

# Petroleum Geology of South Australia

## Volume 4: Cooper Basin

*edited by:*  
**D.I. Gravestock, J.E. Hibburt and J.F. Drexel**



**PRIMARY INDUSTRIES  
AND RESOURCES SA**

# **The petroleum geology of South Australia**

## **Volume 4: Cooper Basin**

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**D.I. Gravestock, J.E. Hibburt and J.F. Drexel**

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**PRIMARY INDUSTRIES**  

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## **Petroleum Group**

Primary Industries and Resources South Australia

101 Grenfell Street, Adelaide

GPO Box 1671, Adelaide SA 5001

Phone National (08) 8463 3201

International +61 8 8463 3201

Fax National (08) 8463 3202

International +61 8 8463 3202

E-mail mesa@msgate.mesa.sa.gov.au

Web site www.mines.sa.gov.au

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# PREFACE

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This summary of the petroleum geology of the South Australian portion of the Cooper Basin forms the fourth volume of *The Petroleum geology of South Australia* series and follows on from *Volume 1: Otway Basin* published in 1995, *Volume 2: Eromanga Basin* (1996) and *Volume 3: Officer Basin* (1997). The remaining volumes will be published over the next few years and are:

Volume 5: Stansbury, Arrowie and Warburton Basins

Volume 6: Duntroon and Bight Basins

It is intended that the volumes be 'fit for purpose' and, consequently, this has resulted in some compromise on print quality and cost. To avoid delays in publication, the volumes are not being indexed. However, this approach enables each volume to be updated and republished quickly as significant new data come to hand. Seismic contour maps and image-processed data which include the latest open file interpretations are continuously available on request from PIRSA's seismic interpretation digital database.

Any and all comments on this volume on the Cooper Basin are welcome and will assist us in improving future publications. Please address correspondence to the Director, Petroleum Group, PIRSA. Further information is available through our World Wide Web site.



# INTRODUCTION

## BASIN OUTLINE

The Cooper Basin forms the most significant element of Australia's largest onshore oil and gas province. Since the discovery of natural gas at Gidgealpa in 1963 and oil at Tirrawarra in 1970,  $229 \times 10^9 \text{ m}^3$  (8.2 tcf) of recoverable raw gas and  $6.9 \times 10^6 \text{ kL}$  (43.9 mmstb) of recoverable oil<sup>1</sup> have been found in South Australia at 1 January 1998. A total of  $129 \times 10^9 \text{ m}^3$  (4.6 tcf) of gas and  $4.6 \times 10^6 \text{ kL}$  (29.1 mmstb) of oil have been produced to date. The Tirrawarra Field contains 80% of known oil reserves; one-third of South Australia's Cooper Basin gas reserves are in the Moomba and Big Lake gas fields. Pipelines supply Cooper Basin gas to Adelaide and Sydney as well as a number of regional centres, ethane to Botany Bay, and a liquids pipeline carries oil, condensate and liquefied petroleum gas (LPG) to Port Bonython.

The Cooper Basin is a Late Carboniferous to Middle Triassic, non-marine sedimentary basin which underlies the desert region of northeastern South Australia and South-West Queensland. One-third of the basin ( $35\,000 \text{ km}^2$ ; 13 500 square miles) is in South Australia; the unconformity at its upper surface varies in depth from 970 to 2800 m while the base of its deepest trough reaches ~4400 m below sea level. As shown in Figure 1.1, the Cooper underlies the southwestern Eromanga Basin (or Great Artesian Basin, a major water resource). The Eromanga Basin is Jurassic to Cretaceous in age and contains a number of small to medium sized oil fields. There is one small population centre at Moomba (a fly-in fly-out camp) which is the hub of the region's gas treatment and gas and oil pipelines. A map of oil and gas fields and pipelines is shown in Figure 1.2 while infrastructure is described more fully in Chapter 4.

## SEISMIC AND WELL COVERAGE

Based on 40 years of exploration and development, including drilling 1200 wells with an average success rate of ~30%, leading to the discovery of 121 gas and 25 oil fields (at 31.12.97), it may seem reasonable to assume that the Cooper Basin in South Australia is a mature petroleum province. However, although this assumption may be true for petroleum production licence areas (PPL; ~8000 km<sup>2</sup> (3100 square miles) or <25% of the basin in South Australia), it

<sup>1</sup>Number refers to Cooper oil only. Total recoverable oil (Cooper and Eromanga) in SA is  $17.5 \times 10^6 \text{ kL}$  (110 mmstb). See Chapter 14 for recovery factors.

does not apply to the main portion of the Cooper and overlying Eromanga Basins which Primary Industries and Resources South Australia (PIRSA) considers to be relatively underexplored. Within PPLs (excluding those in the sparsely drilled Nappamerri Trough, Fig. 2.6) there are  $7 \text{ km}^2$  (1750 acres) on average surrounding each well drilled. In contrast, outside PPLs, there are  $66 \text{ km}^2$  (16 500 acres) on average surrounding each well drilled. In simple terms, the Cooper Basin is about nine times more poorly explored outside production licences than within them, based on well density.

The distribution of seismic lines has become increasingly focused over the past four decades as oil and gas discoveries demanded more accurate structural delineation for locating appraisal and development wells. As shown in Figure 1.3, ~80 000 km of two-dimensional (2D) seismic have been recorded and, in the past six years, 15 three-dimensional (3D) surveys. Figure 1.4 provides a

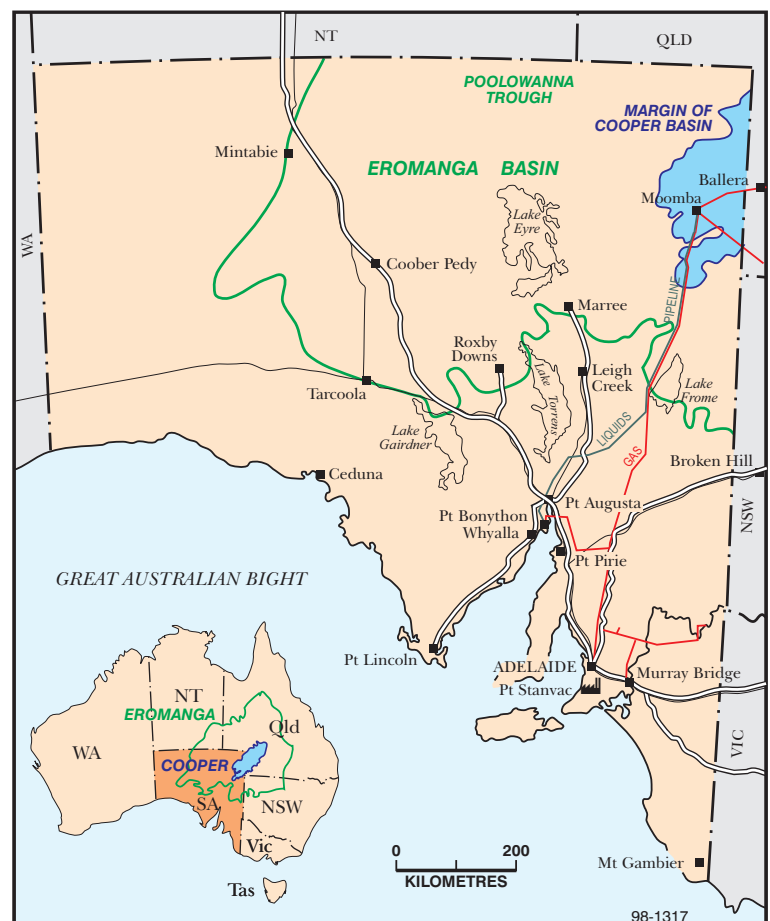


Fig. 1.1 Location map of Cooper and Eromanga Basins in South Australia.

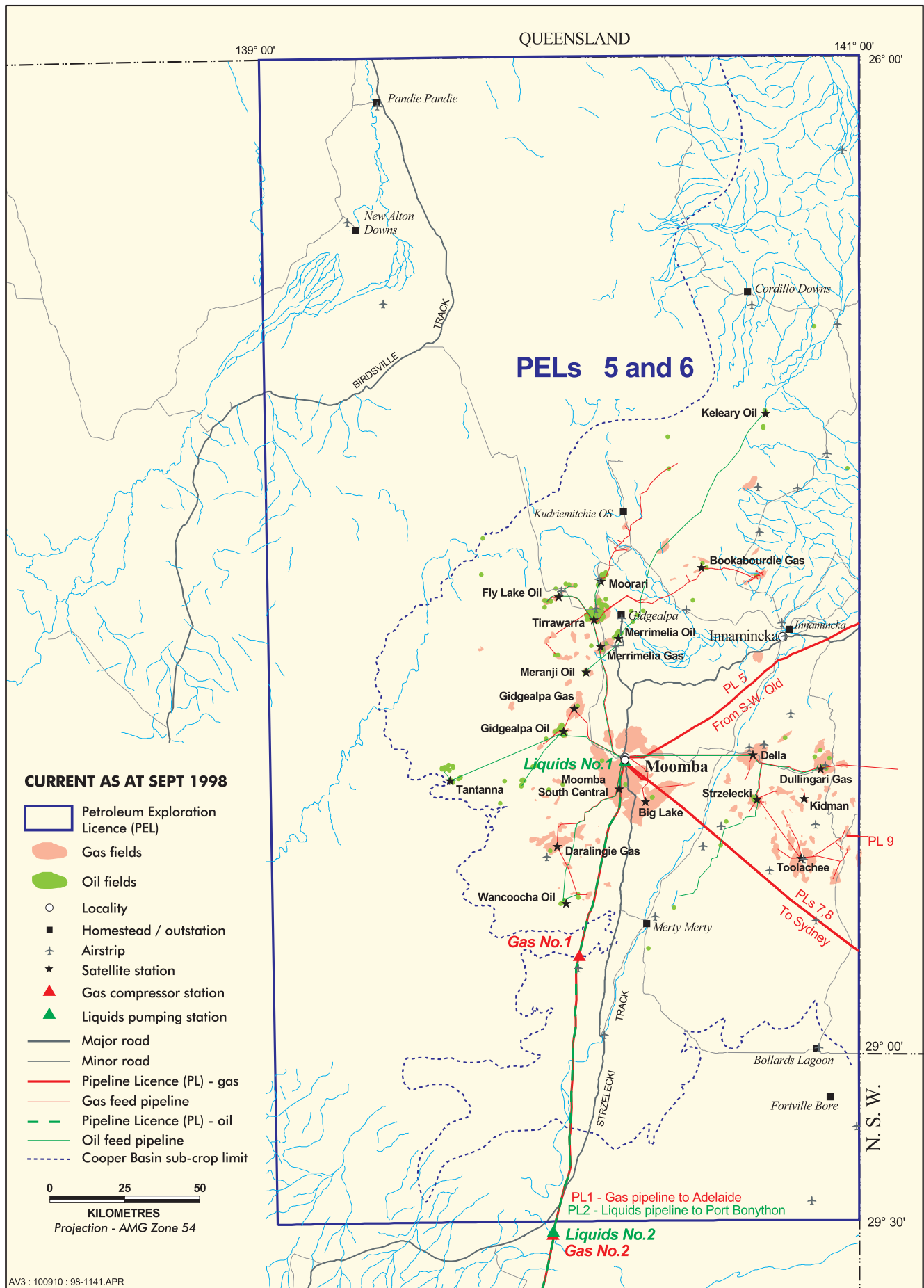


Fig. 1.2 The Cooper Basin in South Australia showing locations of oil and gas fields and major pipelines.

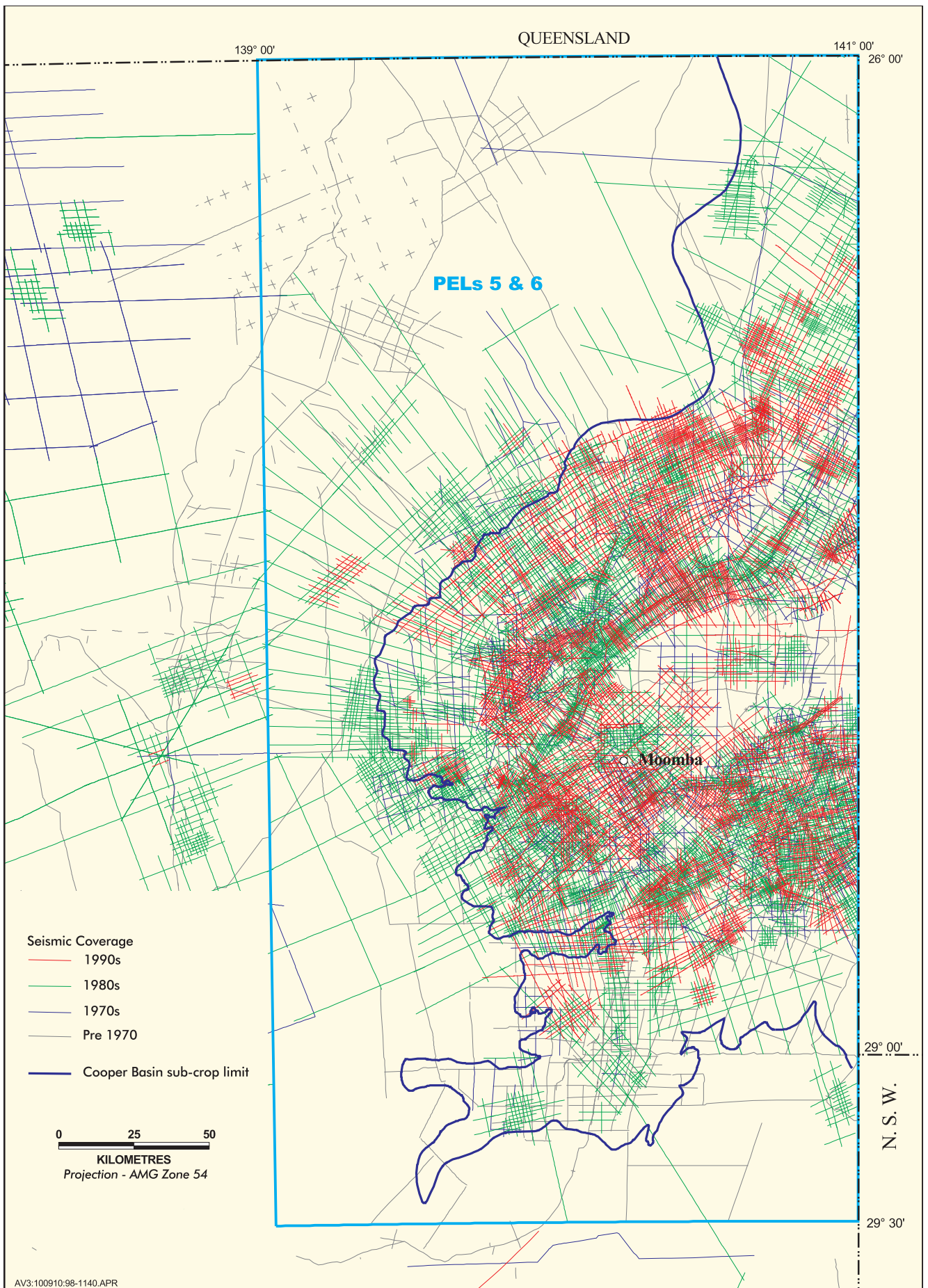


Fig. 1.3 Cooper Basin seismic coverage 1957–97.

breakdown of seismic line distribution in each of the four decades since recording began. Seismic lines recorded between 1957 and 1969 were of a reconnaissance nature and relatively long and widely spaced (Fig. 1.4a). In the decade 1970–79, the Cooper Basin margin became increasingly well defined and seismic surveys concentrated on locating major gas-bearing structures within the basin (Fig. 1.4b). The discovery of Mesozoic oil in 1978 in good quality Eromanga reservoirs and rising oil prices in the early 1980s encouraged completion of an oil and gas liquids pipeline from Moomba to Port Bonython (Fig. 1.1). Closely spaced seismic grids were recorded in this period to locate subtle Mesozoic structural traps (Armstrong and Barr, 1986). During the 1980s long lines were also recorded across the western and southwestern Cooper Basin margin to locate basin edge stratigraphic plays (Stanmore and Johnstone, 1988), and Australia's first 3D survey was recorded at Cuttappirrie (Fig. 1.4c).

In the past decade little seismic has been recorded outside the Cooper Basin but coverage inside increased markedly with the recording of 3D surveys totalling 3100 km<sup>2</sup> (1200 square miles), notably at Moomba, Toolachee, Dullingari–Burke, Merrimelia and Pondrinie, shown by the solid red areas in Figure 1.4d. At the same time, modification of parameters used in 2D seismic recording has led to an improvement in bandwidth at the high frequency end with a corresponding increase in resolution (Hughes and Fitzgerald, 1995).

Seismic exploration over the past 40 years has focused downward from regional lines, through grids for prospect definition, to 3D for prospect element delineation. There has been a recognition that not only are undrilled prospects relatively small, but prospect elements such as fluvial channels which cross large structures are also small (e.g. Mackie *et al.*, 1995). Reservoirs are stacked vertically but many tend to be laterally restricted and have a stratigraphic trap component. From one point of view it could be concluded that focusing on play elements in particular areas leaves other areas relatively lightly explored.

## FUTURE OPPORTUNITIES

Several methods of assessing undiscovered Cooper Basin reserves are described in Chapter 14. Middle of the range estimates suggest that 60 229 x 10<sup>9</sup> m<sup>3</sup> (2 tcf) of recoverable gas and 5.4 x 10<sup>6</sup> kL (34 mmstb) of recoverable oil remain to be discovered. While newly discovered fields tend to be small ( $\leq 280 \times 10^6$  m<sup>3</sup> or 10 bcf), the Cooper Basin Joint Venture has made gas–condensate discoveries of medium size in the last two years e.g. Goyder 2 (Santos Ltd, 1997a), Dorodillo 1 (Santos Ltd, 1997b) and Cabernet 1 (Santos Ltd, 1998).

Santos Ltd has held exploration tenements over the Cooper Basin continuously since 1954. Petroleum Exploration Licences (PELs) 5 and 6 were originally more extensive (see Ch. 2), but relinquishments have reduced the area to ~73 000 km<sup>2</sup> (~28 190 square miles). Farmins were initially the method of obtaining an interest, but company acquisition has now become the most common means. However, this is about to change following the expiry of PELs 5 and 6 in February 1999. Both business and governments are now rising to the challenge of making Australia more competitive. The South Australian

Government has decided that acreage in the Cooper Basin region, exclusive of production (and potentially retention) tenements will be made available for competitive bidding on expiry of PELs 5 and 6. In order to facilitate this process, the legislative regime is under review, data issues are being addressed and the necessity of access to existing processing plant and associated infrastructure is being considered and data and land access issues are being addressed.

## Regulatory regime

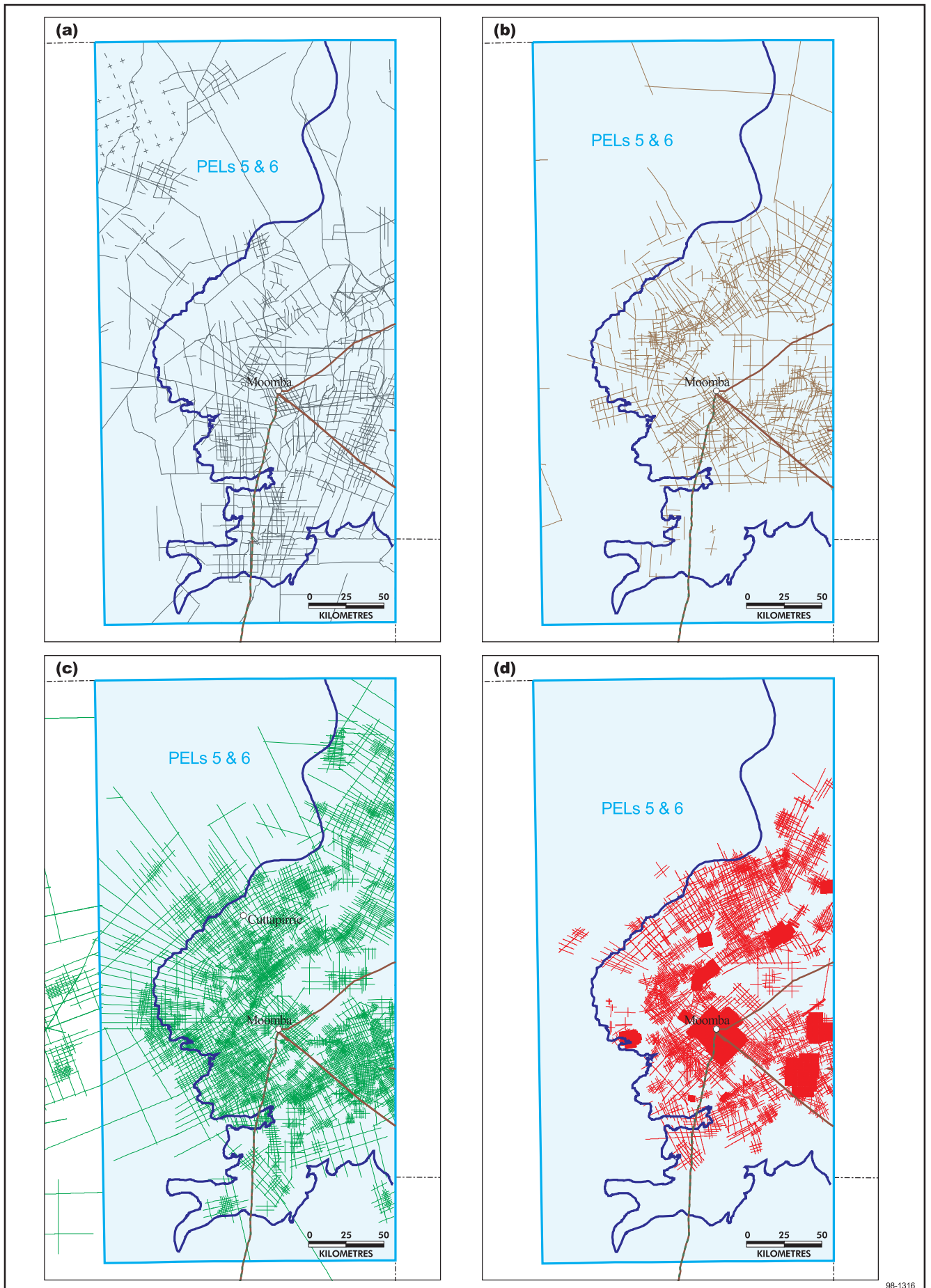
- A green paper on a review of the *Petroleum Act 1940* was released in mid 1997.
- A Bill for a new Petroleum Act is scheduled to be introduced into Parliament during 1998.
- Objective regulation is being implemented with the willing assistance of industry and following valuable contributions from community interest groups.
- Amendments to the *Petroleum Act* and other legislation with regard to native title issues are under consideration.

## Access to infrastructure and markets

- An analysis has been released of the estimated cost of independent processing and transporting petroleum compared to tolling through existing facilities (see Ch. 13).
- Access provisions under the federal *Trade Practices Act 1974* possibly apply to facilities such as the Cooper Basin infrastructure and there is pressure to clarify this issue.
- The South Australian Government considers upstream access a State issue and would prefer that industry introduces self-regulation via a public code setting out conditions under which gas would be tolled through existing petroleum processing and transportation facilities and including binding arbitration in the event of a dispute.
- A right of access is already provided to sales gas transmission pipelines in South Australia and legislation implementing the agreed national pipeline access regime is now in place.
- Direct producer–consumer contract negotiations have been facilitated and a number of new contracts recently negotiated.

## Access to data

- Extensive verified digital databases, including well, core analysis, production statistics etc.
- GIS data which include topography, geological mapping, environmental data, tenements, well locations etc.
- Seismic shotpoint database (>80 000 km recorded in the Cooper Basin), well log database (on CD-ROM), and a regional seismic interpretation (eight horizons, contours, isopachs, time and depth maps, and images).
- Both field and processed seismic tapes are being transcribed onto Exabyte (with the latter edited to facilitate work station loading).



98-1316

Fig. 1.4 Cooper Basin seismic coverage (a) 1957-69, (b) 1970-79, (c) 1980-89, (d) 1990-97.

- Systems have been implemented to safely store and rapidly retrieve physical data items (including cores, cuttings, seismic sections and seismic tapes).

### Access to land

- South Australia has a multiple land use policy with exploration and production activities permitted (and extensively occurring) in a number of reserves under the *National Parks and Wildlife Act 1972*.
- A Bill for a new Petroleum Act provides for regular availability of acreage for competitive work program bidding and improved certainty of tenure provisions.

The opening of the Cooper Basin to competitive bidding will provide a unique opportunity for explorers. Advantages include established infrastructure and markets, proven play concepts, high wildcat discovery rates, access to detailed data and a Government with a proven track record of facilitation of responsible petroleum exploration and development.

# HISTORY of PETROLEUM EXPLORATION and DEVELOPMENT

B.J. O'Neil<sup>1</sup>  
Chapter 2

## INTRODUCTION

The Cooper Basin has been the focal point for oil and gas exploration and development in South Australia since the first hydrocarbon discovery there in 1963. The Permo-Carboniferous sediments which comprise the basin were revealed in Innamincka 1 in 1959. Progress in the region has resulted in a substantial national development, so much so that by the early 1980s the Moomba facilities were regarded as a Vital National Installation with respect to any actual or presumed military, terrorist or serious vandalism threats or actions.

The name 'Cooper's Creek Sub-basin' appears to have been adopted in 1962 when the Bureau of Mineral Resources (BMR) flew an aeromagnetic survey in the region. Bouguer gravity maps resulting in 1965 from helicopter gravity surveys indicated the basin's outline (Wongela Geophysical Pty Ltd, 1965; Wopfner, 1965, 1966; Kapel, 1966a, b). Cooper's Creek Basin attained formal status through summaries of the extent of structural and stratigraphic knowledge about the basin (Kapel, 1966a, b; Martin 1967a, b; Wopfner, 1969, 1970). A basin definition referring to the 'Cooper Basin' was not published (Evans, 1966). Within a short period of time, however, the name was abbreviated for convenience. This occurred informally at first (Hollingsworth, 1989; see, e.g., Condon, 1967) and the first published reference in a scientific paper highlighting the 'Cooper Basin' appears to have been that of Paten (1969).

An outline of significant events in petroleum exploration and production in the Cooper and Eromanga Basins is chronicled in Appendix 1. The account of petroleum exploration and development in the Great Artesian Basin and the Eromanga Basin, contained in the second volume of the *Petroleum geology of South Australia* series (O'Neil, 1996), is extended here to review Cooper Basin developments. Also included are notes pertaining to Aboriginal and European occupation of the region.

