SECOND AGSO PETROLEUM GROUP SEMINAR

17-18-19 November 1993

Key Abstracts

Record 1993/83

AGSO

AUSTRALIAN GEOLOGICAL SURVEY ORGANISATION

SECOND AGSO PETROLEUM GROUP SEMINAR

17-18-19 NOVEMBER 1993

KEY ABSTRACTS

Record No. 1993/83

DEPARTMENT OF PRIMARY INDUSTRIES AND ENERGY

Minister for Resources: Hon. Michael Lee, MP
Secretary: Greg Taylor

AUSTRALIAN GEOLOGICAL SURVEY ORGANISATION

Executive Director: Harvey Jacka

ISSN: 1039-0073

ISBN: 0 642 19862 4

CONTENTS PAGE

REGIONAL DEEP SEISMIC OF THE NORTH WEST SHELF 1
by the AGSO North West Shelf Study Group (J.B. Colwell,N.F. Exon, P.J. Hill, G.W. O'Brien, C.J. Pigram, D.C. Ramsay, H.M.J. Stagg, H.I.M. Struckmeyer, P.A. Symonds, J.B. Willcox)

PRE-JURASSIC RIFT ARCHITECTURE AND TECTONIC DEVELOPMENT, TIMOR SEA/ASHMORE CARTIER REGION 3
by G.W. O'Brien, J.B. Willcox, S. Baldwin, C.J. Pigram, M. Morsel & J. Ostby

TECTONIC EVOLUTION OF THE BASS STRAIT REGION, AND ITS IMPLICATIONS FOR PETROLEUM POTENTIAL 5
by J. B. Willcox & J. Colwell

THE OTWAY BASIN - A COMPLEX PASSIVE MARGIN IN SOUTHEASTERN AUSTRALIA 8
by D. M. Finlayson, G. W. O'Brien and C. V. Reeves

PHILIPPINE MARINE SEISMIC SURVEY PROJECT 10
by Chao-Shing Lee, Malcolm C. Galloway, Aidan Moore and Andrew Fraser

DEEP WATER PETROLEUM PROSPECTS IN THE LORD HOWE RISE REGION 12
by P.A. Symonds & J.B. Willcox

EVOLUTION OF THE CANNING BASIN AND ITS PETROLEUM SYSTEMS: PROGRESS REPORT 14
by M. J. Jackson, J. Kennard, K. Romine, P. Southgate, M. Sexton, R. Shaw, C. Foster, P. Jones, R. Nicoll, G. Young, I. Zeilinger

CONTENTS (cont.) PAGE

PETROLEUM POTENTIAL OF THE BOWEN AND SURAT BASINS, EASTERN AUSTRALIA 16
by R. J. Korsch, C. J. Boreham, A. T. Brakel, C. B. Foster, M. G. Nicoll, J. M. Totterdell, K. D. Wake-Dyster & A. T. Wells

PETROLEUM SYSTEMS AND GEOLOGIC PROCESSES 17
by Marita Bradshaw, John Bradshaw, Tom Loutit, Andrew Murray & Roger Summons

GEOCHEMICAL TOOLS FOR EVALUATING PETROLEUM GENERATION IN MESOPROTEROZOIC SEDIMENTS OF THE MCARTHUR BASIN, NT, AUSTRALIA 18
by Roger E. Summons, Dennis Taylor, and Christopher J. Boreham

PETROLEUM GEOSCIENCE INFORMATION MANAGEMENT 19
by Tom Loutit, John Bradshaw, Clinton Foster, Chris Parvey, Sandy Radke (BRS)

POTENTIAL OF GAZETTAL AREAS - BIGHT AND OTWAY BASINS, SOUTH AUSTRALIA 21
by A.J. Hill, Oil, Gas and Coal Division, Department of Mines and Energy, South Australia

REGIONAL DEEP SEISMIC OF THE NORTH WEST SHELF

AGSO North West Shelf Study Group
(J.B. Colwell, N.F. Exon, P.J. Hill, G.W. O'Brien, C.J. Pigram, D.C. Ramsay, H.M.J. Stagg, H.I.M. Struckmeyer, P.A. Symonds, J.B. Willcox)

In the period since late 1990, AGSO has acquired more than 23 000 km of deep-seismic data on a regional grid extending from North West Cape to the western Arafura Sea along Australia's North West Shelf (see Figure). These data frequently show basin-forming structures down to depths of 10-12 s two-way time (ca 15-30 km). The primary objective of this work is to resolve the structural framework and history of the North West Shelf, and so help the exploration industry evaluate the critical regional factors influencing the development of a viable petroleum system within the the various basin segments.

The first-pass evaluation of the data is leading us to some conclusions about the formation of the North West Shelf that are at variance with a number of generally accepted ideas. These conclusions include:

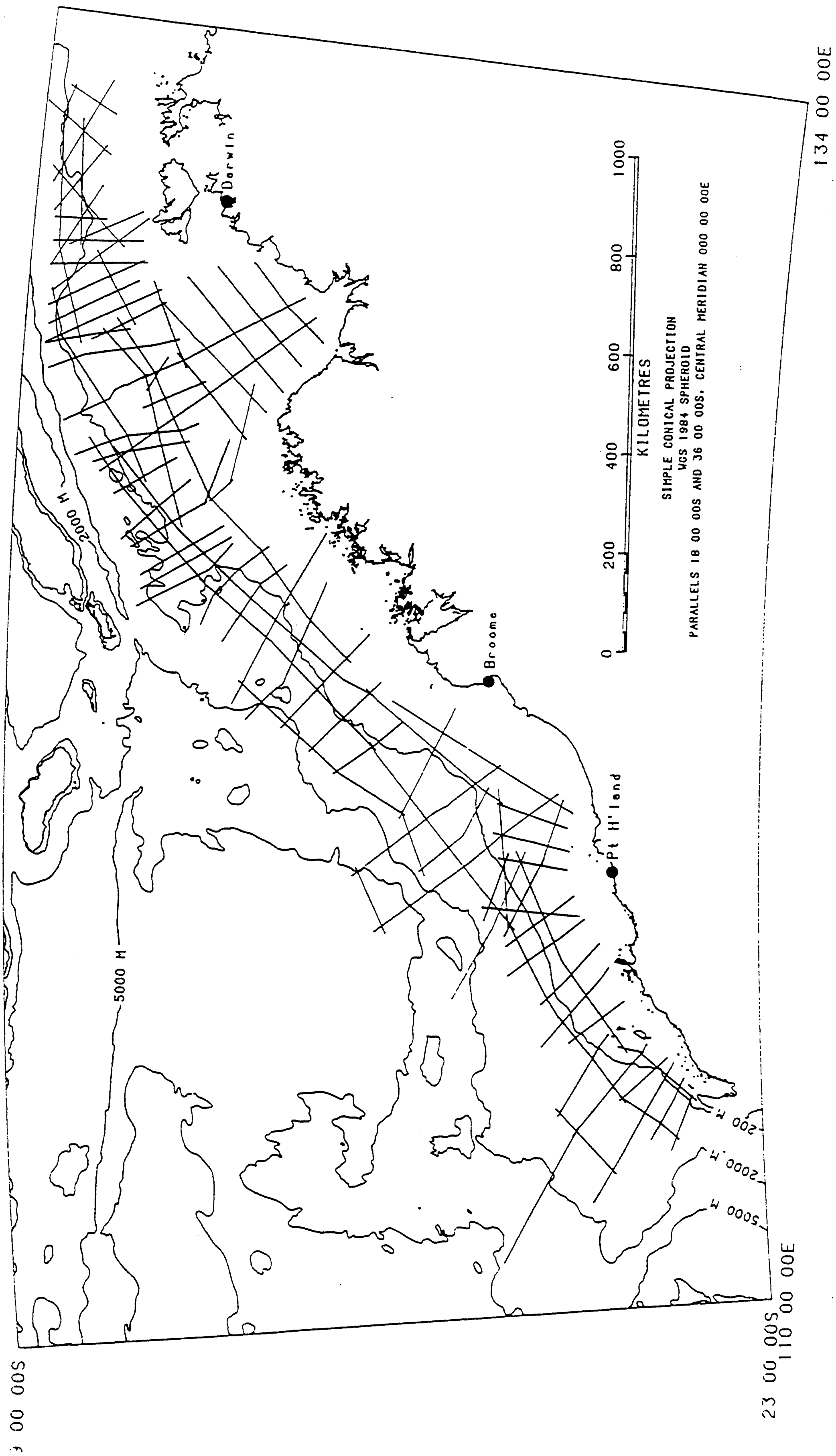
- Deep-seismic data can provide an image that reflects the entire history of a basin, rather than only the more recent events, as with most conventional data. The interpretation of the style and origin of many structures (and, therefore, the mode of basin formation) can change quite radically when the entire basin history is visible.

- Whilst the Westralian Super-basin is known to date from at least the Permian, conventional interpretations still refer to a 'rift-onset' phase in the Late Triassic. Deep data show that, while the Late Triassic was a time of prominent tectonism, the amount of extension was uniformly small and the event certainly had nothing to do with basin formation, which may have taken place as far back as the Early Palaeozoic.

- The poly-rifting history of the North West Shelf (?Early Palaeozoic, Late Palaeozoic, Mesozoic) with probable commensurate variations in tectonic transport direction has produced a structural style which reflects multiple reactivations of original structures, as well as developing new structures. Many of the more recent structures appear to show little evidence of extension; also, in the Mesozoic, there is strong and widespread seismic evidence that strike-slip movements and periodic inversions due to compression are far more widespread than has previously been acknowledged. A consequence of this complex history is that virtually all hydrocarbons are reservoired in structures that are the reactivation effects of pre-existing structures.

- Deep-seismic data show that deep structures frequently display similarity of form and style along an entire margin segment, reinforcing the intuitive notion that linked tectonics are important in continental margin development. Regional deep-seismic data therefore provide some hope of developing models of margin formation that enable the development of all the margin basins to be placed in a consistent framework.

In summary, we believe that a regional grid of deep-seismic data, supplemented by intervening high-quality conventional data, provide a far better opportunity to develop realistic margin formation models for the North West Shelf than would be the case with conventional data only. Such models, in addition to helping explain the success or failure of existing hydrocarbon plays, may also provide a predictive tool that will assist further exploration.



The North West Shelf, Australia, showing the locations of deep-seismic lines recorded by the Australian Geological Survey Organisation to August, 1993.

