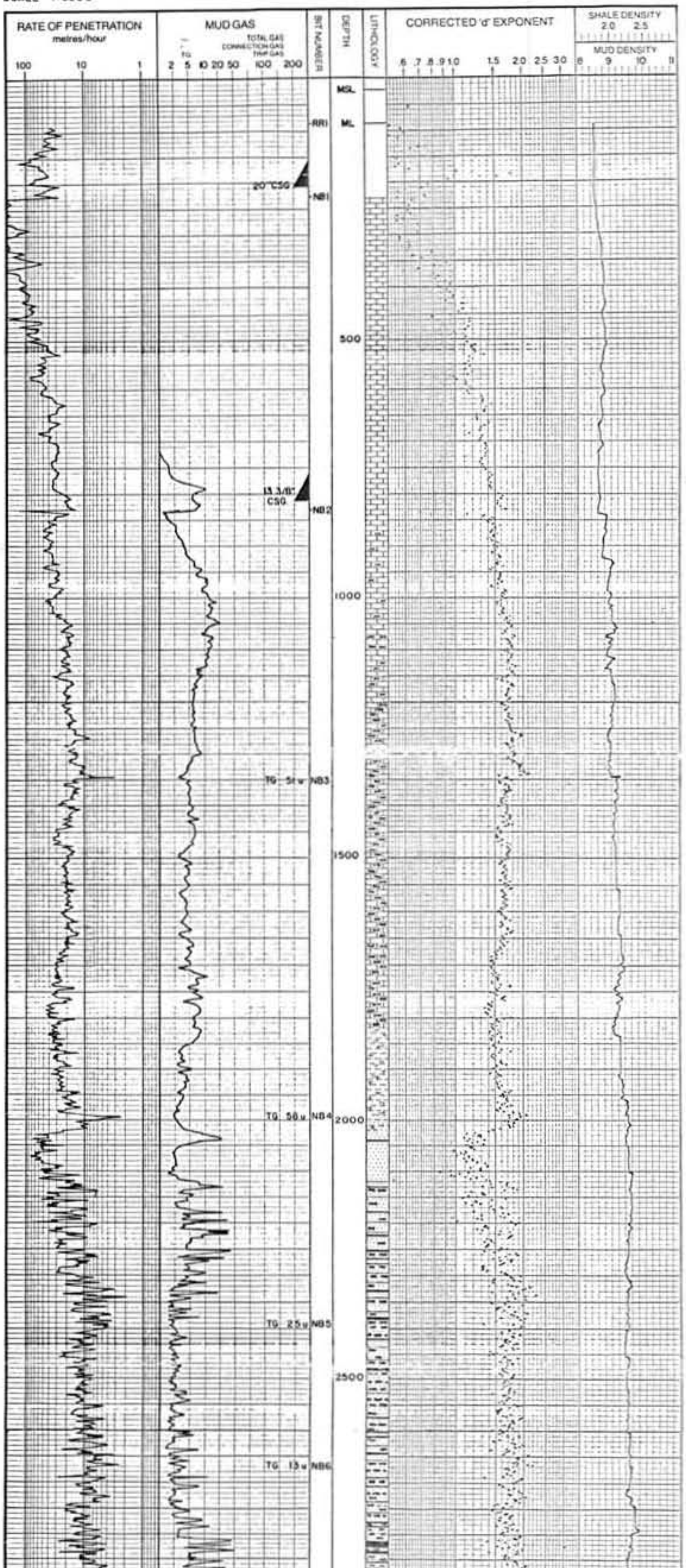


Figure 17.