The names for drillholes, topographic features and places in the Cooper Basin reflect both indigenous and non-indigenous aspects of the area (Wilkinson, 1997; Fig. 2.1). Words or phrases from local Aboriginal dialects have been adapted and adopted in the region (Cleland *et al.*, 1925; Johnston and Cleland, 1943; Johnston, 1943; Wilkinson, 1997). For example, Gidgealpa Waterhole apparently comes from Kilyalpa, a mythical woman who created the land and over whom a grey cloud once appeared while she prayed for rain (Wilkinson, 1997; see also Manning, 1990); Innamincka from words meaning deep, dark hole, yerna minka (you deep) for the large waterhole in Cooper Creek at

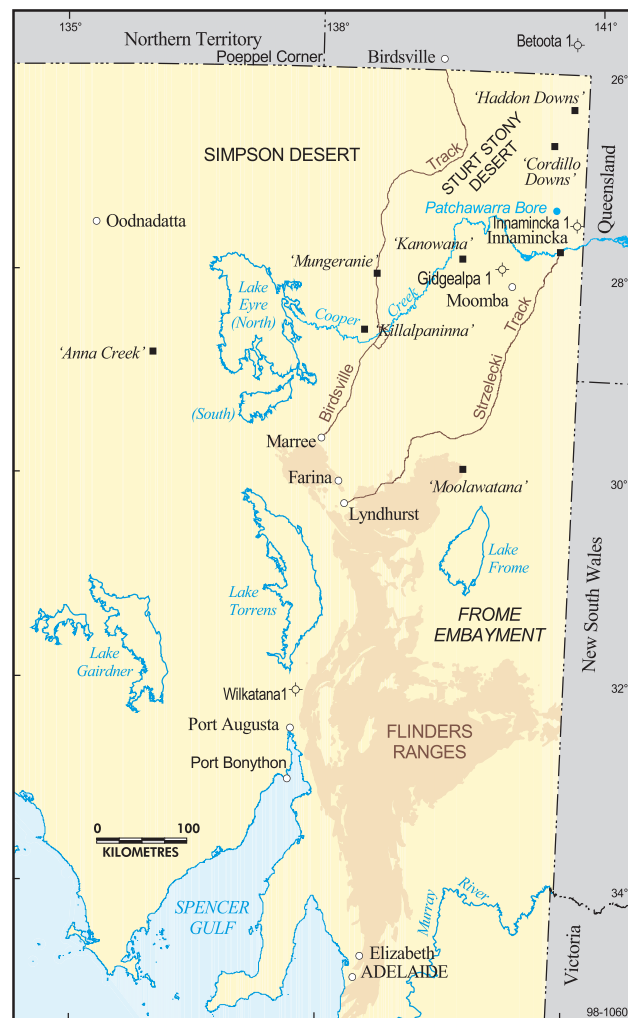


Fig. 2.1 Map of some of the key locations referred to in the text (see also Ch. 1).

this location, or yidriminkani (or yae-ni-mem-gi or Ynaminka—you go into the hole); Kopperamanna from the lake which was a meeting place for Aboriginal people near Cooper Creek; Pando from the word for lake; the dry claypans of Lake Moonba from moonba (big noise or thunder—Manning, 1990) or from moonda (beyond—Wilkinson, 1997; one version of the change of the name to Moomba is that American oilmen adapted it for ease of pronunciation—Manning, 1990—but another is that it was changed to match the Melbourne Moomba Festival which had been inaugurated in 1955—Wopfner, pers. comm. 1998); Boobook from the name for a mopoke bird; Brolga from Buralga, a dancer who turned into the bird; Cooba for some acacia plants and Marpoo for the sandhill wattle in particular; and Dieri after the lake and the main local tribe.

<sup>1</sup>Consultant Historian, 36 Tallack St, Windsor Gardens SA 5087.

Some non-local Aboriginal words and placenames have been used (e.g. Lowanna, Mina and Pooraka). Other names are derived from animals (e.g. toolache, brumby and perenty), plants (e.g. boxwood, mulga, beanbush and correa), geological and geographical connections (e.g. Namur, Nealyon and regolith), prominent people or industry identities (e.g. Sir George Grey, Sir Sidney Kidman, W. Paxton, Sir Douglas Mawson, J. Lhotsky and R.C. Sprigg) and an assortment of miscellaneous origin.

## ABORIGINES, LAND EXPLORATION AND PASTORAL SETTLEMENT IN THE 'CORNER COUNTRY'

Archaeological and anthropological evidence (e.g. Fenner, 1936), together with contemporary data and oral traditions, have helped designate several Aboriginal groups in the Eyre region and that it was an important trade and ceremonial centre (Fig. 2.2). Northeast South Australia and South-West Queensland 'is the driest part of Australia (and the only part without a seasonal pattern to its rainfall) and one of the warmest ... The Aboriginal people ... had a lifestyle closely attuned to this most unpredictable of Australian environments. In good seasons large groups could gather to harvest the food and hold ceremonies ... In poor seasons people lived in smaller groups, making use of the rare water sources such as mound springs and using skin water-bags for travelling' (Horton, 1994, p.350). Lake Kopperamanna, ~70 km southeast of the Cooper Basin, was a focal point for the distribution of pituri (a narcotic) from northern Australia, stone for artefacts from the east and west, and pigments, particularly ochre from the Flinders Ranges, from the south.

The principal group associated with the region is the Dieri tribe (alternatively Diyari, Diyeri or Diari), fringe desert and desert peoples who have occupied land east of Lake Eyre and along the lower Cooper Creek towards the State border. There may be clans within the Dieri tribe according to regional affiliations: Berndt and Vogelsang (1939) divided the tribe into Ku'nari (Cooper Creek Dieri

and Oandu (Lake Hope Dieri). The Dieri's neighbours include the Dhirari (or Thirrari) people adjoining Lake Eyre, whose country 'was the southernmost point known to have been reached by pearl shell in its extraordinary trade from Cape York' (Horton, 1994, p.278); the Ngamini people on the Warburton Creek and Diamantina River, whose major meeting place for trade and ceremonies was Goyder's Lagoon north of Lake Eyre (Horton, 1994, p.780); and the Yawarawarka people who attended big corroborees at Anna Creek, west of Lake Eyre (Horton, 1994, p.1221) although their area extended beyond South Australia.

In European times the area where South Australia, New South Wales and Queensland meet has been known as the 'Corner Country'. Early explorers associated with the area include: E.J. Eyre who travelled in 1840 south of Lake Blanche and through Dhirari country to the southern of the two lakes which bear his name (Eyre, 1845; Manning, 1990); Captain C. Sturt in 1844–45; A.C. Gregory who came south from Queensland to the east of Lake Blanche while searching for the missing explorer L. Leichhardt in 1858; R.O'H. Burke and W.J. Wills, who crossed the continent from Melbourne in the south to the Gulf of Carpentaria in the north, in 1860–61; and J. McKinlay and A.W. Howitt, leaders of search parties for Burke and Wills in 1861. Howitt made other journeys in the area. J.McD. Stuart, who had accompanied Sturt as a draftsman and whose expeditions to and across the centre of the continent in 1860–63 rivalled that of Burke and Wills without the catastrophic consequences, also made two trips west of Lake Eyre in 1858 and 1859 in the proximity of Dhirari country. In 1863 S. White traversed an area from Lake Blanche to Cooper Creek and Lake Hope while recording bird life in central Australia. Major P.E. Warburton explored for possible stock routes northeast from Lake Eyre along Cooper Creek in 1866. J. Lewis also ventured along Cooper Creek in 1874–75 while leading a government party north and east of Lake Eyre to see the extent to which it could be navigated.

On his journey from Adelaide to discover the fabled inland sea in central Australia, Sturt named the Great Stony Desert (now the Sturt Stony Desert), Strzelecki Creek after the Prussian-born Polish scientist and explorer P.E. de Strzelecki who had explored southeastern Australia, and 'Cooper's Creek' after South Australia's Chief Justice, Sir Charles Cooper. The latter was named in November 1845, three months after Sturt first discovered it, during which time he crossed it several times and confirmed that it was the same river. Ten months later the New South Wales Surveyor-General, Major Sir Thomas Mitchell, another noted explorer, named the northeastern reaches of Cooper's Creek, Victoria River, in honour of Queen Victoria (Mitchell, 1848). Gregory's expedition in 1858 showed they were the same river: from Sydney he had gone to Queensland and ventured south along the upper Cooper and down Strzelecki Creek. Consequently, from May 1861 an Aboriginal name, Barcoo, was adopted officially. By the mid 1930s it was accepted that an Aboriginal name could not apply to the whole river and Barcoo was being considered archaic (Parker and Somerville, 1943). A local Aboriginal name for Cooper Creek was Kunadi (Mattingley and Hampton, 1988), Ku'nari (Berndt and Vogelsang, 1939) or Kunara (Johnston and Cleland, 1943). From 1944 Cooper



**Fig. 2.2** Tribal groupings of Aborigines in the Eyre region extending from the northeast of South Australia (after Horton, 1994).

Creek was applied to the stretch from the mouth of the creek to its junction with the Thomson River in Queensland and Barcoo was retained for the northeastern reaches (Parker, 1944, p.100). Sixteen years after Sturt named it, Cooper Creek achieved prominence in the annals of Australian exploration for its connection with the ill-fated Burke and Wills expedition (Moorehead, 1963). Their main depot, with the famous tree upon which the party members waiting for them to return from the Gulf had carved 'DIG' to indicate buried supplies, lies northeast of Innamincka on Cooper Creek across the border with New South Wales. In the attempt to reach Adelaide from this depot, Wills died on Cooper Creek to the west of Innamincka and Burke perished downstream. J. King, their companion, survived through the timely intervention of the local Aborigines (Donovan and Donovan, 1996; Wilkinson, 1997).

The only semblance of a sea that Sturt might have located was the drainage system associated with Cooper Creek: it drains ~155 000 km<sup>2</sup> including the Diamantina and Thomson Rivers originating in Queensland and its widest frontage is 60 km in the south. In an arid desert zone, the creek usually flows between April and July. On the occasions when it has been in flood, for example in 1891, 1906, 1989 and 1997, the region is inundated with water and spectacular scenes of fauna and flora are evident. Although between 1918 and 1949 flooding of the Cooper did not extend beyond the Birdsville Track at Kopperamanna (Bonython, 1963), some of the floods have reached Lake Eyre North. Among the notable occurrences were the floods of 1949 and 1950 when the lake was filled for the first time in more than 100 years of European history in the area (Fenner, 1952), 1974 when major flooding filled the lake for a second time (Vickery, 1974) and in 1984 when Lake Eyre South filled and flooded into Lake Eyre North (Kotwicki, 1986).

The explorers did not consider the northeast suitable for agricultural or pastoral activities but the reports by leaders of search parties for Burke and Wills resulted in sheep and cattle stations being established in the vicinity of the Cooper Creek and Diamantina River: better pastoral land elsewhere in South Australia had already been occupied (Donovan and Donovan, 1996; Wilkinson, 1997). Indicative of the toughness of the country, however, was Professor J.W. Gregory's description of the vicinity of Lake Eyre and central Australia as 'the Dead Heart of Australia' after his travels there in the summer of 1901–02 (Gregory, 1906). His view was reinforced by the published accounts of the ornithologist Captain S.A. White's (1914) trip to central Australia, *Into the dead heart*, and of Dr C.T. Madigan's (1946) geological investigations from 1927 to 1939 in and around the Simpson Desert, *Crossing the dead heart*. White's father had explored around Cooper Creek in 1863 and White himself participated in a South Australian Museum expedition in 1916.

The initial tolerance by Aboriginal people of the infrequent incursion by explorers onto their land changed with the encroachment of the pastoral industry: incoming pastoralists met with 'fierce resistance by everyone, from the Dieri in the south to the Kalkadoon in the north' (Horton, 1994, p.350; Mattingley and Hampton, 1988). After one clash when the Dieri wanted to prevent the Europeans from moving cattle into their country, a wounded station hand

The blacks have caught me asleep at last, and all but killed me. They have been giving us a great deal of trouble for some time, and seemed determined to do as they liked with us and with the cattle until we were compelled for the preservation of our lives and property to put a stop to the slaughter of our cattle and attacks upon our men ... We must have more men and arms to defend our position and our property, otherwise this country will have to be abandoned by the settlers. It is very hard; for we have done our best to form a station and have uniformly treated the blacks with kindness and consideration.

*In December 1865 a party of nine Europeans from Sir Thomas Elder's Lake Hope Station were at Lake Perigundi (on the perimeter of the Cooper Basin) where they were attacked by the Dieri. This extract is part of the station manager's account contained in Dean (1866).*

wrote: 'We shall not be able to settle the up-creek country until we are stronger-handed, as I am afraid it is now open war between the blacks and us' (Horton, 1994, p.282). This pattern gradually broke down. Two German religious groups, Lutheran and Moravian Brethren, established mission stations in 1867 at Lake Killalpaninna, 65 km east of Lake Eyre, and at Lake Kopperamanna, 12 km further east (Stevens, 1994). The latter ceased in 1868 but the Killalpaninna Lutheran Mission survived until 1914 and was closed as a ration depot in 1917. Once the pastoral industry gained a foothold, a change of equal significance came with the employment of Aborigines. Harry Redford (alias Captain Starlight) drove stolen cattle overland down Cooper Creek from Queensland in 1870 and this route was soon extended south by pastoralists down Strzelecki Creek to form the primitive Strzelecki Track. In 1883 South Australia's Government Geologist, H.Y.L. Brown, followed the creek on his return from the first formal geological surveying work, for minerals, in the northeast of South Australia.



*Graves at Killalpaninna ruins, Cooper Creek, 1979. (Photo T014689)*

As unreliable as the water supplies were, the route down Strzelecki Creek became the 'lifeline to the Corner Country' and was used for transporting food, supplies and mail: even shearers travelled to and from Cordillo Downs by bicycle

In accordance with the instructions conveyed ... I left Adelaide on March 21st and proceeded to Beltana, which place I left on the 24th, with two men and five camels, arriving at Waukaringa on April 4th, and remained until the 9th, during which time I made an examination of the strata with relation to the probability of obtaining artesian water at the Government bore.

Arriving at Thackaringa, in New South Wales, I crossed over to the Mooloolooloo Hills, and proceeded northward to the Yandama Creek, which I followed to Milparinka, arriving there on May 2nd. Bad weather and rain detained me at the latter place a few days, and it was not until the 7th that I left, *via* the Reefs and Granite diggings, for Innamincka, arriving on the 19th. On the 22nd I travelled northward to the North-east corner peg, and thence along the Queensland boundary to Pandie-Pandie station, on the Diamantina river ; then, turning southward down the Diamantina Swamp to Clifton Hills, and thence up Cooper's Creek to Innamincka, arriving there on June 16th. My return journey began on the 18th, following down the Strzelecki Creek to Mulligan Springs ; thence on to Blanchewater, Mount Lyndhurst, and Beltana, arriving at the latter place on July 7th and Adelaide on the 10th.

The chief objects of this journey were to ascertain the extensions from New South Wales into South Australia of the gold-bearing rocks of Mount Brown, and the Cretaceous formation in which artesian and other water has been found. The gold-bearing rocks were not found to extend across the border into South Australia, as far as could be ascertained. The Flinders Ranges is the nearest point in this colony where rocks likely to prove auriferous outcrop, the intervening country being covered over with Cretaceous and Tertiary formations. There may, however, be some low outcrops occurring amongst the sandhills, but this is not very likely, and they cannot exist to any great extent. The extension of the Cretaceous and the Tertiary area into this colony from New South Wales and Queensland was proved along a distance of 225 miles of boundary of the former, and 300 miles of that of the latter colony.

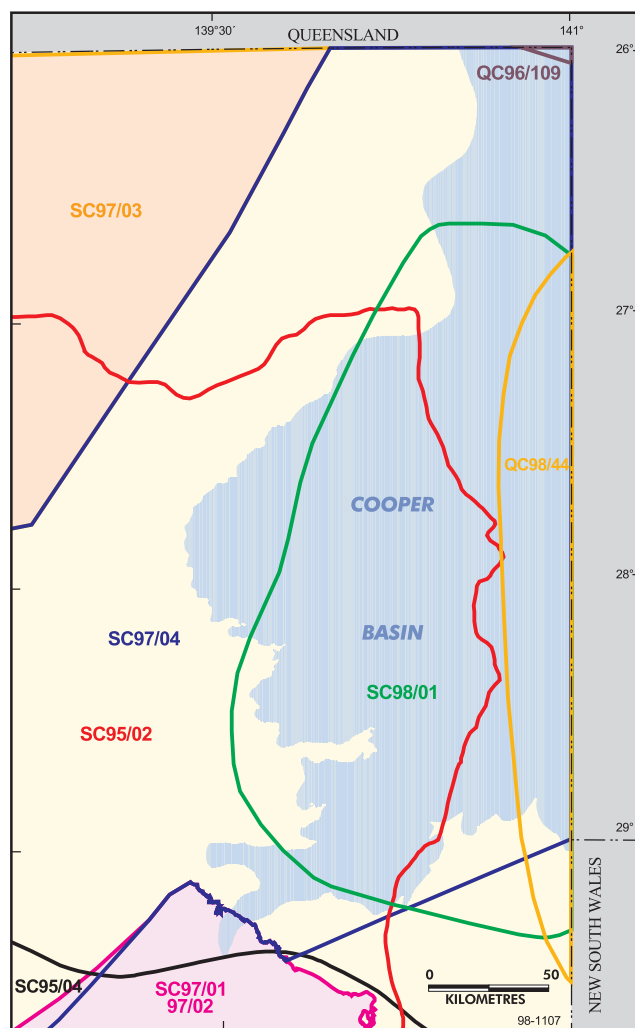
*Henry Brown's introduction to the report on his 'flying visit' to parts of the northeast, 1 August 1883 (Brown, 1883).*

across the Cobbler Sandhills and by following the pads of the camels used by Afghan and other camel drivers with wagons and coaches (Fitzpatrick, 1980; Donovan and Donovan, 1996; Wopfner, pers. comm. 1998). From September 1916, following the severe drought of 1913–15, E.R. Waite (Director of the South Australian Museum), Captain White and others travelled this route from Farina railway station to Innamincka where they inspected Burke's burial site (Waite *et al.*, 1917; White, 1917; Linn, 1989). They used 'Bullocky Jack ... an old Coongie black' as their guide along a flooded Cooper Creek between Innamincka and Kanowana (Waite *et al.*, 1917, p.410) and returned to the railway at Hergott Springs (now Marree) via Mungerannie, Kopperamanna and Killalpaninna Lutheran Mission. The group investigated the meteorological, anthropological and zoological aspects of the region, noting in particular the impact of European people and settlement (especially sheep and cattle) on the land and the Aborigines.

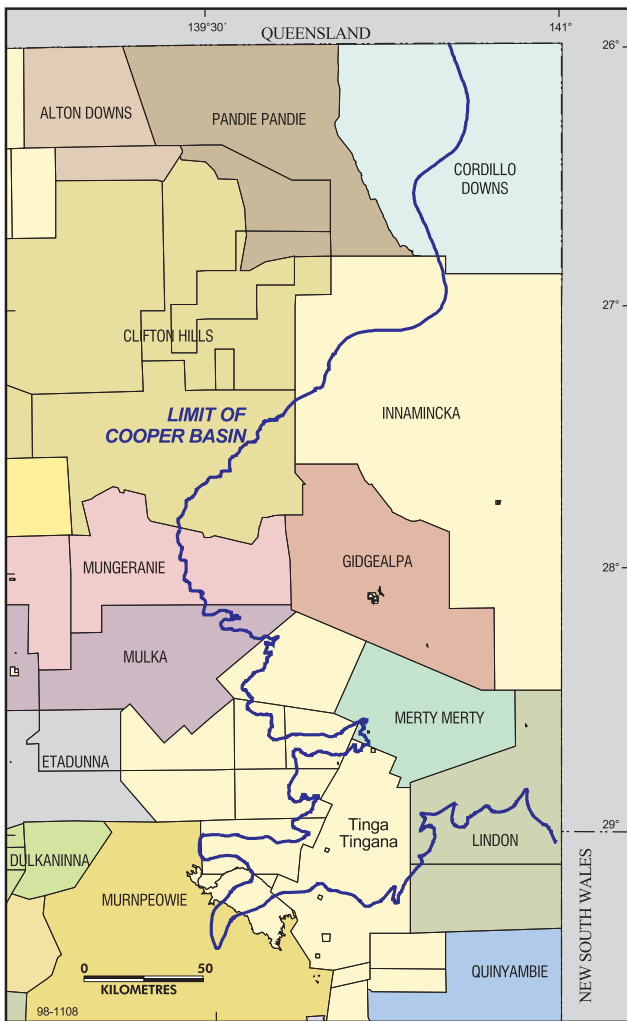
A comprehensive summary of the origins and development of the pastoral industry in the Cooper region is beyond the scope of this chapter. Information pertaining to

land tenure, including details of pastoral holdings and native title claims, can be obtained from the Lands Titles Office and the Native Title Group in the Department of Administrative and Information Services and the Pastoral Management Board in the Department of Environment, Heritage and Aboriginal Affairs (Figs 2.3, 2.4). The following comments on the properties and leases particularly associated with the region—Innamincka, Gidgealpa, Merty Merty, Tinga Tingana and Cordillo Downs—have been compiled from those sources and from Donovan and Donovan (1996).

The northern portion of the Innamincka run was taken up in 1875 as Coongie Station by H. and N. Wilson. Subsequent transfers saw the run acquired by S. Kidman (later Sir Sidney Kidman) and issued under a new lease to him in 1902. The first lease for the southern Innamincka run was issued in 1874 to J. Becker and H. Colless and then in 1882 to W. Campbell of Victoria. Between 1882 and 1886 Campbell took up other leases in the surrounding area, which had been issued in 1875–78 and 1880–81 to people such as S. Newland, and formed Innamincka Station. A small settlement began at Innamincka where a police camp at a crossing point on Cooper Creek had been established in 1882: then came the building of a police station (1883), store (1884) and hotel (1885). In April 1890, 2.59 km<sup>2</sup> (a square



**Fig. 2.3** Native title claims relating to the Cooper Basin at 30 October 1998: claims are registered on a state basis.



**Fig. 2.4** Pastoral leases in the Cooper region at 30.6.1998. The leases, including those referred to in the text, are named. These should be regarded as indicative of their historic sense: the size and shape of most leases have changed significantly since they originated late in the 19th century.

mile) of the lease was reserved for a town named Hopetoun: the Earl of Hopetoun was Governor of Victoria (1889–95) and Australia's first Governor-General (1901–03). But in January 1892 the name Innamincka was adopted instead. As Campbell's leases expired between 1895 and 1897, they were re-issued to the executors of his estate. The leases were surrendered and re-issued in 1902 before being acquired by S. Kidman in 1908. Kidman's estate and other parties held the leases from 1930 followed by the Innamincka Pastoral Co. The 'town' was able to survive, barely. The Innamincka pastoral lease was surrendered in December 1988 (after the Innamincka Regional Reserve was formed).

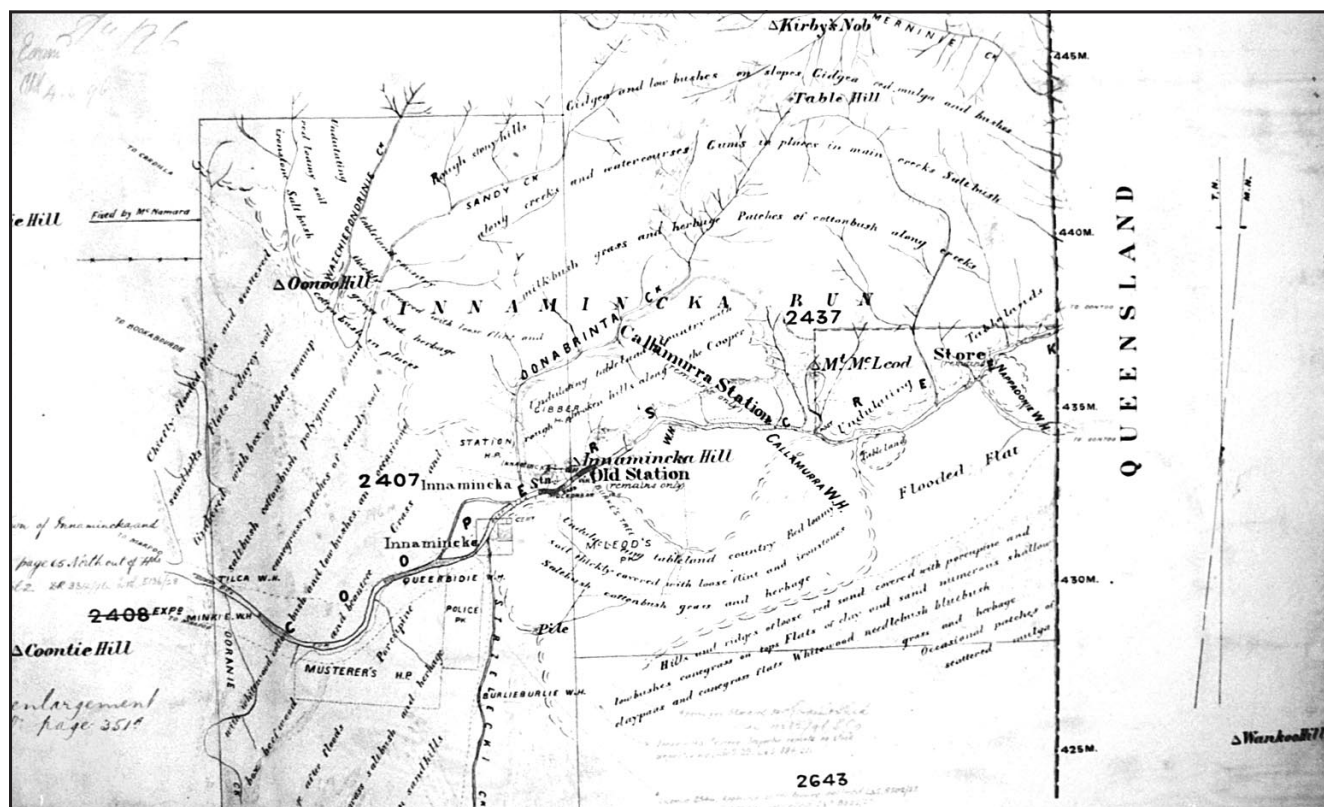
Cordillo Downs Station lies in the far northeast corner of South Australia immediately beyond the northern extent of the Cooper Basin. J. Fraser (sometimes Frazer) took up Cardilla [sic] Downs in about 1877 and the lease was taken up by E. Chapman in 1878. P. Waite took over the lease in 1883, later transferring it to the Beltana Pastoral Co. (a partnership of Waite, Sir Thomas Elder and N.E. Phillipson, which gradually acquired control over an extensive portion of the Corner Country). After a severe drought in 1902 Cadelga (once Cadelgo Downs) and Haddon Downs

Stations were added to their southern neighbour's lease in 1903 and 1905 respectively: those homesteads became out-stations. Cadelga, on the Northern Territory border, was first leased to Chapman in 1878 and it changed hands three more times before being held by the Bank of New South Wales from 1890 and subsequently by the Beltana Pastoral Co. Haddon Downs, which adjoined the Northern Territory and Queensland borders, was first leased to Chapman in 1877 and subsequent lessees included the Australasian Mortgage Co. of Sydney. The Beltana Pastoral Co. leased all of these properties, including that which the Bank of New South Wales held between Cadelga and Haddon Downs, as Cordillo Downs from 1898 to 1981 when the lease was taken over by the Brooklands Pastoral Co.