PRE-JURASSIC RIFT ARCHITECTURE AND TECTONIC DEVELOPMENT, TIMOR SEA/ASHMORE CARTIER REGION

G.W. O'Brien1, J.B. Willcox1, S. Baldwin2, C.J. Pigram1, M. Morse1 & J. Ostby3

1 Australian Geological Survey Organisation
2 University of Sydney
3 Nopec Australia

Mapping of AGSO regional deep crustal seismic data from the Timor Sea (Fig. 1) has allowed the areal distribution and the architecture of the entire Petrel Sub-Basin rift system to be determined for the first time. The Petrel System consists of at least four discrete rift segments, all of which are essentially massive half-graben. Within any individual segment, one side of the sub-basin is characterised by large displacement, planar normal faults which merge with, and disappear into, a relatively flat-lying surface at about 9 sec TWT. This surface probably represents the broad boundary between the brittle upper, and ductile lower, crust. The opposing basin margin has a characteristic 'ramp' geometry, where the faults are high-angle, and have little displacement. Each segment has an opposite 'polarity' to that of the adjacent compartment, with this polarity-switch taking place across broad (15-20 km wide), NE-trending accommodations zones which are typically structurally complex.

The Petrel Sub-Basin extends from the onshore, in the far southern part of the Bonaparte Gulf, NW-WNW to at least the Timor Trough (Fig. 1). The sub-basin is orthogonally over-printed by the NE-trending Late Palaeozoic and Mesozoic tectonic elements, and its continuation NW past the Malita Graben has, until now, been conjectural. However, deep seismic data trending NE along the strike of the Malita Graben clearly images the Petrel rift system at a depth of 7-8 sec TWT, striking orthogonally to the Malita trend. Further NW, the rift is even deeper, and can be seen to extend from the eastern Sahul Platform, south-west to the southern Vulcan Sub-Basin. In this northern-most rift compartment, the rift segment is essentially a massive, 350 km wide half-graben; the segment's large displacement margin trends NW near the Paqualin 1 well, with the opposing 'ramp' margin striking NNW along the eastern third of the Sahul Platform.

Mapping of structures within the post-rift section has shown that, in most cases, structuring within the Petrel Sub-Basin 'proper' takes place *via* the reactivation of major, under-pinning rift structures, principally over the large displacement margin. NNW compression in the latest Triassic, for example, has produced the majority of structures within the Petrel Sub-Basin, and indeed, numerous structures over parts of the Sahul Platform. The large displacement margins have also acted as a locus for salt diapirs; the opposing ramp margin is both largely unreactivated and unaffected by salt diapirism.

Measurement of the total amount of upper crustal extension within the Petrel Sub-Basin has shown that this extension is probably insufficient to explain the total thickness of post-rift section and it appears that rifting within the Petrel rift system proceeded via a combination of upper and lower crustal thinning. Integration of deep crustal seismic and gravity data has shown that the prominent gravity high which trends north-west along the middle of the Petrel Sub-Basin is due to a combination of intruded lower crust and, more importantly, a relatively shallow Moho under the zone of maximum basin extension.

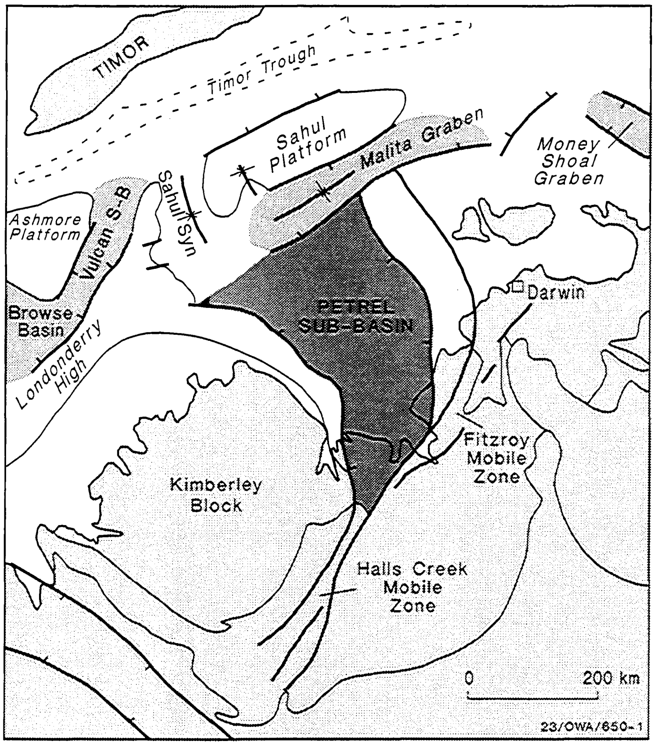


Figure 1 - Geology of the Timor Sea, north-western Australia, showing the relationship between the onshore and offshore tectonic elements.

TECTONIC EVOLUTION OF THE BASS STRAIT REGION, AND ITS IMPLICATIONS FOR PETROLEUM POTENTIAL

Barry Willcox & Jim Colwell

Although the Bass Strait basins have been extensively explored since the 1960's, little could be deduced about their primary architecture and origins until the recent acquisition of AGSO's deep seismic reflection/refraction data set. In the Gippsland Basin, where exploration is generally regarded as mature, most effort had concentrated on traps, and led the development of petroleum fields, at the relatively shallow 'top Latrobe Group' (Eocene) level. Only with the decline in reserves, has the emphasis turned to deeper plays in the (Late Cretaceous) 'intra-Latrobe' and Golden Beach Formation. As a consequence of the early exploration strategy, the huge volume of industry seismic data collected in the region mainly compises records with a relatively short 4-6 second time span. These records, which imaged basement structures in the Bass Basin and in places along the highly eroded Northern and Southern Platforms of the Gippsland Basin, were used to deduce an extensional origin for the region on a NNE azimuth.

AGSO data set

The AGSO seismic reflection data comprises 1650 km of 12-14 second records in a regional grid through the Gippsland Basin (Figure 1). These data are tied to thirty-five exploration wells in the basin. In addition, and as part of the same acquisition program, two 14-second lines were recorded in the Bass Basin, and ten 10-second lines in the adjacent Boobyalla Sub-basin. Deep reflection events occur consistantly on nearly all profiles from these basins.

The ship's reflection information is complemented by data recorded at onshore stations set up in conjunction with Monash University in Victoria, Tasmania and on Deal Island. Long-offset, wide-angle reflections and refractions were obtained at these stations, by recording signals from the air-gun seismic source as the ship traversed the basin. The arrival energy was detected out to distances of over 200 km. The large number of shots recorded, up to 5000 per traverse, has enabled signal enhacement techniques to be used. The correspondence of the deep refracting layers with events on the seismic reflection profiles provides convincing evidence of the efficacy of the technique.

Further, geological structural mapping within the Strzelecki Ranges of Victoria, has provided information on the trend, style and age of faults in the early basin-fill (Stzelecki Group) and the younger section.

Deep structure

The typical deep structural layers in and beneath the Gippsland Basin are shown by AGSO Line 90/7 (Figure 2). The basin generally contains from 12-16 km of sediment, made up of well-defined sequences which can be related to a 'Southern Margin' rift phase of ?Jurassic-Early Cretaceous age, a younger Tasman Basin rift phase of Campanian age, and a subsequent thermal sag phase. The basin is formed over a detachment surface located at about 8 seconds (16 km) under the depocentre. The Moho is present at 10 seconds, and depth conversion shows it to shallow from about 30 km regionally to about 25 km under the basin. The detachment forms a ESE-trending, south-dipping, ramp under the northern flank of the basin and wraps around its western, onshore, prolongation. It clearly extends as a sub-horizontal surface under the 'Central Deep' and Bassian Rise, and can be traced southwestwards beneath the other Bass Strait basins.

In general, the Gippsland Basin is not floored by basement blocks which show any systematic increase in tilt towards its depocentre, except perhaps at its western end. The randomly distributed tilt of the basin-forming blocks, confined mainly over the northern ramp, strongly suggests that basin formation was largely a result of oblique extension ('transtension'), probably on a NW-SE azimuth. Simple extension appears to have been confined to its western end. Wrench-related movements were influential in structuring of the main rift-fill (Strzelecki Group) throughout the Early Cretaceous.

The deep data show that structuring of the sediment-fill into prospective anticlines probably commenced as far back as the mid Cretaceous. Some of the deep structures are not reflected at the commonly mapped top Latrobe level, and may provide additional plays for the future.

An integrated geological history for 'Southern Margin' basins

The study has led to the conclusion that the Gippsland Basin is unlikely to be a product of NNE-SSW orientated extension as proposed in some earlier interpretations. It appears to be of strike-slip to transtensional origin, with the earliest movement in the Late Jurassic or pre-Late Jurassic, in a left-lateral sense, sub-parallel to the basinal axis (that is, approximately NW-SE) (Figure 3). Simple extensional tectonics are confined largely to the headwall area at the western end of the basin.

A similar geometry and age has been inferred for other 'Southern Margin' basins: for example, NW-SE extension in the Eyre Sub-basin and probably in the Ceduna Depocentre of the Great Australian Bight Basin; extension in the Robe Trough; and left-lateral transtension along the Otway Basin-Tasmania margin. This evidence suggests that the Gippsland Basin is part of a linked system of basins which developed on a common detachment or detachment complex during the breakup of Gondwanaland. Figure 3 shows the development of this system in terms of movements between several microplates in the Bass Strait region.

Petroleum prospects

A prolonged history of anticline development in the Gippsland Basin, and associated extension in the southeastern Bass Basin, may have led to several opportunities for petroleum migration and entrapment. In particular, some mid Cretaceous and early Late Cretaceous structures in the Gippsland Basin are not reflected at the traditionally mapped top and near-top Latrobe levels.