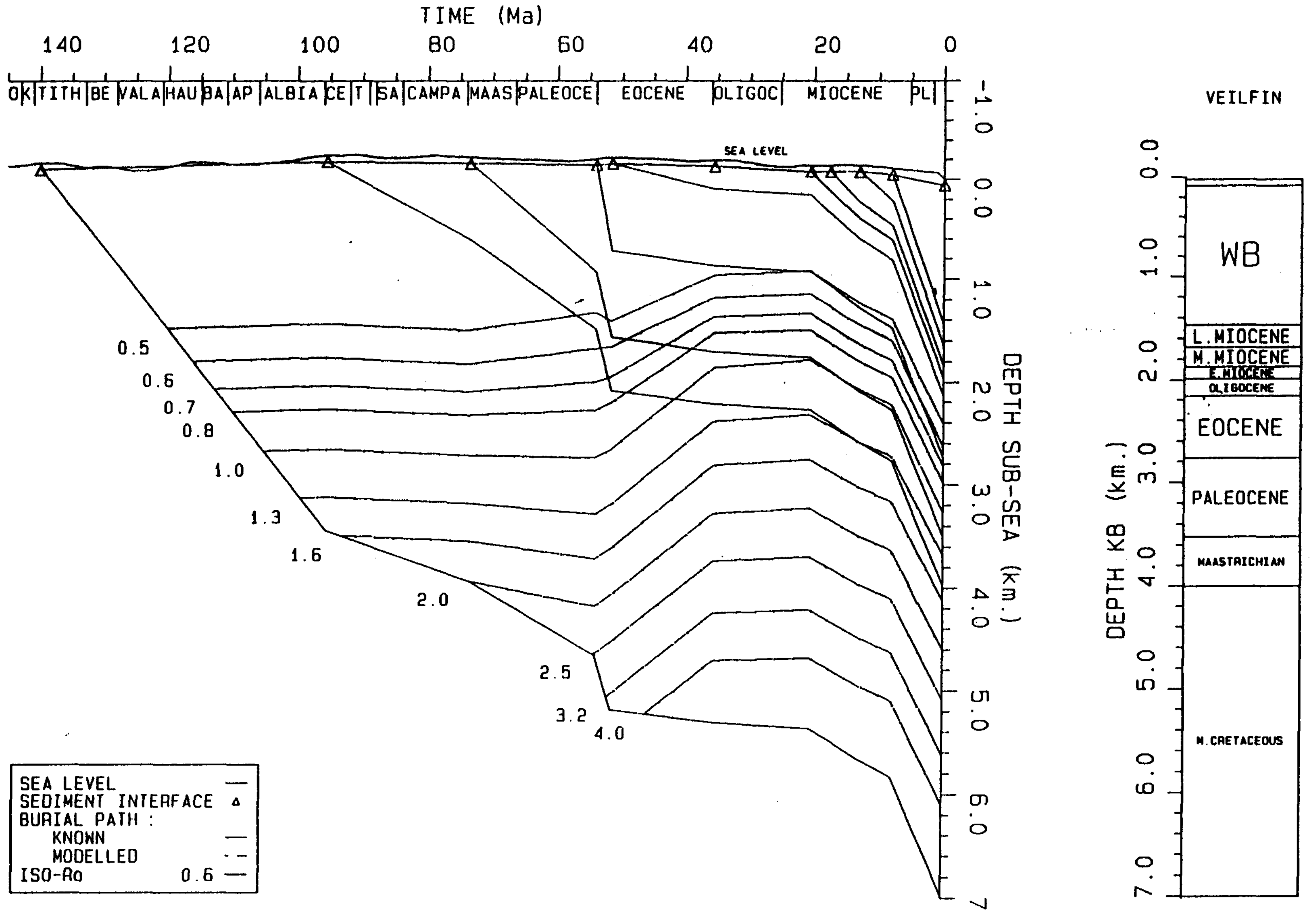
9.5 GEOHISTORY - VEILFIN No.1.

[by Paul E. Williamson.]

Modelling of the timing of source rock maturity for Veilfin 1 was carried out as part of a geohistory study (Fig. 18). The maturity for the onset of oil generation for the type of terrestrial source rocks in the Gippsland Basin is considered to correspond to a vitrinite reflectance of 1.0 and the onset of thermal gas generation at 1.3. On that basis present day maturity for oil generation would occur in the lower Latrobe Group and at a depth of around 3.0 km. At the time of the Miocene compressional event which contributed to trap formation at top Latrobe Formation the lowest Latrobe Group was mature for oil generation. Since that time maturity has moved shallower in the section with subsequent burial and increased temperatures in the sediments. The thermal gas window now occurs in the interpreted upper Strzelecki Group at a depth of approximately 4.0 km.