In modern times a lease around Gidgealpa was taken up by H.L. Napier and J.E. Dunn as tenants in common in February 1966. Dunn held the lease for 17 years from March 1968. Since March 1985 P.D. Brazel and various partners have held the lease whose southern boundaries bordered Merty Merty Station and traversed the area of Lake Moonba and Big Lake Moonba. Merty Merty, part of the Strzelecki country, had been taken up by M.R. Oakes in 1919. Kidman took it over when Oakes left in 1924 and it was subsequently held by Kidman's estate and other parties. From January 1930 the lease was held by the Innamincka Pastoral Co. until December 1965 when R.G. and W.E. Rieck took over the lease, which was later managed by their estate. Tinga Tingana Station was created in 1877 by W.C. Burkitt who combined the land he had taken up in the mid 1870s with other lessees' land. Burkitt occupied the run when it was offered for sale in 1877 but did not renew the lease when it expired in 1889. The lease was then auctioned as four blocks with Bristow Bros securing one block for 21 years. However, this and the other unsold blocks were acquired by the Warren family of Anna Creek in 1892 under a miscellaneous lease (a reduced rent and no deposit was required for improvements upon the property). Drought apparently caused J. Warren to abandon the lease in 1895 and the run was left under various caretakers such as A. Pope and J. Patterson. In 1909 Pope moved from Innamincka to part of Tinga Tingana Station, possibly as a lessee. Four years later he was joined with J. Patterson to run another part. They both held contracts at different times for delivering the mail from Farina along the Strzelecki Track to Innamincka. Pope left in 1914 but Patterson remained until 1937. Oakes took over some of the lease as part of Merty Merty in 1919 before abandoning it in 1924. Tinga Tingana was not re-occupied by pastoralists until 1966 when H.P. Robertson was issued with an annual licence to graze stock. The lease was taken up in 1968 by H.F. and L.A. Robertson who created a new Tinga Tingana Station by combining the old one with Monte Collina Station: subsequent transfers were to Marin Investments (1972), H. and L. McIntyre (1978) and K.D. and R.P. Ogilvy (1987). The station now forms part of the Strzelecki Regional Reserve (Fig. 3.2) and the lease continues to be maintained pending the resolution of native title concerns.

## THE EVOLVING PETROLEUM SEARCH

The early search for oil and gas in South Australia (1866–1930s) was largely confined to the populated areas or the coastal regions of the South-East. Boring on the



Innamincka Run in 1896. The map shows the station situated on the Cooper Creek, also the site of the township and the Strzelecki Creek leaving the Cooper near the site of the township. (Courtesy of Donovan and Associates/Pastoral Management Board)

Coorong by the Salt Creek Petroleum Oil Prospecting Co. between 1881 and 1883 was the first real attempt to drill for oil in Australia. This early work was undertaken by individuals or small syndicates and was generally neither systematic nor overly scientific in nature.

After World War I, the Federal Government took an increasing interest in the oil search as a national responsibility. The Commonwealth Oil Advisory Committee (1936–40), which comprised Dr L.K. Ward (South Australia’s Director of Mines, 1912–44), Dr A. Wade (who had reported previously against South Australia’s oil prospects; Wade, 1915) and Dr W.G. Woolnough, facilitated geological surveys and drilling operations through subsidies and hiring equipment for committed, modern explorers. Such assistance encouraged higher standards of exploration and reporting, so that companies began to employ more geologists with appropriate skills to focus on the technical aspects of oil exploration.

The Federal Government in the 1930s attempted to provide for uniform legislation over oil-bearing land and partly in response to this and partly because of the State Minister of Mines A.L. McEwin’s own desire to establish local oil supplies, the South Australian Parliament revised the legislation over petroleum. Early in his term as Minister (1939–65), McEwin concluded that the oil search had to be encouraged despite his own department querying the State’s petroleum prospectivity. A Petroleum Bill was introduced into Parliament in October 1940: it passed through both Houses comfortably. The *Mining (Petroleum) Act 1940* (hereafter cited as the *Petroleum Act*) provided for extensive grants of land to companies searching for oil as its basic aim

was to increase substantially the area available for oil exploration, prospecting and development while at the same time providing for more secure tenure than companies had previously been given. South Australia’s *Mining (Prospecting for Oil) Act 1928* had limited the area for oil prospecting to a maximum of 65 km<sup>2</sup> for each permit holder, either directly or indirectly, for up to two years and required permit holders each year to either spend at least £1000 or to drill at least 305 m. The new Act provided for exploration, prospecting and production by way of: an oil exploration licence (OEL) for areas not less than 2590 km<sup>2</sup> for two years, with the right of renewal; an oil prospecting licence for areas between 21 and 518 km<sup>2</sup> for up to four years; and an oil mining licence for areas between 10 and 259 km<sup>2</sup> for up to 21 years. There was no upper limit to the area that could be held: although the fee was £50 per annum for every 259 km<sup>2</sup>, the maximum fee payable was £500 so an applicant in principle could secure the whole State! The legislation also asserted the Crown prerogative over petroleum, even where a previous alienation of land had provided for private ownership rights. In addition, a royalty of 10% of the selling value of any crude oil produced from the licence area was payable to the State.

After World War II some larger companies became involved in petroleum exploration and regional geological investigations focused attention on major sedimentary basins, including the Great Artesian Basin. Large parts of the State had been condemned on little or no evidence, such was the prejudice against South Australia’s geological potential as an oil and gas province. The official line—that it was most unlikely that there would be oil in payable quantities in the State—was maintained in the Department

of Mines until the evidence proved incontrovertible (Ward, 1944; O'Neil, 1982; Lewis, 1983; Sprigg, 1983b; O'Neil, 1995). The work of some professional geologists in private companies, the university and the department did much to dispel the doubts from the early 1950s when the entrenched thinking began to be challenged more widely.

To be fair, the scepticism about South Australia's commercial oil prospects was based on the scientific observations, interpretations and conventional beliefs of the day and because charlatans abounded. The results of investigations by the department, private prospectors and companies justified the cautious tones. To October 1944, 39 oil boreholes with a cumulative total depth of 13 072 m had been drilled in South Australia (Ward, 1944). This included 2071 m drilled at five sites selected by diviners. More than £200 000 had been spent with negligible results. There were no geological indications of commercial deposits of petroleum and time and effort were not to be wasted on a seemingly futile search. In his summary of the oil search to 1944, Ward suggested planned, organised professional oil searches were necessary and ultimately this approach took hold.

A catalyst was the change in South Australia's economy from an agricultural base to an increasingly industrialised one. In sponsoring secondary industries for the State, Sir Thomas Playford (Premier, 1938–65) continually stressed the need for independent, reliable sources of energy. At first coal was considered to be sufficient. The potential for uranium to supply an atomic energy reactor was raised through the Radium Hill Project (1954–61), the contract for which brought the State into the international energy resource market (O'Neil, 1995, 1996). But it was the possibility of oil and gas in South Australia which provided an alternative to the use of coal.

Playford's views on the need for independent energy resources was illustrated by his efforts to have an oil refinery established in Adelaide, which culminated with the opening of Port Stanvac, ~15 km south of Adelaide, constructed by the Standard Vacuum Refinery Co. (Australia). The first crude oil was processed at Port Stanvac in March 1963. That and other petroleum products—its major product was fuel—continue to be processed there for the local markets, principally Adelaide and the metropolitan area.

In harmony with the Playford Liberal and Country League Government's desires, the Mines Department was placed in a sound position to promote oil and gas exploration and development. Playford's active involvement in petroleum exploration and development was unparalleled for a political figure and he was always promoting the benefits for South Australia (Cooper, 1992). He was keen to learn and he had a high level of understanding: helped by a good memory, he comprehended technicalities and detail. With the exception of 1963 when severe flooding intervened, his annual holidays from 1960 to 1964 included field trips to the northeast region (usually with the Minister of Mines, company management and departmental chiefs and staff). In that year Minister McEwin did join a field party (which included Barnes, Parkin and Wopfner from the department and the managers of Delhi Australian and French Petroleum) in a traverse across the Simpson Desert from Oodnadatta via Dalhousie Springs and Poeppel Corner to Birdsville to inspect French Petroleum's seismic work.



*Simpson Desert party (on the lower Macumba River after crossing near Warrina Siding), July 1960. On this trip Premier Sir Thomas Playford inspected seismic and drilling operations in the northeast and across the recently reconnoitred route from the Birdsville Track to Oodnadatta. From left: kneeling, Lee Parkin (Deputy Director of Mines) and Jack Whitford (Engineering and Water Supply Department [EWS]); standing, John Rattus (Mines Department), Warren Bonython (explorer, in profile), Jack Clark (News), Lawson Glossop (Advertiser), Charles Easley (Delhi), Tom Barnes (Director of Mines), EWS worker (not with party), the Premier, EWS worker (not with party) and Laurie Steel (EWS). (Courtesy of H. Wopfner; photo 42140)*

Ultimately, new ideas and concepts, new investigative and explorative techniques, and new strategies in the local oil and gas search were to pay dividends in the 1960s.

## **EXPLORING THE GREAT ARTESIAN BASIN REGION**

South Australia's geology and geography necessitated generous concessions to attract explorers and developers and ahead of anywhere else in Australia the legislation in 1940 made available huge areas to encourage companies to explore for oil. Only by issuing licences on very favourable terms could the State Government attract large companies and overseas interests to invest in oil and natural gas exploration. The *Petroleum Act* came into effect on 31 July 1941 but its impact on petroleum searches was thwarted by World War II. Although some exploration was undertaken it was only after the war that the Act's effectiveness became apparent when several companies were attracted to explore in the State, but practical results did not follow immediately.

Drilling in the Great Artesian Basin had been predominantly for water supplies and most of the drilling stopped short of the deep, pre-Jurassic strata. The first information that was useful for petroleum exploration in the Great Artesian Basin in South Australia was obtained with the drilling of the Patchawarra Bore, 55 km north of Innamincka. Searching for water in September 1914, the bore was abandoned at 1664 m having reached the Early Cretaceous Allaru Formation. It did not fully penetrate the Cretaceous succession but water and minor gas flowed from the Late Cretaceous Winton Formation.

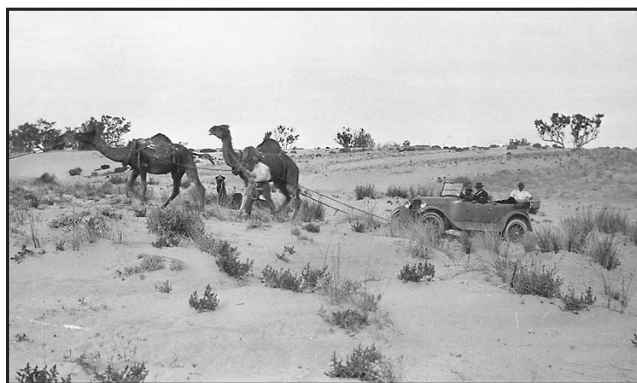
In general, the attention of most of the few professional and academic geologists interested in the State was not

directed at petroleum. Dr R. Lockhart Jack (Assistant then Deputy Government Geologist, 1912–31) accompanied by J.B. Cleland (Professor of Pathology, Adelaide University) and Mr Reid, (General Manager of the Beltana Pastoral Co.) travelled to the northeast in May 1924 during which he conducted surface mapping while investigating groundwater supplies. Jack (1925) reported on areas south and north of the Cooper Basin where he had mapped a fold structure and noted the presence of gentle folds in the Cordillo Downs area. The outcropping Tertiary anticlines were tantalising pieces of evidence for petroleum explorationists but Jack, who was not a petroleum geologist, did not assess their importance. Likewise, Woolnough, the Federal Government's Geological Advisor, visited the Innamincka area in 1927 and also overlooked them (Sprigg, 1983b). A subsequent study by Jack (1930) was on the structure of the State's remaining sedimentary basins. The relevance of his observations assumed greater importance later: '[Jack's] detailed basin cross sections ... based on water well information provided the first reliable preview of Mesozoic-Tertiary geology across the State, and was an invaluable foundation on which to base oil exploration in the central Great Artesian Basin in particular. Santos Ltd. must be deeply indebted to Dr. Jack' (Sprigg, 1983b, pp.C38–9).

The Great Artesian Basin attracted serious attention for oil and gas during World War II with a search in the Frome Embayment. The remoteness of the basin had meant the costs of exploration and development were prohibitive for such a distant and unpromising area. The lack of oil seeps and the failure of the many artesian bores to provide any sign of oil and only some shows of gas suggested that the area was not hydrocarbon prospective.

The private sector remained hopeful: Zinc Corporation's exploratory work in the Embayment was a sign that an oil and gas search was becoming feasible. Small quantities of natural gas had been reported from several widely separated artesian bores in the Embayment and in 1940 the company commissioned a report on the petroleum potential of the northeast and the adjoining States. The assessment was pessimistic about the geological aspects of discovering petroleum (De Verteuil, 1940).

However, Zinc Corporation's investigation was to stimulate action after the war. A confidential report in 1944 drew attention to the gas detected in artesian bores in the Embayment (Mawby, 1944). This was followed by a report



*Lockhart Jack's party at Accalana Crossing on the Strzelecki Track, 1925. (Photo N001025)*

In the winter of 1924 I had one of the most interesting trips of my life; to Cordillo Downs Station, an area of a square degree in the N.E. corner of South Australia. The party was made up of Mr. Read, the General Manager of the Beltana Pastoral Co. which owned Cordillo & several other stations; and Prof. Cleland who was using a vacation holiday to investigate a mysterious sickness that was destroying the morale of the Station staff, and myself, on a quest for more water. We travelled in a Dodge tourer, festooned with swags, bags, spares, water and provisions. It was about 400 miles from the railway through Murnpeowie Station, Mt. Hopeless Station, a set of nasty sandhills known as the Cobbler, Innamincka, Cooper's Creek, and thence 85 miles to the H.S. of Cordillo Downs ... Over the widespread Upper Cretaceous beds capping the Great Basin, a post-Cretaceous formation was laid down ... several hundred feet thick ... the Desert Sandstone. We crossed several of these areas in a car looking for bore sites, doing about 4 miles an hour and bumping over anything less in size than a sack of wheat. Anything larger we avoided, but we estimated that here 20% to 80% of the surface was made up of such gibbers.

But the whole of Cordillo Downs, as I saw it, was not 'Mesa'. Much was plain, either carrying a normal proportion of gibbers, with occasional dunes of wind blown Indian red sand. Depressions, too indistinct to be recognisable as stream beds, were evidently flooded and silted over by the occasional flood flows from the hills. In places these flood flows had scooped out waterholes of various sizes, recorded on a station wall map as from a 3 month hole to a few marked permanent, that is to say capable of lasting two years without replenishment, and generally marked by the presence of large gum trees. The flooded flats carried mulga, and the rest saltbush, blue bush, mitchell grass and various types of herbage such as the so-called geranium, and a prickly weed known as 'Tableland mulga'. The last three afforded feed even when quite dry, in fact everything but the eucalypts was edible.

Three stations: — Cadelga, Haddon Downs, and Cordillo Downs — were formed despite the fact that they were three to four weeks journey from Port Augusta by buggy, and more by camel teams ... [The stations] once carried 150,000 sheep. A great drought culminating in 1902, reduced the flocks to 2,200 ... When the drought broke the strongest survivor absorbed the other two and though content to keep down to 50,000 sheep, made many improvements. Perhaps the most spectacular was the dog proof fence guarding the sheep against the dingoes. This, a netting fence, six feet high, with two lines of barbed wire above it. The perimeter and a subdivisional fence, were at least 300 miles long.

*Some of Lockhart Jack's recollections of his trip to the northeast in 1924. Though once having carried sheep, it became cattle country partly because of the lack of water, the marauding dingoes and the low level of feed for stock (Jack, 1964, pp.192-4).*

which reasoned that oil in the region was a remote prospect but that the likelihood of there being natural gas justified exploratory drilling (Osborne, 1945). The first OEL under the *Petroleum Act* was for an area of 10 360 km<sup>2</sup> in the southern part of the Great Artesian Basin east of Lake Frome. OEL 1 was granted to A.J. Keast on behalf of Zinc Corporation in April 1945; when the licence was surrendered in the following April, OEL 2 was granted to them for two years. OEL 2 (18 518 km<sup>2</sup>) included the area of OEL 1 and an additional area further west and north.

In January 1947 M. Mawby on behalf of the Australian Mining and Smelting Co. (an associate of Zinc Corporation) was granted OEL 3 for two years over 126 910 km<sup>2</sup>, including the area of the now known Cooper and Eromanga Basins. Gravity and magnetic survey crews then undertook a regional reconnaissance survey intending to locate areas with structural features which could trap natural gas and/or oil over a triangular area from near Tibooburra in New South Wales to the Patchawarra Bore and Moolawatana Homestead in the southern Great Artesian Basin area of OELs 2 and 3 (Sauvé, 1947). The gravity anomaly immediately south of the Patchawarra Bore (Patchawarra Maximum) was considered unique in that it was not reflected as a magnetic minimum in the magnetic data in the area: it was considered worthy of further exploration. The outcropping Innamincka Dome (a gravity high, 80 km long by 24 km wide) formed part of the survey and another high was detected at Cordillo.

In December 1947 OELs 2 and 3 were transferred to the Frome-Broken Hill Co. which was formed by Zinc Corporation, Vacuum Oil Co. and D'Arcy Exploration Co. in September 1947 thereby introducing international expertise and assistance to the search. OEL 3 was reissued to Frome-Broken Hill in June 1948 and a Zinc Corporation subsidiary, Enterprise Exploration, then drilled six wells to explore for gas and oil-bearing strata in the Great Artesian Basin. The first well was at Kopperamanna on the Birdsville-Marree stock route (the Birdsville Track) and

Mr. W.S. Robinson has on several occasions spoken of extending our present gas areas "from Tarcoola to the Western edge of our present Licences and North to Alice Springs". He has, however, stated that "I don't profess to be a geologist, geophysicist, or any other type of expert, but I'll bet there is as good a chance for the location of the "marine series" of sedimentaries there as there is anywhere else in Australia".

Please treat this as confidential but I feel that it is up to me to reply to his very general statement or hunch. I know the general structure over this area from David's maps and also those of Lockhart Jack in your departmental Bulletins, but I was wondering whether you could have someone in your Department draw up some sections East-West and North-South to illustrate the present conception of the structure underlying this area. No detail is necessary but just a general idea so that I may enlarge on the subject when I meet him early in January.

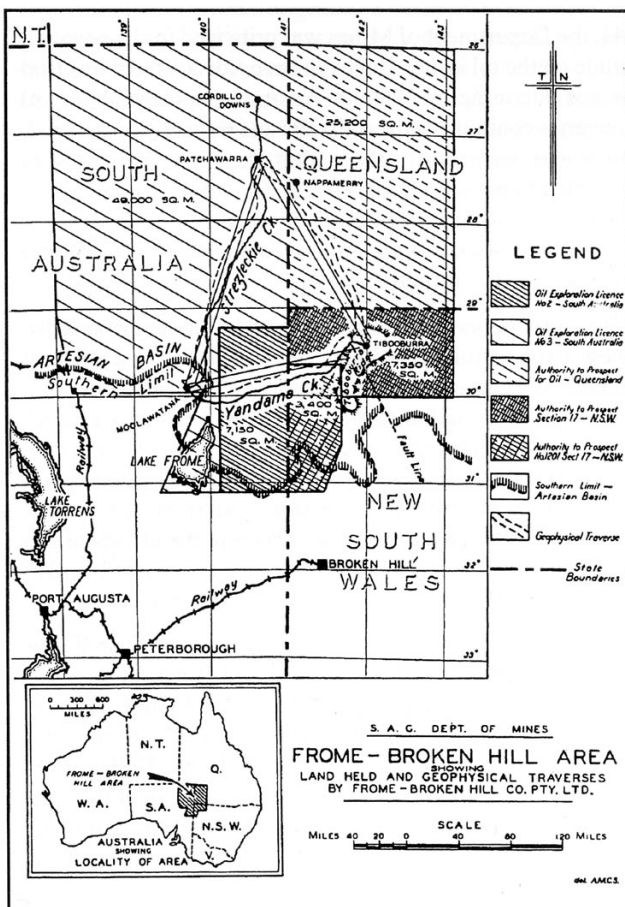
Please do not take this seriously but anything you could do would be appreciated.

*Maurie Mawby wrote personally to the Director of Mines, Ben Dickinson, in December 1947 to explain part of his interest in the region (Mawby, 1947).*

replaced a well drilled between 1906 and 1908 ~1 km from the new site. This was probably the first use of an oil field rotary rig in Australia (Willington, 1949; Robertson, 1988) but due to the loss of tools, drilling ceased at 992 m. The drilling of a deviated hole from January 1949 from 875 m enabled the well to be completed as an artesian bore. The six wells drilled, using the imported rig, were completed by April 1951. Some methane was detected, but there was nothing to encourage further drilling for petroleum and the licence was surrendered. The Lake Frome area was considered to have been investigated thoroughly and though dry gas had been reported in several wells in the Frome Embayment in association with water, the prospects of finding commercial oil were rated low. Australian Mining and Smelting was granted OEL 6 over part of the east and northeast for two years from January 1954. The area of ~145 230 km<sup>2</sup> covered the earlier OELs 2 and 3. After re-examining the previous geophysical and geological results the company abandoned OEL 6 in December 1954.

## SANTOS AND PARTNERS: EARLY TRIALS AND TRIBULATIONS

Over time the importance of Australia having a domestic supply of oil and gas became more critical than it had been prior to World War II. Between 1946 and 1953 petroleum exploration in the Great Artesian Basin amounted to about 18 months geological surveying, 28 months of geophysical work, and some drilling in the Frome Embayment. The incentive offered by the Rough Range oil discovery in Western Australia in November 1953, and then the formation of Geosurveys of Australia and Santos in March 1954 were important for petroleum exploration locally and brought a revised approach to exploration thinking. The Suez crisis, which peaked in January 1957, added to the national importance of the oil search. While only 20 holes were drilled for oil in Australia in 1957, oil and gas



*The areas held by Frome-Broken Hill in South Australia (OELs 2 and 3) and interstate and its geophysical traverses, as at 20 November 1947. (Mining Review, Adelaide, 87 p.21)*

discoveries elsewhere in Australia sustained interest in, and hopes for, the local search.

Santos—the acronym for South Australian Northern Territory Oil Search—took up the cause of oil exploration in the State. The company grew out of the association of J.L. Bonython and R.F. Bristowe, who maintained an interest in the possibility of oil in South Australia. Bonython had not forgotten the view expressed by a grand-uncle that oil would be found in the Great Artesian Basin, if at all, in Australia. Bristowe had flown over this terrain on trips to and from Darwin and he found it interesting that the country from the head of Spencer Gulf to the Flinders Ranges was similar to the oil-bearing regions he had observed when flying between Iran and Russia in his role as a King's Messenger. While this layman's view of the likelihood of oil is far too simplistic, as is often the case, the interpretation based on geographical features had a practical consequence. The two men pooled their ideas in 1954, studied relevant literature and were advised by Dr M.F. Glaessner of the Geology Department at Adelaide University to see R.C. Sprigg in the Mines Department.

Sprigg's open-mindedness about South Australia's oil prospects had already caused him to clash with S.B. Dickinson (later Sir Ben Dickinson; Director of Mines, 1944–56). In 1952 he had tried unsuccessfully to persuade the Director to allow him to assess the petroleum possibilities of the Great Artesian Basin. His earlier interest in oil and in Frome-Broken Hill's investigations had been stimulated further through working with a Russian hydrogeologist, I. Chebotarev, in the department. Chebotarev had re-examined the geochemical records of old bores while pondering theories of oil migration (Chebotarev, 1955). He told Sprigg that his experience in Russia suggested that the northeast was the place to look for oil (Sprigg, 1983b; O'Neil, 1995).

The request for information from Bonython and Bristowe contributed to Sprigg resigning from the department in late February 1954. Less than a week before Santos was incorporated in March, Sprigg registered his own exploration company, Geosurveys of Australia, which was founded as a consulting firm to assist uranium explorers but first began to investigate nickel deposits in the far northwest of the State. Sprigg engaged Dr R.O. Brunnschweiler as Senior Petroleum Consultant to manage the contract between Geosurveys and Santos (Wopfner, pers. comm. 1998). They were not the only companies interested in 'the good oil': five OELs were issued in 1954 compared with the same number in the previous 14 years and more than half the State was held under licence.

Geosurveys and Santos aspired to acquire all of the northeast they could for the long-term. In March 1954 Bristowe was granted OEL 7 for two years, an area of 361 960 km<sup>2</sup>, but which included very little of the Cooper Basin, and in September 1954 OEL 7 was transferred to Santos. The licence initially adjoined OEL 6 but when Australian Mining and Smelting surrendered OEL 6 in December 1954 Santos applied to have the area included in OEL 7. This was approved in November 1955 and the area then totalled 507 397 km<sup>2</sup>, including an area offshore (Fig. 2.5).

Perhaps the least intangible [evidence] was a sample of water brought to the Department of Mines in 1934 by a boring contractor who obtained it from a borehole 180ft. deep on Wilkatana Station. Minute blebs of oil were present in the water and only 1.2 grammes were obtained for examination ... Further work will be done on this oil if a larger sample can be obtained, but there was no more oil obtainable after the first signs were seen.

*One of the more promising comments in Keith Ward's survey of the State's oil prospects in 1944 (Ward, 1944, p.30).*

Floated as a public company with a share issue commencing in October 1954, trading in Santos on the Stock Exchange began in February 1955. Then Geosurveys and Santos investigated north of Port Augusta at Wilkatana where a trace of subsurface oil had been made two decades before. Sprigg, whose interests lay elsewhere, went along with Santos in the short-term as the company intended to concentrate on that area. With Bonython and Bristowe he visited Wilkatana where they noted spots of oil in a water bore. After the discovery of oil in Wilkatana 1, Sprigg initiated the proper drilling of the Wilkatana field. From May 1955 the Mines Department's diamond drill and percussion rigs and a Failing 1500 from the BMR drilled 24 holes for Santos. The drilling recovered oil—there were minor traces in dolomitised Early Cambrian limestones—but not in economic quantities (Sprigg, 1958).

By the mid 1950s the Mines Department was contributing actively to the search for hydrocarbon deposits. Although initially opposed to the likelihood of oil and gas, Dickinson finally oversaw the introduction of geophysical techniques and the move to seismic work. In 1953 Premier Playford saw seismic crews in operation in America. Given the success that had been obtained through seismic exploration work, he decided that South Australia should run its own seismic surveys. There were no contract crews in Australia and the States relied on the services of the BMR, then the only seismic operation in Australia. This further stimulated Playford to approve the purchase of the expensive equipment plus the capital expenditure for the camping requirements.

Soon after commencing seismic surveys in the Wilkatana area in 1955 the department expanded its role in geophysics and implemented regional geological mapping, aerial photography and geophysical survey programs, which provided great assistance to oil exploration companies over the long term. Commercial success did not follow from the exploratory drilling at Wilkatana, but the work attracted much interest especially from the Premier and the Minister. They were enthusiastic about resource development and this required a shift in thinking by key personnel in the department: if their political masters wanted oil found then there would have to be a very good excuse for it not to be!

