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ABSTRACTS

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EYRE SUB-BASIN: STRUCTURAL FRAMEWORK AND HYDROCARBON POTENTIAL

H.M.J. Stagg & J.B. Willcox

The Eyre Sub-basin (Figs 1, 2) is an element of the Great Australian Bight (GAB) Basin; it forms a 'perched' extensional basin underlying the Eyre Terrace in water depths of 200--1200 m on the western side of the GAB. The sub-basin covers 8000 km^2 and contains up to 6000 m of ?Jurassic to Tertiary sediments in two major half-grabens that developed between a master detachment fault and a major detachment branch during the continental extension that preceded the separation of Australia from Antarctica. Modern seismic surveys have been carried out by Esso (1979, 1982), BMR (1986), and Japan National Oil Corporation (1990). A good-quality regional to semi-detailed seismic grid is available throughout the sub-basin. The only exploration well in the sub-basin, Jerboa 1 (Fig. 3), was drilled by Esso in 1980 on a small, tilted, basement fault block in the southern (major) half of the sub-basin. Jerboa 1 (TD 2537 m, water depth 771 m) was abandoned as dry, with the basal sediments (Early Cretaceous) thermally immature. However, good-quality reservoirs and moderate-quality source rocks were penetrated in the deepest section of the well, and these may be thermally mature in the deeper parts of the sub-basin.

Stratigraphy

In Jerboa 1, the basal section, above Precambrian basement, consists of 410 m of Berriasian to earliest Valanginian non-marine sediments. The oldest sediments are poorly-sorted sandstones thought to be derived locally from basement outcrop soon after basin initiation. The rest of this interval consists of fluvial and lacustrine sandstone with interbedded siltstone and shale. Eastwards-prograding foresets in the west of the basin in the upper part of this interval suggest probable deposition in a deep lake. Units in this section have average porosities of 17--20% and were regarded by Esso as the main exploration targets.

The basal section is unconformably overlain by thick early Valanginian to

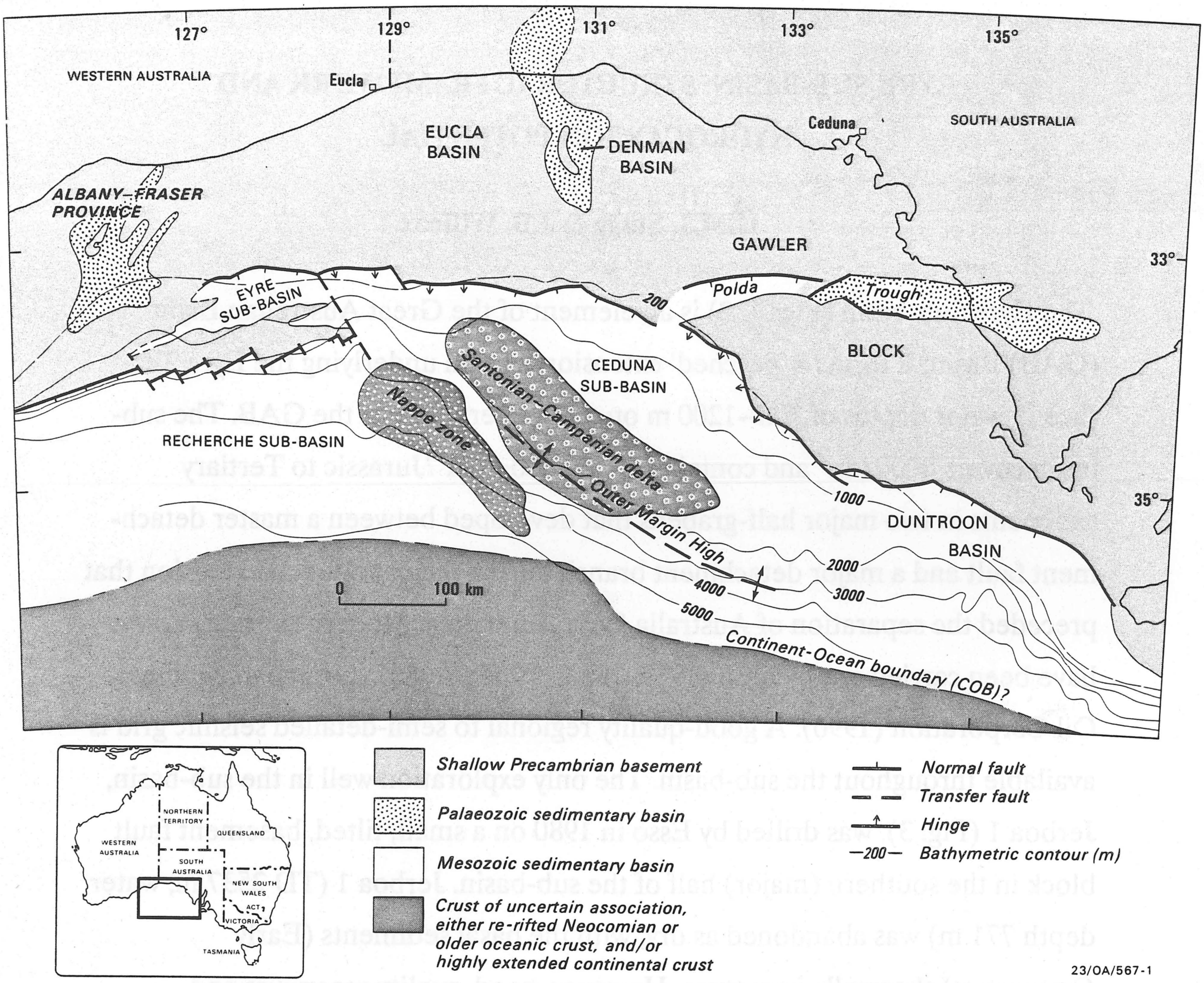

Fig. 1. Tectonics of the Great Australian Bight Basin.

Barremian dark-grey to dark-brown shale with rare interbeds of siltstone deposited in a fresh or brackish-water lake.

Following a 15 Ma hiatus, the earliest marine influence was in the middle-Albian when a thin, shale-prone, prograding unit was deposited unconformably across the Barremian shale. After a further hiatus of about 3 Ma in the late Albian, marine sedimentation resumed in the Cenomanian with deposition of a further 452 m of interbedded shale, claystone, and sandstone in a near-shore environment.

At Jerboa 1, the Turonian to Early Eocene section is absent; this represents a 40 Ma gap in the sedimentary record, and is a major basin-wide unconformity throughout the GAB. Although some of this section may be preserved in the structurally lower parts of the sub-basin, it is clear that a major erosional event,

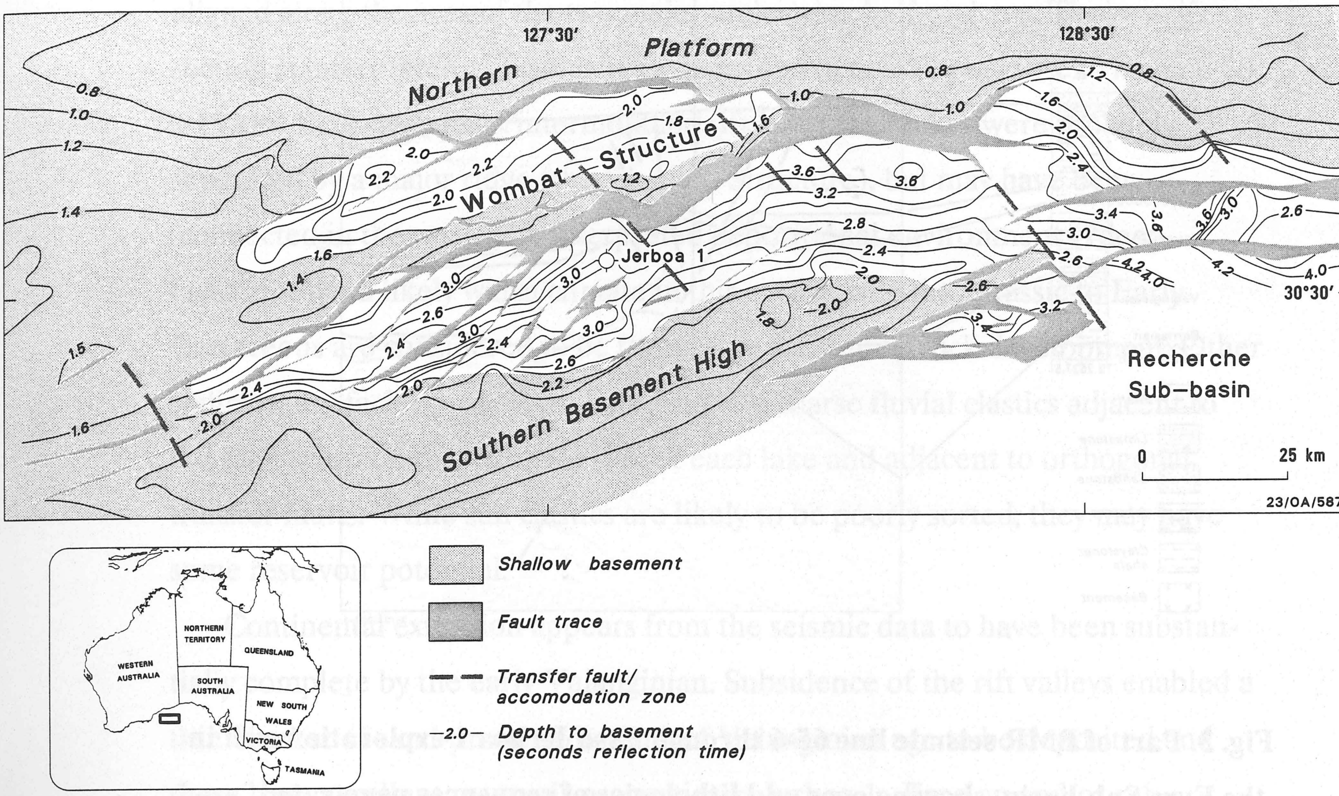

Fig. 2. Structure map of Precambrian basement in the Eyre Sub-basin; contours in seconds TWT.

probably combined with lengthy periods of non-deposition, affected the region. Sedimentation resumed in the latest Early Eocene with the deposition of a 28 m-thick section of Hampton Sandstone. The Hampton Sandstone was succeeded by calcilutite and marl of the Eocene--Oligocene Wilson Bluff Limestone and poorly consolidated, open-marine, prograding carbonate which dominates the remaining 335 m.