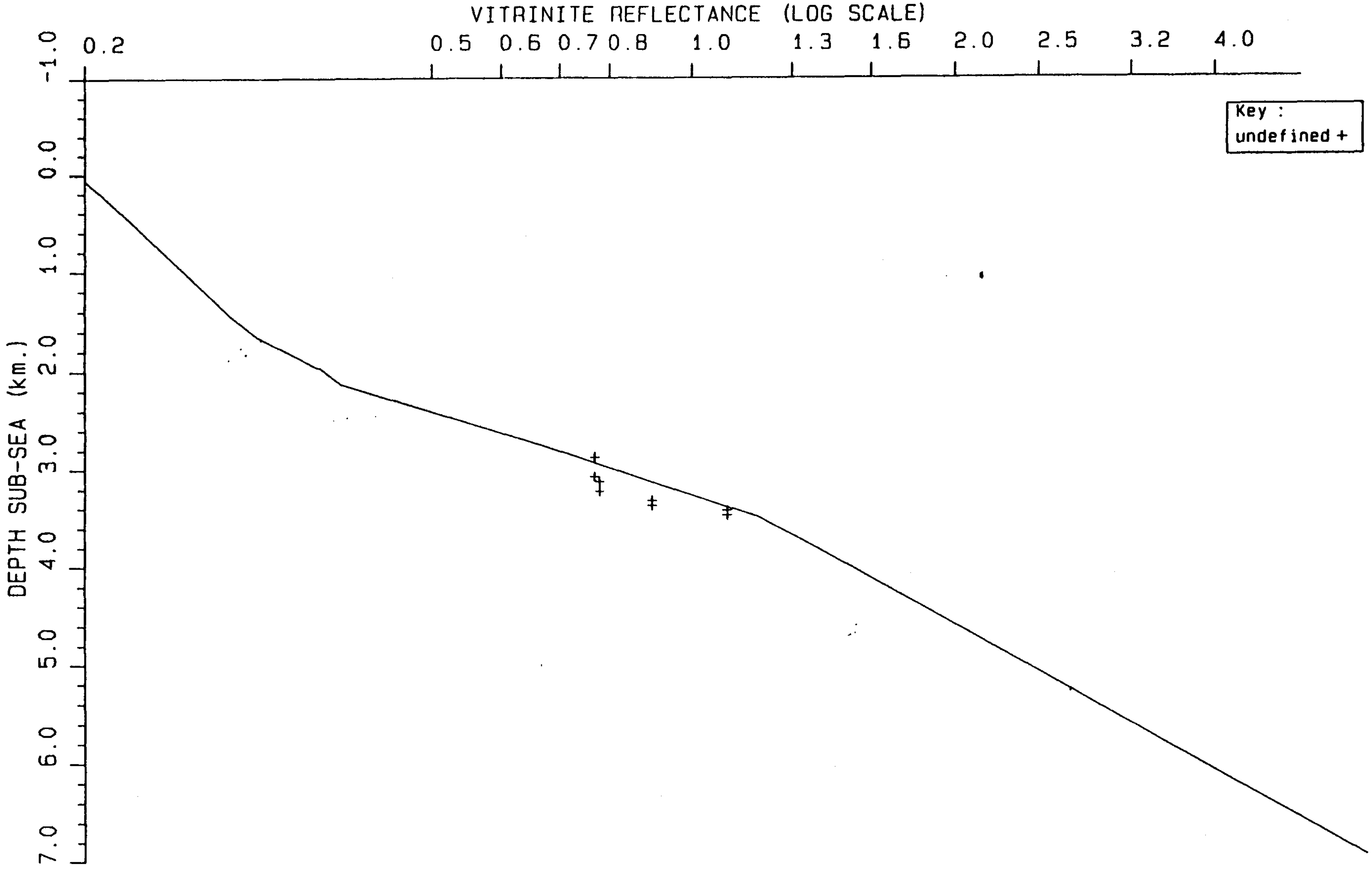
The vitrinite reflectance data in the Veilfin 1 well correspond to the levels of vitrinite reflectance calculated in the geohistory program (Fig. 19).

The inferences from the geohistory study are that oil in the region could be sourced from the regionally best source rock intervals in the lower Latrobe Group. Hydrocarbons now occur within the basin at immature levels for oil generation. These hydrocarbons have thus migrated vertically into traps set in their present form by seal facies overlying structures associated with compression and erosion of the top Latrobe Group reservoirs in Miocene time. Since migration of existing oil at that time could have resulted in loss, it can be inferred from the geohistory results that hydrocarbons would need to have been produced from lower Latrobe strata subsequently subjected to rapid burial since that period. Hydrocarbons sourced from the Strzelecki Group since the Miocene are more likely to be gas.



GEOHISTORY PLOT : VEILFIN

Figure 18.



COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT : VEILFIN

Figure 19,

9.6 INTERPRETATION PROBLEMS.

[by Tun U Maung.]

This section illustrates the type of difficulties encountered in interpretation of seismic data in Area V91-G3. Seismic data quality is generally good down to the Lower M. diversus seismic marker over all of Area V91-G3. Below this level data quality deteriorates dramatically because of the loss of reflection energy due to water bottom peg-legs, and interbed multiples caused by the presence of thick coal beds in the shallow part of the Latrobe Group (Mebberson, 1989 and Maung & Nicholas, 1990). Reflection coefficients of 0.4 are not uncommon for some of these coal beds. As these coal beds decrease in number and thickness towards the east, the data quality is generally good down to the Near Base of Lower L. balmei seismic marker. Confidence in deeper interpretation is limited by interference from multiples.