Meanwhile, in mid 1956 Geosurveys had undertaken gravity and magnetic surveys in the Great Artesian Basin between Birdsville and Marree. A Geosurveys' geologist, Dr H. Wopfner, mapped some large anticlinal structures near Oodnadatta and Jack's earlier observations were recalled (Wopfner, 1990). The visit of the world-renowned American petroleum geologist Dr A.I. Levorsen to Australia

early in 1957 at Bonython's invitation proved vital in promoting the petroleum search. At a meeting on 8 February in Adelaide where the data obtained through Santos's investigations at Wilkatana and elsewhere in OEL 7 and its areas outside the State (the Amadeus Basin and Melville Island) were presented, Levorsen was not overly impressed with the results. In particular, he is said to have remarked that Santos would need the Bank of England to fund the work at Wilkatana, which had the potential for 'Fords and Chevies', whereas with proven anticlines in the Great Artesian Basin the 'Cadillacs and champagne' were further north (Gibbs, 1988; Wilkinson, 1988; Wopfner, pers. comm. 1998), Levorsen recommended that Santos increase its holdings and focus its attention in the northeast, even extending into South-West Queensland. His positive and public support for the likelihood of oil in that huge region where Santos had been reluctant to venture provided a fresh impetus to exploration.

As Sprigg had continued to ponder what might lie north of Wilkatana, he then sent Wopfner to investigate outcropping anticlines in the Great Artesian Basin. In March and April 1957 during a ground and aerial survey Wopfner mapped fold deformations in the Cordillo Downs – Innamincka – Morney (Queensland) area. Within two weeks of commencing, he had identified and mapped major structures and then produced the first structure map of this part of the basin (see Wopfner, 1990, fig. 3). Surface mapping by Wopfner, S. Rowe, D. Chase and G. Swindon commenced on 22 May. Between 3 July and 1 August Wopfner undertook a detailed air reconnaissance in a light plane piloted by Brunnschweiler: their total flying time in the air was 136 hours over 11 days. Both aerial

That was actually quite amusing at times because ... we would engage in some quite clandestine operations. We would have a clean skin Land Rover and would drive up to Mootwingee and have a look around the Palaeozoic outcrops, saying that we were university graduates ... At one stage I was even passed off as the brother of one of the miners who had come back from South Africa on a visit ... The first year in Oodnadatta was very rewarding. I was able to map some structures which so far had not been known to exist in that area. '57 started off with that operation in the Mootwingee Ranges and then Reg [Sprigg] said, 'Do you have time to go up to Cordillo Downs?' I said, 'Where the hell is Cordillo Downs?' 'Well it's up in the northeast corner. The Lands Department are just flying the aerial photographs and I have arranged that you can do some flying with them and I also arranged for a Land Rover to be up there so you can do a little bit of the ground recce.' I said, 'All right, when do I leave?' This was at 11 o'clock in the morning. So he said, 'Well our Secretary booked you on the Butler airflight to Broken Hill at 3 o'clock in the afternoon.' That was the occasion when I came back with the map where we had all these magnificent anticlines marked. When I came back quite a number of people would say, 'Now what sort of grog had you been drinking up there that you had all these visions?'

*Heli Wopfner recalled the investigation in March and early April 1957, which included the first aerial reconnaissance in the Cooper Basin (O'Neil, 1989a). Wopfner joined the Department of Lands flight at Cordillo Downs and covered an area from there to Morney, Innamincka and the Coongie region. He and Dick Chase undertook a ground reconnaissance also.*

reconnaissances added several likely surface anticlinal structures to that noted by Jack. Indicative of their large size, some were mapped using the Sokol's altimeter and while flying at wing-tip level with cuestas and mesas (see Sprigg, 1958; Gravestock *et al.*, 1986, cover; Wopfner, 1988, fig. 1). During this second survey Sprigg visited the Cordillo Downs area for the first time and carried out a short reconnaissance verifying that the structures noted by Wopfner were really Cretaceous and not basement.

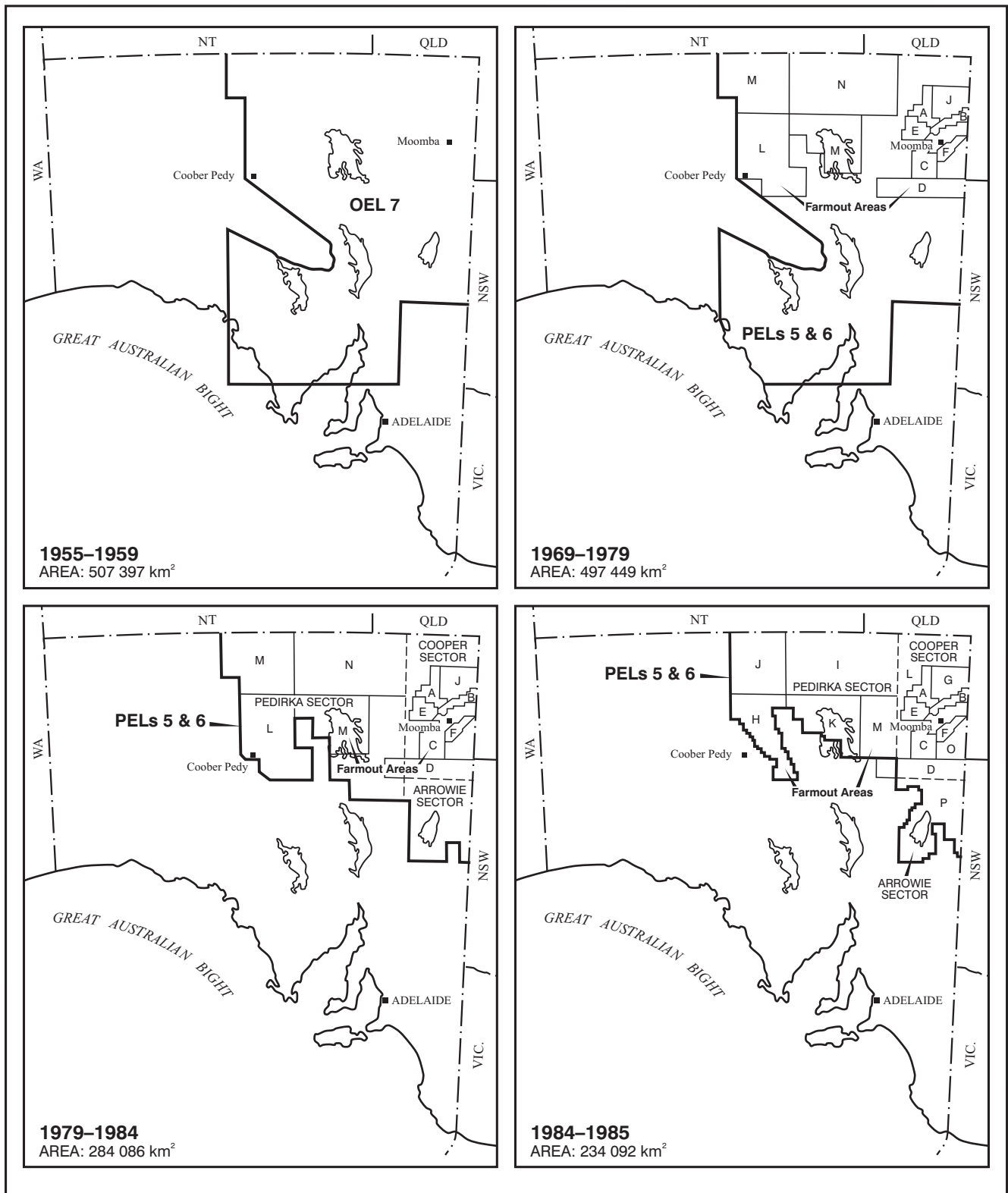
It was subsequently realised that in targeting artesian water the drilling had concentrated on water courses lying along synclines. Pastoralists searching for water had focused on the watercourses and major river channels where the feed was best. There were an estimated 6000 water bores in the Great Artesian Basin by 1958 (Sprigg, 1958). Thus elevated structures such as the Cordillo or Innamincka Domes had not been subjected to groundwater or stratigraphic drilling.

Late in 1957, after Santos had drilled Oodnadatta 1, a BMR seismic crew which had operated northwest from Oodnadatta was moved to Cordillo Downs. These were the first seismic surveys in the western and central Great Artesian Basin: geophysical surveys prior to this had been gravity and magnetic only. Santos extended the Frome-Broken Hill 1947 triangular traverse and completed the Marree-Birdsville section and linked up with its Cordillo Downs Station survey line. To confirm the structural framework in depth, in addition to the seismic survey Geosurveys, on behalf of Santos, drilled five shallow structural-stratigraphic holes in the Haddon Downs area between October 1957 and January 1958 (Sprigg, 1958; Wopfner, 1960). The holes traversed the eastern limb of the Nappamilkie Anticline and the Haddon Syncline. The deepest reached 458 m and some water was intersected.

Levorsen's business acumen extended to introducing Santos to the Delhi-Taylor Oil Corporation (later Delhi International Oil Corporation) of Dallas, Texas. The nature of the oil search, South Australia's size and the limited geological knowledge about oil taxed Santos fully. Levorsen realised that Santos lacked the resources and finance to explore properly and felt that Santos needed to obtain the financial backing and petroleum industry



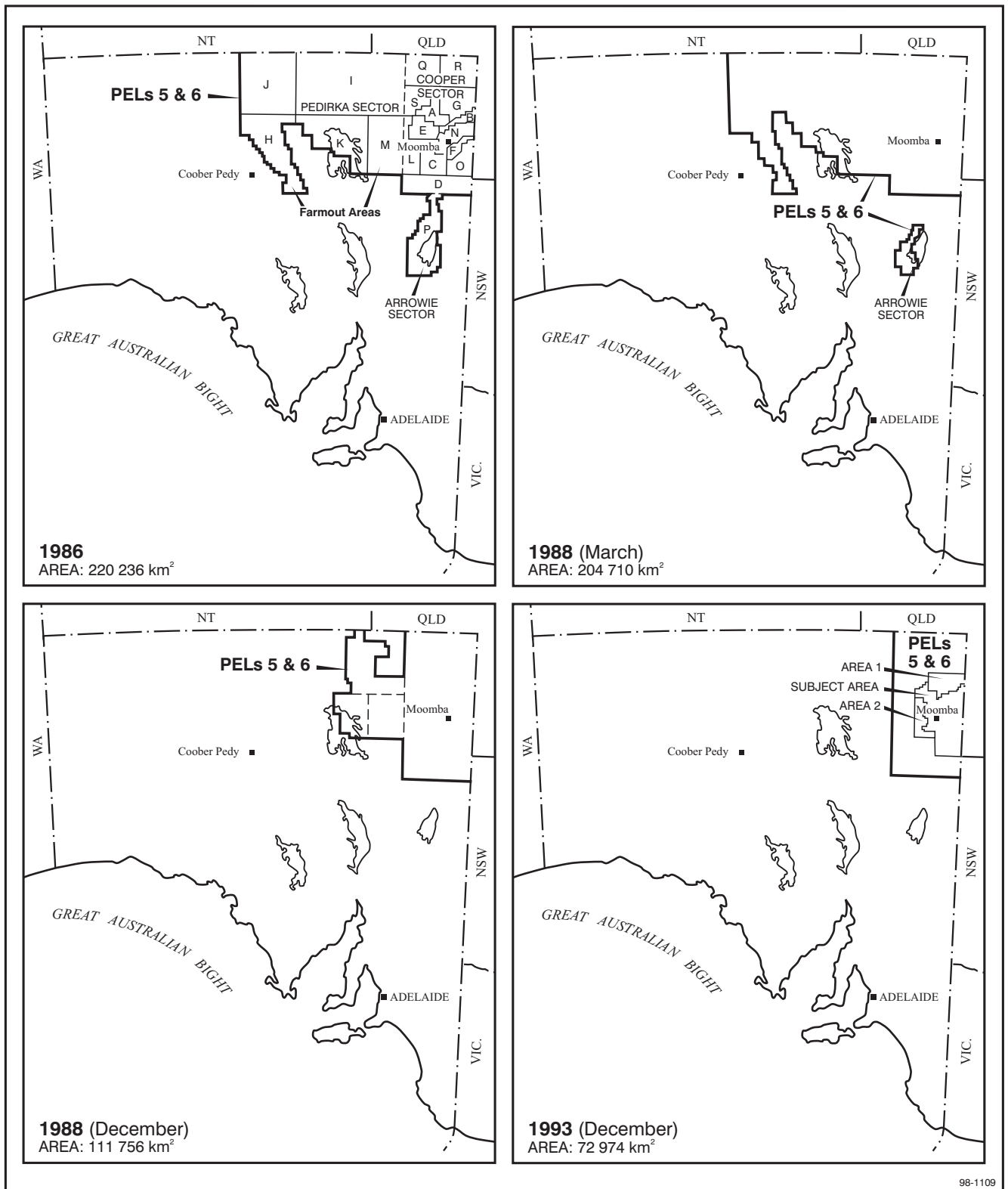
*Rudi Brunnschweiler (left) and Heli Wopfner at Betoota airstrip with the Sokol aircraft during the first light plane reconnaissance of the Cooper Basin, July 1957. (Courtesy of H. Wopfner; photo 46049)*



**Fig. 2.5** Tracing the broad trend of the area acquisition and relinquishment in the Cooper Basin, South Australia from 1955 to 1998. Note that the period from 1959 to 1969 is not shown: the area remained the same as for 1955 to 1959 but OEL 7 was renamed OELs 20 and 21. The outline of the area has not changed since 1993.

expertise that an American oil company could provide as a risk-taking partner which would accept the reality of drilling a few dry holes while pursuing exploration goals more broadly. His recommendation to bring in a partner was based on his belief that if Santos had an area with at least 3050 m of sediments then hydrocarbons in commercial

quantities were almost certain. He recommended Delhi-Taylor because of its reputation for ‘excellent seismic exploration, a well-site technology unsurpassed and a determination to break new ground’ along with numerous success stories to justify this reputation (*Australasian Oil and Gas Journal*, 1958). In December 1957 Delhi-Taylor’s



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Vice-Chairman, two geologists and a geophysicist inspected the anticlinal structures that Wopfner had investigated.

In addition, Levorsen had recommended that encouragement be offered to the petroleum industry through government subsidies for exploration and implementing geophysical surveys (Gibbs, 1988; Passmore, 1994). While South Australia already promoted the search for oil through its legislation, the Federal Government acted on Levorsen's suggestion for stratigraphic drilling in an approved

Australian basin to be subsidised on a £-for-£ basis. The Petroleum Search Subsidy Scheme under the *Petroleum Search Subsidy Act 1957* subsidised stratigraphic drilling by private companies in some sedimentary basins to the tune of £500 000 initially and then £1 million from 1959, when a second Act allowed for subsidies for geophysical work. The Federal Government also provided taxation concessions for investors in oil exploration companies and for the companies themselves.

The arrangement when Delhi joined the search in May 1958 was for it to be the operator of the geophysical and geological work, to drill two deep wells (one each in South Australia and Queensland) and to acquire a 50% interest in a geological, seismic and drilling program (spending at least £2 million over the ensuing four years) in the licence area. The company formed Delhi Australia Petroleum and opened an office in Adelaide. Its combination with Santos became known as Delhi-Santos. The partnership also looked for extra financial assistance: Frome-Broken Hill's earlier lack of success in South Australia had not deterred its hopes and the company joined Delhi-Santos as an equal partner in March 1959. This method of a licensee farming-out areas to others prepared to farmin to a joint arrangement was legislated for in 1958. Amendments to the *Petroleum Act*, which were to favour Santos and Delhi, also allowed the creation of a chequerboard system through which licence areas could be subdivided so that other companies could participate. The time for working the new blocks was extended from one to five years. Frome-Broken Hill's farmin agreement was a temporary one under which it was to pay for the drilling of three wells in South Australia and Queensland to earn a one-third interest in OELs 6 and 7.

The Mines Department undertook seismic investigations in largely unknown sand covered areas near Innamincka, which had become a ghost town by 1954 because of a decline in the pastoral industry, and into South-West Queensland from August 1958 to May 1959 for Delhi. Playford had acceded to Delhi's request to improve and expand the seismic operation prior to this survey. The departmental seismic crew was contracted by Delhi to shoot traverses across and along the Innamincka Dome and a regional traverse from Innamincka via Cordillo to Betoota. The department supplied the technical staff under the leadership of K.R. Seedsman and B.E. Milton, seismic equipment, caravans and two drills while Geosurveys provided non-technical services, carrying facilities including double-decker buses, a drill and other equipment to fulfil the logistical requirements of the survey. Using the advice of Geosurveys, Santos selected a drill site 35 km northeast of Innamincka. The Strzelecki Track, a former stock route which had petered out after the 1930s depression because of a lack of water bores, was then built by the government over the 460 km from Lyndhurst to Innamincka



*Geosurveys adapted double-decker buses as mobile camps for its field survey parties: this bright yellow one was the kitchen at the Innamincka camp in 1958. (Photo T001671)*

to allow the area to be serviced by vehicles involved in the petroleum search (Donovan and Donovan, 1996).

The Premier and the Minister attended the pegging ceremony at Innamincka in February 1959 and drilling commenced at the end of March. Innamincka 1, the first well to drill through the Cooper Basin and to penetrate the full Eromanga Basin sequence, was completed to 3852 m by November. It reached gently dipping Ordovician beds (which were assigned questionably to the Devonian at the time and for the next 30 years) and revealed thin Permian sediments beneath a thick Triassic sequence. Oil and gas prospectivity was suggested by minor hydrocarbon shows in sediments within the Mesozoic succession. Thirty-five cores were taken during the drilling and ten drillstem tests were run. These provided evidence of gas with water and oil-cut mud in the Permian and Mesozoic which encouraged further exploration.

The Delhi-Santos search also included areas in South-West Queensland where Santos held ~175 084 km<sup>2</sup> under Authorities to Prospect 66P and 67P around Haddon Corner. In 1958 the companies proposed that the South Australian and Queensland governments consider the areas in the two States as one exploration prospect: the whole area under consideration was larger than the State of Texas (*Australasian Oil and Gas Journal*, 1958). OELs 6 and 7 in South Australia expired in February 1959 and were reissued as OELs 20 and 21 (~457 520 km<sup>2</sup>). Delhi-Santos's interest in the Cordillo Downs area had led to access roads being built together with an airstrip at Haddon Downs for larger aircraft. In the event, the companies could not achieve their



*Drilling Innamincka 1. (Photo T001689)*

The drilling crew was running joints of pipe into the hole in rapid succession as they prepared to conduct a drill-stem test on the Innamincka No. 1 exploratory well in South Australia. Engrossed in their work, they paid scant attention to a man sitting on an apple box next to the driller on the derrick floor.

But the man's eyes were glued on the crew as they lowered more and more lengths of pipe into the hole. Suddenly, a messenger ran up and said: 'It's dinnertime, Sir Thomas.'

Thus Sir Thomas Playford, Premier of South Australia, arose from his apple box and journeyed to the camp for his evening meal. But as soon as he finished eating he wasted no time getting back to his favourite perch.

'It's quite a bit different from putting down a percussion drilled water well on my fruit orchard,' he observed.

The Premier's vigil on the apple box at Innamincka symbolized the interest of people all over Australia in Delhi's exploratory drilling program in the vast, primitive, outback region. The Great Artesian Basin lies underneath this area of Central Australia.

*Sir Thomas Playford's personal interest in the oil search impressed Delhi as the company's magazine indicated admiringly (Delhi-Taylor Oil Corporation, 1960, p.8).*

aim to work their holdings as a whole: the exploration and development programs were operated and reported to the respective governments independently. But in 1960 the South Australian Mines Department participated in drilling Betoota 1 in Queensland. That well went through the same sequence as at Innamincka but on the flank of a structure and it ran into a conglomerate so the well was stopped. Frome-Broken Hill withdrew from its farmout agreement with Delhi-Santos after Betoota 1.

## THE BREAKTHROUGH

Discoveries of oil and gas in the first half of the 1960s in Queensland, the Northern Territory, Western Australia and offshore Victoria continued to encourage speculators, investors and companies. The general mineral boom of that decade brought many large and small overseas and Australian companies onto the petroleum scene. For example, Sprigg with others formed and promoted Beach Petroleum in 1960 and later held licences in the Northern Territory and elsewhere. In 1962 H. Harvey (a Santos director since 1957) arranged for Total Exploration, a subsidiary of the French Petroleum Co. (Australia), to inject £800 000 into Delhi-Santos by purchasing one million shares. More foreign and interstate capital came to the fore after a gas discovery was made in 1963: Burmah Oil, for example, joined in the search in 1965. The State Government readily accepted that foreign capital and imported technology and expertise were necessary in the search and development phases.

From 1960 the aeromagnetic and gravity surveys became better organised and more systematic. New seismic techniques and technologies and exploration strategies in the industry led the Mines Department to expand its operations to focus on 'soft rocks' for petroleum. Its geophysicists worked in the vicinity of Birdsville from July to November 1960 and work was carried out at Durham Downs and Innamincka Dome for Delhi between August and

We got to the point below the water-bearing sandstone where we hit a lot of hard red rock ... an ominous sign. The Director was coming into my room the moment any core arrived and chewing his fingernails. Playford was personally very interested in what went on. When they hit the red rock they thought they had hit bedrock. I didn't know either because I didn't know what went on below the Jurassic sandstone. I wrote to a friend [Dorothy Hill of the Department of Geology at the University of Queensland] and said, 'Could you send me some samples down urgently of what you are drilling through in Queensland in the sequence?' She sent me down a selection of relevant specimens and that was all I had to go by, what they were drilling through below the aquifer sandstone. I looked at the samples and thought, 'This is not bedrock.' I didn't know quite what it was. The Director was in my room at the time and he was very distressed to know whether we were in bedrock and I said, 'Hold your horses, we are not in bedrock yet', so he went off. And then we ran into coal far below that, which made it even funnier. That coal was probably Permian, so we were well above bedrock.

Finally we went through the coal, unknown sections, and we went into some other very hard rock. Red. Red is usually the bad sign, because it is not very marine. I suddenly recalled that I had seen some red sandstones very similar to this in samples of Devonian from western New South Wales. I thought, 'Someone has got to say something or someone around the place will have a stroke, so I will make a stab at it.' So I said to the Chief Geologist [Tim O'Driscoll], 'I think we are in the Devonian because I have just been picking through the cuttings and I think I saw some shelly bits that remind me of some bits I saw in the Devonian rocks from western New South Wales.' So they remained in that rock, nobody had a stroke, and eventually they just drilled on and on; it was still in the same formation so they eventually decided to stop the bore ...

They accepted the fact that it was Devonian ... Afterwards I modified it a bit to say it could be Cambrian because we have got some Cambrian red beds out on the eastern side of the Flinders Ranges. It could be those but that is the only alternative. But it is not Precambrian and it is not all that old, just hard.

*The experienced departmental palaeontologist, Dr Nell Ludbrook, describing the excitement associated with drilling the wildcat Innamincka 1 well (O'Neil, 1989b). Zang (1992) and Cooper (1986) have shown this to be Ordovician.*

November. A field party continued seismic shooting from Birdsville to Marree at the end of May 1961. The search was encouraged by the news in December 1961 of the discovery and potential of the Moonie oil field in Queensland, where Australia's first production of oil in commercial quantities began in 1964 (Wilkinson, 1988).

The results of the department's seismic surveys in the northeast between 1960 and 1964 helped to define structural trends in the Cooper Basin and were particularly important in identifying the Gidgealpa-Merrimelia-Innamincka (GMI) Ridge, with the consequential discovery of natural gas. But ultimately the situation developed to the stage where the department could not justify undertaking work which contract seismic crews should have been doing at that stage of exploration. As the expense of continually modernising the department's equipment was not justified, after 1964-65 its operations were scaled down and the

detailed seismic work was left for contractors operating for exploration companies. The use of foreign seismic contractors such as Namco, United Geophysical and Geophysical Services International resumed a trend that Frome-Broken Hill had adopted in the late 1940s (Hollingsworth, 1989). The department's seismic field work was then directed to lesser known provinces to encourage exploration in neglected areas like the Frome Embayment, the Officer Basin and the Arckaringa Basin. But it maintained its strong interest in geophysical interpretive work and departmental geologists continued to inspect wellsite operations and analyse the preliminary data, such as cuttings samples, cores and wireline logs.

Controlling an orderly petroleum search was important and the department's Petroleum Exploration Section (formed in January 1962, which became a Division in mid 1965) maintained oversight of company activities, recorded the data obtained by private drilling, conducted independent reservoir assessments, ensured that aquifers were protected (so that subsurface waters of different salinities did not mix), supervised the maintenance of wellsites (especially so that they were cleaned properly and restored after drilling), advised the government on gas pipeline matters and, primarily, retained the information for public distribution under the *Petroleum Search Subsidy Acts* which required publication of the information after six months. Releasing information promptly enabled the exchange of ideas, which encouraged more petroleum exploration.

The surface structures at Innamincka and Betoota were bald-headed: the Permian rocks did not extend over the crest of the structures. After seismic work in 1960 and 1961 a large subsurface structure without surface expression 65 km south of Innamincka was drilled in 1962. Dullingari 1, the first well to be sited using seismic survey results, penetrated thick Eromanga and Cooper Basin sequences, including more than 610 m of Permo-Triassic sedimentary rocks and showed unmetamorphosed sediments unconformably underlying the thick Permian strata. Gas shows were encountered in the Permian but equipment problems meant that the reservoirs were not evaluated. Delhi-Santos wells in South Australia in 1963 (Pandieburra 1 and Putamurdie 1) and Queensland (Orientos 1 and Narylco 1) extended the knowledge of the area's geology and justified more exploration. Although these wells were plugged and abandoned, they revealed sediments with petroleum potential. They were all on-structure, where the Permian was often missing, and so it was decided to test off-structure.

Spudded in August 1963, Delhi-Santos's first off-structure well on the eastern flank of the GMI Ridge, Gidgealpa 1, penetrated a thick Permian section with several sands with good reservoir properties (Wopfner, 1966). A fossiliferous Cambrian carbonate sequence with porous zones tested gas-cut salt water. The drilling focused on the early Palaeozoic sediments and the Permian section, which contained gas shows, was so badly washed out and caved that it could not be tested. Although the logs showed excellent porosity in the Permian sands Santos was reluctant to proceed. Acting on the advice of Wopfner, the State Government then insisted that the Permian sands be tested at any cost or another well be drilled on the same structure (Wopfner, 1963, 1990).

Gidgealpa 2 was drilled on-structure and drillstem tests in the Permian sands after the discovery of gas on 31 December 1963 indicated a flow of 56 634 m<sup>3</sup>/day (2 mmcf/d). On completion the well produced gas and condensate. Five development wells were then drilled to test the extent of the field, which was determined at 18 km in length by 6.5 km in width. Delhi-Santos's primary objective had been oil: gas was a secondary consideration. In the circumstances, Delhi-Santos sought to utilise the gas discovery. This testing of commercial quantities of gas from the Permian was the first petroleum discovery in the Cooper Basin and led to further drilling.