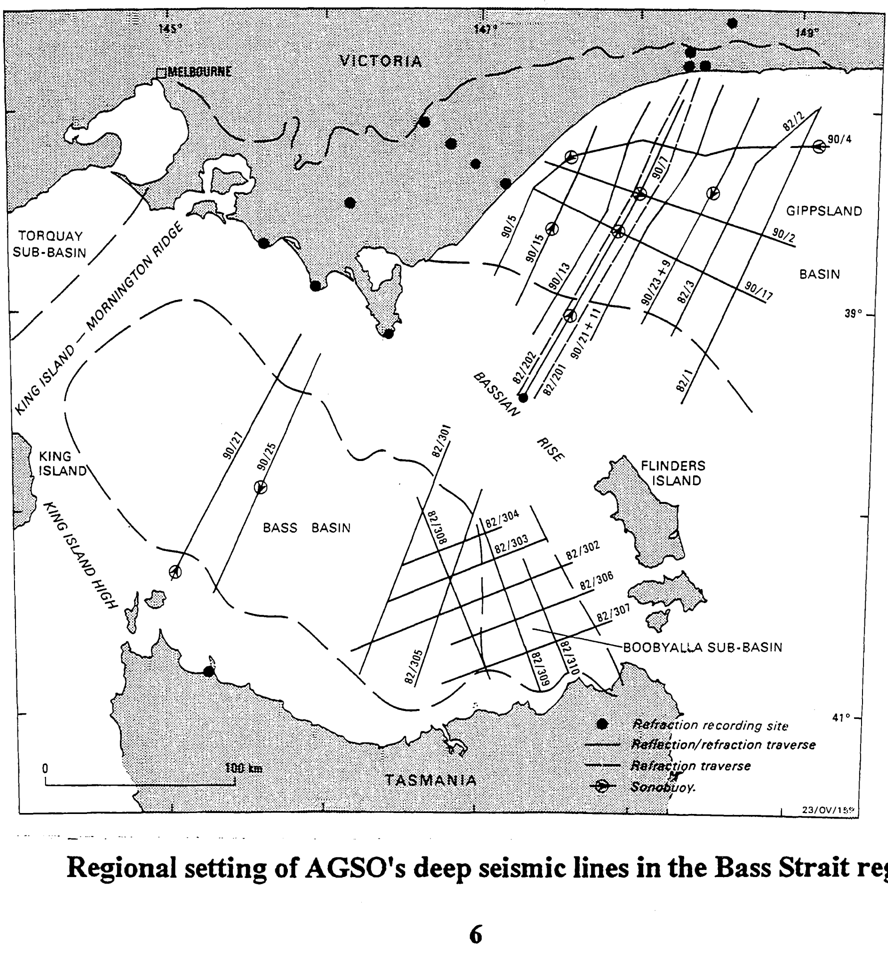


Figure 1. Regional setting of AGSO's deep seismic lines in the Bass Strait region.

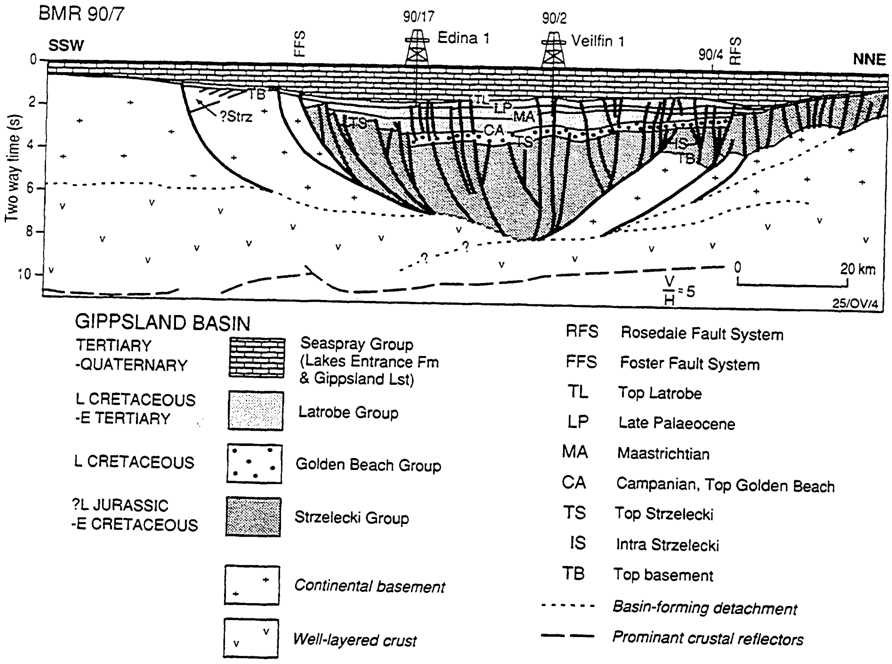


Figure 2. Deep structure of the Gippsland Basin interpreted from Line 90/7.

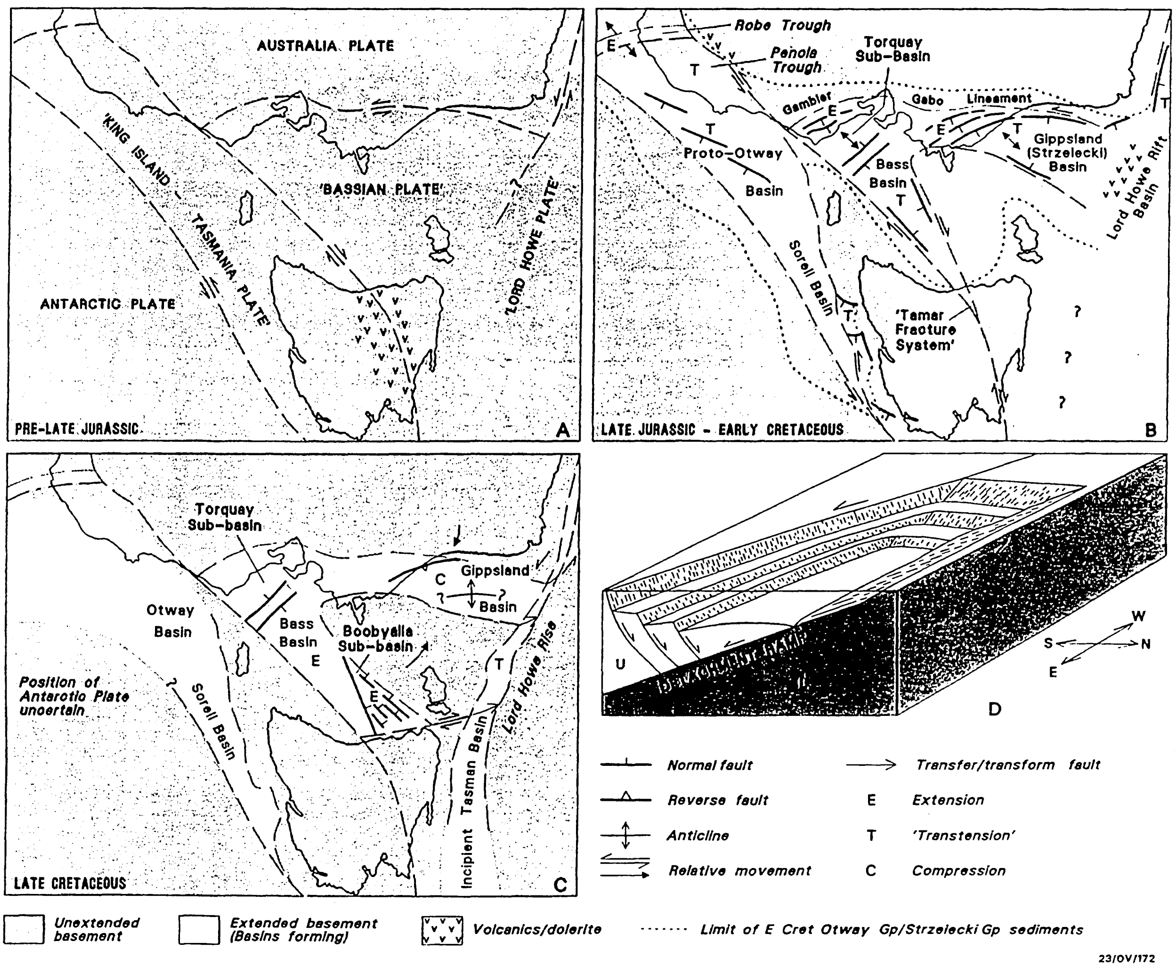


Figure 3. Conceptual model for development of the Gippsland and other Bass Strait basins as part of a linked, largely transtensional, system.

THE OTWAY BASIN - A COMPLEX PASSIVE MARGIN IN SOUTHEASTERN AUSTRALIA

D. M. Finlayson(1), G. W. O'Brien(1) and C. V. Reeves(2)

(1) - Australian Geological Survey Organisation, Canberra.
(2) - International Institute for Aerospace Survey and Earth Sciences, Delft.

The Otway Basin is one of a group of Mesozoic basins on Australia's southern margin which comprise the Austral petroleum system (Bradshaw, 1993), formed during the rifting episode that resulted in the separation of Australia from Antarctica. The complex nature of the structures in the basin is a result of its location between a continental margin to the west where Australian-Antarctic separation occurred relatively close to the Australian craton, and a margin to the east, where lithospheric extension failed to develop totally in the Bass Strait region, but instead occurred south of Tasmania.

During the last two years AGSO has conducted a geophysical program in the (mainly) onshore part of the Otway Basin as a National Geoscience Mapping Accord (NGMA) Project. The partners in the project were SADME, GSV, and VIEPS at Monash and La Trobe Universities. The aims of the project were to acquire new information on the early basin structures and to improve knowledge of the tectonic events that resulted in basin evolution and development. This paper highlights a range of new AGSO geophysical data available from the basin and its significance in providing a tectonic framework for exploration.

AGSO deep seismic profiles in four target areas of the onshore basin provide definative data on the development of early rift segments along the northern margins of the basin and the nature of processes within basement. Early extension produced landward dipping half-graben above detachments at mid-crustal levels (e.g. Fig. 1). Cratonic fragments/basement highs isolated the main depocentres of Crayfish Sub-group sequences in a number of troughs prior to the regional subsidence and deposition of the Eumeralla Formation. The (?tectonic) systems tracts associated with early basin development are still not well defined.

The structures at the margins of basement highs have influenced later marine deposition. Significant crustal thinning (shallowing of the Moho) is evident on deep seismic lines seaward of the Tartwaup fault zone, emphasizing its importance as a controlling feature in Late Cretaceous and subsequent marine deposition.

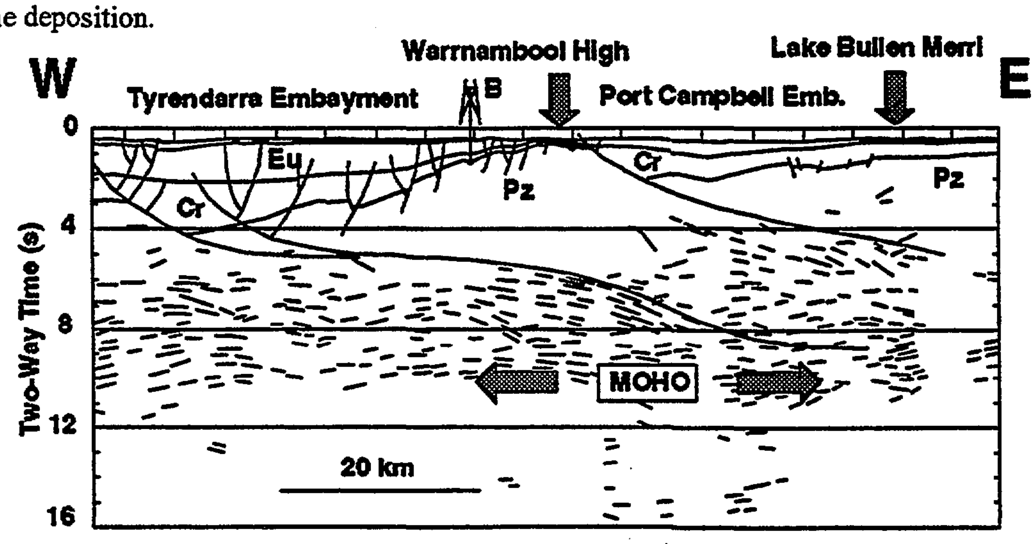


Figure 1. Line diagram of deep seismic profile across the Warrnambool High illustrating the depth of the early rifts and the possible detachments within the mid-crust. The Moho depth under Lake Bullen Merri is 31 km.