A set of zero-phase synthetic seismograms was generated for Cod No.1, Conger No.1, Salmon No.1, Swordfish No.1 and Veilfin No.1 wells. There is general agreement between the synthetic seismograms and the seismic sections.

Although several horizons were interpreted and mapped by Esso in 1985, 1989 and 1990, only two horizons, i.e. interpreted Top of Latrobe Group and Near Base Lower L. balmei seismic marker, have been selected and modified for presention in this report. The latest Esso mapping in 1990 does not cover the whole of Area V91-G3 and the 1989 mapping is a complilation of already existing maps. The 1985 mapping was undertaken prior to the relinquishment of several blocks by Esso in the vicinity of this area. The compilation and synthesis of these maps produce a reasonably accurate depth map which covers the whole area. The modified maps on top of Latrobe Group and Near Base Lower L. balmei are shown in Plates 48 and 49.

Although Area V91-G3 is surrounded by known major petroleum accumulations (Plates 13A & 13B), it lies in a part of the Gippsland Basin where the determination of velocities for time-depth conversion is a difficult and perplexing geophysical problem because of the presence of high-velocity Miocene channels in the shallower part of the section (Birmingham & others, 1985, and Blackburn, 1986). These channels contain carbonates of significantly higher interval velocity than the surrounding sediments. These channels produce two-way time 'pull-up' effect at the underlying top of Latrobe Group and deeper levels on the seismic sections. These channels are approximately 11 to 15 km wide and 700 m deep and produce a pull-up effect of approximately 150 ms. The axes of the channels are approximately in a NNW-SSE direction. The approximate outlines of the high velocity Miocene channel M-1 and intermediate velocity Miocene channel M-2 are shown in Plate 50, and are based on Esso's 1974 and 1990 interpretations. There are no well data for the Base of Miocene Channel M-2 horizon, because it has not been intersected in any wells. Most of the G88A lines in the central part were recorded parallel to the axis and eastern edge of the Miocene channel M-1. Uncertainty in the selection of velocities for time-depth conversion, to correct the pull-up effect of these channels, allows a wide range of possible structural interpretations.

In 1990 mapping, Esso has used two methods for the determination of average velocities to the top of Latrobe Group for time to depth conversion. For the central part of the the area, below the high velocity Miocene channel M-1, the interval velocity analysis method was used, and for the area outside the high velocity Miocene channel M-1, a smoothed normal moveout velocity (VNMO) and conversion factor (derived from well velocity data) method was used (Cordier, 1985). The average velocities derived from each of these methods were combined into one composite average velocity map for depth conversion. Previous applications of smoothed VNMO method, has consistently failed to accurately compensate for the pull-up caused by the high velocity Miocene channel M-1 in the central part.

Veilfin No.1 (1984), the most recent well drilled to test a prospect below the high velocity channel, showed that the highest velocities to the top of Latrobe Group are found in the area below the eastern flank of the channel and not below the thickest part of the channel as would be expected. This is primarily because of very high interval velocity channel fill, localised along the eastern flank of the channel. In other words, the zone of maximum pull-up lies slightly east of Veilfin No.1 well. This high velocity trend runs parallel to the eastern edge of the channel, east of Veilfin No.1 and Cod No.1, and west of Swordfish No.1 (Plate 50). The Veilfin No.1 well also indicates that further complexity of the velocity analysis for the top of Latrobe Group is due to the distortion of ray paths caused by prograding wedges within the channel, for lines along the channel, and the shape of the base of the channel, for lines across the channel. It is therefore important to carry out further investigations, by acquiring more 2D and 3D seismic data, to have a thorough understanding of the Miocene channels to accurately map and evaluate the prospects present in this area.

Depth conversion to the top of Latrobe Group was carried out by multiplying the gridded time map by the gridded average-velocity map. The depth conversion of the Near Base of Lower L. balmei seismic marker was carried out by adding interval thicknesses to the gridded top of Latrobe Group depth map. These interval thicknesses were derived by multiplying interval times from the seismic lines by the interval velocities; these interval velocities were calculated from interval normal-moveout velocities derived by using Dix equation (1955) for a single interval. The interval velocities were tied to the well velocities by applying a conversion factor derived from well velocity data.

The form of the depth maps shown in Plates 48 and 49 are quite different to the form of the time maps because of the steep velocity gradients associated with the channels. The area is dissected by two NW-SE trending normal faults at the top of Latrobe Group (Plate 48). These faults increase in number and displacement on the deeper Near Base Lower L. balmei seismic marker level (Plate

49). Many of them show an increase in displacement on the the low side, indicating that they were active during deposition (Plates 51 to 56).