There was controversy between the joint venturers as to whether or not Gidgealpa 2 should be drilled: Delhi's view to drill prevailed despite the financial constraints to do so. The department's support and the interest of the Premier and Minister at the political level were crucial (O'Neil, 1995). Playford had approved the formation of a second seismic team to work in the South-East because he was anxious over progress in the Cooper Basin. He wanted work to proceed there without interruption and so intervened when Delhi-Santos were about to cease drilling. The department and its Minister had little trouble in convincing the Premier to persuade Delhi-Santos to continue, although they had ostensibly fulfilled the licence requirements. The strong stance over Gidgealpa was justified and further discoveries gave rise to the questions of how best to develop the gas and would it be commercially viable or just become a 'graveyard of Christmas trees'.

The impact of the Gidgealpa discovery was obvious: by the mid 1960s licences were held by oil and gas explorers for most of the State. In March 1964 Levorsen again visited Adelaide for further discussions with Playford and McEwin. Their vital interest in oil and gas was evident when they attended a talk by Professor E.A. Rudd on a possible petrochemical industry based on the gas finds (*News*, 1964). Less than a decade before, Playford had approached the Dow Chemical Co. to ascertain its interest in such a possibility.

On top of the large licence areas available in South Australia, the Petroleum Search Subsidy Scheme had encouraged investment from overseas: 'There is little doubt



*Norman Miller, Chairman of Delhi-Taylor Oil Corporation when Gidgealpa 2 was drilled, indicating the location of the discovery on a seismic section at the American Association of Petroleum Geologists' Conference, San Diego, May 1996. (Photo 46506)*

We had looked very closely at the logs and the results of Gidgealpa 1, which had incidentally encountered a beautiful permeable section in the Permian. That Permian section had been washed out so badly by sloppy drilling that it was impossible to test most of it because you couldn't find an open hole test tool for it. It was equally impossible to set casing in cement because there wasn't a perforating tool which would be able to perforate that thick cement jacket. Now knowing that, we suspected, again on the logs, that some of the sands could be prospective. We knew from the seismic the sands would thin across the Gidgealpa structure but there was still good evidence that a thin Permian sand cover would extend right across the anticline.

We therefore suggested that they should drill a second hole or, knowing damn well that there wasn't a tool in Australia which could do the job, test the Permian section in Gidgealpa 1 to the Minister's satisfaction. This we were able to do under the *Petroleum Act* and we demanded that the companies fulfil the wish of the Government to test the Permian section in Gidgealpa 1 or alternatively drill a second well on structure or near the structure culmination.

Of course this started a really extensive controversy between geophysicists, between geologists and between the various companies. Santos and Total didn't want to have a bar of a second well. They didn't want to test either, because they knew they couldn't. Delhi was divided: the Chief Geophysicist of Delhi, Frank Hinson, resigned from Delhi because he was of the opinion that the structure would be bald-headed. This was at a party given to the honour of Norm Miller and some other high ranking people from Delhi's US organisation, who again had come out to settle some of the argument. It was at that party given by Ralph Freeman (a Senior Geologist with Delhi) that Frank put down the law and told the Chief Geologist of Delhi in no uncertain terms what he could do with his job. It was great fun.

Finally it came to a meeting at the Department: the participants were Tom Barnes, Lee Parkin, John Klug from Santos, who was then Operational Manager, Reg Sprigg, also acting on behalf of Santos, Jeff Greer from Delhi, Claude de Lapparent from Total and me. The Department made it quite clear that we would not budge from our position: either one of the works would have to be carried out. So they left. Delhi was inclined towards the second well. Then the whole thing actually went back to the Minister. It went to Tom Playford and it took Tom Playford's well-known gentle persuasion and arm twisting with some of the Directors of Santos that Santos would finally agree that the second well would be drilled. That second well was Gidgealpa 2.

*Heli Wopfner relating the flavour of the times (O'Neil, 1989a). Wopfner's diaries, PIRSA (1963) and O'Neil (1989c, 1990) support Wopfner's account that the department's insistence on Gidgealpa 2 being drilled led to the gas discovery.*

that the *Petroleum Search Subsidy Act* was one of the major factors which led to success in the search for petroleum, both oil and gas, in this country. It was one of the features which encouraged overseas capital into the search in Australia' (Rudd, 1966). Having induced overseas companies to Australia, the industry came to rely on them for growth and support, especially as many of the local companies did not have sufficient capital to qualify for subsidy payments or to sustain proper programs. Delhi-Santos, for example,



*Gidgealpa 2 capped by a 'Christmas tree' and ready for gas production. (Photo N013046)*

received more than £1.5 million in drilling and geophysical subsidies, which placed the partners fourth on the list of subsidy recipients from 1958–59 to 1963–64 (*Australasian Oil and Gas Journal*, 1965). Over time there were numerous revisions and refinements to the scheme. Some such as the amendments in 1964 adversely affected exploration in the Cooper Basin: they removed the subsidy for borehole surveys and detailed structure drilling, reduced the subsidy rate for test drilling and stratigraphic drilling, and introduced exclusion circles. The latter, 'one of the more controversial modifications to the Acts', were 'defined areas around discovery wells and fields which were excluded from subsidy' (Passmore, 1994). The 64 km circle imposed around Gidgealpa and Moomba included the most significant discoveries in the basin to then. The original drilling at Gidgealpa had been subsidised under the scheme.

Assessing the potential of the Gidgealpa Field and further exploration in the region occupied much of 1964. Four wells were drilled on the Merrimelia structure in 1964 and 1965 and the first recorded sign of oil, apart from dull yellow fluorescence, in Triassic sediments was made in



*Unable to conceal his delight at the optimistic developments at Gidgealpa, Premier Playford displays a beer bottle containing the first distillate from Gidgealpa 2 while the General Manager of Santos, John Klug, looks on approvingly at Adelaide Airport, 16 February 1964. (Courtesy of the Advertiser; photo 42772)*

Merrimelia 2. A non-commercial gas flow was made at Merrimelia 4. A perceived lack of porosity and effective permeability was considered to count against Merrimelia containing commercial hydrocarbons. More significantly, the discovery by Delhi-Santos of natural gas at Moomba 1, drilled from March 1966 further vindicated the department and the believers in the industry. Several exploration wells at Moomba, 30 km south of Gidgealpa, proved the existence of large widespread gas reserves and paved the way for the Cooper Basin to be developed.

## SECURING DEVELOPMENT

After the Innamincka pegging ceremony in 1959, Playford apparently learned from Delhi's Deputy Chairman that the company was more interested in controlling pipelines than in the oil and gas itself (Sprigg, 1993). The Premier then organised a study of the relevant American legislation to ensure State ownership of any pipeline development. In the March 1965 election campaign, he promised a new power station capable of utilising natural gas would be constructed at Torrens Island (Adelaide) and that there would be a pipelines authority to control the gas supplies. Despite the Playford Government's defeat at this election, the proposals were proceeded with by the in-coming Australian Labor Party (ALP) Government. The ALP Premier, F. Walsh, the new Minister of Mines, S. Bevan, T.A. Barnes (Director of Mines, 1956–70) and L.W. Parkin (then Deputy Director of Mines) travelled to the USA and Europe for almost three months in 1966 to examine pipeline developments. While overseas the news of the Moomba discovery reached them and made it clear that South Australia had an energy resource that could be developed. The probability of a pipeline being constructed to carry the gas reserves to Adelaide was confirmed.

The State Government wanted to build, own and operate the pipeline to carry the gas to Adelaide but the expense was beyond South Australia's financial capacity. The proposal required a combination of Federal and State Government and private sector (the gas producers and consumers) capital. This was in line with the model studied overseas. A State instrumentality could also secure lower interest rates and a longer loan repayment period. The Natural Gas Pipelines Authority of South Australia (PASA) was established by the *Natural Gas Pipelines Authority Act 1967*. Based on the structure of the Alberta Gas Pipelines Authority, the initial PASA Board comprised representatives from the State Government (two) and one each from the Electricity Trust of South Australia (ETSA: established in 1946, now ETSA Corporation and Optima Energy), the South Australian Gas Co. (Sagasco: established in 1861, now Boral Energy), Santos and Delhi. PASA was given the power to construct and operate pipelines for carrying natural gas and related substances within South Australia.

The tide turned in securing the pipeline development when ETSA, Sagasco, Adelaide Cement and South Australian Portland Cement all agreed to purchase natural gas (Donovan and Kirkman, 1986; Gibbs, 1988; Young, 1990). ETSA in particular had to be convinced that there was a place for gas: it was reluctant to build a power station fired by gas when the known reserves were minimal while a station had a 30-year write-off period. The decision to convert its planned coal-burning station at Torrens Island to



*The Moomba Natural Gas Processing Plant under construction in September 1969. (Photo N019880)*

gas was vital: the Adelaide market was large enough to justify the cost of pipeline construction. But for Cooper Basin gas to compete, the price had to be at or below the price of fuel oil or coal from New South Wales, the main alternatives available. To justify significant use of gas, the price also had to be below the cost of Leigh Creek coal. ETSA remained a stumbling block in the negotiations over gas supplies and prices: because it could use either oil or gas for generating electricity it had a valid commercial reason not to buy gas instead of oil unless the price was more favourable. ETSA made a few minor concessions but the producer companies were forced to agree to its terms, which included a 20-year contract for specified volumes of gas at an average price of 26 cents per 1.055 gigajoule (GJ) delivered in Adelaide, without regard to the effects of inflation (Young, 1990).

The 56 cm outside diameter pipeline over 750 km from Moomba to Adelaide was completed in July 1969 and was opened officially at Elizabeth in November. For many years Sagasco had distributed a town gas blended from coal gas, LPG and other hydrocarbons to Adelaide and some regional centres. Converting to natural gas, initiated in 1969, was completed in the metropolitan area in early 1971. Adelaide was the second city in Australia (after Brisbane) to be provided with clean, and cheap, natural gas through a pipeline (Donovan and Kirkman, 1986).

Other legislative changes also reflected the importance of the petroleum search. Amendments to the *Petroleum Act* in 1958 increased the terms of exploration and prospecting licences to five years with the right of renewal. Then in 1967 the Act and its regulations underwent a major revision and redefined many of the terms to account for recent developments and petroleum research. These amendments strengthened the power of the Minister to enforce exploration and production. The 1967 Act renamed the OEL as a petroleum exploration licence (PEL), the oil prospecting licence was repealed and the oil mining licence was replaced by a petroleum production licence (PPL). The area for a PEL was not to exceed 25 900 km<sup>2</sup> and a five-year exploration program had to be maintained. Upon each renewal of a PEL at least a quarter of the area granted originally was to be excised from the lease. The PPL, for up to 259 km<sup>2</sup>, was granted for 21 years with the right of renewal: it imposed a royalty of 10% per annum of the value of the petroleum at the wellhead. The Act provided for the



*The Moomba Natural Gas Processing Plant in November 1969. (Photo 43830)*

conservation of resources, the prevention of operations contaminating water or petroleum-bearing formations, 'proper' drilling operations and the disposal of associated waste products. Pipeline construction and operation required licences. A Petroleum Advisory Committee was established to consider appeals and objections to the Minister's decisions under the Act.

Delhi-Santos's OELs 20 and 21 were reissued in March 1969 but were not converted to PELs 5 and 6 (an area of 497 450 km<sup>2</sup>) until after 30 June 1969 (Fig. 2.5). At that time the licensees reduced their area by surrendering the region seaward of Eyre Peninsula. PELs 5 and 6 were issued for a guaranteed 20 years without area relinquishments and with nominal exploration requirements and the right of renewal for a further 20 years, an option which was revised at the start of 1979.

The *Natural Gas Pipelines Authority Act* and *Petroleum Act* extended the Government's powers and authorised it to control and regulate the oil and gas exploration, development and production processes. The oil and gas below the surface and the production and transport facilities above were increasingly under Crown control.

## PROVING UP THE COOPER BASIN

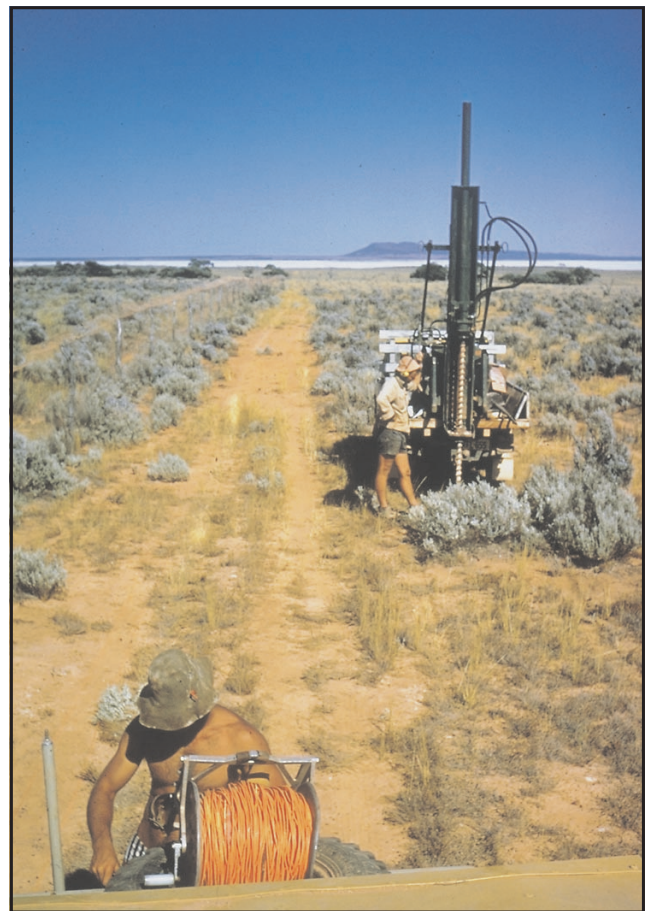
### Gas and oil exploration

The perception of South Australia being deficient in energy resources was slowly overturned. Natural gas in the Permian reservoirs at Gidgealpa and Moomba showed that the Cooper Basin was a gas province and the opening of the Moomba-Adelaide pipeline demonstrated the commercial viability of the region. The oil potential remained a tantalising possibility however.

The boom that permeated the Australian mining scene in the 1960s introduced several exploration companies to the Cooper Basin as partners with Delhi-Santos in specific areas (farmout blocks). Farmin arrangements injected badly needed capital to the petroleum search in 1969 and 1970 and, partly as a result, sufficient discoveries were made to compete with Esso-BHP's Gippsland Basin gas for supply to Sydney. Participants in the Cooper Basin included Vamgas, Bridge Oil, Alliance Petroleum Australia, Crusader Oil, Pexa Oil and Western Mining.

In 1970 more than 5000 km of seismic data were recorded and 20 exploration wells drilled in the Cooper Basin region. The Della gas field was discovered in July 1970 by Pursuit-Delhi-Santos-Vamgas with their first well on the Nappacoongee-Murteree Ridge (Pycroft, 1973). In 1969 Alliance had earned a 50% interest in the Merrimelia-Innamincka Block through an agreement with Delhi-Santos-Vamgas: Alliance then drilled Merrimelia 5 which was completed as a gas producer in 1970 (Bowering and Harrison, 1986). Other Cooper Basin gas discoveries in 1970 were Packsaddle, Tirrawarra, Mudrangie and Strzelecki. Bridge Oil's announcement in July 1970 of a gas flow from the Patchawarra Formation and light crude oil in the Tirrawarra Sandstone at Tirrawarra 1 indicated that the long search for oil might at last pay dividends. Although this first oil to flow to the surface in the basin indicated that oil in commercial quantities existed in South Australia, the extent of the reservoir and how it might best be brought to market remained to be established.

Tirrawarra brought a liquids pipeline to the coast into serious contention but flooding at Moomba during 1971 slowed an evaluation of the area. The discovery set the scene for more exploration in the basin with gas being found at Big Lake, Coonatie, Dullingari, Burke, Brumby and Kanowana in 1971 and 1972, as well as oil and gas at Fly Lake and Moorari. In addition, the gas reserves were revised and upgraded in several instances such as Toolachee, Della and Tirrawarra (Hollingsworth, 1989). Between July 1970 and April 1972 a further six wells were drilled on structure at



*A small-scale Department of Mines seismic refraction survey, 1973. (Photo T023007)*

Della where five of the seven wells produced gas (Pycroft, 1973). The number of potentially significant gas reservoirs in the northeast was growing (Wopfner, 1972).

Meanwhile in December 1972 R.F.X. Connor became the nation's first Federal Minister for Minerals and Energy (1972–75). Connor's resolute pursuit of his own or the ALP's policies wrought havoc in the resources sector. He advocated a national natural gas pipeline grid across the continent; a uranium processing and export industry; alternative energy sources to reduce reliance on overseas oil; the establishment of a petrochemical industry; increasing Federal control over the seas and submerged lands around Australia; and a government Petroleum and Minerals Authority (PMA) to undertake mineral, oil and gas searches and development and to provide venture capital to replace much of the current overseas investment. The PMA was established in 1974 with the funds being raised by the Federal Treasurer abolishing both the drilling subsidies under the Petroleum Search Subsidy Scheme and the tax concessions to mining companies controlled by overseas interests.

In order to develop local reserves for later export while seeking to maximise the prices of what was exported, Connor placed export controls on mineral and energy resources. South Australia's interests were affected when the Federal Government banned the export of LPG in 1974 because Connor wanted it marketed locally. He restricted the involvement of foreign companies such as Aquitaine and Delhi by insisting on at least 50% Australian equity in uranium, natural gas and coal projects. One result of the Federal policies for marketing indigenous oil and gas was the pronounced decline in exploration and development in the South Australian Cooper Basin: in 1973 one well was drilled and none in 1974 and 1975 and few seismic surveys were conducted (Hollingsworth, 1989). The exclusion circle provision of the Petroleum Search Subsidy Scheme was removed in 1972 and the subsidy rate for onshore geophysical operations returned from 30% to its original 50%. However, the scheme was closed in June 1974, with work approved before then continuing until 1976 (Passmore, 1994). In 1975 the Federal Government introduced a levy of \$106.29/kL (\$16.90/bbl) on all old oil production once more than 318 000 kL/year (2 mmbbl/year) were produced. These political decisions added to the difficulties of working in the Cooper Basin and introduced unwelcome delays to plans for development.

In 1974 Aquitaine negotiated a purchase of part of Delhi's interests in the Cooper Basin but the Federal Government withheld its approval. Instead the Government bought 25% of Delhi's interests in all new fields discovered after 1974 and 50% of its production interests in all fields discovered before 1974. In the areas of PELs 5 and 6 which had not been farmed out Vamgas derived a 20% share of Delhi's interests and the Federal Government had a 25% interest less the Vamgas-derived interest, but excluding fields discovered before 1974. In the non-farmout areas this meant that the respective interests, in effect, were Santos 50%, Delhi 30%, Vamgas 10% and the Federal Government 10%. This arrangement was on a par with the conditions that Aquitaine had been negotiating. In 1975 the High Court of Australia adjudged the formation of the PMA to be illegal

and the Fraser Government subsequently sought a buyer for the interest (see below).

Drilling activity recommenced in 1976 and Namur 1, which discovered gas in the Jurassic Namur Sandstone, focused attention on the Eromanga Basin. As the first economic petroleum discovery in the South Australian sector of that basin, Namur led to a change in thinking about its prospectivity. In 1978 the first commercial oil was discovered in the Eromanga Basin in the Hutton Sandstone at Strzelecki 3: the field came on stream in 1983. The well was intended to test the Permian (following up gas shows which had been detected in Strzelecki 1 in 1970) with a secondary Jurassic target: the Cooper Basin was still considered the prime target. However, the well established the Eromanga Basin's petroleum potential and encouraged more exploration targets to be drilled. Another oil discovery in that basin, Dullingari North 1, spudded in August 1979, was drilled to test the gas potential to the north of the Dullingari gas field where the first well had been drilled in 1962 (Mount, 1981). Dullingari 1 had penetrated shallow Eromanga oil and Permian gas but neither were recognised and it was completed as a water bore. The gas discovery well, Dullingari 2, was not drilled until 1972 and was followed by gas appraisal wells Dullingari 3 and Dullingari 4, the latter also revealing some oil.

From the earliest time the Cambrian was always a target and eventually that oil turned up [with] gas in the Permian. The Mesozoic through all this time had been overlooked and it was because some escaping oil from some of the existing holes mystified people as to where it was coming from that the potential of oil in the Mesozoic emerged and a whole new era of exploration developed as a consequence ... In some ways it is a vindication of the original concept developed by Sprigg when he first got people interested in the whole area.

*Bruce Webb commenting on the shift to the Mesozoic as the target zone (O'Neil, 1993). Note that Owen Nugent (a senior geologist with Delhi at the time), though conceding that most of the Jurassic was flushed by artesian waters, suggested that the lower Hutton (Poolowanna Formation) might provide stratigraphic trap potential by virtue of its position over 'prospective Triassic and Permian sediments' (Nugent, 1969, p.107). This radical viewpoint, recognising the possibility of hydrocarbon migration from the Cooper into the overlying Eromanga Basin, was returned to 20 years later: it is now considered to account for much of the Eromanga oil in the Cooper region.*

These discoveries led to an upgrading of the oil prospectivity of the region and a reappraisal of known structures. Changes in drilling practices and philosophies were key components in the new finds. Initial search in the Cooper region targeted Mesozoic rocks, but the drilling had been on structures where the Mesozoic was thin, poorly developed or non-existent. In 1963 the search shifted to the Permian following the Gidgealpa gas discovery: Mesozoic sediments were drilled through with little regard before testing the Gidgealpa Group (Sprigg, 1982, 1983a). Thus by the late 1970s a broader perspective and imagination was being applied to the petroleum search in the region.

## Gas to Sydney and a petrochemical plant

The Cooper Basin's emergence as a significant national development involved questions of public ownership and control. Natural gas was a key, cheap, reliable and efficient energy resource but dilemmas over the related questions of the price and future of gas supplies were matters of concern. The problems were exacerbated by the agreement in May 1971 between the producer companies, the South Australian Government and the Australian Gas Light Co. (AGL) to supply gas to New South Wales. The Queensland Government consented to the dedication of three small fields (at that time all the gas discovered in South-West Queensland) to the agreement. Subject to the proving of adequate gas reserves in a number of dedicated fields, AGL was to be provided with  $56.6 \times 10^9 \text{ m}^3$  (2000 bcf) of natural gas (Schedule B) until 2006 with an option of a further  $22.7 \times 10^9 \text{ m}^3$  (800 bcf; Schedule A) after additional reserves were established. This took priority over developing supplies for Adelaide: contracts for South Australian customers then only ran to 1990. By September 1972 sufficient reserves to fulfil Schedule B had been established and the agreement became binding. There appeared to be good potential for future discoveries to cater for the Adelaide market from 1991.

The State Government supported the expansion of gas sales, since it opened up the possibility of developing a petrochemical plant: the Minister for Mines had consented to the agreement, subject to there being sufficient reserves for a petrochemical project. The gas discoveries in the early 1970s had encouraged the companies to plan treatment facilities and they investigated the processing of the wet gas and liquids that would be available after dry gas had been produced for Sydney and Adelaide, including the storage and use of ethane as the feedstock for ethylene production at a petrochemical plant. An environmental impact inquiry in 1973 approved Redcliff on the northern Spencer Gulf as the site for a petrochemical complex. Local companies did not have the capacity to commit themselves to a project of the magnitude envisaged and so the State Government looked to overseas interests to establish the industry either individually or as part of a consortium. Dow Chemical expressed interest in 1973 in developing a complex but the project depended on there being sufficient proven and probable reserves of gas after meeting the market demands.

The agreement had been made with AGL for several reasons: the development of the Cooper Basin was ensured by the arrangement because it guaranteed the companies a sizeable and profitable market; a spin-off from the development would be a petrochemical plant; to provide for an annual renegotiation of the gas price, by arbitration if necessary; and to encourage an active exploration program for discovering additional supplies of gas for Adelaide. The dilemma, however, was that the accelerated rate of exploration required to meet these expectations would be satisfied only by securing longer term pricing arrangements. The price of gas had to be sufficient so that the companies could be induced to continue exploring, otherwise there was little incentive for them to do so.

Ongoing arguments over gas prices caused long-term difficulties. The State Government was inclined to pay the cost of the gas discovered but nothing extra to ensure future

exploration. The companies were so cost-conscious in these formative years that they perhaps focused on the cost of their programs with fixed concepts in mind (developing known fields) ahead of the benefits from the high risk exploration needed to discover new fields. This was understandable as the companies, who were all struggling to provide capital, desired the successful development of the Cooper Basin to ensure their survival and possible growth beyond being exploration companies with limited or no cash flows.

The companies' need for long-term contracts and to raise capital from their bankers to maintain their operations and develop the Cooper Basin hinged on the pricing issue. The price of gas that had originally been agreed to with AGL was too low in the circumstances that would prevail when the gas was delivered to Sydney. This price was renegotiated in 1973 after AGL was convinced that an increase in the price for its gas was justified and that the price for Sydney should be about the same as that for Adelaide. This led to a significant improvement in the price paid by AGL and gas prices were stabilised for some time.

The pricing negotiations with AGL enabled the major financing necessary to expand the field operations to be arranged. The price had to account for the prospect of liquid discoveries, with the local supplies not being jeopardised by the supply interstate. But the assumption that after finding gas the companies would find oil was not being fulfilled: the initial discoveries of oil were very slender. The long-term contracts seemed unlikely to be sustained by the liquid discoveries. Indeed, the inability to secure a petrochemical plant despite strenuous efforts throughout the 1970s was also a disincentive to explorers discovering liquids-rich gas. This placed considerable pressure on the Producers by making it difficult for them to raise capital for the work because the gas price was so low that at times the prospects did not seem very viable.

An expanded role for PASA was another significant step. As well as being the operator of the pipeline, under the revised pricing agreement PASA took on the responsibility of being the sole purchaser of gas from the producer companies on behalf of South Australia. This was a more convenient and satisfactory procedure with PASA fixing the price and negotiating changes annually. For example, the initial individual contracts with ETSA and Sagasco, which were due to expire in 1990, were renegotiated in 1974 into a single contract between the producer companies and PASA. The contract period was reduced to 1987 with larger quantities of gas being supplied in the earlier years: a \$15 million exploration program was included in order to find gas for beyond then.

## The Producers

Given the mechanics of production and depletion of gas fields, replacing the dedicated field approach with an integrated supply system would rationalise the development of the Cooper Basin, provide economies of scale in production and enable sufficient increased gas production to support gas liquids development. The removal of dedicated reserves in certain fields to specific contracts and the introduction of a unitised system of dealing was achieved when the ten companies working the core of PELs 5 and 6—Alliance Petroleum Australia, Basin Oil, Bridge Oil Developments, Bridge Oil, Crusader Resources, Delhi



Signatories to the South Australian Unitisation Agreement on 21 December 1976. (Courtesy of the Advertiser; photo 42746)

Petroleum, Reef Oil, Santos, Total Exploration Australia and Vamgas—formalised their dealings as the Cooper Basin Producers Unit (the Producers) in 1975. In this the Government and the Producers agreed to a complex procedure for producing and supplying (but not marketing) gas more efficiently. Delhi and Santos continued their joint operatorship, the former for exploration and the latter for development.