New AGSO images of the gravity field provide improved information on Mesozoic tectonic events. US Navy Geosat data for the Southern Ocean have been combined with onshore Bouguer gravity data and the resulting images highlight the major fracture systems in the Southern Ocean (Fig. 2). In particular, the Spencer and Tasman fracture systems have possible correlations with onshore gravity features to the west and east of the Otway Basin. A major offshore gravity lineament (?fault system) and the onshore margins of the Otway and Sorell basins define the "Otway-Sorell microplate".

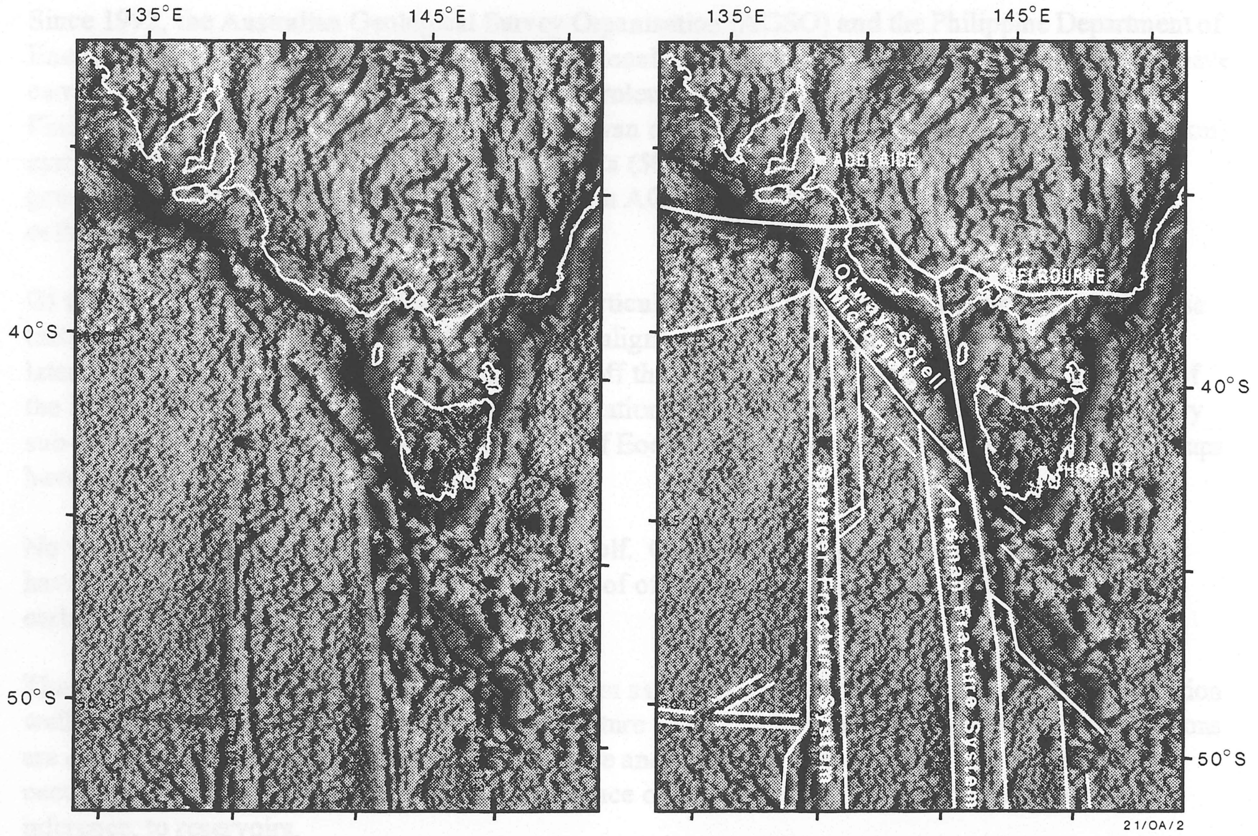


Fig. 2 Geosat and Bouguer image of SE Australia with bounding features of the Otway-Sorell microplate.

Long wavelength aeromagnetic data from the western Otway Basin indicate three principal structural directions: NS, NE-ENE, and NW-WNW. Shorter wavelength curvi-linear anomalies, 30-40 km long, are interpreted as intra-sedimentary faults associated with relay zones at depths less than 1000 m, and high amplitude short wavelength data are associated with near-surface volcanics and possible CO_2 conduits.

The structural fabric and regional geological data suggest that the rifting history of the basin may have taken place in two stages, rather than within a simple rift-to-drift framework proposed previously. The initial stage, from 150 to ~120 Ma, took place within a stress regime dominated by NW-SE extensional transport (similar to that of basins of the Great Australian Bight). E-ENE-striking extensional rift segments such as the Crayfish Platform-Robe Trough, developed during this period, contemporaneous with the deposition of thick sediments of the Crayfish Subgroup. Other parts of the basin, such as the Penola Trough, developed within a strongly trans-tensional (left-lateral, strike-slip) environment. After a period of uplift and block faulting at ~120 Ma, rifting recommenced with an extensional transport direction oriented NNE-SSW, contemporaneous with the deposition of the Eumeralla Formation. This latter rift episode produced the 'traditional' normal fault orientation within the Otway Basin.

PHILIPPINE MARINE SEISMIC SURVEY PROJECT

Chao-Shing Lee, Malcolm C. Galloway, Aidan Moore and Andrew Fraser
Australian Geological Survey Organisation

Raymundo Apostol, Nelson Trinidad, Ranilo Abando, Dennis Panganiban, and Edmundo Guazon
Department of Energy, Republic of Philippines

Since 1992, the Australian Geological Survey Organisation (AGSO) and the Philippine Department of Energy (DOE), funded by the Australian International Development Assistance Bureau (AIDAB), have carried out a cooperative project to assess the petroleum potential of four new frontier basins in the Philippines: Ragay Gulf, Tayabas Bay, NE Palawan and Cuyo Platform. New seismic data (2750 km) and geochemical direct hydrocarbon detection data (5000 km) were collected by using the AGSO's geoscientific vessel, Rig Seismic, and processed in AGSO. Onshore oil and gas seep samples were collected by DOE and analysed by AGSO.

Of the four survey areas, the Ragay Gulf is of particular interest with complex structure, multi-phase tectonism and thick sediment infill (Fig. 1). It is aligned in NW-SE, and is clearly a Tertiary, left-lateral strike-slip basin, formed by major splays off the Philippine Fault as a result of the collision of the Pacific and Eurasian Plates. Seismic interpretation has revealed the existence of five sedimentary sub-basins with 2.5 - 6 seconds (two-way time) of Eocene to Recent sediments. Several potential traps have been evaluated for hydrocarbon reserves.

No well has been drilled offshore in the Ragay Gulf. Onshore well log information and stratigraphy have assisted in the correlation and interpretation of offshore seismic data and allowed important carbonate and clastic reservoirs to be recognised.

The geochemistry data, both from the water bottom sampling and onshore seep and leaking exploration well sampling have confirmed the presence of mature source rocks from which generated hydrocarbons are currently migrating to the surface both onshore and offshore. This indicates the widespread occurrence of mature source rocks, and the presence of migration pathways to the surface and, by inference, to reservoirs.

From onshore well and outcrop information the primary reservoir targets are the carbonate sequences of both Early and Late Miocene age. The widespread volcanogenic clastic sands may be cleaner beneath Ragay Gulf than onshore. They are a secondary target and should not be overlooked, especially as gas reservoirs.

A wide diversity of play types are recognised which could have been sourced from three separate source kitchens in the Bondoc, Burias and Ragay Sub-basins. Both sandstone and carbonate reservoirs are believed to be present in a variety of traps formed during an early, pre -middle Miocene phase of structuring (eg. Arena) and a later phase which has in some cases continued up to the present (eg. Anima Sola). Specific entrapment possibilities are:

1) Compressional fault-dependent traps, eg. Anima Sola.
2) Compressional anticlinal fault independent traps, eg. Alibijaban and Palad.
3) Late Miocene carbonate reefal buildups, eg. Apud and Gorda.
4) Early Miocene carbonate reservoirs in drape over highs, eg. San Narciso and Bagulaya.

The exploration permit for Ragay Gulf has been opened for application. The AGSO and DOE project teams are continuing to work on the remaining areas: Tayabas Bay, NE Palawan and Cuyo Platform.

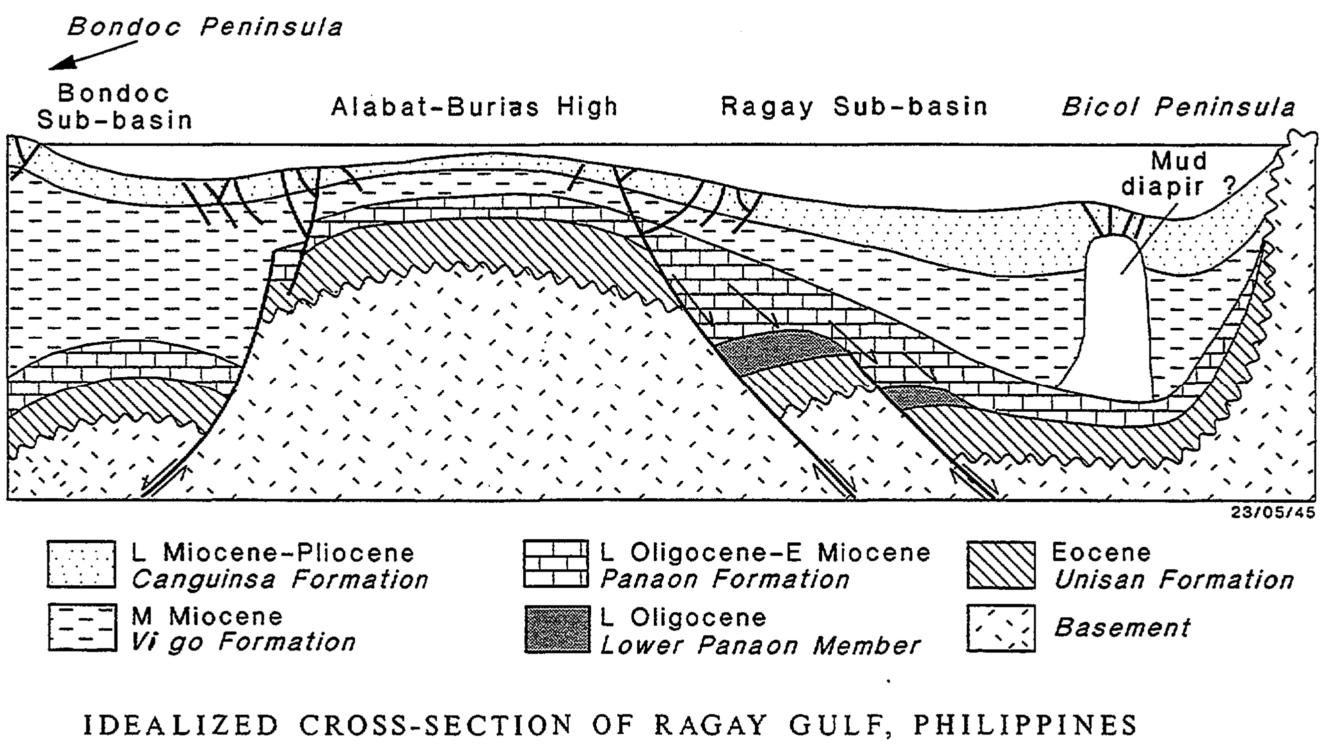


Fig. 1 The cross-section of Ragay Gulf, Philippines - a simplified model.