9.7 PROSPECTS AND LEADS.

[by Tun U Maung]

A total of seven prospects (G3-P-A to G3-P-G) and one lead can be recognised at the top of Latrobe Group and Near Base Lower *L. balmei* seismic marker maps (Plates 48, 49 & 50).

9.7.1 Prospect G3-P-A.

Prospects G3-P-A is a fault-dependent closure mapped only at the Near Base Lower *L. balmei* seismic marker (Plate 49) and is located south of Sawbelly No.1 well. It straddles the eastern edge of a high velocity Miocene channel M-1 (Plate 50), and therefore there is some doubt as to the validity of time-to-depth conversion; there is no closure on the time map at this mapping level. The mapping of Prospect G3-P-A was mainly based on two lines traversing the structure and a few lines around it. The two lines are G74A-1083 (in approximately E-W direction) and G74A-3053 (in N-S direction); both lines terminate within the closure and therefore the mapping is not very reliable. Plate 51, seismic section of line G74-3053, illustrates this situation. More seismic data is necessary to properly evaluate this prospect.

9.7.2 Prospect G3-P-B.

Prospects G3-P-B is a fault-dependent closure mapped only at the Near Base Lower *L. balmei* seismic marker (Plate 49) and is located northeast of Conger No.1 well. It straddles the boundary of Area V91-G3, and a small northwestern part of this prospect (about one-fifth) lies outside Area V91-G3.

Prospect G3-P-B lies entirely outside the high velocity Miocene channel M-1 (Plate 50), and there is no significant problem in time-to-depth conversion. Also, the mapping of Prospect G3-P-B is based on 3D seismic lines, spaced 300 m apart, and trending in NW-SE direction. It is located about 5.0 to 7.0 km southwest from the central part of the probable hydrocarbon generation area, but the hydrocarbon migration paths may be obstructed by its north-bounding fault (Plate 50). Plates 52 and 53, seismic sections of north-south line G77A-3057 and NE-SW line G77A-3091 respectively, illustrate this prospect. The southeast extension of the sealing fault should be examined more thoroughly as the 3D lines terminate near the southeastern edge of the prospect.

9.7.3 Prospect G3-P-C.

Prospect G3-P-C is the only four-way dip closure mapped at the top of Latrobe Group and is located about 800 m east of Cod No.1 well.

It has a 25 m vertical closure and is present up to the Near Top of Lower L. balmei seismic marker (Plate 53, seismic section of NE-SW line G77A-3091). Cod No.1 well was drilled near the crest of a large time high and was dry. The well is located on the eastern flank of the high velocity Miocene channel M-1, about 3.8 km west of the eastern limit of the channel (Plate 50). The top of Latrobe Group map shows an approximately NE-SW trending ridge extending from about 2.0 km northwest of Conger No.1 across Cod No.1, and continuing to about 3.5 km west of Cod No.1 well. Prospect G3-P-C lies on this ridge (Plate 49). As the eastern flank of this closure is located below the steeply dipping eastern flank of high velocity Miocene channel M-1 (Plate 50), probably coinciding with the zone of maximum pullup, the prospect is considered to be extremely high risk. The application of a slightly different velocity value will probably eliminate most or all of the critical dip. A thorough investigation and understanding of the high velocity Miocene channel M-1 and associated velocity problems is necessary to properly evaluate this prospect.

9.7.4 Prospect G3-P-D.

Prospect G3-P-D is a large fault-dependent closure mapped at the top of Latrobe Group and Near Base Lower L. balmei seismic marker around Veilfin No.1 (Plates 48 and 49). The crest of the structure appear to migrate to the southeast with increasing depth and the size of the closure also increase with depth (Plate 50). It is located within the high velocity Miocene channel M-1 but there is no significant velocity problem as the closure exists on the time maps at both mapping levels. Only the size, shape and location of the crest of the closure might change if a slightly different depth-conversion velocity is applied.

Prospect G3-P-D has approximately 25 m and 85 m of vertical relief at the top of Latrobe Group and Near Base Lower L. balmei seismic markers respectively. In the Veilfin No.1 well, which is located close to the crest of the closure, the top of Latrobe Group sands were water-wet, presumably due to lack of fault seal at this level (Plate 53). Tight gas sands were encountered from 3011 to 3469 mSS, indicating that the fault seal is apparently effective at deeper levels. Salmon No.1 well, which is located considerably downdip at both levels, was water-wet. There is, therefore, approximately 50 m of untested vertical relief at the Near Base Lower L. balmei seismic marker level, between the Veilfin No.1 and Salmon No. 1 wells, which may have oil potential.