Basement structure

To the north and west the Eyre Sub-basin is bounded by the Northern Platform, of Precambrian basement, while to the south it is bounded by the subsided and eroded Southern Basement High (also Precambrian). The major boundaries are generally ENE-trending, with marked NW--SE offsets interpreted as the expression of transfer faults. To the east, the sub-basin appears to be contiguous with the Recherche and Ceduna Sub-basins above the eastwards-deepening

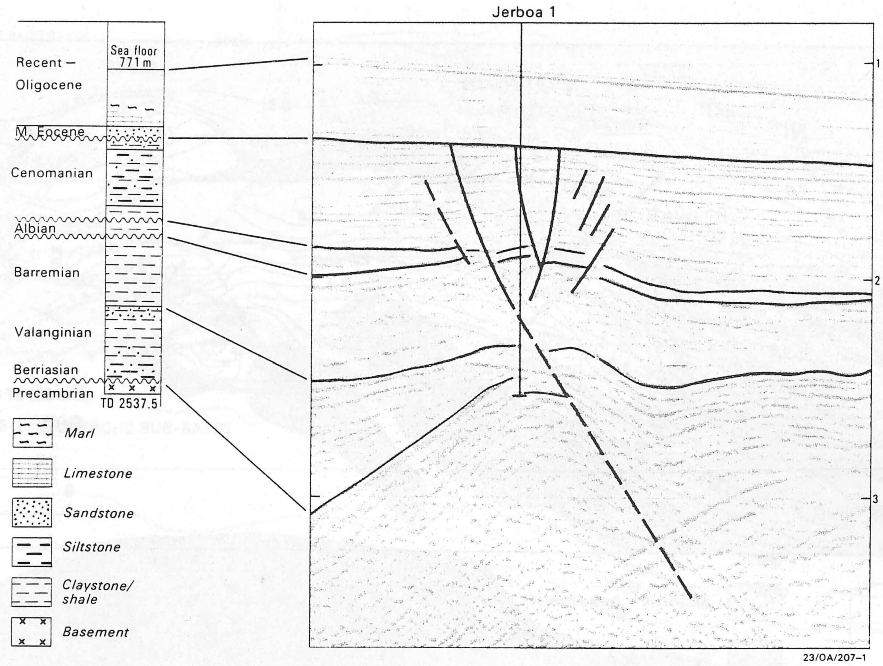

Fig. 3. Part of BMR seismic line 65-6 through Esso Jerboa 1 exploration well in the Eyre Sub-basin, showing ages and lithologies of sequences penetrated.

Southern Basement High; thus its eastern boundary is somewhat arbitrary.

Internally, the sub-basin is divided by the shallow basement of the Wombat Structure into two major ENE-trending half-grabens. As with the northern basin margin, internal basement structures are also strongly offset by SE-trending transfer faults. The northern half-graben is narrower and shallower than the southern one, and contains more than 2 s two-way-time (TWT), i.e. ca 3000 m of sediment. The southern half-graben contains up to 3.5 s TWT (>5000 m) of sediment and is quite complexly structured, particularly in the west. The basement surface within this half-graben has been cut into slivers by relatively minor faulting with generally SW to WSW trends; the Jerboa structure is one of these basement slivers.

Basin evolution

The earliest syn-rift sediment in the Eyre Sub-basin is interpreted as ?Late Jurassic--Berriasian (i.e. older than the deepest sediment penetrated in Jerboa1). This section is concentrated in two discrete, elongate depocentres aligned along the axes of the two major underlying half-grabens. The syn-rift section is interpreted as having been deposited in two large (150 x 20 km and 80 x 15 km) ENE-trending ?intermontane rift lakes. The lakes were probably separated by a major ridge (the Wombat Structure), but may have been connected in the west. The interpreted depositional environment (?deep lacustrine) and likely warm climate in this area during the Jurassic to Early Cretaceous are considered to be favourable for source-rock development. Other sedimentary facies present probably include coarse fluvial clastics adjacent to the fault scarp on the northern side of each lake and adjacent to orthogonal transfer faults. While suh' clastics are likely to be poorly sorted, they may have some reservoir potential.

Continental extension appears from the seismic data to have been substantially complete by the early Valanginian. Subsidence of the rift valleys enabled a thin blanket of sand-prone sediments of Valanginian age to be deposited and these have excellent reservoir properties in Jerboa 1. Erosion and/or subsidence caused the original two depocentres to coalesce across the western end of the Wombat Structure, although there was still an intervening ridge to the northeast.

During the Barremian, a thick, rift-fill sequence of non-marine claystone and siltstone was deposited in a continually subsiding rift valley. For the first time, the Wombat Structure was completely buried. The depositional system was probably a broad (50 km-wide) rift valley with subdued topography, flanked to the north, south, and west by exposed basement that had been eroded down to not much higher than the valley floor. Interpreted environments include shallow lacustrine and mature fluvial plain.

The onset of marine conditions in the middle Albian is marked by a thin, basin-wide prograding dark shale. After this transgression, a thick section of Cenomanian near-shore sediments was deposited. This section forms a seawards-thickening wedge across the monocline in the east of the sub-basin, while in the west it forms a 400--800 m thick blanket onlapping basement in the north. Cutting the top of the Cenomanian section is a major, low-angle unconformity, which is particularly evident above areas of high basement. This unconformity extends throughout the GAB and represents a time gap of up to 40 Ma, from breakup onwards. Its origin is unclear, but it is probably related to the complex process of separation of Australia from Antarctica.

Tertiary sedimentation can be divided into two phases. In the Paleocene--Early Eocene a thin, prograding sand (not penetrated in Jerboa, 1) was deposited on a shelf across the northern half of the sub-basin. An erosional phase, interpreted as Early Eocene to early Middle Eocene in age by Bein & Taylor (1981: *APEA Journal,* **21**, 91--98), resulted in channels cutting through the Paleocene--Early Eocene prograding unit and deep into the Cretaceous section at the eastern end of the sub-basin. Carbonate sedimentation became dominant in the Middle Eocene, and has continued throughout the Tertiary and Quaternary.

Hydrocarbon generation and maturation

Although the only well drilled in the Eyre Sub-basin was dry, there is some cause for optimism in the search for hydrocarbons. A number of good-quality reservoirs were identified in the Berriasian--Valanginian section in Jerboa 1, with average porosities in the range 17--24%. Regional seals could be expected in the thick overlying Barremian claystones. It is expected that the thin prograding shelf-edge Paleocene--Early Eocene sands may have suitable porosities, though the quality of the overlying seal is likely to be poor.

At Jerboa 1, TOC data show that most of the section penetrated is relatively organic-rich. Shaly sequences throughout the well have moderately high TOC concentrations averaging 0.94% in the Albian section, 1.05% in the Barremian section, and 1.84% in the Berriasian--Valanginian section. The most organically rich shales occur towards the base of the Berriasian, where TOC averages 2.88% (maximum 5.46%). The kerogens in the shales are dominantly amorphous, and are rich in extractable hydrocarbons, suggesting that they have a high potential for liquid hydrocarbon generation. The shales are fairly thin at Jerboa 1, but they may be both thicker and more thermally mature in locations away from basement highs, i.e. in flanking depocentres.

The main limitation on hydrocarbon generation in the Eyre Sub-basin is expected to be thermal immaturity. The maximum vitrinite reflectance (V_R) value recorded in Jerboa 1 was 0.51, near the base of the well. The onset of maturity ($V_R = 0.65$) would occur at depths of approximately 3000 m in the depocentres adjacent to Jerboa 1, with peak maturity at 3500+ m. Consequently, thecharging of structural traps similar to those at Jerboa-1 requires substantial vertical and lateral migration from more deeply buried source rocks. On the basis of thermal maturity, it would appear that plays near the major basement fault on the southern flank of the Wombat Structure in water depths of 300--400 m have more chance of tapping a suitable deep and mature hydrocarbon source.

MULTIDISCIPLINARY STUDIES IN THE VULCAN SUB-BASIN, TIMOR SEA

G.W. O'Brien & A. Williams

Since the discovery of the Jabiru and Challis oil fields in the mid 1980s, the Vulcan Sub-basin has been one of Australia's most active oil exploration areas. Despite this, success recently has been elusive, mainly because a detailed understanding of its structure and development has been lacking. This is critical, as the oil-bearing structures have probably developed as a direct result of structural reactivation during the Mesozoic and Tertiary.

To support exploration BMR has been carrying out a major study of the Sub-basin and nearby tectonic provinces, acquiring 20 000 line-km of high-resolution airmag data, 1894 km of deep crustal (12--14 s) seismic-reflection, and nearly 3000 km of high-resolution seismic reflection and water-column-geochemistry data. Integration with conventional industry seismic data has shown that the tectonic history is more complex than previously thought.

Interpretation of image-processed airmag data and flight-line profiles has revealed a major set of NW-trending features that offset the NE-trending normal faults within, and especially along, the margins of the sub-basin. The features can be mapped in detail on seismic and are believed to be transfer faults which accommodated major crustal extension during the Permo--Carboniferous. Extension in the Triassic and Jurassic was relatively minor, and thus within the central sub-basin, where the Triassic and Jurassic are thick, transfer faults are not well-developed and are difficult to map. Rather, flexure over, or reactivation along, more deeply seated Permo--Triassic transfers was responsible for significant structuring of the Triassic and Jurassic.

Several hydrocarbon discoveries are near intersections of the NW and NE fault systems, which thus may be important in the entrapment of hydrocarbons. Water-column hydrocarbon anomalies were detected along a major transfer zone, implying that these zones can provide migration pathways. A prominent transfer zone separates the Vulcan Sub-basin from the Browse Basin, and may have affected sedimentation in both areas. In the central Vulcan Sub-basin, a major transfer separates the Paqualin and Swan Grabens from the Cartier Trough to the north. Recognition of these transfer faults has potentially major implications for our understanding of the structural and sedimentological history, and the petroleum prospectivity, of this region.