DEEP WATER PETROLEUM PROSPECTS IN THE LORD HOWE RISE REGION

P.A.Symonds & J.B. Willcox

Australia has a potential offshore jurisdictional zone of about 12 million km^2, of which about 6.5 million km^2 is continental margin associated with both the continent and the island territories. Although enormous areas of the margin have few or no wells, large sedimentary basins, some of considerable thickness and structural complexity, and containing indicative exploration leads, are known from AGSO and other reconnaissance seismic data to occur in the deepwater, beyond the frontier of conventional offshore hydrocarbon exploration. These basins are generally thought of as inaccessible and too high cost/high risk at current oil prices to warrant a concerted exploration effort. Conventional quantitative assessments of Australia's undiscovered petroleum potential do not generally take account of potential petroleum resources in these very remote deep-water areas.

One such area of remote, deep-water basin development occurs in the Lord Howe Rise region off eastern Australia. This region is an enormous area of complex seabed lying 300-1500 km east of Australia, and extending over 20° of latitude (approximately 2200 km). It includes relatively shallow water elongate plateaus and ridges such as the Lord Howe Rise, and the Norfolk, West Norfolk and Dampier Ridges, and intervening deeper water basins such as the Lord Howe, Middleton and New Caledonia Basins (Fig. 1). Australia has a large seabed claim in this region amounting to about 1.65 million km^2 - 20% of the area of the Australian land mass - because of its territorial ownership of Lord Howe Island, on the western Lord Howe Rise, and Norfolk and Philip Islands, on the Norfolk Ridge.

Rifting in the region may have commenced in the ?Late Jurassic-Early Cretaceous during a NW-SE oriented extension event that formed the southern Australian margin rift system, and initiated the Otway, Bass and Gippsland Basins. During the Late Cretaceous, NE-SW oriented extension related to rifting and left-lateral movement between Australia and Lord Howe Rise produced the Boobyalla Sub-basin beneath southeast Bass Strait, and a broad extensional terrane throughout the Lord Howe Rise region. Breakup and seafloor spreading in the Tasman Basin commenced in the Campanian (about 80 Ma) and ceased in the early Eocene (56 Ma), with the conjugate margins separated by about 300-1000 km of oceanic lithosphere. As breakup occurred near the western edge of the extensional terrane the eastern Australian margin is a narrow, largely basin-free region. However, the Lord Howe Rise region is underpinned by extended lower crust and upper mantle, overlain by zones of upper crustal extension and rift basin development, such as beneath the western part of the rise (Fig. 1). Recently, the region has been interpreted in terms of a detachment model in which southeastern Australia is an underplated upper plate margin, with the Lord Howe Rise/Norfolk Ridge region being its complementary lower plate margin.

Regional reconnaissance seismic data indicate that the rift system beneath the western Lord Howe Rise consists of a 200 km wide zone of horst and graben structures in water depths of 1000-2000 m. Elsewhere, particularly beneath the eastern third of the Lord Howe Rise, relatively thin sediments overlie basement, which is commonly planated. Individual graben are up to 50 km wide, several tens of kilometres long, and are best developed north of Lord Howe Island, where sediment fill is up to 4500 m in places. Diapir-like structures have been recognised in several of the grabens (Fig. 1). South of Lord Howe Island, the extensional basins appear to be less complex and some of the horst blocks appear to contain dipping strata of Mesozoic age, possibly comparable to the Strzelecki Group of the Gippsland Basin. The nature of the sediments filling the basins on the Lord Howe Rise is a matter of conjecture. They are generally assumed to be of late Mesozoic age, but correlation with the older sedimentary basins of eastern Australia cannot be completely ruled out. If the basins developed along the lines of classical models for rifted margins, the earliest basin fill could be fault controlled terrestrial clastics containing potential source rocks and petroleum reservoirs - perhaps similar to the Late Cretaceous coal measures that are considered to be the main source rock in the Taranaki Basin of eastern New Zealand, along strike from the Lord Howe Rise. Restricted shallow-marine silts and clays of Maastrichtian age are known to overlie basement at Deep Sea Drilling Project Site 207 on the southern Lord Howe Rise. Equivalent sequences could provide potential source and reservoir facies within the upper part of the rift basin fill. During the latest Cretaceous and Paleocene, restricted oceanic circulation resulted in the widespread deposition of black shale - a rich potential source rock -throughout the region. Such facies may be present within the Lord Howe rift basins and the New Caledonia Basin.

Three potential petroleum plays can be identified on the western Lord Howe Rise. Fault structural/stratigraphic traps within the fluvial to shallow-marine, rift-fill sediments are the most widespread potential play identified to date. Sub-unconformity traps created by dipping reflectors within the horst blocks, potentially sealed by the rift and post-breakup section, would be dependent on a source within the pre-rift 'Strzelecki equivalents' or older section. Potential plays are associated with diapir-like structures, which occur northeast of Lord Howe Island, in water depths of 1500 m. Because of the age of movement of the 'diapirs', this play is only valid if there has been late (?post-Oligocene) maturation and migration.

Other substantial areas of basin development in the Lord Howe Rise region are Cretaceous rift basins beneath the eastern margin of Lord Howe Rise and the western margin of the West Norfolk Ridge system (Fig. 1), and a structurally complex, wrench-related graben beneath the Taranui Gap near the southern end of the Norfolk Ridge.

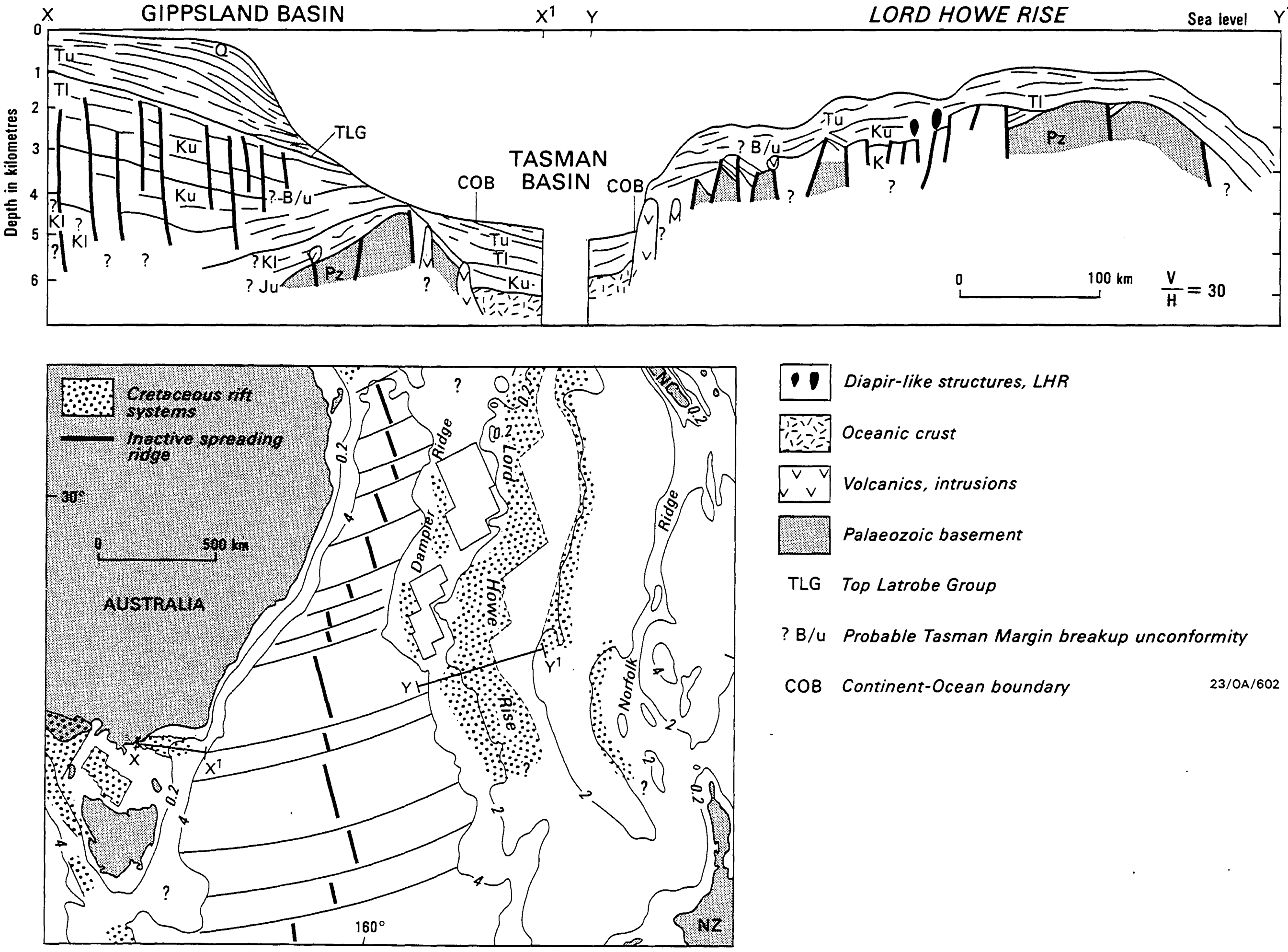


Figure 1. Reconstructed schematic section of the Gippsland Basin and Lord Howe Rise showing the nature and distribution of the Cretaceous rift system around the Tasman Basin.