9.7.5 Prospect G3-P-E.

Prospect G3-P-E is a fault dependent closure mapped at the Near Base Lower L. balmei seismic marker only (Plate 49) and is located within the high and intermediate velocity Miocene channels M-1 and M-2 (Plate 50) but there is no significant velocity problem as the closure exist on time map at this mapping level. The mapping of the prospect is based on two or three lines traversing the closure, so that more seismic data are required to properly evaluate the prospect.

Prospect G3-P-E has a vertical relief of approximately 50 m and may be associated with the partial inversion of its north-bounding fault. Plate 55, a seismic section of north-south line G74A-1122, illustrates this prospect.

9.7.6 Prospect G3-P-F.

Prospect G3-P-F is a fault dependent closure mapped at the Near Base Lower *L. balmei* seismic marker only (Plate 49) and is located within the high and intermediate velocity Miocene channels M-1 and M-2 (Plate 50) but there is no significant velocity problem as the closure exist on time map at this mapping level. The mapping of the prospect is based on two or three lines traversing the closure, so that more seismic data are required to properly evaluate the prospect.

Prospect G3-P-F has a vertical closure of approximately 25 m and is located about 2.5 km northeast from the centre of the probable hydrocarbon generation area and lies in the hydrocarbon-migration pathways (Plate 50). Plate 56, a seismic section of an approximately east-west line G88A-9067 illustrates this prospect.

9.7.7 Prospect G3-P-G.

Prospect G3-P-G is a large fault-dependent closure mapped at the top of Latrobe Group and Near Base Lower *L. balmei* seismic marker southwest of Salmon No.1 wells (Plates 48 and 49). The crest of the structure appear to migrate to the southeast with increasing depth and the size of the closure also increase with depth (Plate 50). It is located within the high velocity Miocene channel M-1 but there is no significant velocity problem as the closure exists on the time maps at both mapping levels. Only the size, shape and location of the crest of the closure might change if a slightly different depth-conversion velocity is applied.

The vertical relief of Prospect G3-P-G is approximately 25 m and 50 m respectively. The closure at the top of Latrobe Group, is wholly outside V91-G3 Area whereas the closure at the Near Base Lower *L. balmei* seismic marker straddles the boundary of Area V91-G3 with only about one-fourth of the closure lying within V91-G3.

9.7.8 Lead.

The top of Latrobe Group map indicates a east-west trending nose west of Cod No.1 well which may have a potential pinchout trap (Plate 49). The trap involves a three-way dip closure, combined with a facies change from shoreface sands of the upper Latrobe Group, into offshore marine shales of the Gurnard Formation. More seismic data is necessary to properly evaluate this lead.

9.7.9 Summary.

In summary, the depth conversion methods discussed for this area were considered reasonably successful in correcting the pull-up effect caused by the high and intermediate velocity Miocene channels M-1 and M-2 in this area. However, the uncertainty in the selection of depth conversion velocities allows for a wide range of possible structural interpretations. More investigations, by acquiring more 2D and 3D seismic data is required, to have a thorough understanding of the Miocene channels, and to map the prospects present in this area with a high level of confidence.

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APPENDIX 1

MARINE SEISMIC SURVEYS, 1962-1974

No.	Survey Name	Year	Operator	Contractor	Energy Source	No. of km Surveyed	Fold	BMR Reference Number
1.	Ninety Mile Beach	1962 -63	Arco Ltd	Western Geophysical	Explosives	-	1-2	PSSA 62/1640
2.	Gippsland-Bass St.-Anglesea-S.A.	1963	Haematite	Western Geophysical	Explosives	1610	1-2	PSSA 62/1645
3.	Gippsland Shelf	1964	Esso Australia	Western Geophysical	Explosives	1030	6	PSSA 64/4550
4.	Offshore Gippsland Basin	1965	Shell Development	Geophysical Services International (GSI)	Explosives	1000	4	PSSA 65/11045
6.	Eastern Bass St.	1966	Esso Australia	GSI	Explosives	3590	6	PSSA 66/11070
7.	Gippsland EC-67	1967	Esso Australia	GSI	Explosives and Airguns	750	6	PSSA 67/11184
8.	Sole Structure	1967	Shell Development	Compagnie de Generale Geophysique	Sparker	320	1	PSSA 672/11187640
9.	Gippsland EH-68	1968	Esso Australia	Western Geophysical	Aquapulse	1126	12	PSSA 68/3015
10.	East Gippsland Basin seismic and magnetic	1968	Magellan	Western Geophysical	Aquapulse	226 555	12 12	PSSA 68/3049 P(SL)A 68/1
11.	Gippsland G69A seismic and magnetic	1968-1969	Esso Australia	Western Geophysical	Aquapulse	438 2570	12 12	PSSA 68/3058 P(SL)A 69/4
12.	Gippsland G69B	1969	Esso Australia	Western Geophysical	Aquapulse	4000	12	P(SL)A 69/4