SEISMIC INTERPRETATION AND MAPPING OF THE WESTERN TASMANIAN MARGIN

A.M.G. Moore

The continental margin of western Tasmania is underlain for most of its length by the Sorell Basin. North of 40°30 S it is underlain by the southernmost part of the Otway Basin (Fig. 4). Industry and government reflection seismic data have been integrated and interpreted to produce a regional representation of the geological structure of the continental shelf and upper slope. Major sequence boundaries on seismic sections were tied to unconformities in the three wells that have been drilled in the study area and were correlated with known unconformities in the Otway Basin. Maps of the subsurface structure were made, to identify leads and to plan further geophysical exploration (Moore, 1991: *BMR Record* **1991/70**, in prep.). The southernmost part of the Otway Basin, and three sub-basins of the Sorell Basin were mapped (King Island, Sandy Cape, and Strahan Sub-basins). A fourth is named and briefly described here: the Port Davey Sub-basin.

The Sorell and other basins of the southern Australian margin originated from the rifting and breakup of eastern Gondwana, and the drifting apart of Australia and Antarctica from about 95 Ma. In the southern Otway and Sorell Basins the movement is thought to have been mainly a left-lateral wrench. The oldest section overlying basement is probably equivalent to the Late Jurassic Casterton beds (Fig. 5) or Early Cretaceous Otway Group of the Otway Basin, laid down in a rift-related continental setting, with volcanism (Exon & others, 1987: *BMR Report* **279**). An unconformity dated at about 95 Ma separates the Otway Group from the marginal and shallow-marine sediments of the Late Cretaceous Sherbrook Group equivalent. A younger unconformity separates the Sherbrook Group equivalent from the shelf clastics of the Wangerrip Group (Palaeocene--Eocene). In the Strahan Sub-basin, the Wangerrip Group is shown by seismic to have a considerable unconformity within it, separating the massive sandstones of the Pebble Point Formation from the overlying mudstones of the later Paleocene--Eocene (Pember Mudstone equivalent). At the top of the Pember Mudstone, an unconformity that appears on seismic as a maximum flooding surface separates the mudstone from the clean quartz sandstones of the Middle and Late Eocene Browns Creek Group, probably the equivalent of the

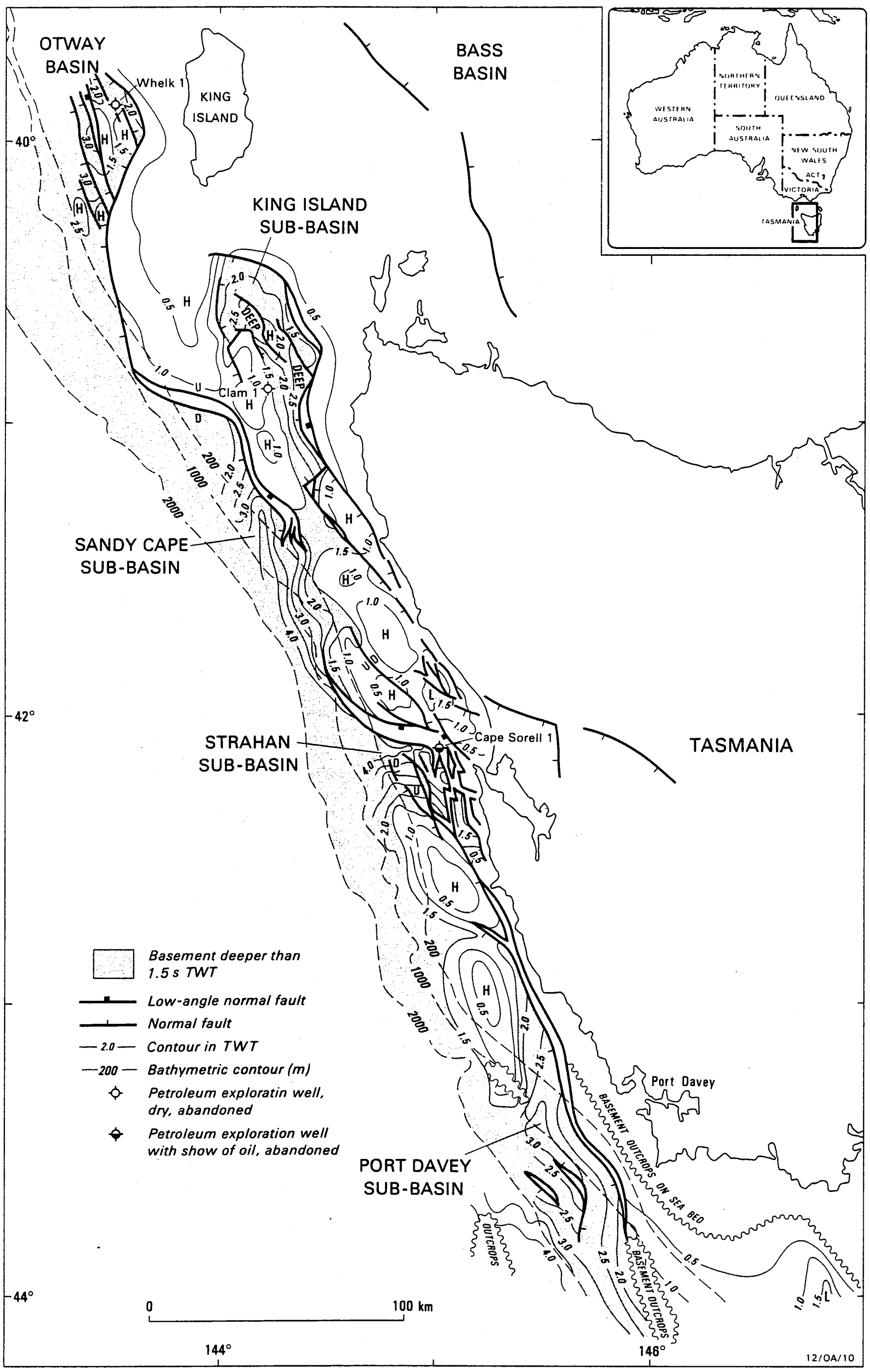

Fig. 4. Structure of the Sorell Basin and southern Otway Basin, on the western Tasmanian margin (seismic contours on basement).

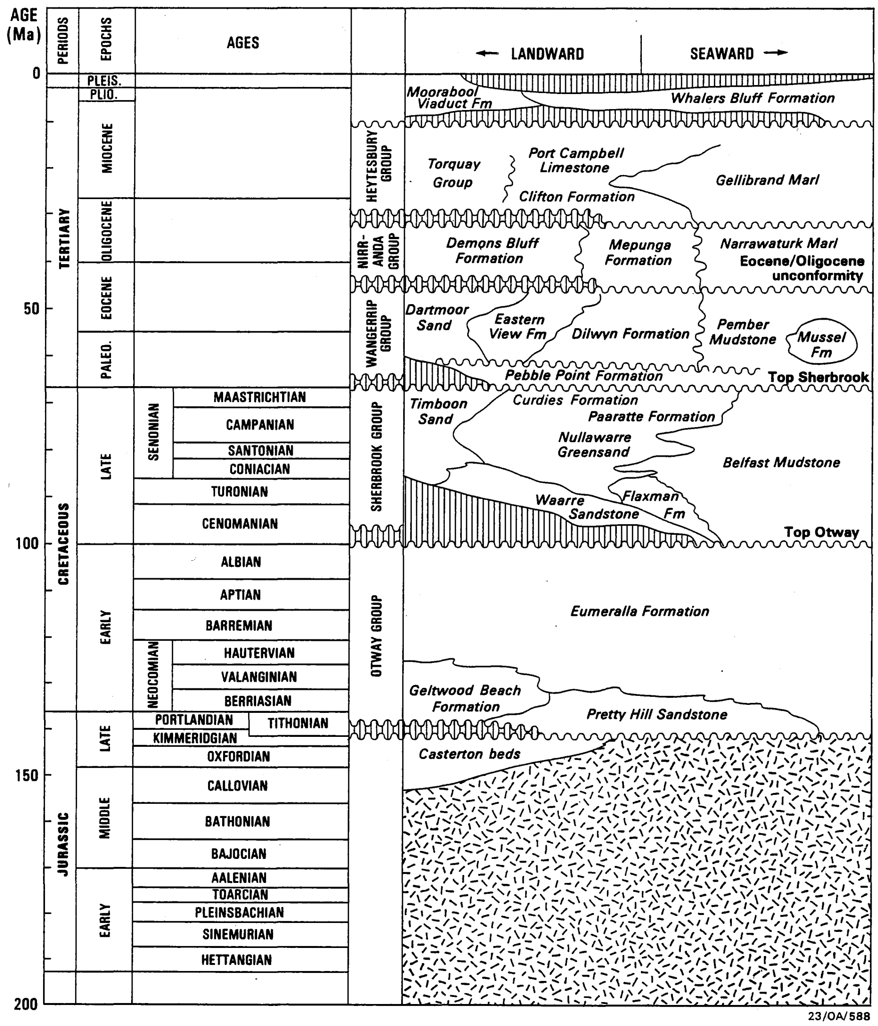

Fig. 5. Stratigraphy, offshore western Tasmania.

lower part of the Nirranda Group in the Otway Basin. An unconformity of Oligocene age (ca. 30 Ma) separates the shallow-marine, largely terrigenous sediments of the Palaeogene Nirranda Group from the Late Oligocene and Neogene open-marine, largely carbonate Heytesbury Group

Structure

The development of sub-basins here is related to the presence of WNW-striking faults and their association with the dominant NNW-striking, major bounding strike-slip faults. During the left-lateral movements that produced this margin, WNW-striking offsets of the major faults were 'releasing bends', allowing extension and the early development of depocentres such as the King Island, Sandy Cape, and Strahan Sub-basins. NNE-striking fault segments, such as those bounding the King Island Sub-basin and the southernmost Otway Basin on their eastern sides, are possibly expressions of the 'transfer faults' in the Bass Basin proposed by Etheridge & others (1987: *Canadian Society of Petroleum Geologists, Memoir,* **12**, 147--162).