EVOLUTION OF THE CANNING BASIN AND ITS PETROLEUM SYSTEMS: PROGRESS REPORT

M Jackson, J Kennard, K Romine, P Southgate, M Sexton, R Shaw, C Foster, P Jones, R Nicoll, G Young, I Zeilinger

Current studies in the onshore part of the Canning Basin are directed towards an evaluation of the prospectivity of its main petroleum systems - Larapintine 2 and 3, and to the production of an updated set of maps and sections depicting the evolution of the basin succession. This follows on from the successful application of sequence stratigraphic techniques to the Devonian of the Lennard Shelf (1990-92), which resulted in a new phase of exploration activity in the basin. The systematic basin analysis (1993-94) will define - main basement elements and structural features; tectonic events that have affected the basin sediments; subsidence and uplift history of the various parts of the basin; and the character and distribution of key elements (eg source, reservoir, seal) of the Larapintine 2 and 3 petroleum systems. To date, tectonic, structural, stratigraphic and palaeontological studies have been completed in the western half of the basin. Some of the more significant advances include:

- Fourteen megasequences (referred to by the letters A through L), ranging in age from Early Ordovician to Early Cretaceous, each comprising a number of depositional sequences, have been mapped (see figure). Within some of the sequences it is possible to identify and map individual systems tracts and to relate these to features of direct petroleum significance. For example, organic matter-rich intervals within Megasequence A2 (cf Goldwyer/Nita) appear to correlate with maximum flooding intervals near the top of the Transgressive Systems Tract.

- Conodonts from Megasequence B (cf Carribuddy Group) indicate a late Ordovician age, rather than Silurian-Devonian as previously thought. This age revision has obvious implications to the Larapintine 2 Petroleum System as it places potential seal facies (Mallowa Salt) above potential source and reservoir beds (Bongabinnie, Goldwyer and Nita Formations) without a significant time break.

- Megasequences of early Ordovician age (A0,A1,A2), were deposited in a series of SE-trending half grabens with growth faults on their northern margins. Previously these rocks had been classified as epeiric sea deposits of relatively uniform thickness. The relationship between source-bed quality and location within these half-grabens is currently being assessed.

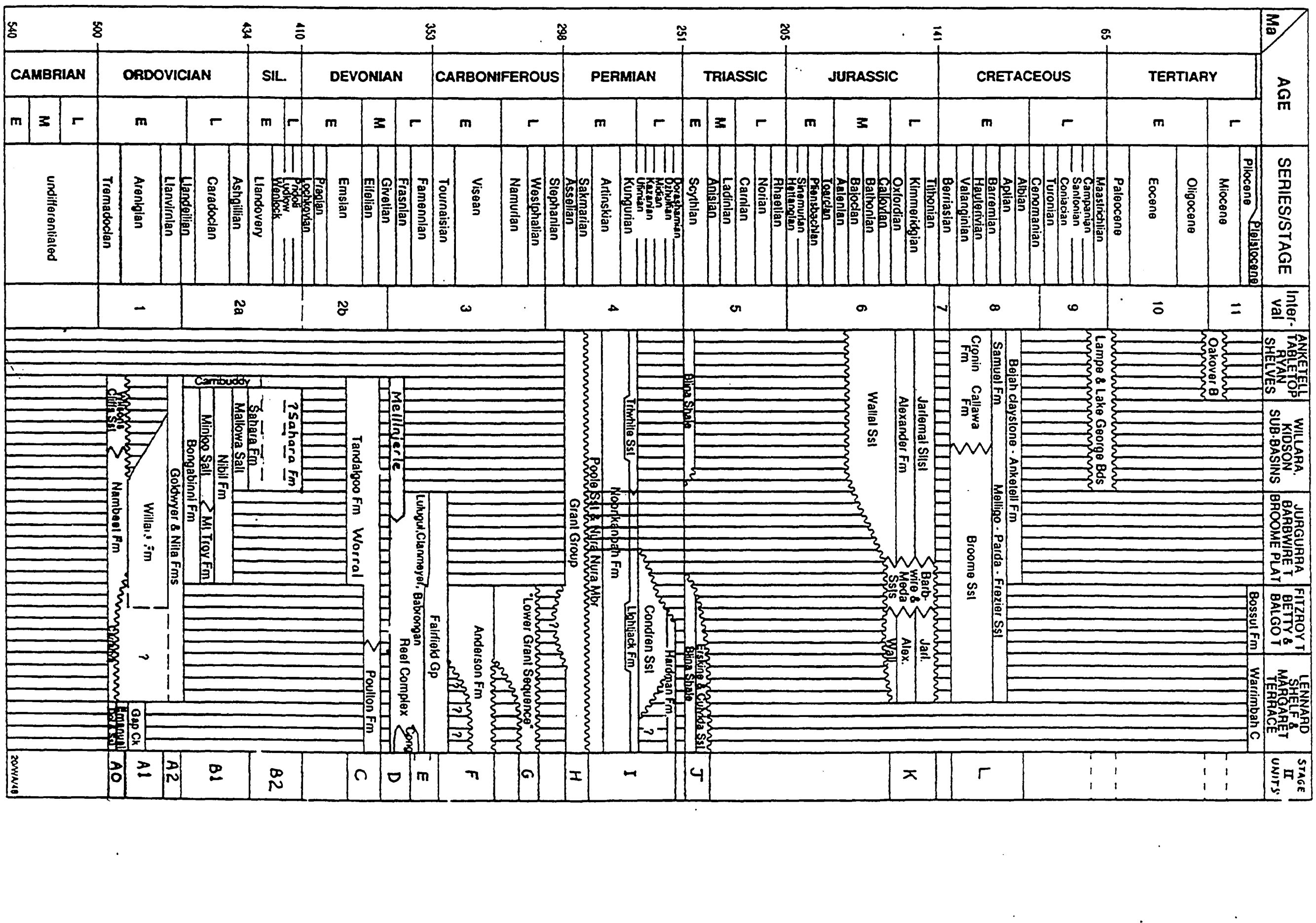
- The Admiral Bay Fault Zone (ABFZ), bounding the northern margin of one of these half-grabens, and other SE-trending fault zones within the Willara Sub-basin are much more complex than previously shown. They comprise several closely-spaced fault traces that show variable syn-sedimentary growth along strike. Most of these fault zones are offset by NE-trending accommodation zones characterised by overlapping fault relays. Similar features can be recognised on the northern margin of the Broome Platform suggesting these relay zones may be fundamental features of the basin. Extensive base metal mineralisation and several petroleum shows occur in the Cudalgarra - Great Sandy area at the intersection of the ABFZ and one of these relay zones.

- Evaporite dissolution mounds ('Sombreros' or 'turtles'), commonly 5-10 km across and up to 200 msec (about 200 m) thick, have been mapped across an area of 2500 sq km in the western part of the Willara Sub-basin. These occur within Megasequence C (cg Tandalgoo and Worral Formations) and therefore indicate dissolution of salt during the Devonian (~380my). Previous studies had not identified 'turtles' in rocks older than the Permo-Carboniferous Grant Group (~300my). As these mounds have been identified as potential petroleum reservoirs burial history and maturation scenarios need modifying in the light of this information.

- The stratigraphic position and distribution of potential reservoir beds in the Devonian - Permian have been significantly revised in the NE part of the Broome Platform. This result illustrates the advantage of sequence stratigraphic over lithostratigraphic correlations.

- Sequence interpretation of shallow company seismic lines and deep 1988 BMR lines, combined with revised biostratigraphic dating from Nerrima 1 well, have important implications for the prospectivity of the large, Triassic, wrench-related anticlines in the Fitzroy Trough. The base of Megasequence H (cf Glacial Grant Group) is almost twice as deep as previously mapped (2-3 secs TWT, not 1-1.5 secs). Preliminary burial history models for this area indicate any potential source beds in Megasequences D,E, and F (Reef complexes - Anderson Formation), would have passed through the oil generating zone before the large anticlinal structures were formed.

- The stratigraphic and structural framework that has been established to date is forming the basis for characterisation and evaluation of the various petroleum systems and ultimately identification of the more prospective areas for future exploration.



Canning Basin Megasequences (column headed 'Stage II units') compared with main lithostratigraphic units recognised in the basin. Column headed 'Interval' refers to stratigraphic intervals mapped in BMR Bull 210.

PETROLEUM POTENTIAL OF THE BOWEN AND SURAT BASINS, EASTERN AUSTRALIA

R J Korsch, C J Boreham, A T Brakel, C B Foster, M G Nicoll, J M Totterdell, K D Wake-Dyster & A T Wells

Onshore Sedimentary & Petroleum Geology Program
Australian Geological Survey Organisation

The "Sedimentary basins of eastern Australia" project is a cooperative National Geoscience Mapping Accord project being conducted jointly by the Australian Geological Survey Organisation, the Geological Survey of Queensland, and the New South Wales Department of Mineral Resources (Geological Survey and Coal & Petroleum Geology branches), with cooperation from CSIRO, universities and industry.

TERRANE & PROVINCE ANALYSIS

AGSO has conducted three deep seismic surveys in eastern Australia that crossed at least part of the Bowen-Gunnedah-Sydney basin system and the New England Orogen. These three surveys show three different crustal geometries, which must be accommodated in any model to explain the evolution of the Bowen, Gunnedah and Surat basins.

SUBSIDENCE/UPLIFT HISTORY

Tectonic subsidence curves demonstrate that the Bowen and Surat basins have undergone a complicated basin history. The Taroom Trough subsided in the Early Permian due to thermal relaxation following the eruption of a thick volcanic pile. This was interrupted in the Late Permian by the onset of rapid subsidence, interpreted as a foreland loading phase. In the Denison Trough, initial rapid subsidence was due to mechanical extension and formation of half graben, and was followed by much slower rates of tectonic subsidence. Foreland loading in the west was not nearly as significant as the eastern part.

BASIN PHASES AND FILL HISTORY

The current phase has involved the interpretation of a regional grid of seismic lines north of 26°S. Interpretation of this data set, which involved over 260 lines and 5000 line km of data, is almost complete and the data have been entered into Petroseis™ System Software. Over 20 major seismic reflection events have been discriminated and the application of seismic stratigraphic principles indicates that the majority of the reflection events are sequence boundaries. A major advance has been the application of sequence stratigraphic principles to the thick, predominantly continental (mostly fluvial and partly lacustrine) sediments of the Bowen Basin. Products will include isopach and structure contour maps on sequence boundaries and other prominent reflectors, in two way time.