The complicated Unitisation Agreement pooled (or unitised) the respective interests in the oil and gas reserves, with the development costs for the production, processing and delivery of the oil and gas to the Adelaide and Sydney markets being shared on the basis of each companies' net reserve ownership. Henceforth, as a group, the Producers could negotiate with PASA while maintaining their individual commercial independence and identity. The agreement also redressed the duplication of facilities: it was far more efficient to build one central processing unit which provided gas at a cheaper cost for the Producers and to the customers. Taking about five years to complete, the unitisation process was reputed to be the first such large-scale agreement concluded in the world: more than 120 principal documents were signed (*PESA Journal*, 1990).

The legislative framework to facilitate the new arrangement, the *Cooper Basin (Ratification) Act* and Indenture, was passed by Parliament in November 1975 but the actual agreements were not signed until 21 December 1976, three days after the gas supply to AGL began. The Act provided *Trade Practices Act 1974* (Cwlth) exemption for a number of agreements including the Producers Unitisation Agreement, an Interim Gas Sales Agreement (a new gas sales contract with PASA expiring in 1987) and the Future Sales Requirement Agreement (another conditional agreement for gas reserves to be supplied to South Australia between 1988 and 2006). In addition, the State Government agreed that AGL's entitlement to Schedule B quantities would take precedence to PASA's contract, while petrochemical fuel and feedstock would have precedence ahead of AGL's Schedule A and future contractual quantities for PASA. Supply to PASA after 1987 was made subject to the proving of reserves in addition to those sufficient to fulfil Schedule A. As well, the Act provided rights to buried pipelines in the Cooper Basin without the need for licences, a special form of PPL with sub-licences in

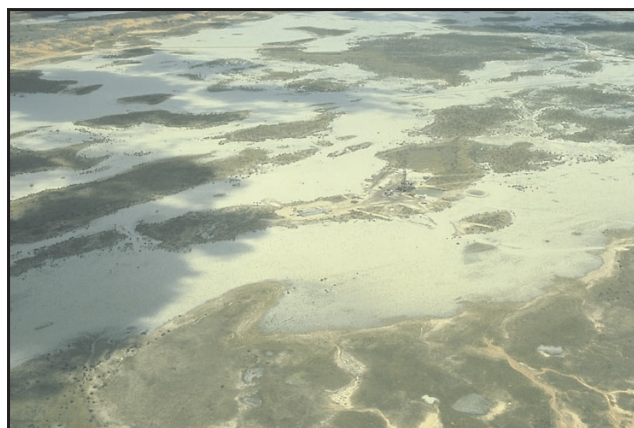
favour of all Producers, royalty limitation provisions, a grant of freehold land at Moomba and certain exemptions from stamp duty and other imposts.

As part of the indenture under the Act, the Producers secured an agreement from the Government to maintain the Strzelecki Track from Lyndhurst to Moomba at no cost to the Producers. This followed the 1974 and 1975 floods which had highlighted problems with the condition of the track. Flooding in December 1975 had again isolated Moomba and closed its airstrip. At the same time, a gas blow-out threatened Big Lake 9: this was averted with the help of Royal Australian Air Force helicopters which flew in barytes from Leigh Creek (Donovan and Donovan, 1996).

## South Australian Oil and Gas Corporation

Commercialisation dominated activities relating to the Cooper Basin in the 1970s, particularly as exploration and production were so severely affected by political factors, but with the arrangements in place there was a reluctance by some Producers to explore beyond the licence requirements. This was understandable at times: oil and gas exploration and development has always been an expensive business and the cost of drilling in the Cooper Basin was about \$300 000 per well and rising in the mid 1970s (South Australian Government, 1976). Although companies had invested capital, time and effort to develop the oil and gas potential, at times their degree of commitment was questioned as the State faced the prospect of its gas supplying AGL until 2006 while contracts only provided supply to South Australia to 1987. The time horizon that the Producers and the State Government had differed because from a commercial viewpoint the companies did not want to put money into exploration when they could not expect a return until after 1987.

The Government's focus was on ensuring supplies of gas for South Australia beyond 1987. As a result of the Producers' intransigence, the Government arranged an independent exploration program through the South Australian Petroleum Exploration Group (SAPEG) which was formed in the Mines Department in 1976 and funded by a levy on gas consumers (Devine [1977]; Young, 1986). The Producers maintained some limited exploration work but SAPEG funded the exploration and drilling of wells under the sole risk provisions of the various joint operating agreements. As operator Delhi carried out the drilling, testing and seismic surveys under SAPEG's instructions: its



Flooding in the Cooper Basin, 1976. (Photo T011895)

first well, Munkarie 1 discovered what ultimately turned out to be  $2832 \times 10^6 \text{ m}^3$  (100 bcf) of gas. SAPEG then tried new concepts in drilling Coochilara and Kirby. The latter was a deep well into tight reservoirs hoping to find permeable streaks. Both were plugged and abandoned, Kirby 1 after sub-commercial gas flows.

SAPEG's future was uncertain: it was initially expected to operate for one year when the concept would be reviewed. Yet again, changing circumstances opened a window of opportunity. The Federal Liberal Government under M. Fraser had determined to sell its holding in the Cooper Basin which the PMA had acquired from Delhi under Connor's 'buy back the farm' policy. The State Minister of Mines and Energy (1975–79), H.R. Hudson, indicated to the Federal Minister of National Resources that he would prefer to see the PMA's interest sold to South Australia. On a trip to the United Kingdom and Europe in 1976 Hudson had investigated government instrumentalities, particularly their energy policies. Based on his observations overseas, Hudson initiated the idea of creating a company to acquire the holding, which was possible because its location within PELs 5 and 6 required the Minister's assent to any transfer. A limited liability company, the South Australian Oil and Gas Corporation (SAOG), was incorporated in September 1977 after SAPEG was hived off from the re-named Department of Mines and Energy.

SAPEG's arrangements with the Producers for exploring in PELs 5 and 6 were transferred to SAOG which then joined the Producers Unit. The State Government was now a significant shareholder in the hydrocarbon reserves of the Cooper Basin. SAOG was a government instrumentality set up to look after the interests of the people of South Australia, yet it was expected to operate as a commercial entity. There was a view that the entity would only last a few years, probably until a decision about future reserves had been made. Few anticipated that the company would grow into an independent explorer/producer in its own right and the Government was ambivalent about the matter. SAOG eventually outgrew its function as an arm of government controlling development in the Cooper Basin and it gradually adopted a more commercial orientation. But there was little immediate monetary gain for the Government because SAOG sought to establish its credibility as an explorer, and as a member of the Producers Unit, by re-investing in exploration and its own future growth. Successive State Governments accepted this, although from 1980 steps towards privatising SAOG were taken.

## COOPER BASIN LIQUIDS PROJECT

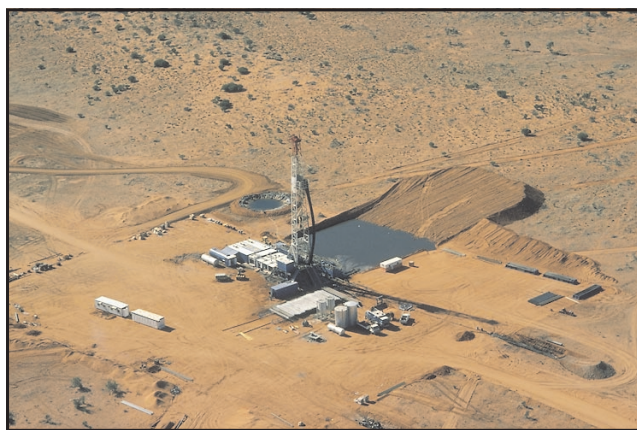
In the 1980s two milestones occurred in South Australia's petroleum resources sector. The first was the demise of Delhi on the local scene. In January 1979 Santos acquired the sole responsibility for the development and production of the Cooper Basin gas and condensate fields. Meanwhile, Delhi became the exploration operator in PELs 5 and 6 and held the development and production role for the Eromanga oil fields. During 1981 CSR purchased Delhi's Australian petroleum interests which, in turn, were acquired by Esso Exploration and Production Australia Inc. The new owner attempted to maintain operatorship of the exploration operations but Santos and its subsidiary companies Vamgas and Alliance Oil (with the help of SAOG) voted against



Fractionation plant at night, Port Bonython, July 1984. (Photo 43378)

Esso. Santos became the operator for all exploration and development in PELs 5 and 6. The Delhi office in Adelaide closed in January 1988. The second notable event followed from the Cooper Basin being proved to contain Australia's largest known onshore oil reserves. This ultimately facilitated the \$1.5 billion Cooper Basin Liquids Project which saw an expansion of facilities in the region.

The oil discoveries made during the late 1970s, together with the large amounts of condensate which could be extracted from the supply of dry gas to Sydney and Adelaide, made a project to develop and market Cooper Basin gas liquids and oil feasible. This took the place of the previously proposed petrochemical plant. In early 1980 Santos (on behalf of the Producers) announced the decision to proceed with a liquids project. In 1981 the State Government passed the *Stony Point (Liquids Project) Ratification Act* to assist the project, involving the granting of a special pipeline licence for the 659 km Moomba – Port Bonython liquids pipeline and exemption from various taxes. The first stage of the project, the construction of a fractionation plant to split the petroleum into ethane, propane, butane, naphtha (condensate) and crude oil at Stony Point on Spencer Gulf (now Port Bonython), began in 1981. In February 1983 the first shipment of condensate received through the Moomba – Port Bonython pipeline was shipped to the Geelong oil refinery in Victoria; in March 1983 the first shipment of Cooper Basin crude oil was sent from Port Bonython; and in June 1984 LPG production began, with the first loading for export to Japan coinciding



Drilling rig on-site in the Cooper Basin, 1982. (Photo 43379)

with the project's official opening. The production of condensate was replaced by naphtha production: the first export shipment was in April 1991.

Of the six oil fields in the initial stages of the project, Tirrawarra, Moorari, Fly Lake – Brolga and Woolkina produced oil from the Cooper Basin, Strzelecki from the Eromanga Basin and Merrimelia produced oil from both basins. The project required oil and gas reserves to be sustained and more oil and gas to be proven. This pressure meant that exploration was maintained through the mid 1980s and development was stimulated. For example, eleven wells were drilled at Tirrawarra between 1970 and 1972, including the oil and gas discovery at Tirrawarra 1, but the combination of its remote location north-northwest of Moomba, high infrastructure costs and the Federal levy on old oil production from 1975 made it uneconomic to develop the field (Pecanek and Paton, 1984). The drilling of Tirrawarra 12 in 1980 was the start of development for the Liquids Project when production from additional fields was amalgamated. However, the Federal Government revised the old oil levy structure in 1983 and introduced an increasing marginal levy rate: as production increased the levy rose from 20% to 40% of the oil price for production exceeding 822 kL/day (5170 BOPD). This continued to limit development at Tirrawarra, particularly the northern dome of the main field (Pecanek and Paton, 1984).

Drilling and seismic work by the Producers between 1982 and 1984 discovered several small fields but not the major ones hoped for. In addition to this exploration, an Accelerated Gas Program was conducted from 1983 to 1985 in exchange for a gas price increase. The Producers spent \$60 million in those three years: 2556 km of seismic data were acquired, 43 wells were drilled, four wells were stimulated by massive hydraulic fracturing and some gas discoveries were made. In 1981 SAOG commenced re-examining Permian tight gas reservoirs in the Big Lake Field with a view to experimenting with the fracture stimulation technology (Stanley and Halliday, 1984). Two wells, Big Lake 26 and 27, were drilled and tested in 1982. Four earlier attempts to stimulate gas production in the Big Lake Field in the 1970s had been unsuccessful. The initial results from the new trial encouraged the joint venturers to drill two more wells at Big Lake and wells at Burley, Kirby and McLeod. Subsequently the technique was applied elsewhere in the Cooper and Eromanga Basins (Ch. 11).

This program extended the proved, probable and possible gas-in-place reserves by  $36.8 \times 10^9 \text{ m}^3$  (1300 bcf; Hollingsworth, 1989).

## GAS PRICES

After the gas price issue had been resolved by 1975, there followed a period of generally small, fluctuating rises in the price of Cooper Basin gas. In September 1982 an arbitrator awarded the Producers a significant increase in the price of gas for South Australia. The Government negotiated a compromise with the Producers: the initial increase was phased in over the year with the price of gas to rise almost 165% in four years. However, the Producers were required to spend at least \$55 million on the Accelerated Gas Program to prove up additional gas supplies. The substantial increase in price and anticipated stability in prices over a relatively long period enabled the Producers to structure their exploration plans accordingly. The Government removed a tax on Sagasco, a licence fee based on 5% of sales which had been introduced in 1974. From 1 March 1983 the exploration levy paid by gas users to SAOG towards the cost of locating future gas supplies was also discontinued.

In September 1983 independent arbitrators set the price of Cooper Basin gas for the Sydney market until September 1985 at \$1.0083 per GJ. This fuelled the belief that the \$1.10 per GJ (rising to \$1.62 per GJ over several years) arbitrated in 1982 for South Australian consumers was excessive. More discussions with the Producers led to the formation of a Natural Gas Task Force in September 1984 to coordinate the gas price and supply issues. These negotiations in the early to mid 1980s for gas supplies to South Australia beyond 1987 proved unsuccessful as adequate supply guarantees could not be given because sufficient quantities to satisfy Schedule A of the AGL agreement were still not proven.

Following these failed negotiations, the *National Gas (Interim Supply) Act* was passed by State Parliament in late 1985. This Act reserved certain quantities of gas not subject to the contract for Sydney and all ethane for South Australia's use, provided for the effective reservation of all gas outside of the core producing area of the Cooper Basin (the Subject Area), determined a price schedule for the gas and negated the PASA Future Sales Requirement Agreement (the post-1987 conditional gas supply agreement) so that PASA could make new arrangements with the Producers or with suppliers outside South Australia. The current gas price for South Australia, \$1.62 per GJ, was to remain until the end of 1985, when it would revert to the 1982 arbitrated price plus an adjustment for inflation since then. At the next price arbitration the disparity between the Adelaide and Sydney prices was to be removed with the gas price being set at the price arbitrated for Sydney.

Negotiations between PASA and the Producers resumed in the late 1980s as further reserves were proven up. In March 1989 new Gas Sales Contracts were signed for natural gas supplies from the Subject Area, as well as from two other Blocks in PELs 5 and 6 to the end of 1994. The initial contract could be extended to 2001 if sufficient reserves were proven by 1992: it could then be extended on a year-by-year basis to form a rolling ten-year supply arrangement. (Under the contract either party could call for a price review from 1993 and each three years thereafter. By

agreement neither party triggered a review of prices to apply for 1993 or 1996.) PASA negotiated the contract on the basis of the price which had operated since 1 July 1988, with any future increases limited to 95% of the rate of inflation. This agreement effectively replaced the *Natural Gas (Interim Supply) Act*: gas reserved under the Act would progressively come under the agreement except for sufficient ethane to supply a possible petrochemical plant. Establishing a formula for an ongoing reduction of gas prices in real terms and for ensuring a supply on a ten-year rolling basis was a major achievement.

## **ENVIRONMENTAL AWARENESS/ CONSIDERATIONS**

By the 1980s environmental concerns for conserving natural resources and preventing pollution were never far from the spotlight, be they local, national or international issues. Although the growing trend towards classifying land as either a reserve (in the form of national, conservation and recreation parks and regional and game reserves) or Aboriginal land continued to alarm the minerals and energy sector, the situation was not as dramatic as the perception: approximately only 5% of the State was considered to be totally restricted from exploration and mining (Martins and Stone, 1993). However, the environment of the Cooper Basin region was one area deserving special attention.

The Mines and Energy Department in conjunction with the petroleum industry progressively introduced several codes of environmental practice for exploration and development work in PELs 5 and 6. The department encouraged companies to develop appropriate procedures and some companies had already begun to enforce their own guidelines. In 1983 Santos's Government Liaison Officer began managing the environmental aspects of the company's upstream activities in the Cooper Basin and then Santos established an environmental group. The first code was adopted for seismic work in 1984. At that time the visible effects of seismic lines were being criticised by environmentalists. The codes achieved spectacular results: the presence of seismic lines in the stony gibber plains is now difficult to detect after a year or two, while signs of many earlier lines made using a bulldozer are still quite obvious.

In 1986 the State Government implemented a multiple land use policy so as not to deny or limit access for exploration or development in an area without first reviewing the subsurface rights and resource potential (Morozow, 1988). The new policy was first applied at Innamincka on land incorporating the Innamincka and Cooper Creek State Heritage Areas and the Coongie Lakes, which covered much of the productive zone for oil and gas in the northeast (Fig. 3.2). The Innamincka Regional Reserve was created under amendments in 1987 to the *National Parks and Wildlife Service Act 1972*. Subsequently the Strzelecki Regional Reserve was instituted in 1991. Within the Innamincka Regional Reserve an area of high environmental value was recognised around the Coongie Lakes. The biological diversity, cultural heritage, scientific interest and social amenity value of this area were acknowledged in 1988 by the establishment of the Coongie Lakes Control Zone. Petroleum exploration and development were not excluded from this 647 km<sup>2</sup> zone,



*Track-mounted drilling rigs were adopted for traversing sand dunes and negotiating the desert terrain. Being very manoeuvrable, they minimised surface damage and reduced the environmental impact of the petroleum search. (Photo 40401)*

although more stringent planning and operating requirements were needed.

The regional reserve classification recognised that pastoral, tourist, mining and petroleum activities could be conducted compatibly with environmental safeguards in ecologically sensitive areas. Development approvals were to be granted through both the Minister of Mines and Energy and the Minister of Environment and Planning. The latter could not create reserves without considering the former's views and the former could not approve petroleum and mineral exploration licence applications without first obtaining the latter's comments. Exploration work programs were also subject to discussions with the Department of Environment and Planning as part of the departments' agreed policy and the issuing of PPLs depended on the Minister of Environment and Planning's approval, or the Governor's if disputes arose. Cooper Basin PPLs were excluded from this process.

The evolution of the multiple land use concept highlighted that mining and environmental interests did not always have to be at loggerheads. In October 1989 new regulations were introduced under the *Petroleum Act* and an environmental assessment and a code of environmental practice became a mandatory requirement before petroleum exploration and development operations could be approved. The requirements were seen in some quarters to be heavy-handed, and in others to be not enough. In 1995 Santos applied to conduct a seismic survey in the Coongie Lakes Control Zone, which was subsequently undertaken after extensive assessment and approval. The environmental outcomes of this operation were as anticipated and are likely to lead to the recovery of seismic lines within a few years. This program has demonstrated that exploration can proceed even in the most sensitive areas, with a reduced risk of long-term adverse impacts. While it again highlights the success of the multiple land use concept, new requirements for environmental management are currently in preparation in consultation with the petroleum industry. For example, the environmental assessment of abandoned petroleum wellsites (PIRSA Petroleum Group, 1998).

## THE MODERN DECADE

### The licence area and the Producers

In 1979 the exploration rights granted to Delhi–Santos had been modified when the companies volunteered to halve the area covered by PELs 5 and 6 to 284 086 km<sup>2</sup>. The area covered was then divided into the Cooper, Pedirka and Arrowie Sectors. The Cooper Sector is not subject to any relinquishment provisions until February 1999 when the exploration rights to the whole Cooper Basin expire without the right of renewal. The Pedirka and Arrowie Sectors were subject to relinquishment of 25% at five-year intervals commencing in February 1984. Under the 1984 conditions of renewal the area of PELs 5 and 6 was reduced to 231 948 km<sup>2</sup> and Delhi–Santos were required to drill 54 wells and acquire 4000 km of seismic in the Cooper Sector. In subsequent years additional voluntary minor relinquishments were made until February 1989 when the area of PELs 5 and 6 was halved again (to 111 756 km<sup>2</sup>). Within a year the area was again reduced (to 73 202 km<sup>2</sup>) and minor reductions to the exploration zone in the PEL area have followed: the area of a PPL is excised from the exploration licence when a PPL is issued.

The Brown Liberal Government (1993–96) confirmed in 1995 that no rights of renewal would apply to existing Cooper Basin exploration tenements on their expiry in 1999. This policy was intended to facilitate active upstream industry competition in gas exploration and supply as bids would be sought for new tenements from the industry at large. The more than 80 PPLs then existing over about 3500 km<sup>2</sup> were not to be affected by the expiry of PELs 5 and 6. But in September 1997 Premier J. Olsen (1996–) announced that the Liberal Government agreed to allow Santos to retain tenure over the Nappamerri Trough until at least 2013. In accord with their rights under the *Ratification Act*, in November 1997 Santos and its partners were issued with 17 PPLs over the Nappamerri Trough (Fig. 2.6). The licences cover an area of about 4100 km<sup>2</sup> and contain a potentially large resource of gas in very low permeability reservoirs. The company will have to spend more than \$100 million over 15 years to retain all of this area until 2013. Partial acreage relinquishment will apply at the end of five and ten years and relinquishment requirements will apply in 2013 to any areas where commercial production has not been established.

As operator Santos is now responsible for 13 joint ventures, the Cooper Basin Producers Unit and the Downstream (for the transport, processing and storage of liquids at Port Bonython) Agreement in South Australia. Until late 1996 each share (a participation factor) in the Producers Unit reflected the net quantity of gas, ethane, condensate and so on and the quantity of reserves contributed by that company (Fig. 2.7). The reserves were recalculated biannually and the participation factor changed in response to new discoveries and adjustments to reserves' estimates, among other things. The complex arrangement had led to court proceedings more than once. After two decades the review and adjustment method of establishing a company's share was discarded. The arrangement was simplified by instituting a fixed participation factor for both exploration and production interests and for all petroleum products within PELs 5 and 6 (the exception being the



Goal attainment scaling applied to the environmental assessment of abandoned petroleum wellsites. **(top)** -2 score (much less than expected outcome): the track is prominent because of a scraped surface, windrows along its edges or gully erosion. **(bottom)** +2 score (much more than expected outcome): the track contours and colour blend with the surroundings and the earthwork disturbance is indistinguishable. (Photos 45045, 45049)

Patchawarra East Block, which retained its existing interests). Fixed participation factors were also applied to the Downstream Agreement. The change has reduced both the time and cost involved in the review process and the potential for litigation.

In regards to the agreement to supply Cooper Basin gas to AGL (Fig. 2.8), in 1995 the Australian Competition and Consumer Commission (ACCC) initiated a review of its 1986 authorisation of the agreement. Although the agreement is shielded from the provisions of the *Trade Practices Act* by the *Ratification Act*, authorisation had been given previously to enable holding any gas price arbitration under the agreement in New South Wales instead of South Australia. In 1996 the ACCC determined that the Agreement contained three anti-competitive clauses (providing for first right of refusal, take-or-pay and exclusive dealings). Accordingly the authorisation was withdrawn excepting for a time-limited authorisation of a gas price establishment clause. In 1997 the Producers won their appeal to the Australian Competition Tribunal against the determination (*PESA News*, 1998).

### Royalties

In the late 1980s the State Government had taken the view that South Australia should not receive less royalties

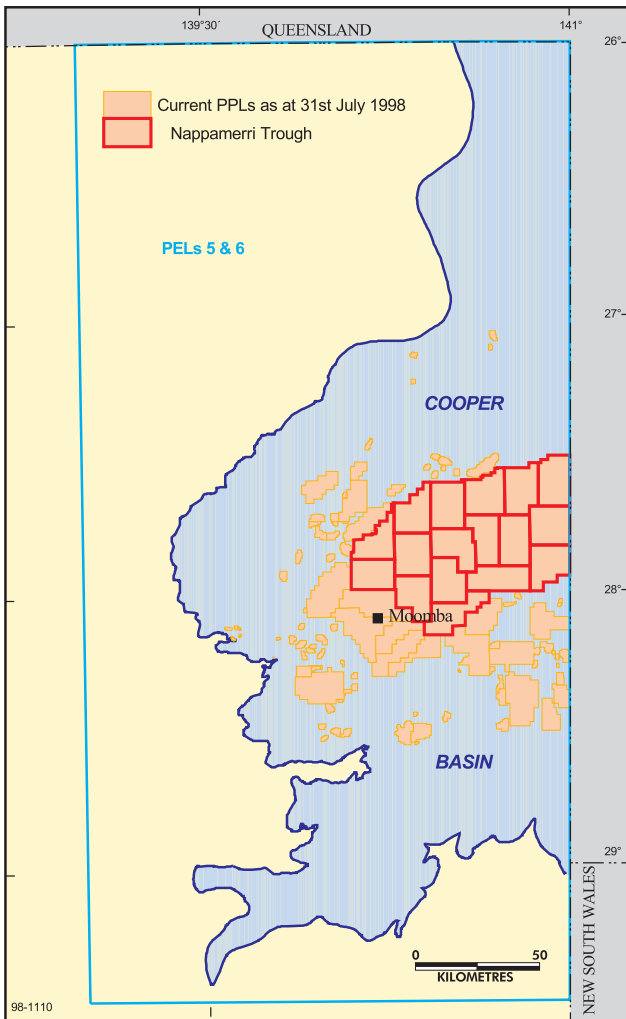


Fig. 2.6 PPL holdings at 30 June 1998.

than those applicable under comparable interstate situations. Under the *Ratification Act* and Indenture, the Government received a 10% royalty on the value at the wellhead less deductions for capital and operating expenses for processing and treatment, and related financing arrangements. The Mines and Energy Department had calculated that the future return from the region would be less than 5% of the selling value of the petroleum: the equivalent value under interstate rates was up to 2% more. Thus in August 1989 a review of the royalty rate was initiated with the Producers.

After considerable negotiation the Government reached agreement with ten of the eleven Producers (Delhi dissented) to increase the royalty payments by reducing the deductions allowed to companies for the wellhead value calculation while retaining the 10% royalty rate. Under amendments in 1991 to the *Ratification Act* a new royalty regime, payable monthly instead of six-monthly, was introduced from January 1991 (Fig. 2.9). In order to facilitate enhanced oil recovery schemes and the rehabilitation of abandoned production facilities, the Government allowed the Producers to deduct downstream restoration costs and the drilling costs for non-petroleum producing wells. The royalty scheme was also applied to three small producing fields of the Producers outside the Indenture area.

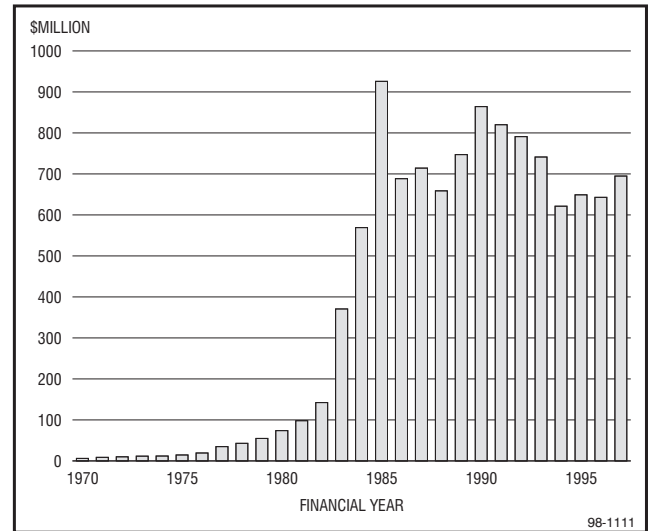


Fig. 2.7 Cooper Basin petroleum sales.