Southern Otway Basin

The southernmost part of the Otway Basin, west of King Island, has mainly Cretaceous fill. Near the eastern bounding fault there are various basement horsts and terraces at a depth of around 2 km. The Whelk 1 well was drilled on one of these horsts. The seismic shows that the well did not reach basement but bottomed in volcanics, probably Early Cretaceous. The basin thickens abruptly about 20 km west of the eastern boundary, to more than 5 km, but most of the section in Whelk 1 is structurally separated from these deeper parts. Isolation from source rocks has been suggested as a reason for the absence of hydrocarbons in the well. Many closures and fault-terraces have been mapped, some of them basinward of the Whelk 1 site, and thus more favourably located for the accumulation of hydrocarbons.

King Island Sub-basin

The King Island Sub-basin has been roughly outlined by seismic, mainly of 1960s vintage, and is 20 to 40 km wide and 80 km from north to south. Maximum depth is about 4 km near the NNE-striking bounding faults, and the fill is mainly Cretaceous. On seismic, the upper part of the Late Cretaceous onlaps the flank of the Clam Anticline, and an apparent angular unconformity separates the onlapping sequence from the lower part of the Late Cretaceous. The graben probably developed early in the Late Cretaceous. This would make it younger than the southern Otway Basin to the north. The King Island Sub-basin can hardly be said to have been tested by the one well drilled in it (Clam 1).

Sandy Cape Sub-basin

The Sandy Cape Sub-basin is largely unexplored, even though it lies partly under the continental shelf. No wells have been drilled in it, the nearest being Clam 1. The intra-Late Cretaceous unconformity in Clam 1 is important because it helps to define the age of the fill in the adjacent parts of the Sandy Cape Sub-basin. If the two sub-basins are the same age, then the succession onlapping basement is the mudstones and other marine sediments of the Late Cretaceous, and not the continental sediments of the Otway Group (Early Cretaceous). This must enhance the prospectivity of the sub-basin. The Belfast Mudstone is a potential source rock and seal.

Strahan Sub-basin

The Strahan Sub-basin has been comparatively well explored with seismic, and has been tested by one well (Cape Sorell 1). It is a pull-apart rhombic trough located at a 'releasing bend' where the regionally dominant NNW-trending strike-slip faulting is offset to the WNW. WNW faulting also forms the Macquarie Harbour Graben onshore.

In the Cape Sorell 1 well, live oil was encountered in the lower part of the drilled succession, which was Paleocene and Maastrichtian, and much thicker than predicted. The well was drilled on the flank of a supposed Cretaceous structural closure that is now interpreted as an erosional high on a Late Paleocene unconformity surface. A culmination of the Paleocene topography lies to the southwest and a Cretaceous anticline to the west. The ?Late Paleocene unconformity in the well can be traced on seismic and its surface has some hundreds of metres of relief. The main channels are related to the principal faults. This Paleocene unconformity would seem to offer a good play for hydrocarbons, covered as it is by the argillaceous Pember Mudstone/Rivernook Formation equivalent.

Port Davey Sub-basin

The Port Davey Sub-basin is dominated by a re-entrant of the continental slope basin onto the shelf offshore from Port Davey. It is bounded to the north by an E--W excursion of one of the NNW-trending faults. Its extent is hard to define, because of the paucity of seismic, but it is smaller than the other depocentres both in area and thickness. The interpretation suggests that the Port Davey Sub-basin was initiated in the Paleocene.

Petroleum prospectivity

There are several structural closures in the area studied, although none have been identified yet in the Port Davey Sub-basin. The sediments beneath the slope are thick enough to have enabled petroleum to mature (5000 m in the southern Otway Basin, 6000 m in the Strahan Sub-basin and adjacent to the Sandy Cape Sub-basin, and 4000 m in the King Island Sub-basin). The live oil in the basal section of Cape Sorell 1, and the hydrocarbons reported from bottom samples in the Strahan and Sandy Cape Sub-basins (Willcox & others, 1989: *BMR Record* **1989/13**), are strong indications that mature source rocks are widely present. Potential reservoir rocks have been encountered in the wells, e.g. the Maastrichtian massive sandstones and quartz conglomerates in Clam 1 and clean quartz sands and conglomerates in Cape Sorell 1. Mudstone and shale that are potential seals were found in the Paleocene of Cape Sorell 1 (Pember Mudstone equivalent) and near the base of the Late Cretaceous in Clam 1 (Belfast Mudstone equivalent).

Conclusions

The western Tasmanian continental shelf and upper slope have been mapped in the subsurface by reinterpreting old seismic data, and integrating it with modern records.

The area shows the general features of strike-slip tectonics, indicating left-lateral movement directed to the NNW. Offsets of this faulting striking WNW are associated with the development of sub-basins in the Late Cretaceous and Paleocene.

The southern Otway Basin west of King Island contains several prospective structures. Whelk 1 well did not reach basement, as was thought, but terminated in Early Cretaceous volcanics.

Clam 1 in the King Island Sub-basin was drilled on the flank of a large high; it was dry but cannot be said to have adequately tested the sub-basin.

The Sandy Cape Sub-basin remains inadequately explored and indeed has not yet been drilled. The little seismic that has been done indicates the presence of structural closures and a thick slope basin.

The Strahan Sub-basin has been adequately outlined by seismic. Live oil was found in the lowermost portion of Cape Sorell 1. The Paleocene unconformity is a valid petroleum exploration play.

The Port Davey Sub-basin is smaller and thinner than the other three sub-basins.

BROWSE BASIN PETROLEUM PROSPECTIVITY STUDY

S.J. Cadman & J. Conolly

This soon-to-be-released publication gives a regional overview of the under-explored Browse Basin (excluding the Territory of Ashmore--Cartier Islands) and a detailed evaluation of areas to be considered for release by the Federal and West Australian Governments in Vacant Area Release No.2 of 1991. The precise areas to be released will be announced in early November. The package summarises regional geology, exploration history, hydrocarbon discoveries, regional geophysics, palaeogeography and play concepts. Plates and figures include: regional cross-sections, interpreted seismic sections, regional and prospect level TWT maps, palaeogeographic time slices, composite logs, well and engineering summaries, prospect montages, burial history plots, source rock/maturation data, and porosity data.

The Browse Basin (Fig. 6) is wholly offshore, trends NE--SW, and underlies 100 000 km^2 of the continental shelf and slope west of the Kimberley district of Western Australia. Most of the basin lies in water depths greater than 200 m.

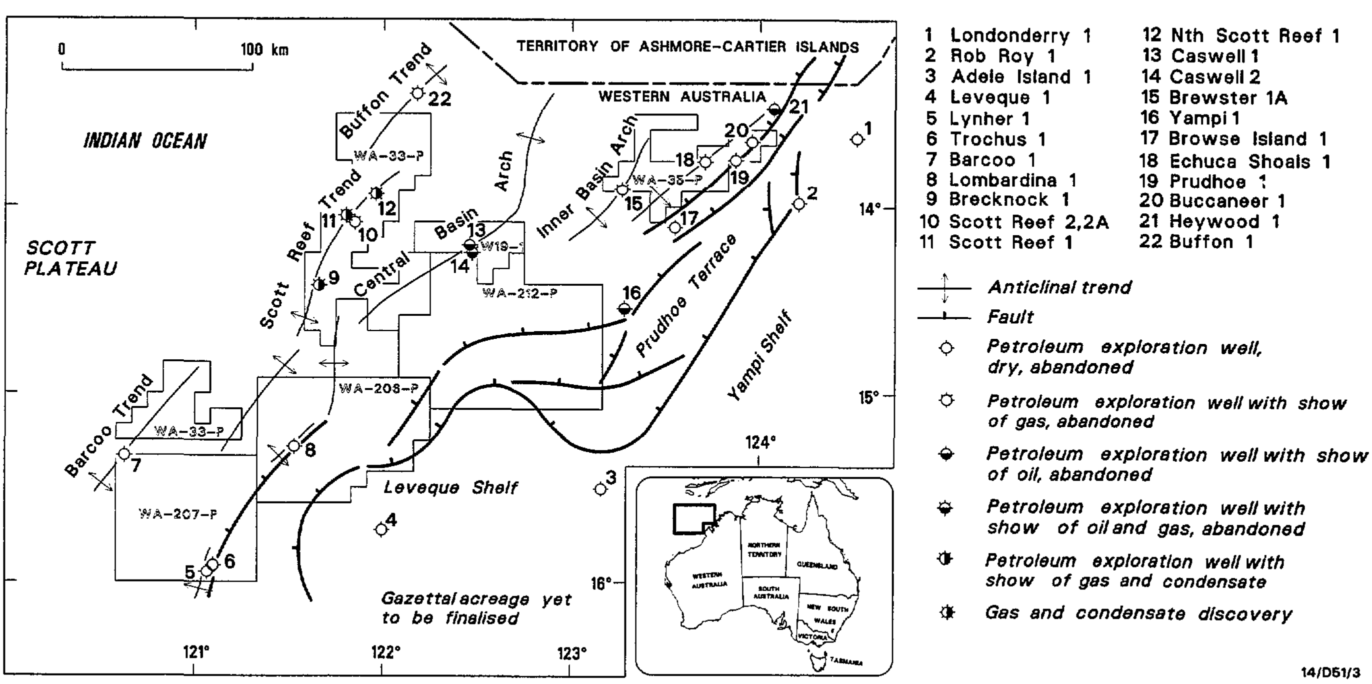

Fig. 6. Browse Basin study area.

Exploration began in 1963, when an aeromagnetic survey by Woodside (Lakes Entrance) Oil Company NL discovered a sedimentary basin seaward of the Kimberley Block.

A regional to semi-detailed grid of seismic data of varying quality has since been acquired. Twenty-two wells have been drilled, of which four were stratigraphic tests of the eastern basin margin, four are interpreted not to have tested valid structural closures, and 11 encountered either hydrocarbon accumulations or significant shows. The biggest discovery in the basin is the Scott Reef gas/condensate accumulation; Woodside Petroleum estimates recoverable reserves at Scott Reef as 499 x 10^9 m^3 of gas and 34.3 x 10^6 kL of condensate.