PLAY ELEMENT EVALUATION

A wide range of geochemical data has been collected on an extensive collection (approximately 90) of oils and condensates and 11 gas samples from the Bowen and Surat basins. The bulk of liquids were generated from terrestrial land-plant organic matter. Biodegradation can be recognised in both the liquid and gas samples. The oils and condensates were generated at similar maturation levels between 0.65% and 1.05% vitrinite reflectance equivalent, but the bulk of the gas generation occurred at slightly higher maturation levels between 1.1% and 1.3% vitrinite reflectance equivalent. Source-related aromatic biomarkers suggest that the petroleum was generated from the Permian.

PETROLEUM SYSTEMS AND GEOLOGIC PROCESSES

Marita Bradshaw, John Bradshaw, Tom Loutit, Andrew Murray & Roger Summons

A petroleum system can be defined as a mature source rock and all its generated hydrocarbon accumulations (Magoon & Dow, 1991). The system includes all the geological factors necessary for the oil and gas fields to exist - that is the source, reservoir, seal, trap, overburden required for maturation and migration pathways. The petroleum systems concept can also be applied at a continental-wide scale by the establishment of an overarching framework of "super systems". Basins that share similar age of sequences, similar facies and in particular similar source rock type, and similar structural history are linked together into broad petroleum "super systems". Knowledge gained about the operation of a petroleum system in more explored areas can then be used predictively in frontier regions. Six Phanerozoic petroleum "super systems" have been defined (Bradshaw, 1993).Useful generalisations can be made, and insights gained, by contrasting the operation of key processes in the different "super systems". In this talk we will focus on the processes of source rock deposition, and hydrocarbon generation, migration and entrapment in the Larapintine and Gondwanan "super systems".

The Larapintine "super system" is characterised by lower Palaeozoic marine facies, including carbonates, evaporites and excellent marine source rocks. Oil prone source rocks were deposited during marine transgressions. Most of the organic matter was contributed by single celled organisms and as such the source rocks have a particular chemistry and maturation behaviour, often with a compressed oil window. The layer-cake stratigraphy of many Larapintine sequences with widespread regional seals provided by marine shales and evaporites has an influence on migration pathways and trap configurations. As an initial generalisation one could expect lateral migration to dominate over vertical migration and faults to seal, though the pattern and intensity of later structuring will also have significant impact on these factors.

In contrast, the late Carboniferous to middle Triassic Gondwanan "super system" is characterised coarse glacigene clastics followed by coal measures. The source rocks are predominantly non-marine, and associated with the floodplain environments. The lacustrine shales are lean in organic matter, perhaps reflecting annual overturn in lakes due to seasonal changes in temperature. In the Cooper Basin, Permian intraformational fluvial and deltaic shales provide a rich, mainly gas-prone, higher plant source which also produces oil and condensate. The heterogeneity of the organic material from the forests contributing to the source rocks results in a greater range of products generating over a much wider range of maturities than for the typical Larapintine source rocks. The Gondwanan sequences in eastern Australia are predominantly terrestrial and sand prone, lacking widespread marine shales to provide regional seals. Migration pathways tend to be complex with ample scope for both lateral and vertical migration. The characteristic trap type is stacked reservoirs within anticlinal closure. Similar generalisations can be made for the other "super systems" and in this way, a model is provided against which to analyse the unique petroleum systems in each basin.

BRADSHAW, M.T., 1993 - Australian petroleum systems. PESA Journal 21, 43-53.

MAGOON, L.B. & DOW, W.G., 1991 - The petroleum system - from source to trap. American Association of Petroleum Geologists Bulletin, 75 (3), 627.

GEOCHEMICAL TOOLS FOR EVALUATING PETROLEUM GENERATION IN MESOPROTEROZOIC SEDIMENTS OF THE MCARTHUR BASIN, NT, AUSTRALIA

Roger E. Summons1, Dennis Taylor2, and Christopher J. Boreham1

1. **Onshore Sedimentary and Petroleum Geology Program, Australian Geological Survey Organisation, P.O. Box 378 Canberra, ACT, 2601.**

2. **CRA Exploration Pty. Ltd., P.O. Box 3709 Manuka, ACT, 2603.**

Conventional maturation measurements in Proterozoic and Early Palaeozoic sediments are rendered complex because of the absence of true vitrinite. Reflectance and fluorescence measurements of alginite and bitumen are helpful but only in the hands of experienced operators. Whole-rock geochemical tools such as Rock Eval and TOC are useful for evaluation of petroleum potential but they can be imprecise when applied to maturity assessments.

In this collaborative study of Roper Group source rocks we studied core and cuttings from exploration boreholes recently drilled into the McArthur Basin sediments. We determined the depth profiles for hydrocarbon generation based on Rock Eval analysis of whole-rock, solvent-extracted rock, kerogen elemental H/C ratio and pyrolysis-gas chromatography Although we found that Hydrogen Index (HI) and the Tmax parameter were strongly correlated with other maturation indicators, they were not sufficiently sensitive nor were they universally applicable. Maturation measurements based on saturated hydrocarbon biomarkers are useful in immature sediments but their low abundance in most mature bitumens and oils precludes their applicability. Chemical maturity indicators based on aromatic hydrocarbons and particularly the methylphenanthrene index (MPI) were, however, powerful indicators of relative maturation. By making systematic down-hole measurements they could be used to define the oil window and to detect migrated fluids where their maturities differed from those of the in-situ bitumens.

PETROLEUM GEOSCIENCE INFORMATION MANAGEMENT

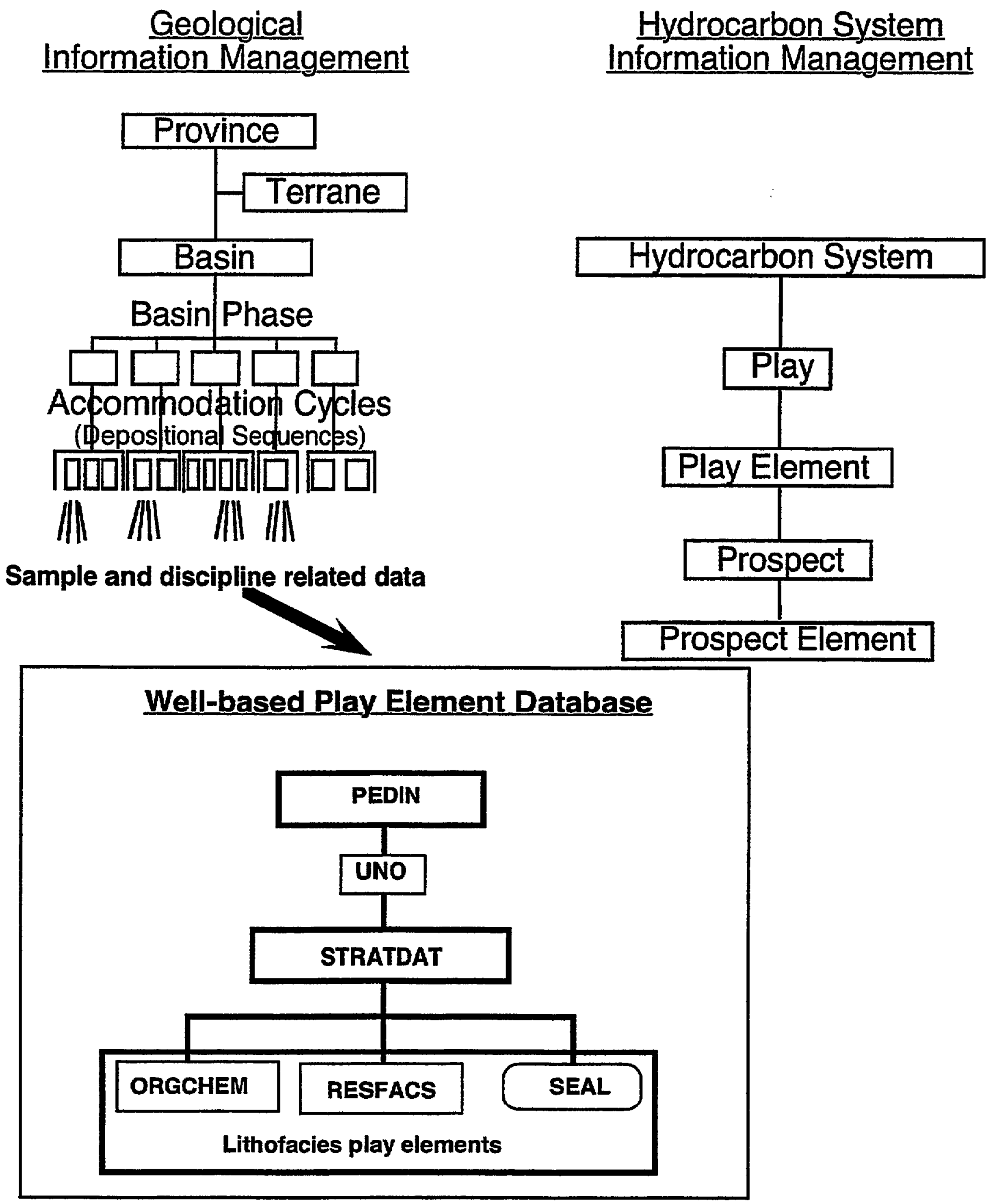
Tom Loutit, John Bradshaw, Clinton Foster, Chris Parvey, Sandy Radke (BRS)

Information management is a fundamental component of petroleum resource evaluation procedures. A prototype petroleum information system called Petroleum Resource Evaluation, Data, Information, Concepts and Templates (PREDICT) is being developed and will be implemented in phases during the next few years. The system consists of, 1) a relational database to handle text and numerical data, 2) multimedia hardware and software to handle graphical data such as charts, maps and cross sections, 3) template construction software to generate graphical reports and create dynamic linkages between graphics and the relational database, and 4) an advisory module that assists the user with data/information movement and analysis required during the process of evaluating sedimentary basins.

The data structure is built around a geological information management scheme that is based on an understanding of major geological processes that control the formation of sedimentary basins and basin evaluation methodology. The relational component of the system consists of a hierarchy of information layers or "bins" including tectonostratigraphic provinces, terranes, basins, basin phases and depositional sequences, and smaller geological units. Petroleum geoscience data is stored in time-series form within the hierachical scheme and linked to the depth and spatial datasets from which it was derived. Observations related to the components of petroleum systems such as play and play elements (source, reservoir, generation timing, etc.) are also stored in a hierarchical information scheme that is linked to the geological "bins" described above. Information is displayed on a series of templates that describe the geological evolution of the basin and the processes that control the character, timing and distribution of petroleum system elements. The graphical templates provide an interactive medium to access, query and analyse information used to document the interpretations displayed in each template. The templates "curate" the supporting graphics and data with the use of dynamic links or pointers.