No.	Survey Name	Year	Operator	Contractor	Energy Source	No. of km Surveyed	Fold	BMR Reference Number
13.	Offshore Lakes Entrance	1969	Endeavour	United Geophysical	Airguns	819	24	P(SL)A 69/7
14.	Tasman-Bass St.	1969	Magellan	Teledyne	Sparker and Airguns	3000 229	1-24 1-24	PSSA 69/3023 P(SL)A 69/11
15.	Gippsland G70A	1970	Esso Australia	GSI	Airguns	190	24	P(SL)A 70/3
16.	Sailfish reflection and refraction	1970	N.S.W. Oil & Gas	Teledyne	Sparker Airguns	174 530	1 24	PSSA 70/884
17.	Seaspray	1970	Endeavour	Teledyne	Airguns	400	24-48	P(SL)A 70/9
18.	Gippsland Basin	1970	Shell Development	GSI	Airguns	860	24	P(SL)A 70/10
19.	Gippsland G71A seismic and magnetic	1971	Esso Australia	GSI	Airguns	1450	48	P(SL)A 71/5
20.	Gippsland G71B	1971	Esso Australia	GSI	Airguns	2980	24	P(SL)A 71/6
21.	Gippsland G72A	1972	Esso Australia	GSI	Airguns	867	24	P(SL)A 72/14
22.	Shell Deepwater Scientific	1972-1973	Shell Development	Seismograph Services Ltd	Airguns	10,904	24	P(SL)A 72/30
23.	Gippsland G73A	1973	Esso Australia	GSI	Airguns	618	24	P(SL)A 73/14

No.	Survey Name	Year	Operator	Contractor	Energy Source	No. of km Surveyed	Fold	Reference
24.	Gippsland G73B	1973	Esso Australia	GSI	Airguns	131	48	P(SL)A 73/15
25.	1973 Seismic Survey	1973	Shell Development	GSI	Airguns	515	24	P(SL)A 73/19
26.	Northeast Furneaux	1973	Magellan	GSI	Airguns	208	24	PSSA 73/225
27.	Gippsland G74A (Area V91-G3)	1974-1975	Esso Australia	GSI	Airguns	2926	48	P(SL)A 74/15
28.	BMR Continental Margin Geophysical	1970 1973	BMR	CGG	Sparker		1	BMR Record 1974/98

MARINE SEISMIC SURVEYS, 1976-1988

Appendix2

No.	Survey Name	Year	Operator	Contractor	No. of km Surveyed	Fold	Energy Source	Cable Length (m)	Number of Channels	BMR Reference Number
1.	G76A Marine Seismic	1976	Esso Exploration & production	GSI	903	48	Air Gun	2400	96	76/10
2.	G77A Marine Seismic (Area V91--G3)	1977	Hematite Petroleum	GSI	2745	48	Air Gun	2400	96	77/15
3.	GB79 Marine Seismic	1979	Beach Petroleum	GSI	79	48	Air Gun	2400	96	79/23
4.	Flinders 1980 Marine Seismic	1980	Otter Exploration	GSI	401	48	Air Gun	2400	96	80/13
5.	G80A and Extension Marine Seismic (Area V91-G3)	1980	Hematite Petroleum	GSI	1532	48	Air Gun	2400	96	79/22
6.	GBS80 Marine Seismic	1980	Bass Strait Oil & Gas	GSI	516	48	Air Gun	2400	96	80/01
7.	GC80 Marine Seismic (Area V91-G1)	1980	Cultus Pacific	GSI	507	48	Air Gun	2400	96	80/12
8.	GC81A Marine Seismic (Area V91-G1)	1981	Cultus Pacific	GSI	217	48	Air Gun	2400	96	81/18
9.	G81A Marine Seismic (Area V91-G3)	1981	Hematite Petroleum	GSI	437	36	Air Gun	2400	96	81/14
10.	GA81A Marine Seismic (Area V91-G2)	1981	Aust. Aquitaine Petroleum	Western Geophysical	3583	48	Air Gun	2400	96	81/60
11.	GB81 Marine Seismic	1981	Hudbay Petroleum	Western Geophysical	360	36	Air Gun	1800	72	81/2
12.	GBS81 Marine Seismic	1981	Bass Strait Oil & Gas	GSI	297	48	Air Gum	2400	96	81/13
13.	GP81A Marine Seismic (Area V91-G1)	1981	Phillips Aust.	Western Geophysical	2303	48	Air Gun	2400	96	81/64
14.	GS81A Marine Seismic	1981	Shell	GSI	2614	48	Air Gun	2400	96	81/59