Stratigraphy and prospectivity

Sedimentation probably began in the Late Carboniferous to Early Permian in an early extensional phase associated with the breakup of Gondwana. Tension at the end of the Permian caused block faulting on the eastern margin and uplift of the Scott Plateau to the west.

In the centre of the basin, Permian sediments are too deep to be valid exploration targets. On the eastern flank, Permian sandstone, siltstone, claystone, and recrystallised limestone have been penetrated in several wells, but potential reservoirs are silicified. The overlying Triassic section is mainly sandy, and late gas flushing of Permian reservoirs is a significant risk. This downgrades the potential of Permian stratigraphic traps on the eastern margin.

Triassic sediments are confined to the basin centre. An Early to Middle Triassic section has yet to be penetrated, but in the Late Triassic a regressive paralic sequence was deposited over most of the basin. Tilted fault blocks developed at this time and may provide structural traps in the centre of the basin. To the east, stratigraphic pinchouts and structural closures associated with basin margin faults may be viable objectives. Triassic reservoirs may be silicified, although at Scott Reef excellent porosities were recorded in Triassic sands at 4400 m. Intraformational claystones may provide seals, or, as at Scott Reef, the top seal may be transgressive Middle to Late Jurassic claystone. Late Triassic source rocks contain mainly Type III 'humic' organic matter (gasprone), but an oil-prone Triassic source facies could be present in the central basinal areas.

At the end of the Triassic, sedimentation stopped when block faulting imparted a northeast--southwest structural grain to the basin and uplifted the Ashmore Platform to the north.

In the Early Jurassic, typical rift-valley sedimentation ensued -- fluvio-deltaic to marine sandstone, siltstone, and claystone were laid down over much of the study area. This ended in the Middle Jurassic when renewed block faulting, associated with widespread volcanism, reactivated much of the Triassic faulting and gave rise to the regional 'Jb' or 'breakup' unconformity.

Historically, Early to Middle Jurassic syn-rift sandstones have been the primary targets. The principal play type has been the drape anticline -- horst blocks of Triassic to Middle Jurassic strata draped and sealed by Late Jurassic to Early Cretaceous transgressive claystone. Successful tests include the Scott Reef gas-condensate discovery and the Brecknock and Brewster gas discoveries. Encouraging oil shows were also encountered while drilling the Jurassic in Yampi 1 and Heywood 1.

Drift-phase sedimentation began in the centre of the basin in the late Middle Jurassic. Transgressive marine shale and claystone eventually onlapped high-relief areas; in the centre of the basin they provide a regional seal for the underlying rift sequence. Along the eastern margin, deltaic to marginal-marine sedimentation prevailed through most of the Late Jurassic. Sand is particularly developed in the Tithonian; Tithonian sands sealed by Early Cretaceous claystones are possible targets in the east.

There are regressive Neocomian and Campanian sand sequences on the eastern flank of the basin. Neocomian deltaic complexes are probably restricted to the Yampi Shelf and Prudhoe Terrace, but, in the Campanian, prograding foresets and sand 'mounds' are seen in seismic sections considerable distances from the eastern basin margin, and Campanian deltaic complexes, submarine fans, and turbidite sequences are potential targets. Fair to good quality Cretaceous source rocks lie within the oil window in the central basin, with Late Cretaceous claystone providing seals for stratigraphic and structural traps.

Late Cretaceous plays are untested in the Browse Basin. However, the Caswell wells, on the Central Basin Arch, have provided some encouragement. Here, oil was encountered in thin Albian and Campanian sandstones.

In the Tertiary, subsidence of the outer shelf and a general tilting of the basin to the northeast led to the deposition of thick, prograding carbonate wedges, in which porosity is generally excellent. Recrystallised limestones may provide intraformational seals, and some structural traps may have formed in the north of the basin in the Miocene as a result of the collision of the Australian Plate with Timor. However, these Tertiary carbonate plays are high-risk.

Untested Cretaceous

The Browse Basin is underexplored and has been perceived as a gas province. Although there is potential for further large gas-condensate accumulations, encouraging oil shows indicate that commercial oil accumulations may also be present.

To date, the most important play type has been the Triassic/Jurassic drape anticline. These will continue to be important but the untested Cretaceous deltaic complexes and submarine fans are also prime exploration targets.

PRELIMINARY INTERPRETATIONS OF BMR AND INDUSTRY SEISMIC FROM SEDIMENTARY BASINS IN EASTERN AUSTRALIA

R.J. Korsch

As part of the National Geoscience Mapping Accord, a project entitled 'Sedimentary Basins of Eastern Australia' is being conducted jointly by BMR, the Geological Survey of Queensland (Department of Resource Industries), and the New South Wales Department of Mineral Resources (Geological Survey and Coal Geology Branches), with co-operation from CSIRO, universities, and industry. The aim is to make an integrated analysis of the Bowen, Gunnedah, and Surat Basins with emphasis on the sedimentary, structural, tectonic, and thermal histories of the basins, and thus to make a better assessment of the basins' economic potential for hydrocarbons. The sedimentary successions in the Bowen and Gunnedah Basins are Permo--Triassic; both basins are overlain unconformably by the Jurassic--Cretaceous Surat Basin.

Bowen Basin deep seismic reflection survey

To examine the geometry of the Bowen Basin and test various tectonic and structural models, BMR conducted a deep seismic reflection survey across the basin near Blackwater in late 1989. Reflection data (20 s TWT; 8-fold CMP; explosive source) were recorded along three lines totalling 254 km (see *BMR 90,* fig. 55, p. 116 for line locations). Seismic section BMR89.B01 is dominated by (?mid-Triassic) deformation controlled by thin-skinned thrusting on a series of listric faults which dip to the east and root in a major detachment that also dips to the east. The survey has indicated the geometry of contractional structures in the Bowen Basin, and section BMR89.B01 reveals anticlines that may be of interest to coalbed-methane explorers.

Gunnedah Basin deep seismic reflection survey

BMR carried out a similar survey across the Gunnedah Basin in the Boggabri--Manilla area in the first half of 1991 (*BMR Record* **1990/93**). A total of

253 km of new data to 20 seconds TWT and 8-fold CMP were recorded, along a single east--west traverse. Final stack data will be released on or before 31 December 1991. Gravity readings were made at 360 m intervals and the line was flown for aeromagnetics and radiometrics at heights of 500 ft and 3000 ft AGL.

Regional seismic synthesis (Bowen and Surat Basins)

Reinterpretation of the regional network of industry seismic lines was started in the Taroom--Mundubbera area near the northern edge of the Surat Basin. Applying sequence-stratigraphy, 15 reflectors on the seismic sections were initially selected for mapping.

Because well control is sparse, identification of the reflectors is poor. However, using the Cockatoo Creek 1 well on the eastern flank of the Taroom Trough, the reflectors selected in the pre-Triassic are tentatively identified as the bases of the following units (youngest first): Rewan Group, Baralaba Coal Measures, Gyranda Formation, Flat Top Formation, and Buffel Formation.

Identifying sequence boundaries in the Triassic relied on correlating reflectors with outcrop on the eastern flank of the Taroom Trough, in the Baralaba Sheet area. Six reflectors were recognised. The three upper ones correspond to intra-Moolayember Formation boundaries, two bracket the Clematis Sandstone, and the lower discontinuous reflector is in the Rewan Group. The base of the overlying Precipice Sandstone is an erosion surface on which the Surat Basin succession rests.

Two reflectors in the eastern Surat Basin were identified by correlation with outcrop and the shallow core hole DRD 6. The upper one is identified with the chamositic oolite member of the Evergreen Formation, and the lower, less well-defined event with the base of the Evergreen Formation. The oolite member is generally a strong marker horizon.

Mostly subtle stratal patterns, including onlap, truncation, and downlap, are associated with many of the reflectors and suggest that most of the major events mapped in the Bowen Basin succession are sequence boundaries. These boundaries will be studied further, particularly in the Triassic where the sediments are non-marine. Most Permian reflectors are related to cycles of truncation and succeeding overlaps; others are probably related to deltaic progradation accompanying the formation of coal swamps.

Major thickness changes and some sequence-stratigraphic pinchouts occur westwards in the transition zone between the Taroom Trough and the Comet Platform. In the area of gentle easterly dips off the Comet Platform the sequence-stratigraphic unit identified as the Clematis Sandstone pinches out to the west.

Extrapolation from the Taroom Trough to other provinces is difficult because of lack of continuous line ties, especially to the area between the Taroom Trough and Comet Platform. Marked thinning on the platform and a lack of well control make it hard to recognise sequences.

In the Denison Trough the bases of the following Permian units are probably sequence boundaries (youngest first): Rewan Group; Black Alley Shale; Freitag Formation/Ingelara Formation; mid-Aldebaran Sandstone

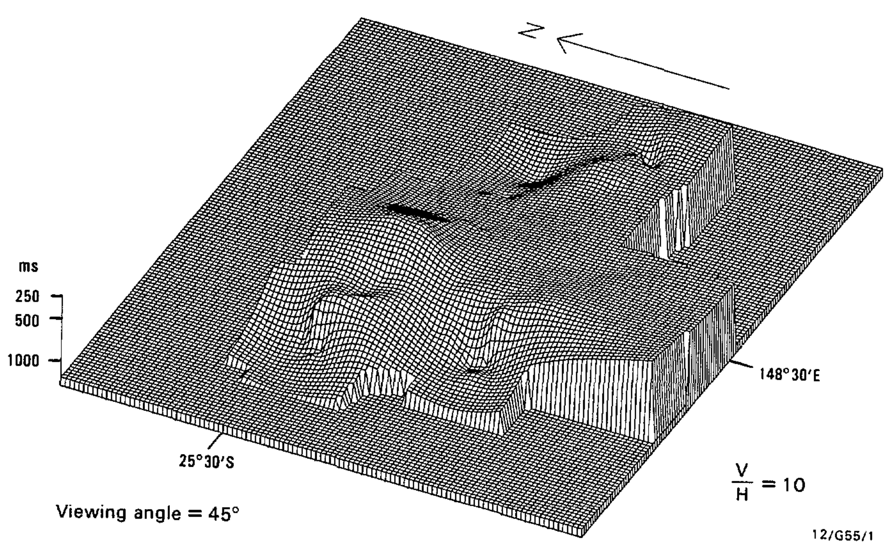

Fig. 7. Isometric mesh diagram showing the top of the Permian coal measures in a small network of interpreted seismic lines from the western Taroom and eastern Eddystone 1:250 000 Sheet areas (Denison Trough). The area of data covered is approximately 34 km north--south and 42 km east--west.

unconformity; Aldebaran Sandstone; Cattle Creek Formation; and intra-Reids Dome beds.