The system is supported by a range of depth-based relational databases, including STRATDAT (depth to age conversion), RESFACS (reservoir, facies and shows data), and ORGCHEM (organic geochemical data), linked to PEDIN. The aim is to streamline the movement of data and information, in the correct form, from the point of generation to the point of use by internal and external clients.

AGSO
Petroleum Information Hierarchy



POTENTIAL OF GAZETTAL AREAS - BIGHT AND OTWAY BASINS, SOUTH AUSTRALIA

A.J. Hill
Oil, Gas and Coal Division
Department of Mines and Energy, South Australia
PO Box 151
EASTWOOD SA 5063

The Bight and Otway Basins (Fig. 1) occupy the central portion of the Australian Southern Rift System which developed during the ?Late Jurassic as a result of the separation of the Australian and Antarctic plates. Two major sequences are prospective for petroleum - Early Cretaceous lacustrine and fluvial rift fill sediments and Late Cretaceous to Early Tertiary deltaic-marine sediments.

Area S93-3, offshore Otway Basin, covers an area of 4736km^2 in water depths generally less than 200m and has in excess of 3000m of Early Cretaceous and 5000m of Late Cretaceous clastic sediments (Fig. 2), containing a number of potential source rock and reservoir objectives. Early Cretaceous and older sediments have not been fully penetrated in the area which was last held by Cultus Petroleum NL until 1991. Since 1963, 4900 kilometres of seismic data have been acquired within the S93-3 gazettal area and 3 wells drilled.

Whilst commercial gas has been discovered in the onshore Otway Basin at Katnook in 1987, enabling construction of a pipeline to supply local markets (22.5 petajoules of gas over 15 years), no hydrocarbons have yet been recovered from the offshore Otway Basin in South Australia. However, two large commercial gas discoveries with an estimated 1 TCF of reserves were made during 1993 in the offshore eastern Otway Basin, Victoria, from Late Cretaceous reservoirs, significantly upgrading the potential of the Basin. A 1600km marine hydrocarbon detection survey conducted by Shoreline Exploration Company in 1983 detected one large anomaly about 16km south of Port MacDonnell, and several small anomalies in the southern half of S93-3. The large anomaly was geographically coincident with 'clouds of gas bubbles' observed on sonar records and an oil source is indicated by the high peak propane values.

A range of prospects and leads have been delineated in the gazettal area with closed areas up to 100 km^2.

Areas S93-1 and S93-2, offshore Bight Basin (Fig. 1) cover a combined area of 55 920km^2 and are located within the Ceduna Sub-basin in water depths ranging from 100 to 1500 metres. Only one well has been drilled over the gazettal areas (Potoroo 1 in S93-2) and in the adjacent EPP 26, awarded to BHP Petroleum (Victoria) in 1991, Greenly 1 drilled in 1993 was plugged and abandoned with encouraging oil and gas shows.

The Basin has undergone several phases of exploration. From 1966-76 Shell Australia shot approximately 25 000km of multichannel seismic data, some of which was reprocessed by BP/BHP in 1981-82 during which time a further 2188km of seismic data were shot. In 1986, BMR acquired further seismic data over the Ceduna Sub-basin using the Rig seismic. In 1990 BP Exploration flew 27 624 line km of airborne laser fluorosensing at 5km spacing over an area of 108 508km^2 extending from the Eyre Sub-basin to the Duntroon Basin and identified 34 anomalies, the strongest 2 occurring over Area S93-1.

Potential source rock and reservoir units have been identified and at least 12km of ?Late Jurassic to Tertiary clastic sediments are thought to exist in this sparsely explored region. Potoroo 1 and Jerboa 1 were both thermally immature to total depth but the onset of maturing is expected within the flanking depocentres.

Potential plays in the Ceduna Sub-basin area include:

- Early to Middle Cretaceous fault-blocks and related structures beneath the central part of the Sub-basin;
- 'flower' structures related to wrenching;
- an 'outer margin high' along the southwest flank of the Sub-basin;
- an extensive Late Cretaceous delta sequence;
- clastic aprons adjacent to the northern basin-bounding fault and orthogonal transfer faults;
- diapiric traps near the southwest margin and
- a huge area of 'nappe-like', transpressional, or gravity-slide structures in very deep water, near and beyond the southwest boundary of the Sub-basin.

Applications for the gazettal areas close on 6 May 1994.

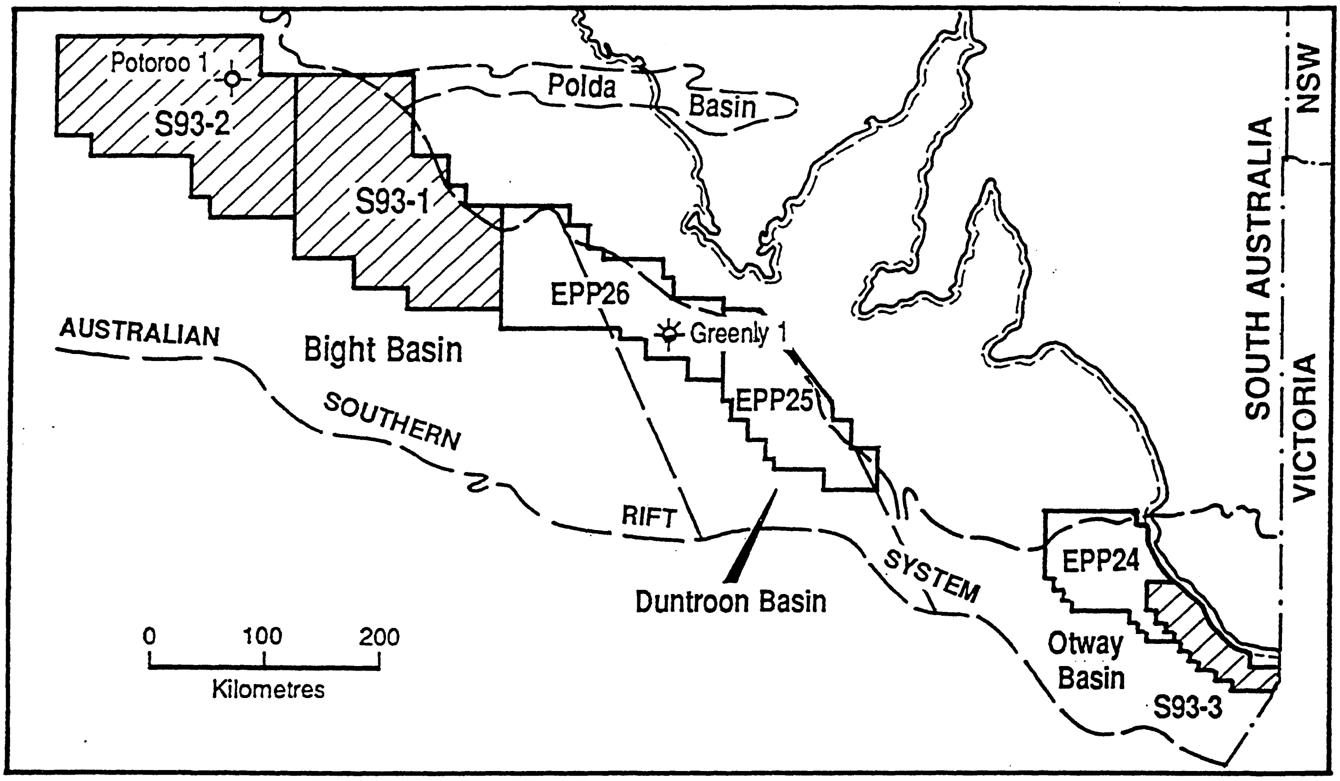


Figure 1 Location of gazettal areas - Bight and Otway Basins, South Australia.

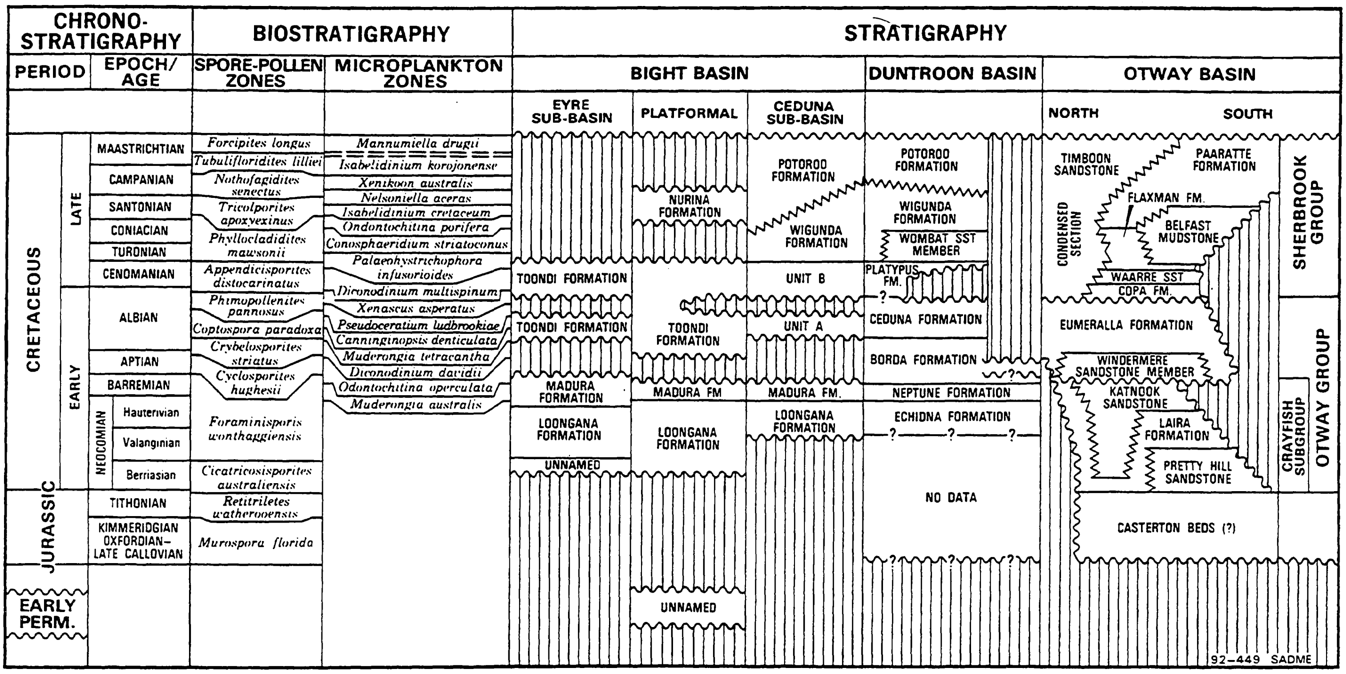


Figure 2 Cretaceous stratigraphic nomenclature of the Bight, Duntroon and Otway Basins, South Australia.