No.	Survey Name	Year	Operator	Contractor	No. of km Surveyed	Fold	Energy Source (m)	Cable Length	Number of Channels	BMR Reference Number
15	G82A, G82B 3D Marine Seismic	1982	Esso Exploration & Production	GSI	1950	48	Air Gun	2400	96	82/30
16.	G82B Extension Marine Seismic	1982	Esso Exploration & Production	GSI	107	48	Air Gun	2400	96	82/31
17.	G82C Turrum 3D Marine Seismic	1982	Esso Exploration & Production	GSI	2650	48	Air Gun	2400	96	82/36
18.	G82D Marine Seismic (Area V91-G2)	1982	Esso Exploration & Production	GSI	30	48	Air Gun	3600	240	82/60
19.	GA82B Marine Seismic	1982	Aust. Aquitaine Petroleum	GSI	431	48	Air Gun	2400	96	82/38
20.	GH82A Marine Seismic	1982	Hudbay Oil	Western Geophysical	785	36	Air Gun	1800	72	82/10
21.	GS82A Marine Seismic	1982	Shell	GSI	1021	48	Air Gun	2400	96	82/53
22.	UT82A Marine Seismic	1982	Otter Exploration	GSI	250	48	Air Gun	2400	96	82/58
23.	GA83A Marine Seismic (Area V91-G2)	1983	Aust. Aquitaine Petroleum	GSI	217	60	Air Gun	3600	240	83/21
24.	GH83A Marine Seismic	1983	Hudbay Oil	GSI	17	60	Air Gun	3600	240	83/07
25.	GUT83A Marine Seismic (Area V91-G1)	1983	Union Texas	GSI	1328	60	Air Gun	3600	240	83/10
26.	GUT83P Marine Seismic	1983	Union Texas	GSI	236	60	Air Gun	3600	240	83/11
27.	G84A Marine Seismic (Area V91-G3)	1984	Esso Exploration & Production	GSI	7288	48	Air Gun	2880	192	84/26
28.	GA84A Marine Seismic	1984	Aust. Aquitaine Petroleum	Western Geophysical	204	60	Air Gun	3600	240	84/17

No.	Survey Name	Year	Operator	Contractor	No. of km Surveyed	Fold	Energy Source (m)	Cable Length	Number of Channels	BMR Reference Number
29.	G85A Scientific Marine Seismic	1985	GSI	GSI	1712	60	Air Gun	1800	120	85/14
30.	GL85A (Seacombe) Marine Seismic	1985	Lasmo	GSI	23	42	Air Gun	2100	96	85/19
31.	GL85B (Tambo) Marine Seismic	1985	Lasmo	GSI	22	48	Air Gun	2880	192	85/19
32.	G85A Marine Seismic Survey	1985	Esso	GSI	500	60	Air Gun	1800	120	85/46
33.	G88A Marine Seismic & Extension (Area V91-G3)	1988	Esso	GSI	3103 1059	75	Air Gun	3750	300	88/4
33A	G88J John Dory 3D Marine Seismic (Area V91-G3)	1988	Esso	GSI	-	75	Air Gun	3750	300	88/4
34.	GF88A Marine Seismic	1988	Petrofina	GSI	4879	60	Air Gun	3000	240	88/3
35.	GH88A Marine Seismic	1988	BHP	Western Geophysical	978	60	Air Gun	3200	240	88/5
36.	GH88B Marine Seismic	1988	BHP	GSI	176	-	Air Gun	3750	300	88/25
37.	GL88A (Marlo) Marine Seismic	1988	Lasmo	GSI	502 296	96 60	Air Gun Air Gun	2560 1856	192 120	88/1
38.	GL88B Marine Seismic	1988	Lasmo	GSI	216	60	Air Gun	1500	120	88/18
39.	GS88A Marine Seismic (Area V91-G2)	1988	Shell	GSI	273	75	Air Gun	3750	300	88/11
40.	GS880 Marine Seismic	1988	Shell	GSI	930	75	Air Gun	3750	300	88/12
41.	GS88C Marine Seismic	1988	Shell	GSI	486	75	Air Gun	3750	300	88/14
42.	GC89A Barra Marine Seismic (Area V91-G1)	1989	Cutlus	Western Geophysical	302	60	Air Gun	3000	120	89/16