The lowest Permian reflector is an unconformity and sequence boundary in the Reids Dome beds. The first regional sequence boundary is at the base of the overlying marine sediments, separating, in the west, the Reids Dome beds from the Cattle Creek Formation, and, in the Taroom Trough, the Camboon Andesite from the Tiverton Formation. Two higher reflectors correspond to sequence boundaries that can be recognised in outcrop and well logs at the bases of the Freitag Formation and Black Alley Shale. The base of the Rewan Group is an obvious sequence boundary, confirming the numerous references in the literature to a regional scour surface at this level.

The interpreted seismic sections are being digitised, and, using *Petroseis* software, fence diagrams, isopach and structure-contour maps, and isometric three-dimensional models (Fig. 7) are being constructed.

DEVELOPMENT OF NEW PLAY CONCEPTS USING SEQUENCE STRATIGRAPHY: DEVONIAN--CARBONIFEROUS, CANNING BASIN, WESTERN AUSTRALIA

M.J. Jackson, J.M. Kennard, P.N. Southgate, P.E. O'Brien, & M.J. Sexton

Using the new concepts of sequence stratigraphy, we are interpreting and integrating subsurface data in the northern part of the Canning Basin (Fig. 8) to provide a better understanding of basin evolution and petroleum prospectivity. These data comprise company shallow seismic, BMR deep seismic, drillhole

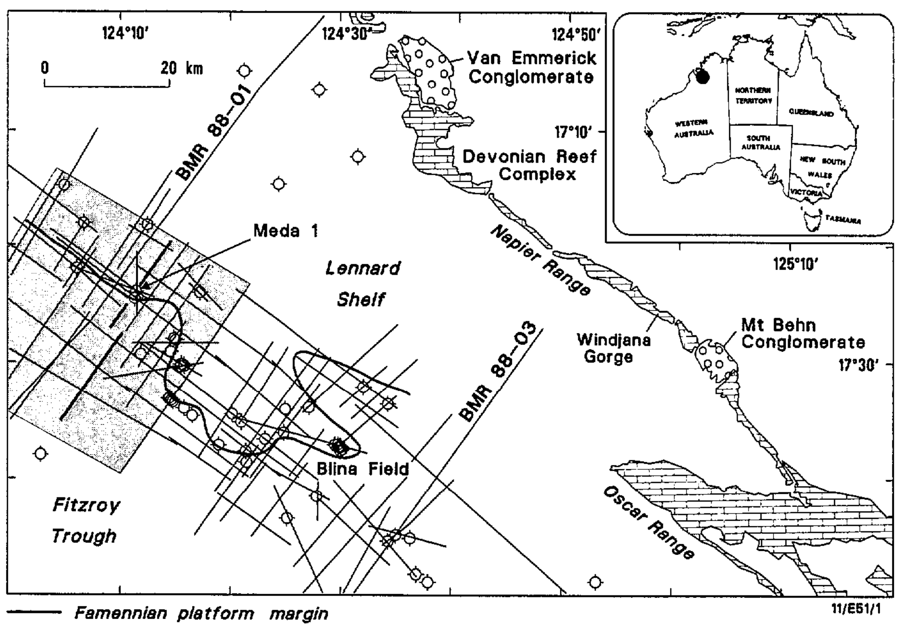

Fig. 8. Regional seismic grid and outcropping Devonian reef complex, northern Canning Basin. Detailed study area is shaded; the screened, broken line denotes the position of the seismic lines shown in Figure 10.

information, and biostratigraphic reassessment of available palaeontological information. The main outcomes are:

-- more confident correlation between seismic and well data
-- recognition of extensive Late Devonian lowstand deposits along the northern edge of the Fitzroy Trough

-- identification of several new petroleum play concepts

-- better understanding of the evolution of subsurface and exposed reef complexes, and

-- development of a detailed relative sea-level curve for Late Devonian--Early Carboniferous time

As the first stage of the Canning Basin Project a detailed sequence-stratigraphic interpretation of about 1200 line-km of seismic and 40 wells was undertaken for the central part of the Lennard Shelf and adjacent Fitzroy Trough. At least 24 'Vail-type' sequences have been identified in this area; 16 Devonian--Carboniferous sequences are shown in Figure 9. Even in such a small area, this new style of genetic approach is solving problems of correlation that have arisen from using traditional lithostratigraphic techniques. For example, we are now able to link genetically five diachronous lithostratigraphic units near the contact between the Nullara Cycle and the overlying Fairfield Group. Our

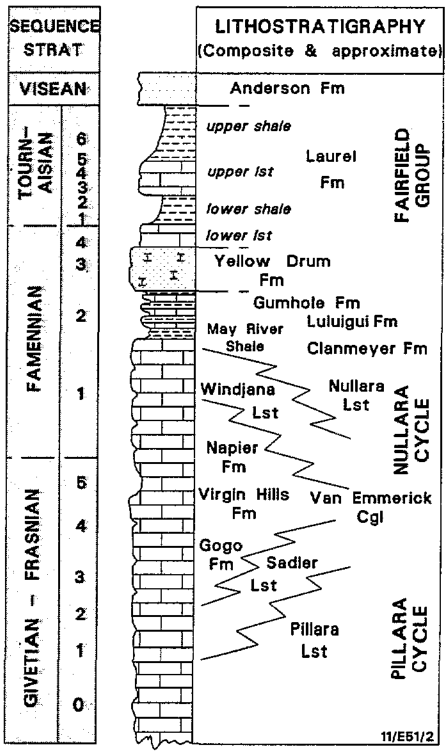

Fig. 9. Sequence-stratigraphic units recognised in this study compared with some of the traditional lithostratigraphic units.

Famennian 2 sequence comprises three systems tracts: lowstand clastics (Clanmeyer Formation), transgressive calcareous shales (May River Shale), and highstand carbonates (variously referred to as the Windjana Limestone, Nullara Limestone, and Gumhole Formation). Ultimately this sequence analysis will generate a genetic stratigraphic framework to systematically relate the plethora of existing lithostratigraphic units.

Detailed sequence analysis of the Devonian--Carboniferous succession has enabled us to identify and map systems tracts and to distinguish two phases of sedimentation: (1) a Givetian--Famennian **reef-rimmed platform complex**, and (2) a **Famennian--Tournaisian ramp complex** (Fig. 10).

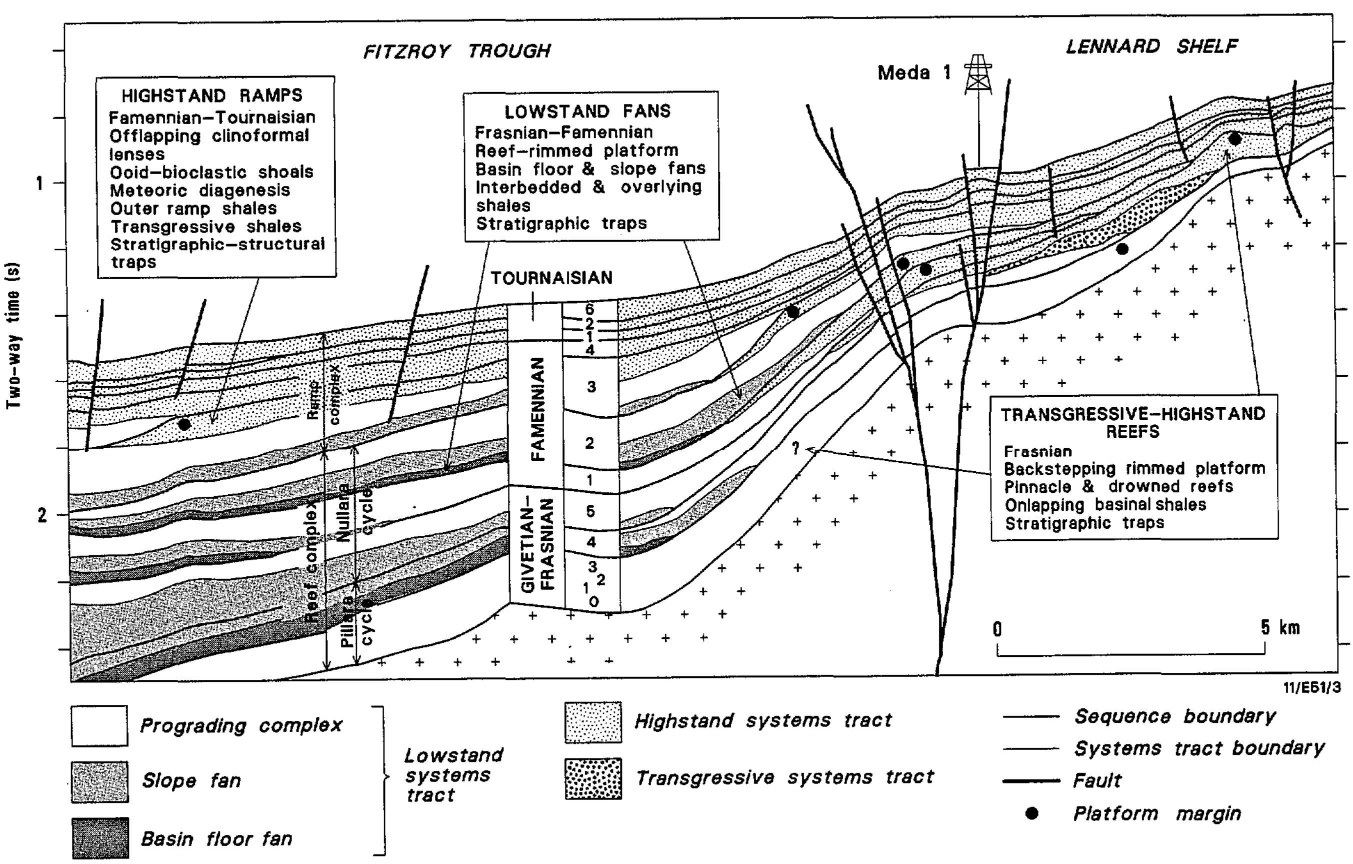

Fig. 10. Line drawing of seismic sections showing new petroleum plays, sequences, and systems tracts. Location of seismic sections shown by a screend broken line in Figure 8.