As well as generating additional revenue for the Government annually, the new royalty system resulted in a small rise in the price of gas: under the gas sales contracts, increases in royalties applicable to PASA flowed on to gas prices in South Australia. Although agreeing to the change, companies such as Santos and Sagasco Resources saw the move as a disincentive: they anticipated oil and gas exploration and development would fall generally and cease in some areas. This did not happen because the disincentive to exploration was rather small when contrasted with the prospectivity of the region and the gains to be made from successful exploration.

### The national arena

During the 1980s steps for the national sharing of natural resources through dismantling barriers to trade were taken for both electricity and gas. The concept of resource sharing was not new: in 1961 the Federal Government had drawn up a plan for an electricity grid serving a large part of central and eastern Australia through nuclear-powered generators and Connor had advocated a national gas pipeline scheme. That a national approach was practicable was demonstrated by Australia's first interstate gas sales via the Moomba–Sydney pipeline (completed in 1976) and South Australia's involvement in the second interstate gas pipeline, from Moomba to Ballera in Queensland. The Federal Government pursued a national natural gas strategy as part of its new federalism approach in 1991.

The Tonkin Liberal Government (1979–82) in South Australia had raised the possibility of piping oil and gas from South-West Queensland to Port Bonython. Queensland's National–Country Party Government under J. Bjelke-Petersen rejected this proposition and decided instead to push for the building of the Jackson–Moonie–Brisbane pipeline. But the prospect for interstate linkages remained attractive. South Australia looked to expand its oil and gas pipeline network both within the State (the Wasleys – Torrens Island pipeline loop was commissioned in September 1986 and the Port Pirie – Whyalla submarine pipeline came into operation in April 1989) and beyond its borders. Thus in July 1991 a ten-year contract was signed for the supply of gas from northwest of Jackson to Moomba for the treatment and

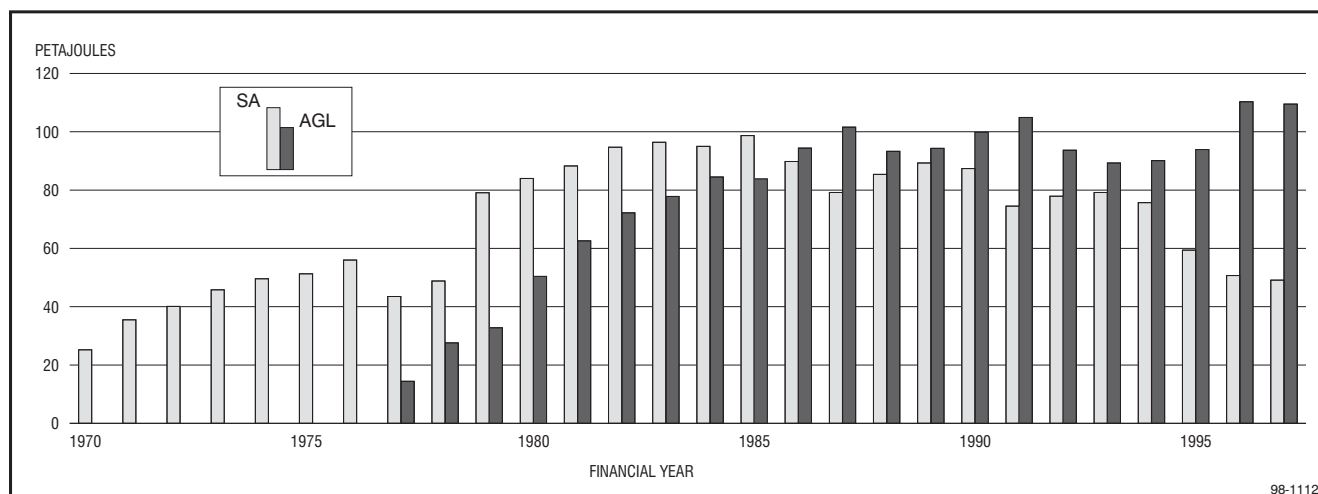


Fig. 2.8 Cooper Basin gas sales to South Australia and AGL.

recovery there and at Port Bonython of sales gas, LPG and condensate for the Adelaide market. This agreement with the South-West Queensland Cooper Basin Producers represented one-third of the State’s demand for gas then although production was not to commence officially until January 1994.

The contract for Queensland gas highlighted the endeavours of the South Australian ALP Government under J. Bannon (1982–92) to secure energy resources and maintain stable prices over a long term. Commencing at the start of 1994, 30 petajoules (PJ) were to be supplied annually, with the Queensland Government considering an option to supply an additional 13 PJ each year. Exploration in South Australia since the Gas Sales Contract in March 1989 had increased the guaranteed supplies to five years but the Government aimed for a ten-year reserve. The downside of the deal was that Sagasco decided to apply for an increase in gas tariffs as soon as the pipeline began operating, because the costs of supply from Queensland were higher (*Advertiser*, 1994). The \$150 million project provided the first interstate gas supplies to South Australia.

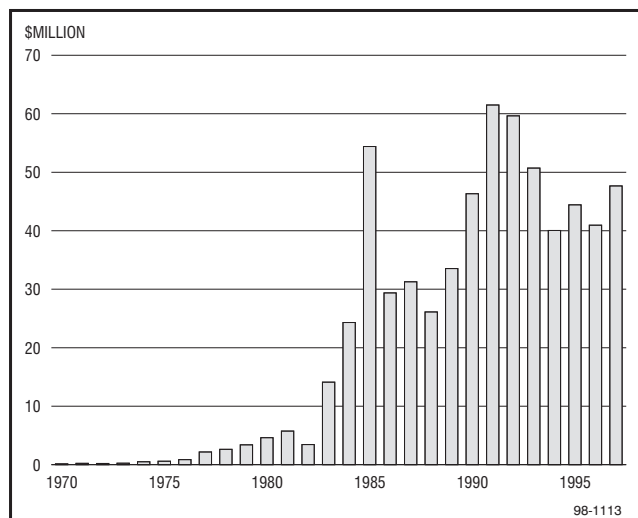


Fig. 2.9 Petroleum royalties generated through the Cooper Basin. Since 1991 these figures include royalties (<2%) from production in the South-East.

The availability of gas from Queensland was a factor in the Arnold ALP State Government’s (1992–93) decision to allow ethane from the Cooper Basin to be supplied to the Imperial Chemical Industry (ICI) ethylene manufacturing plant at Botany Bay in Sydney, a ten-year agreement subsequently signed by the Brown Government. Under the terms of the *Natural Gas (Interim Supply) Act* the Producers could not sell ethane without Ministerial authorisation because of the Government’s ambition for a locally-based petrochemical plant. The Producers had been extracting and storing the ethane underground in depleted fields for later processing in a petrochemical plant. As the possibility of such a facility in South Australia still seemed remote after 20 years of inaction, the Producers were permitted to make the agreement. Santos and its partners commenced the production and supply of ethane concentrate to ICI in July 1996. To supply 16 PJ per year for ten years, an ethane treatment plant was built at Moomba.

In accordance with the agreement on free and fair trade in gas which the Council of Australian Governments endorsed in February 1994, and to remove related legislative and other impediments, the anti-competitive provisions of the *Natural Gas (Interim Supply) Act* have been repealed although many of its provisions had already been modified by negotiated outcomes over the past decade. Other legislation and regulations, which may affect competition, including the *Ratification Act*, are also under review.

### Privatisation

As part of a privatisation program, in November 1993 the Federal Government decided to sell 51% of the Moomba–Sydney gas pipeline to AGL, to seek purchasers for the remaining 49% and to build another pipeline over the same route to carry the ethane to the ICI plant (Forday, 1993). The decision was yet another being made by the Federal and State Governments in reviewing the assets under their control. In 1992 the State ALP Government sold its interests in Sagasco Resources, its direct upstream interest in the Cooper Basin and other Australian basins, to Boral Energy; it was renamed Boral Energy Resources. This interest then comprised a majority shareholding in both Sagasco, the licensee of the gas distribution system in South Australia, and Sagasco Resources. (The two companies had



Trenching in preparation for laying of South-West Queensland gas pipeline to South Australia, 80 km northeast of Moomba, April 1992. (Photo 40368)

merged in April 1987.) The next sale was of PASA's pipeline interests to Tenneco (now Epic Energy) in mid 1995. The PASA gas sales contracts with ETSA and Sagasco were transferred to a new Natural Gas Authority of South Australia. The contracts for additional gas supplies between the Producers and ETSA and Sagasco were affected in mid 1996: the Producers made separate contracts with these organisations for gas supplies mainly beyond 2004. Further Cooper Basin gas discoveries are now necessary to allow new major contracts to be sought for bulk short-term or long-term supply. The recent corporatisation of ETSA (now ETSA Corporation and Optima Energy) was a significant change to the local energy scene. This had little immediate impact on activity in the Cooper Basin although there may be some impact in the longer term as the State Government announced in February 1998 that ETSA Corporation and Optima Energy were to be sold.

### Ongoing exploration and development

Since 1959 more than 1200 exploration and development wells have been drilled by Santos and its joint venture partners, with 146 oil and gas fields previously or currently on stream, and ~80 000 km of 2D and ~3 km<sup>2</sup> of 3D seismic data have been recorded in the Cooper and Eromanga Basins. Over the past 28 years exploration programs have been undertaken to add gas reserves to meet specific contracts such as for the 1970–72 AGL agreement, 1979–81 SAOG sole risk program, the Accelerated Gas Program of 1983–85 and the 1990–92 program for PASA's forward contract (Fig. 2.10). The latest program was announced early in 1996 and involves a three-year, \$200 million expenditure by Santos to drill 125 exploration and appraisal wells. The aim was to take advantage of the impending deregulated gas market by locking in new discoveries to short-term gas contracts. In addition, with the imminent expiry of PELs 5 and 6 an attempt was made to drill as many oil and gas prospects as possible to maximise the area under PPLs by February 1999.

This exploration program discovered two oil and seven gas fields in 1996 and one oil field in 1997 from a total of 48 exploration wells. New gas fields which are relatively rich in liquids are produced preferentially to take advantage of the increased sales value associated with the gas. To date

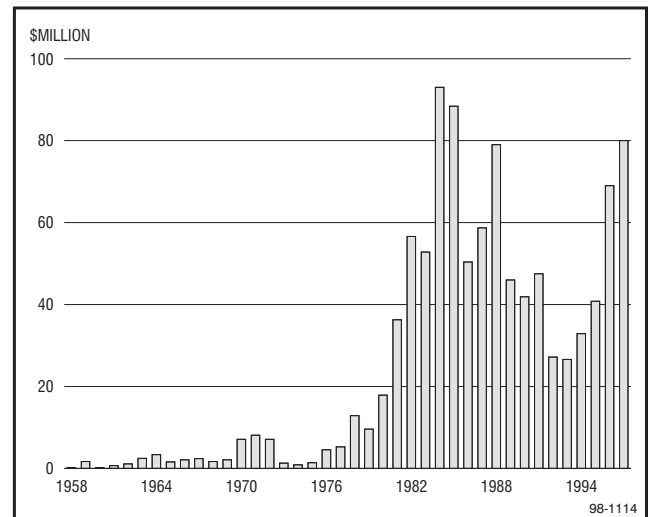


Fig. 2.10 Expenditure on petroleum exploration in the Cooper and Eromanga Basins.

~129 x 10<sup>9</sup> m<sup>3</sup> (4.6 tcf) of gas and 4.6 x 10<sup>6</sup> kL (29.1 mmstb) of oil and condensate have been produced from the Cooper Basin.

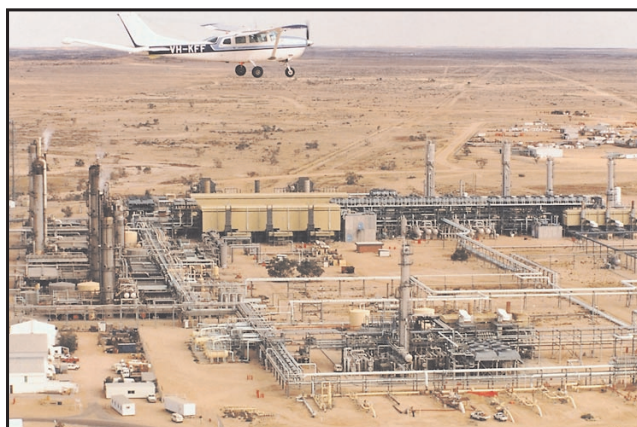
Production has been obtained from all reservoir-bearing units in the Cooper Basin. While earlier exploration focused on simple anticlines and faulted anticlines, more recent exploration has involved untested structural downdip flanks, stratigraphic plays and areas of tight gas reservoirs with potential for large reserves. As the search has become more refined, improved seismic acquisition (including 3D) and processing has helped to produce better results (Heath, 1989). New technologies have also proved important, especially in areas of poor quality oil and gas reservoirs (Ch. 11).

The discoveries in the 1980s and 1990s included the Sturt, Taloola and Tantanna oil fields near the edge of the Cooper Basin. Significantly, Sturt 6 discovered oil in Cambrian volcanics and Lycosa 1 and Moolalla 1 tested gas in the Ordovician. Although the source rocks for these hydrocarbons are Permian, the reservoirs are in Warburton Basin rocks, conventionally regarded as basement (Taylor *et al.*, 1991). Each discovery by the Producers offset the decline in the oil and gas reserves of the region.

From the early 1990s Santos, perhaps recognising that the expected end in 1999 to the company's monopolising role in the Cooper and Eromanga Basins would present it with fresh challenges, began to diversify its exploration and development activities beyond PELs 5 and 6. As 1999 drew closer, however, Santos re-asserted its interest in the prospectivity of the Cooper Basin. In South Australia in 1997 it carried out 2419 km of 2D and 1888 km<sup>2</sup> of 3D seismic and drilled 62 wells comprising 22 exploration wells (9 for gas and 1 for oil were successful), 13 appraisal wells and 27 development wells. Santos's exploration program for 1998 was of a similar magnitude.

### CONCLUSION

Traps in the Cooper Basin and the overlying Eromanga Basin are seismically mappable and the identification of oil and gas reservoirs has been protracted. One result with important repercussions for petroleum exploration and development was that the initial success, notably gas at



*Aeromagnetic–radiometric survey aircraft flying over the Moomba gas and liquids processing plant in August 1993 during a 1810 km<sup>2</sup> survey over the Cooper, Eromanga and Warburton Basins. (Photo 41483)*

Gidgealpa and Moomba, came from the Cooper Basin and consequently the dominant focus in the northeast of South Australia has been on the Cooper Basin. The shift in perception about the prospectivity of the Eromanga Basin that had occurred by the mid 1980s, however, reduced the focus on the Cooper Basin although follow-up exploration programs specifically targeted oil and gas reserves in both basins.

While the expiry in February 1999 of PELs 5 and 6 will bring to a close an important chapter in the history of petroleum exploration in Australia, the story will not end there. The hydrocarbon reserves of the Cooper Basin now service the natural gas needs of South Australia, New South Wales, the Australian Capital Territory and southeast Queensland. There is significant potential for further discoveries in the South Australian sector of the basin. The region is the hub of a major gas production, processing and transmission system and new sources of hydrocarbons can be produced locally and taken onto the local, interstate and international markets expeditiously through the infrastructure in place at Moomba and Port Bonython. Competition for the portions of the Cooper Basin outside the PPLs will offer a rare opportunity to explorers as they will have the opportunity to negotiate access to established infrastructure and markets, the advantage of proven play concepts in an area with high wildcat discovery rates, and access to detailed data and a State Government administration with a proven track record of facilitation of responsible petroleum exploration and development (Laws, 1997).

The visions of the small, brave optimists of the 1950s have been more than matched by the successful oil and gas exploration and development in the Cooper Basin. As always, some things could have been done differently; the rates and types of successes and failures might have been configured in other ways; personalities, politics and projects might have taken different paths and so on. For all of its quirks and foibles, however, the story of exploration and development in the Cooper Basin is a highlight in South Australia's natural resource achievements and the region has brought great benefits to the Producers and to South Australia.

## NATURAL ENVIRONMENT

### CLIMATE

The Cooper Basin is located in the core of Australia's arid region. Seasonal and diurnal temperatures can vary extensively, averaging 36–39°C in summer and 18–24°C in winter. It is not uncommon for summer temperatures to regularly exceed 38°C in the shade, whilst in winter mean minimum temperatures can drop to 5°C with frosts a common occurrence.

Droughts frequently occur throughout the area with an average rainfall of 100–150 mm per year. Local rainfall is irregular and unreliable with a long spell of dry seasons usually followed by one or two good seasons. The major influence on rainfall is of tropical origin taking the form of thunderstorms, and monsoon depressions. Whilst rain may fall at any time of the year, it tends to be summer dominated with the occasional high winter rainfall.

Extreme rainfall and flooding events are usually as a result of the El Nino effect. Since 1974 there have been five major flooding events within the Cooper Basin (Santos Ltd, pers comm., 1998). These events do not necessarily coincide with local rains but are as a result of annual flows originating from upper catchment rains in Queensland.

Winds prevailing from the south to southeast tend to dominate from September to May exhibiting greater variability in winter (Moss and Low, 1996). The windiest days are from September to December. Southwesterly winds which precede cold fronts have a tendency to carry large amounts of sand resulting in dust storms.

### LANDFORMS

Whilst the Cooper Basin is located in Australia's arid zone it has a diverse number of major landforms including dune field, stony tableland, river channels, floodplain, and undulating plain (Table 3.1; Fig. 3.1). Each of these landforms can be divided into minor landform patterns or environmental units based upon their detailed morphological characteristics such as local geology, soil type, topography, drainage patterns and biota.

#### Dune field

Sand dunes whilst similar in form can vary in both height, spacing and morphology from region to region. The most common dunes in the Cooper Basin are crested parallel sand ridges usually aligned north–south. These can sometimes continue without a break for hundreds of kilometres or converge as Y-junctions. Dunes vary in colour ranging from dark red to pure white and can be either siliceous or clay rich. The amount of clay in a dune can

determine its susceptibility to erosion and its ability to restore itself after disturbance.

Dunes can vary in height from 5 to 35 m and densities can range up to 15 dunes per kilometre. The dunes are separated by flat corridors or swales; their soil types can vary from cracking clays to sandy clay loams.

#### Gibber plain and dissected tableland

Gibber plains consist of undulating clay plains and gentle slopes protected by a dense cover of red, highly polished stones called gibber. They are occasionally interspersed with small dunes or silcrete capped mesas and are generally very stable. The gibber is usually embedded in a clayey crust overlying a red duplex soil which is highly susceptible to erosion when disturbed. Dissected tablelands are typified by a complex arrangement of depressions called gilgai and large relatively flat areas with a mantle of gibber interspersed with silcrete capped mesas. The slopes of these mesas are generally composed of red duplex soils and self mulching clays. The steep slopes allow water to attain a high velocity which can result in massive gully erosion where the surface soil has been disturbed.







#### Floodplain

Floodplains adjacent to the Cooper Creek system generally do not become inundated unless river channels overflow their banks; due to the low relief throughout the area, even a small increase in water level can inundate a vast area of floodplains. Floodplains can be very diverse, often occurring in association with the dune fields. As floodwaters advance they wind a path through the dunes slowly filling a system of interdune corridors, swamps and lakes. The soils in the floodplains are generally characterised by self mulching, cracking clays resulting from the deposition of sediments during flooding.

#### Wetlands

The Cooper Creek system forms important wetlands in the Cooper Basin and includes the Coongie Lakes which are of high conservation value. The value of the system is based upon it being an important fresh water source in an arid environment, its habitat diversity and corresponding diversity of flora and faunal species. The system is essentially a series of interconnected river channels containing a string of impermanent shallow lakes and waterholes fed intermittently by the Cooper Creek. Associated with the system are also floodplains, swamps, creeks, claypans and lakes (McLaren *et al.*, 1994). Whilst high local rainfall events contribute to water flows within the Cooper Creek system, the main source of flows are attributed to rivers originating in higher rainfall catchments (e.g. Diamantina and Wilson Rivers).

**Table 3.1** Land systems of the Cooper region (after Santos Ltd, 1993).

DUNE FIELD	GIBBER PLAIN	TABLELAND	FLOODPLAIN	WETLANDS	SALT LAKE
					
Photo 45833	Photo 45831	Photo 45834	Photo 45830	Photo 43780	Photo 45827
<p><b>Description</b> Generally parallel dunes, trending approximately north-south, of red or yellow sands, 5–20 m high and separated by flat interdune corridors or swales. Corridors are sandy, but due to limited internal drainage, often contain claypans; where infiltration is poor salt lakes occur.</p>	<p>An undulating stony plain, sometimes with an occasional small dune or silcrete capped mesa. The highly polished stones or gibbers are usually embedded in a clayey crust, thereby protecting the underlying soil from erosion.</p>	<p>Uplifted and eroded gibber plains that have resulted in the formation of low, but steep silcrete capped hills, escarpments and mesas, and extensive gibber covered footslopes. The tablelands are separated by undulating gibber plains.</p>	<p>Extensive flood-out areas occur adjacent to the Cooper and Strzelecki Creeks, and Wilson and Diamantina Rivers. The floodplains are periodically inundated when the creeks and rivers overflow their banks, depositing a characteristic grey sediment. In places, dunes are either co-dominant or occasionally present.</p>	<p>These comprise the channels, waterholes, swamps and lakes associated with the Cooper and Strzelecki Creeks and Wilson and Diamantina Rivers. Located on or close to the main watercourses these areas are inundated more frequently than the surrounding floodplain. Some of the waterholes always contain water, but the channels, swamps and lakes are frequently dry.</p>	<p>Terminal lakes or pans of varying sizes where evaporation has resulted in the concentration of soluble salts as a surface crust. They are periodically inundated, but are usually dry.</p>
<p><b>Sub-dominant land systems</b> Salt lake, floodplain, gibber plain.</p>	Tableland, dune field.	Gibber plain.	Dune field, wetlands, salt lake.		
<p><b>Soils</b> <i>Dunes</i>: red or yellow siliceous sands. <i>Swales</i>: red massive earths, or grey self-mulching cracking clays.</p>	Crusty red duplex soils.	<i>Slopes</i> : crusty red duplex soils and brown self-mulching cracking clays. <i>Rises</i> : reddish powdery calcareous loams.	Grey self-mulching cracking clays.	Grey self-mulching cracking clays.	Salt overlying grey self-mulching cracking clays.
<p><b>Vegetation</b> <i>Dunes</i>: tall shrubland of marpoo, whitewood and hakea, and hummock grassland of spinifex and sandhill canegrass. <i>Swales</i>: chenopod shrubland and grassland.</p>	<i>Plains</i> : low open shrubland and open grassland of Mitchell grass. <i>Drainage lines</i> : low woodland of gidgee and mulga.	<i>Slopes</i> : low to tall open shrubland. <i>Drainage lines</i> : low woodland of mulga, red mulga and gidgee. <i>Plains</i> : low open shrubland and open grassland of Mitchell grass.	Open woodland of river red gum, coolibah and gidgee with an understorey of lignum, chenopod shrubland and grasses.	Open woodland of river red gum and coolibah with an understorey of lignum and chenopod shrubland.	Chenopod shrubland or completely bare.

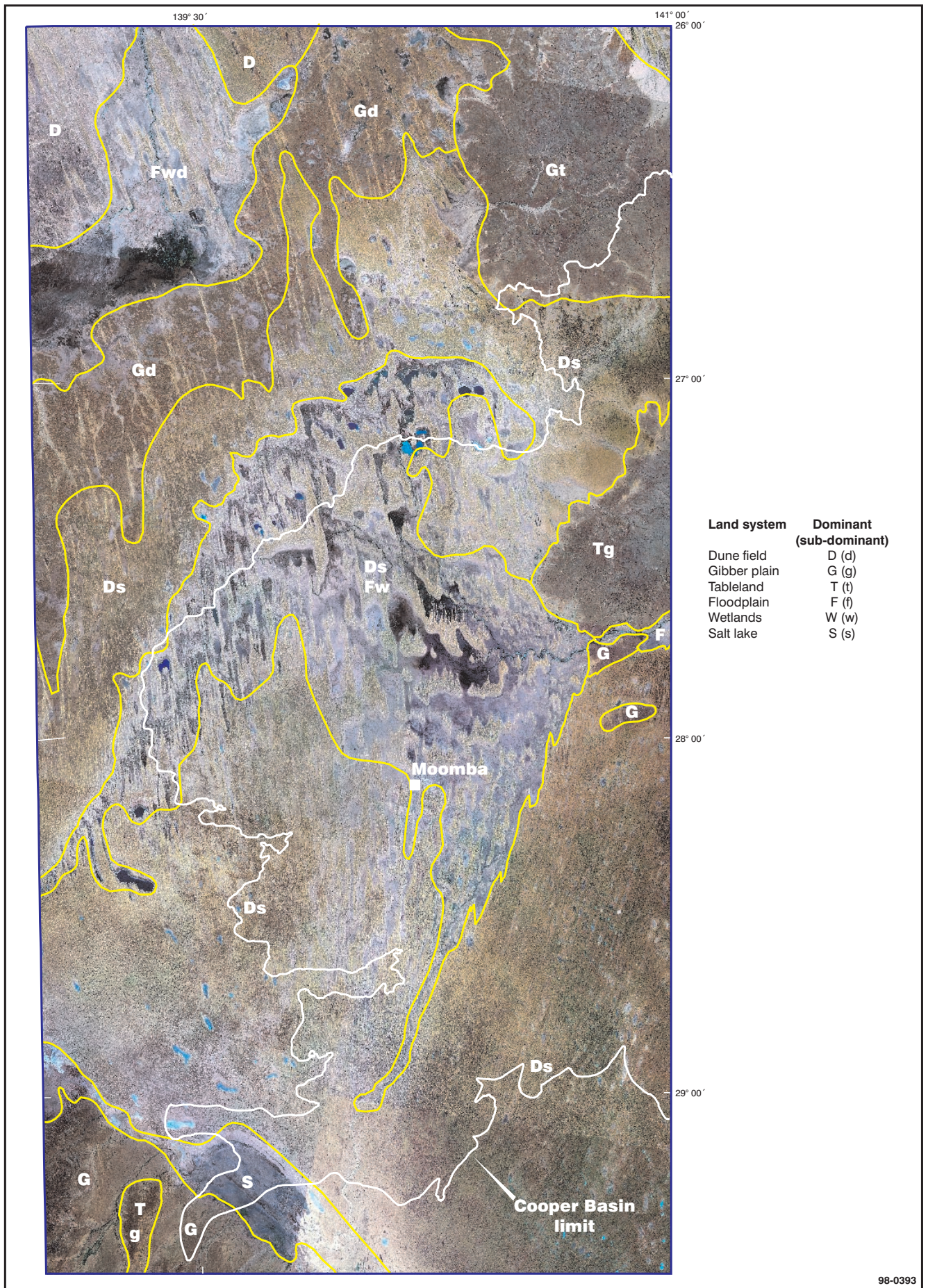


Fig. 3.1 Landsat image and land systems of the Cooper region.