The **reef complex** consists of two cycles of progressively onlapping sequences; the lower Pillara cycle displays successively backstepping platform margins (Givetian--Frasnian sequences 0 to 4), whereas the upper Nullara cycle displays successively advancing platform margins (Givetian--Frasnian sequence 5 and Famennian sequences 1 and 2). Each sequence is characterised by reciprocal lowstand--highstand sedimentation: lowstand clastic-rich sediments restricted to the basin, and highstand carbonate sediments across the platform and platform margin. The lowstand deposits consist of three systems: *basin floor fan, slope fan,* and *prograding complex.*

The *basin floor fans* form sheets tens of kilometres across and 40--100 m thick that onlap the basal sequence boundary basinward of the platform margin. Their upper surfaces are commonly defined by reflectors with high impedance contrasts. These fans were probably deposited during periods of relative lowstand when the platform was exposed, and are likely to comprise terrigenous sands fed by incised river systems whose proximal deposits are preserved locally on the platform (e.g. conglomerates in Meda 1 and Yarrada 1, and conglomerate outcrops in Fig. 8).

The *slope fans* form thick wedges above the basin floor fans and pinch out against the platform slope. They generally have a mounded seismic character, and locally contain distinct 'gull-wing' reflectors that indicate channel-levee complexes within the mounds. The flanks of the mounds display subparallel reflectors interpreted as distal turbidite aprons. The slope fans consist of siltstone, shale and minor sandstone, and their upper faces are prominent downlap surfaces.

The *prograding complex* forms a thick progradational and aggradational lens which onlaps the basal sequence boundary at or near the platform margin, and downlaps basinward, onto the slope fan. In places this downlap surface climbs basinward, suggesting the presence of shingled turbidites at the toe of the prograding complex. The prograding complex is commonly the most volumetrically important depositional system within the reef sequences, and is characterised by well-defined sigmoidal clinoforms. It has been penetrated in several wells; in the Famennian 2 sequence the distal part consists of calcareous siltstone and minor sandstone (Lukins 1), and the proximal parts comprise micritic pelletal carbonates (Mariana 1, Yarrada 1).

Highstand reef carbonates are volumetrically minor compared to the lowstand deposits, but have been intersected in many wells. Transgressive deposits are generally below seismic resolution. The highstand deposits have oblique progradational geometries at the platform margin, parallel reflectors across the platform, and they downlap onto the prograding complex. They comprise back-reef, reef, and fore-reef carbonates.

The Famennian--Tournaisian **ramp complex** comprises successively offlapping, lenticular sequences (Famennian 3 to Tournaisian 4) overlain by two progressively onlapping tabular sequences (Tournaisian 5 and 6). Each offlapping sequence consists of a lowstand clastic wedge with sigmoidal internal reflectors, and a more laterally extensive, mixed carbonate and clastic highstand deposit with oblique internal reflectors. Lowstand slope fans are restricted to Famennian sequences 3 and 4 which mark the transition from a reef-rimmed platform to a ramp. These fans are overlain by lowstand prograding complexes which are the sole lowstand component of the overlying ramp sequences. The highstand systems tracts prograde several kilometres across their lowstand counterparts. In contrast, the onlapping tabular ramp sequences comprise relatively thin lowstand prograding complexes, and thicker mixed carbonate and clastic highstand deposits.

Petroleum plays

This analysis has identified three petroleum plays (Fig. 10): (1) offlapping **highstand carbonate--clastic ramps** of Famennian and Tournaisian age; (2) **lowstand basin floor and slope fans** of Frasnian and Famennian age: and (3) backstepping **transgressive and highstand pinnacle and barrier reefs** of late Frasnian age (Pillara cycle). Previous exploration has been focused mainly on structural closures in the advancing platform of the Famennian Nullara Cycle. Out of 22 wildcats with reef targets, 17 had primary Famennian targets, 5 had primary Frasnian targets, and 3 had secondary Frasnian targets; however, none are considered to have been valid Frasnian reef tests.

The **highstand-ramp play** occurs in an elongate belt near the northern margin of the Fitzroy Trough. It consists of ooid and/or bioclastic shoals which grade basinward into outer-shelf and slope bioclastic micritic carbonate and calcareous siltstone, and pass landward into inner-shelf and coastal micritic carbonate, siltstone, and possible evaporite. Outer-ramp facies and underlying and overlying transgressive shales are potential source rocks. Potential seals are the overlying progradational inner-shelf and coastal facies, or transgressive shales. Reservoir quality is controlled by primary porosity and porosity generated by meteoric diagenesis and dolomitisation during subsequent lowstands. Although this is chiefly a stratigraphic trap, combined stratigraphic-structural traps are likely as a result of Carboniferous faulting. Analogs of this highstand ramp play are the Permian Grayburg and San Andres Fields of the Delaware--Midland Basin, USA, and the Jurassic--Cretaceous fields of the Neuquen Basin, Argentina. This play is similar to the older Yellow Drum Sandstone plays on the Lennard Shelf (a secondary production interval at Blina), but differs in that it is primarily controlled by depositional facies and the porosity trends may be easier to predict.

The **lowstand-fan play** is also along the northern edge of the Fitzroy Trough. Potential reservoirs are turbidite sand sheets within the basin-floor fans, and sand channels flanked by levee complexes in the slope fans. Potential source rocks and seals are provided by interbedded shales and distal deposits of the overlying and underlying prograding complexes. Up-dip pinchouts of the fans are obvious stratigraphic traps. Since many of the Frasnian fans lie deep (2 s TWT), the Famennian fans offer the best hydrocarbon potential. Analogs of this play are the lowstand fans of the North Sea and Gulf Coast.

Transgressive and highstand pinnacle and barrier reefs of late Frasnian age represent a potential play along the southwestern margin of the Lennard Shelf. They were deposited during a period of platform drowning and backstepping, and could be sourced and sealed by onlapping basinal shales. Their reservoir potential is questionable, as extensive submarine cement occurs in equivalent outcropping reefs and in younger Famennian reefs intersected in wells. However, most of these wells were located on structural closures within 'flower-like' fault structures, and cementation may not be as pervasive in reefs away from these fault conduits. This is consistent with the preservation of primary porosity within Frasnian reefs in Needle Eye Rocks 1 (Kemp & Wilson, 1990: *APEA Journal*, **30**, 280--289) on the inner Lennard Shelf southeast of the study area. Although Frasnian platform-margin reefs can be identified in currently available seismic data on the Lennard Shelf (e.g. Fig. 10), pinnacle reefs similar to those identified in outcrop have not been recognised in this area. High-resolution seismic (similar to that documented by Kemp & Wilson, 1990) may facilitate their detection in other areas. Analogs of this reef play are the highly productive Givetian--Frasnian reefs in Western Canada, and Miocene pinnacle reefs in the Salawati Basin, Irian Jaya.

PALAEOGEOGRAPHIC, PALAEOENVIRONMENTAL, AND AGE CONTROLS ON THE COMPOSITION OF PETROLEUM SOURCE ROCKS AND THEIR DERIVED OILS

R.E. Summons & T.G. Powell

Many factors determine the initial composition of organic matter in source rocks and their derived oils. The most important ones appear to be the primary (photosynthetic) source organisms, bacterial degradation during and just after deposition, and lithology. For the various depositional environments in which organic matter accumulates, one can predict the range of kerogen types and, to an increasing extent, the oil compositions and the biological markers that might be present.

Advances in molecular palaeontology have recently contributed to dramatic improvements in our appreciation of the origins of specific chemical fossils in sediments and crude oils. These comprise isotopic anomalies and molecular fossils such as hydrocarbons; e.g. if a fossil hydrocarbon can be accurately traced to its precursor lipid, and thence to a designated organism or group of organisms, it may also be a useful marker of the special environmental conditions favoured by those organisms. The relative abundances of a combination of 'signature' hydrocarbons in an oil can then be used in conjunction with palaeogeographic data to specify the likely environment of its source beds. BMR's organic geochemistry research program has been expanding the list of reliable signature hydrocarbons and also improving the analytical techniques used to measure them.

Fossil hydrocarbons can be roughly discerned as having their origins from any of three main evolutionary lineages of organisms: eubacteria, archaebacteria, and eukaryotes. Those coming from the simpler life forms (eubacteria and archaebacteria) generally indicate past activity of some particular biogeochemical process such as methanogenesis or sulfate-based metabolism. These can be particularly useful as palaeoenvironmental indicators. Aryl isoprenoids, e.g., come from green sulfur bacteria which need light and hydrogen sulfide to thrive.

Thus, finding these biomarkers is an indication of a stratified, sulfate-containing water body with anoxic waters extending into the photic zone.

Molecules that originate from eukaryotes, specifically planktonic algae and vascular plants, can sometimes be traced to a very select group and thus potential environment and age markers. Particularly diagnostic hydrocarbons of this type include the 4-methyl steranes arising from Dinophyceae which are found in Mesozoic and Cainozoic oils but are absent from Palaeozoic oils. These can be especially useful because there are distinct patterns of steroid hydrocarbons that arise from marine and non-marine dinoflagellates. Another informative compound is 24-n-propylcholestane which seems to come exclusively from marine algae and therefore betrays marine source beds. Oleanane which comes from triterpenoids specific to angiosperms is usually associated with Late Cretaceous and Tertiary oils with land-plant input.

Despite the obvious power of petroleum biological markers to identify the contributions of organisms with particular biosynthetic pathways, the simple presence or absence of specific compounds is only rarely diagnostic of a depositional environment or age. Rather, it is different combinations of compounds and their relative abundances which give the most reliable information. In the non-marine regime, the bulk petroleum composition can be used to infer environments ranging from floodplain and delta swamp through freshwater lakes to hypersaline lakes with either sulfate or carbonate water chemistry. Similar predictions can be made for the marine regime where the principal variations relate to degree of terrigenous input and the lithology -- clastic, carbonate, or evaporitic. The primary biological and lithological imprints are usually quite faithfully preserved in immature to moderately mature sediments; however, we need to be more circumspect when dealing with oils because of the possibility of multiple sources and other changes induced by water washing and biodegradation.

We have been applying these concepts in collaborative studies of petroleum seeps and coastal bitumens from South Australia, Victoria, and Tasmania. The studies have shown that there are at least two distinct types of bitumens normally found along the southern margin. Biomarkers reveal that one of these bitumens is from marine source beds and is Mesozoic or younger. The studies also confirm that the other common bitumen type, previously described by D. McKirdy and co-workers from the numerous strandings along the Otway coastline, is lacustrine and from a probable Tertiary source rock.

Carbon isotope measurements ($\delta^{13}C$) on crude oils constitute a quick but relatively crude means of correlation. New mass spectrometry equipment now installed at BMR enables us to isotopically characterise individual hydrocarbons in oils, source-rock extracts, condensates, and natural-gas samples. Data of this type are currently being used to give much improved confidence in correlation studies on both oils and gases and to make maturity assessments on condensates. Carbon-isotope measurements are also being combined with information on chemical structure to understand and define the origins of hydrocarbons in natural samples more effectively.

CURRENT DEVELOPMENT OF THE BMR NATIONAL PETROLEUM DATABASE

P.E. Williamson, S.G. Radke, & E. Petrie

Development of the constituent databases in the BMR National Petroleum Database (Fig. 11) is now receiving a high priority. The databases were originally compiled from data lodged by companies in accordance with legislation, and were later augmented from BMR studies. Australia, unlike many other countries, requires explorers under the Petroleum Search Subsidy Act (PSSA) and Petroleum (Submerged Lands) Act P(SL)A, to lodge basic and interpretive data with the Government. A large percentage of these data, particularly from most offshore operations, can be made publicly available within specified time frames.

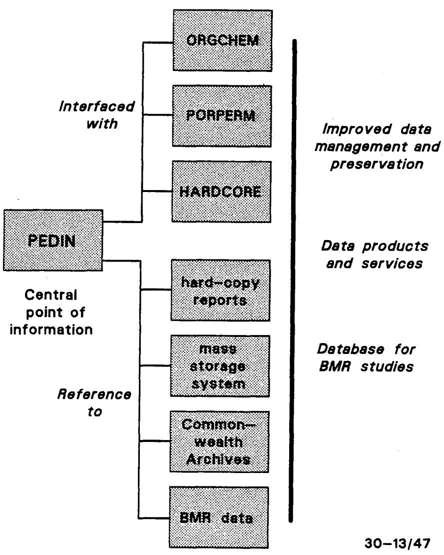

Fig. 11. The elements of BMR's National Petroleum Database.

The physical and digital database, data from other sources, and various second-order digital databases constitute the BMR National Petroleum Database. The data include cores & cuttings and reports, geophysical and well-log reports and data, and the results of specialist studies. These data help support the exploration that underpins Australia's petroleum production, annually worth $7.5 billion. The National Petroleum Database is designed to ultimately allow records of the various physical and digital components to be accessed via the PEDIN database.

PEDIN is an *Oracle* relational database containing basic information and statistics on petroleum exploration and development drilling and geophysical surveys carried out in Australia. PEDIN currently references over 6000 wells, 1985 BMR holes, and 3400 geophysical surveys, and occupies about 25 megabytes on BMR's Data General MV/20000 mainframe. PEDIN has been under development for seven years and has started to realise substantial benefits. This is partly a result of its maturity, as it now contains more comprehensive datasets as well as software to access and manipulate them. The current 'information atmosphere', though, is both nurturing, and demanding much of, PEDIN and databases like it. Information technology is booming and users are requiring more. Thus, from being primarily a digital summary of hard-copy report data PEDIN has become a fundamental component of the growing national Database, which now extends from paper copy to digital data stored in a mass storage system.

The **ORGCHEM** database can be accessed via PEDIN or separately. It contains data on the organic chemistry of oils and on source bed occurrence from some 760 wells.

PORPERM can also be accessed either through PEDIN or separately. It contains petrophysical data including porosity, permeability, lithology, and grain-size from 551 wells in Australia and Papua New Guinea (130 offshore and 421 onshore), along with 6278 sets of core-plug data. Both ORGCHEM and PORPERM are available as Oracle Export and ASCII files.

The Petroleum Titles map of Australia is available in Intergraph design file, DXF file, or SIF file formats. It shows titles, boundaries, pipelines, fields, basins, coastlines, and bathymetry.

The physical part of the Database contains over one million rock samples from wells, around 9000 geological and geophysical reports (including seismic data), periodic reports of exploration activity and statistics, and the results of BMR's Continental Margins and Onshore Petroleum basin studies. The **HARDCORE** database details core-&-cuttings samples and reports.

In addition to the data in Canberra, over 500 000 digital tapes, mainly of seismic field and processed data, are stored at the Villawood Archives in Sydney.

One present direction for BMR's petroleum databases is the development of the archival mass storage system for storing data such as digital well, log, shot-point, gravity, magnetic, and processed seismic data. Non-confidential data stored on this system are available for copying. A second area of development aims at providing the results of BMR regional studies as layered digital databases via the Petroseis system. These developments are designed to provide a comprehensive and convenient database for the petroleum explorer.

ENHANCED OIL RECOVERY: RESULTS AND OPPORTUNITIES

S.R. Le Poidevin & D.J.D. Wright

A recently published NERDDC-funded study of the potential for enhanced oil recovery (EOR) in Australia has identified potential reserves recoverable from onshore and offshore fields by thermal, miscible, immiscible, and other enhanced-recovery techniques. The study was carried out at the request of industry, research organisations, and professional societies at the initiative of Mr John White, former Assistant Director of the Petroleum Branch at BMR. The work was done by oil companies operating in Australia and the State Mines Departments, with Mr Reg Thomas and the Centre for Petroleum Engineering at the University of New South Wales as consultants on economic and technical aspects respectively.

Information was requested on all oil accumulations in Australia, the aim being to obtain the minimum data required to carry out screening studies. An incidental spin-off was the first set of comprehensive data on oil-in-place and oil reservoir parameters in Australia. All the data were passed through technical screening parameters established in several overseas studies, in particular those of the National Petroleum Council (NPC) in the United States. Two sets of criteria were used: an Implemented Technology set, representing the consensus view of technology as at the end of 1984 (the most recent NPC study), and an Advanced Technology set, representing a consensus of expert views of near-term hypothetical future advances in technology (i.e. a target for research). The technical screening established the technically recoverable oil-in-place in Australia for each of the EOR processes.

All the reservoirs assessed as technically suitable for a given enhanced oil recovery process were then simulated with appropriate models and oil production rate, and economic forecasts based on reservoir location and Australian economic parameters were generated. This established the economically recoverable oil-in-place at a range of crude prices.

The results of the study have now been published and detailed results for individual fields have been presented to all oil companies operating in Australia. The published report on the study is available from BMR (*Record* **1991/20**, price $500).

POSTER SESSION

BMR'S NEW STABLE-ISOTOPE FACILITY

R.E. Summons

BMR recently commissioned new mass spectrometry equipment for geochemical studies. The equipment will be used for high-sensitivity, high-precision ratio measurements on carbon, oxygen, sulphur, and hydrogen isotopes and will enable us to study the isotopic composition of materials that are only available in trace amounts. These include microscopic diamonds, microsamples of carbonate minerals and microfossils, and traces of sulfate and sulfide present in carbonate matrices and sediment porewaters. The equipment will also enhance our capacity to accurately analyse minerals and groundwaters.

An important new provision is the capacity to measure the isotopic composition of individual hydrocarbons from sediments, oils, condensates, and gases.

The equipment consists of a high-precision isotope ratio mass spectrometer *(Finnigan MAT-252)* linked to a gas chromatograph via a high-temperature combustion furnace. Thus we can separate complex mixtures of hydrocarbons into their individual components, combust them and then analyse the resulting CO_2 stream for its ^{13}C content. Diversion of the gas chromatograph effluent to a second mass spectrometer *(Finnigan Incos 50)* allows us to reliably identify the compounds being analysed as well as establish their purities. To our knowledge, this instrument configuration is a world first. In addition to this mode, either mass spectrometer can operate in a 'stand alone' mode; the *Finnigan 252* has the capacity for conventional isotopic measurements, using an automatic multi-port inlet system for batches of gas samples and a microsample inlet system for use when only traces of material are available.

Isotope measurements on bulk oils or on the saturate and aromatic hydrocarbon fractions of crudes is a very rough means of correlating oils with their putative source rocks or assigning marine vs. terrestrial origins to oils. With the new equipment a much higher degree of precision will be possible because the comparisons will be made on many individual components. Isotopic data will also be used to determine more effectively the origins of individual hydrocarbons in oils and source rocks and hence improve our understanding of the processes involved in petroleum formation.

For the first time, we will be able to obtain reliable source and maturity information on natural gases and condensates through isotopic means. This is because cracking of the larger liquid hydrocarbons into the gaseous C_1--C_5 hydrocarbons is accompanied by an isotope effect. The isotopic signatures of the large n-alkanes are relatively close to the total-organic-carbon of the source, whereas the smaller n-alkanes are shifted systematically as a function of maturity. Biogenic and thermogenic gases may also be distinguished, and methane from difference sources and/or reservoirs may be characterised more readily.

Isotopic measurements made at the molecular level promise to revolutionise many aspects of petroleum geochemistry, organic geochemistry, and environmental studies.