## Salt lake

Within the Cooper Basin there are numerous ephemeral salt lakes, usually dry, of varying sizes. Due to the high level of evaporation in the region, soluble salts are heavily concentrated in these lakes after episodic flooding during which water levels can fluctuate significantly (Moss and Low, 1996).

## NATIVE VEGETATION

Despite its aridity, the Cooper Basin supports a diverse, if sparse, range of vegetation which is largely influenced by landform, soil and climate. Small differences in habitat such as depressions or drainage lines may produce highly variable micro-ecosystems. As such, local areas may show slightly more growth and a greater variety of species, although during drought periods relatively large areas may often appear quite lifeless and barren.

Due to the low and erratic nature of rainfall and the searing temperatures experienced during summer, most perennial plants within the region must be extremely resilient and able to endure long dry spells. The appearance of herbaceous plants is both episodic and infrequent and depends upon the combination of rainfall and temperature.

### Dune field

Dune crests are usually dominated by perennial, tussocky sandhill cane grass which is an important dune stabilising plant. Depending on seasonal conditions, the flanks of the dunes may be well or sparsely vegetated and are often dominated by an upper storey of low shrubs such as acacia and whitewood with an understorey of grasses and forbs (Sutherland, 1993).

The vegetation on interdune swales can vary considerably depending on the soil type and the level of inundation either from floods or localised runoff or drainage. Interdune swales which have a low level of inundation often support shrubland which can include acacia, hakea and eremophila species (Laut *et al.*, 1977). Where there is sufficient water the swales may support low open woodlands often accompanied by an over-storey of coolibah.

### Gibber plain and dissected tableland

The vegetation on gibber plain and dissected tableland is primarily composed of an ephemeral and biannual cover of Mitchell grass, perennial tussock grassland, annual grasses and low open chenopod shrubland. Vegetation on gibber plains is often short-lived and heavily dependent on the infrequent rainfall events which are required to stimulate both growth and germination. Broad drainage lines and associated outwashes meandering through gibber plain tend to be dominated by low open woodland and composed of species such as dead finish, gidgee and mulga (Tyler *et al.*, 1990).

Mesas located in dissected tableland tend to have a light scattered cover of shrubs such as dead finish and emu bush with an understorey of saltbush species and annual grasses. Isolated trees may occasionally be found on the slopes.

### Floodplain

Most of the floodplains carry sparse low ephemeral or perennial short-lived species, the composition of which is

often variable, determined by the season during which rain falls (Laut *et al.*, 1977). Claypans can carry a wide variety of vegetation including samphire, chenopod shrubland, lignum and cane grass.

Along the outer edges of the floodplains or scattered across dry lake beds is sparse coolibah woodland. The coolibah is probably the tree that is most characteristic of the area as a whole, because it is long lived and can withstand long periods of drought and extensive flooding.

The woodland may alternate with shrubland, grassland and sedgeland. Lignum shrubland can often be found in swampy areas, floodplains and creek banks ranging in density from sparse to almost impenetrable (Wiltshire and Schmidt, 1997). The lignum may sometimes occur in association with acacia and saltbush species.

### Wetlands

The vegetation of the Cooper Creek, Coongie Lakes and associated floodplains varies considerably with over 350 plant species recorded in the area, including the recently discovered endemic daisy *Brachycome coongiensis*. Vegetation fringing the Cooper Creek channel is generally composed of tall mixed woodland and can include river red gum, coolibah, acacia and eremophila species (Badman *et al.*, 1991).

## NATIVE FAUNA

The Cooper Basin supports a rich avifauna population of more than 250 species of water and land birds (Badman *et al.*, 1991). The types of landforms within the region largely influence bird distributions and whilst many birds are generalists and can occur in a wide variety of environments, certain species are restricted to specific areas due to habitat preferences. Many birds that occur in the region are also migratory or opportunistic, taking advantage of favourable seasonal conditions such as high rainfall events or flooding.

Whilst water courses and wetlands are the main focus of bird activity, the more arid environments such as gibber plains and dune fields also support a wide range of species. Many of these birds are ground breeding and therefore very susceptible to habitat disturbance and attack from introduced predators.

The diverse range of habitats in the Cooper Basin support a number of mammal species including rodents, bats and macropods (e.g. kangaroos). For many species watercourse habitats are key focal points. These habitats literally act as oases in an otherwise inhospitable environment. Whilst up to 46 mammal species have been recorded in the region, at least ten are now believed to be either locally or entirely extinct (Sutherland, 1993).

Approximately six amphibian species can be found in the region. These species are mainly located around water courses and surrounding areas, pending favourable seasonal conditions. Although it is not known how many reptile species are in the region it is possible that up to 25 species could exist. Fish fauna is abundant in the Coongie Lakes and Cooper Creek system, which comprises ~23 species of fish. However, the introduction of exotic fish, increased pressure from tourism and the introduction of diseases is having a detrimental effect on the native fish population.

A number of feral animals have become established in the area including rabbits, cats, pigs, camels and the common house mouse. It is believed that many of the introduced species have had adverse effects on the native fauna population either directly or indirectly.

## LAND ACCESS

### Regional Parks and Reserves

There are two regional reserves located within the Cooper Basin, namely the Innamincka Regional Reserve and the Strzelecki Regional Reserve (Fig. 3.2). These were created to conserve the best examples of vegetation and landform in the region (O'Neil, 1995). Regional reserves are constituted under the *National Parks and Wildlife Act 1972* and operate under multiple use concepts whereby the wildlife, natural and historic features of reserves are conserved whilst at the same time permitting the utilisation

of the natural resources of the land. Exploration and production are permitted in the reserves under arrangements administered by PIRSA.

An area defined as the Coongie Lakes Control Zone is located within the Innamincka Regional Reserve and has been identified as a significant arid wetlands requiring special management. Exploration and production activities in this zone are subject to administrative and management procedures agreed to by PIRSA, the Department of Environment, Heritage and Aboriginal Affairs and exploration companies.

### Pastoral lands

Access to pastoral land (Fig. 2.4) requires notice be given to the landowner. The most common issues are the repair of any damaged tracks, fences or gates, and in some circumstances, vehicle and equipment hygiene to avoid the spread of weeds. There are standard techniques for managing such issues and landholders generally accept exploration and production activities.

### National Estate

The Coongie Lakes and the Cooper Creek floodplain are included in the Register of the National Estate. This is a listing of places which relate to the *Australian Heritage Commission Act 1975* and provides an indication of the heritage value of the places which it includes. Such listing may affect operations approved by federal agencies, but does not directly affect petroleum exploration or development except in so far as heritage issues must be taken into account in planning and undertaking activities.

### Ramsar Convention

Australia is a signatory to the Ramsar Convention which was established in 1971 to conserve significant wetlands habitats. The Cooper Creek, including Coongie Lakes, has been identified as a wetlands of international importance under this Convention. The broad objectives of the Convention aim to promote the wise use of wetlands and to maintain their ecological character. South Australia's obligations are to manage the wetlands wisely to maintain their ecological character. Such use does not necessarily restrict exploration access.

## HUMAN ENVIRONMENT

### Aboriginal heritage

Aboriginal history is discussed in Chapter 2. In South Australia it is an offence to disturb or destroy Aboriginal sites, objects or remains (*Aboriginal Heritage Act 1988*). Standard procedures for determining the presence of Aboriginal heritage in South Australia, prior to the commencement of activities, have been determined. These involve consulting with the relevant Aboriginal organisation and maintaining a watch for sites, objects or remains during exploration. These sites are generally no larger than a few hundred square metres and are easily avoided. PIRSA can provide advice to companies on Aboriginal heritage.

### European heritage

Sites of European heritage significance such as historic buildings, graves and geological monuments are found in

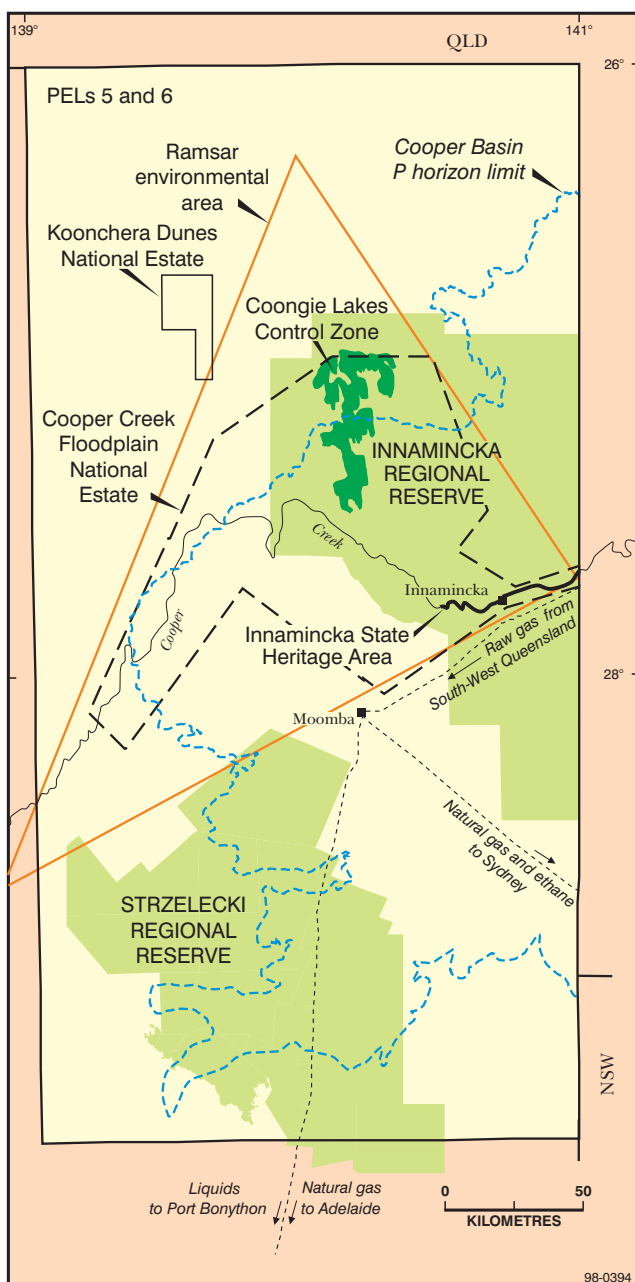


Fig. 3.2 Conservation areas within the Cooper region.

the Cooper Basin. These are indicated on environmental sensitivity maps held by PIRSA. The majority of sites are small and easily avoided during exploration and production activities.

## INTRODUCTION

Raw gas production commenced from the Cooper Basin in 1969 and, at 30 September 1997, 85 gas fields with a total of 354 wells were on-line (Fig. 1.2). A combined total of ~190 PJ (150 bcf) of Cooper Basin sales gas destined for markets in South Australia and New South Wales was sold in 1997. Of this, ~20 PJ were sourced from South-West Queensland<sup>1</sup>.

The first crude oil production began in December 1982 from Eromanga Basin reservoirs in the Strzelecki Field. At 1 November 1997, 28 oil fields with a total of 118 wells were on-line (Fig. 1.2). During 1997, ~0.6 million kL (3.8 million bbl) of crude oil, 0.4 million kL (2.5 million bbl) of condensate and  $0.3 \times 10^6$  tonnes of LPG were sold.

The Cooper Basin Liquids Project was initiated in 1980 and completed in stages from 1982 to 1984 at a cost of \$1.6 billion (\$1997). The project involved construction of a high vapour pressure liquids pipeline from Moomba to a processing plant and storage and loading facilities at Port Bonython, as well as field development, oil collection and crude stabilisation facilities at Moomba.

Shipments of crude oil and condensate commenced in 1983, and LPG handling facilities were commissioned in July 1984. This enabled the Producers to bring the 'wet' gas reservoirs (those containing significant quantities of propane, butane and condensate) into production, which further enhanced production flexibility. Condensate production was replaced by naphtha production at Port Bonython in 1991.

## INFRASTRUCTURE

### Production facilities

A total of 5090 km of pipeline has been laid from the Cooper Basin to gas markets in New South Wales and South Australia, and the liquids load out facility at Port Bonython (Fig. 1.3). Key pipelines in the region are the Moomba – Port Bonython Liquids Line and the Moomba–Adelaide Pipeline, operated by Epic Energy, and the Moomba–Sydney sales gas and ethane pipelines, operated by East Australian Pipelines. The Moomba–Adelaide Pipeline is 781 km long, has an outside diameter of 560 mm and a maximum allowable operating pressure (MAOP) of 7300 kPa. A further 517 km of lateral extensions to the main line service markets in country South Australia, including the Port Pirie, Whyalla and Riverland regions. The Moomba – Port Bonython Liquids Line is 659 km long, has an outside



*Aerial view of a tanker loading at Port Bonython. (Photo 40416)*

diameter of 356 mm and a MAOP of 10 380 kPa. Sales gas is sold to New South Wales markets via a 1760 km network of transmission pipelines (diameter 864 mm, MAOP 6200 kPa), while ethane is provided as feedstock for a petrochemical plant in Sydney via a dedicated 1300 km pipeline (diameter 219 mm, MAOP 15 300 kPa).

Gas emerges at the wellhead at pressures up to 25 000 kPa and temperatures up to 120°C. Gas from individual wells passes via field gathering systems (flowlines) to field satellite stations which separate gas, free water and condensate. Water disposal can be a major issue



*Beam pumps producing oil, Merrimelia Field. (Photo 45016)*

<sup>1</sup> Statistics provided in this chapter are listed in regular reports to PIRSA from the Cooper Basin Producers and are maintained in Departmental databases (e.g. PEPS).

for oil production, and is achieved via evaporation ponds at the satellites. The essentially water-free gas and condensate pass to the central Moomba treatment plant through trunklines. Crude oil is transported by either pipeline or truck to Moomba. Nine oil and 11 gas satellites are currently in operation in the Cooper and Eromanga Basins; ~1010 km of trunklines and 1135 km of flowlines have been laid.

Any free condensate and water are removed from the raw gas by slug catchers at the Moomba plant. The gas stream then proceeds to the CO<sub>2</sub> Benfield plant to ensure that no greater than 3% by volume of CO<sub>2</sub> remains in the sales gas stream. The gas is dehydrated at the molecular sieves before proceeding to the liquid recovery plant where 100% of the remaining condensate, 98% of the LPG (C<sub>3</sub> and C<sub>4</sub>) and 75% of the ethane are removed, leaving sales gas for Adelaide and Sydney with a heating value not less than 37.5 MJ/m<sup>3</sup>. Approximately 8% of the sales gas is used as plant fuel at Moomba. The plant has been designed to process 25.4 million m<sup>3</sup> (900 mmscf) of raw gas and 6000 kL (42 000 bbl) of condensate and crude oil per day. Condensate, LPG, crude and some ethane are transported as a 'cocktail' via pipeline to Port Bonython where they are separated and marketed.



Construction of Della trunkline. (Photo T15557)



Cooper Basin satellite facilities. (Photo 43790)



Carbon dioxide removal towers, Moomba. (Photo 43373)

The feedstock delivered to Port Bonython is sampled, filtered and metered, then pumped through fractionating towers to separate ethane (used as fuel gas for the plant), propane, butane, light, intermediate and heavy naphtha, and reduced crude. Once cooled to ambient temperature, naphtha and reduced crude fractions are mixed together in precise ratios. The resulting two products — naphtha and crude oil — are sent to storage tanks.

When loading to a ship, the products (crude, naphtha, butane or propane) are pumped along the 2.4 km jetty then conveyed through hydraulically controlled loading arms into the ship tanks for transport to Australian refineries or overseas.

A local destination for Cooper and Eromanga liquids is the refinery at Port Stanvac, 10 km south of Adelaide, which produces petroleum products mainly for the South Australian market. The refinery commenced operations in 1963 and the adjacent lubricating oil refinery began producing in 1976. The main products are LPG, solvents, motor gasoline, jet fuel, kerosene, diesel (both automotive and industrial), lube oil basestocks for Australian and overseas markets, fuel oil and bitumen.

## Services in the Cooper Basin

Accommodation and support facilities are located at the Moomba plant. These are operated by the Cooper Basin Joint Venture and are not open to the public; access is by arrangement with the operator.

The existing Moomba camp can accommodate 450 people; an additional 150 beds are currently mothballed. A full range of support services is located at Moomba, including, logging, wireline, fracing, cementing, transport, fuel supply, aviation (including helicopter) and emergency services. The sealed airstrip at Moomba is 1720 m long, and is large enough to accept medium-sized jets.

The production facilities are connected by a series of unsealed 'private' roads, comprising 460 km of main road and 1860 km of access roads, which are maintained by the operator. Some of the public roads in the area are maintained by the operators and the remainder by the Department of Transport.

The township of Innamincka, 65 km northwest of Moomba, is a popular tourist destination. The district office of the National Parks and Wildlife Service is located in the town, along with a hotel, general store, and light-aircraft



Moomba processing plant, Cooper Basin. (Photo 43803)

airstrip. The causeway at Innamincka provides the major crossing point for the Cooper Creek, which in times of flood is impassable by vehicle.

### Transport links

Adelaide (population 1 million) lies ~800 km south of Moomba, and Alice Springs in the Northern Territory is over 500 km to the northwest. Port Augusta is the nearest port (~500 km to the south-southwest). The Birdsville and Strzelecki Tracks are unsealed but provide important routes for heavy transport into the region. Most towns, the Moomba plant, a number of satellites, and station properties have air strips.

### Other industries

The northern part of South Australia is sparsely populated and is relatively undeveloped due to its remoteness and harsh climate. The main primary industry is cattle which are run on large pastoral leases. Tourism (especially ecotourism) is a growing industry in the region — Innamincka provides a staging point to the Innamincka Regional Reserve, Strzelecki Regional Reserve, and the Coongie Lakes wetland system.

### Groundwater

The location, yield and quality of water supplies are critical for operations in the harsh climate of northern South Australia. The Eromanga Basin encloses the multi-aquifer system of the Great Artesian Basin (GAB), one of the world's largest groundwater basins (Habermehl, 1980). Groundwater of the GAB is used by the petroleum and mineral exploration industries, pastoralists and the tourism industry. The shallowest aquifer is ~1000 m deep and provides a guaranteed supply of potable water. More saline water may be intersected in a shallower Quaternary–Tertiary aquifer (Table 4.1). Details of properties of individual bores can be obtained via the SA\_GEODATA database.

**Table 4.1** Groundwater resources of the Moomba region.

Aquifer	Great Artesian Basin	Quaternary–Tertiary
Depth	>1000 m	<250 m
Surface pressure	900 kPa (i.e. free flow)	0 kPa (i.e. requires artificial lift)
Salinity	1000–3000 mg/L	1000–40 000 mg/L
Flow rate	>36 ML/day	0.1–1 ML/day

Access to bores must be negotiated with the owner, which may be the pastoralist, a petroleum exploration company or the Department of Transport. Bores drilled specifically for water require licensing under the *Water Resources Act 1997*.

### ACCESS TO MARKETS

A free market was introduced in 1988 for all oil and condensate produced in Australia. There is no restriction on imports or exports of crude oil or refined petroleum products. A similar regime has applied since 1991 for LPG.

Ex-field natural gas prices in South Australia are also freely negotiated between buyer and seller. There are regulative rights of third party access to gas transmission and reticulation pipelines. Issues relating to rights of access to Cooper Basin processing plant and related infrastructure are currently under consideration.

Markets for crude oil and condensate exist locally, and discoveries in the Cooper and Eromanga Basins are of the highly desirable low sulphur light crude oil type which finds a ready domestic and overseas market.



## INTRODUCTION

The Cooper Basin is entirely covered by the Mesozoic Eromanga Basin. It is one of a number of remnant Late Carboniferous to Early Permian depocentres which lay in the Australian interior of the Gondwana Supercontinent (Fig. 5.1). The Cooper Basin differs from these other depocentres by containing an additional sequence which ranges in age from Late Permian to Middle Triassic and spans the Permo-Triassic boundary without a break in deposition. It also differs in being the only basin with major oil and gas production. Early Permian strata in the neighbouring Pedirka Basin to the west are unconformably overlain by Triassic and younger sequences of the Simpson and Eromanga Basins. The more distant Arckaringa, Troubridge and Nadda Basins to the south and southwest contain sedimentary rocks which are no younger than Early Permian.

East of the Cooper, the Galilee Basin unconformably overlies the Devonian Adavale Basin which was deformed by east–west compression during the mid-Carboniferous Kanimblan Orogeny (see e.g. Mathur, 1987). West of the Cooper, the Pedirka Basin unconformably overlies the Neoproterozoic to Devonian Amadeus Basin which was deformed by north–south compression during the Late

Devonian to mid-Carboniferous Alice Springs Orogeny, as shown by stress vectors in Figure 5.1.

Cambro-Ordovician strata of the eastern Warburton Basin, which underlies the Cooper, have been deformed by post-Ordovician northwest compression and intruded by Middle to Late Carboniferous granite (Gatehouse *et al.*, 1995). The age of this deformation is also correlated with the Alice Springs Orogeny and the stress vector is interpreted as a compromise between the other two, given that both orogenies were nearly simultaneous.

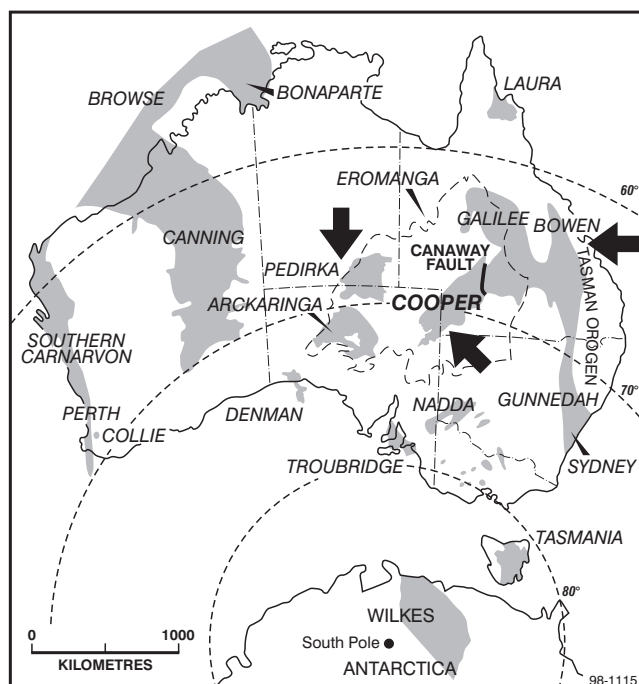
The Cooper Basin is divided into southern and northern parts by a line of anticlinal ridges in South-West Queensland (Arrabury–Karmona Trend; Battersby, 1976) which separates predominantly Triassic depocentres, mostly in Queensland, from predominantly Permian depocentres, mostly in South Australia. This chapter is concerned with the structural setting of the depocentres which make up the South Australian portion of the southern Cooper Basin, i.e. those which contain the greatest thicknesses of productive Permian strata.

## MORPHOLOGY OF THE COOPER BASIN FLOOR

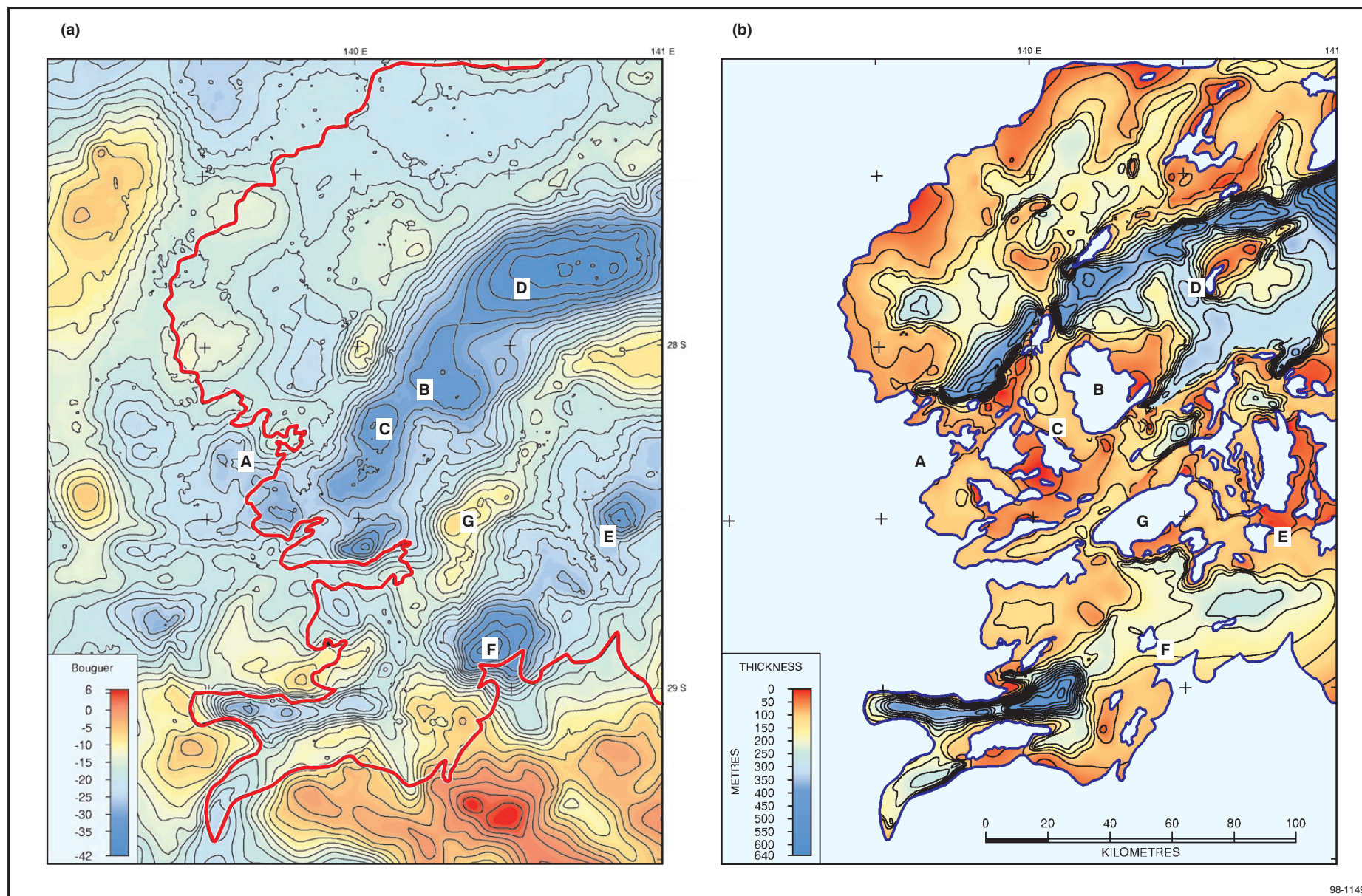
The apparent lack of preserved Devonian strata, and exposure on the basin floor of granites that had been deeply emplaced only ten million years previously, indicates considerable and rapid uplift ~300 million years ago of the region that was to become the Cooper Basin. The Gondwana glaciation was triggered in part by uplift of central Australia and thus the Cooper Basin floor was an ‘erosional land surface carved out of the ground uplifted during the Kanimblan and Alice Springs Orogenies’ (Veevers, 1984, p.239). Early relief was thus topographic rather than structural (cf. Wopfner, 1981; Kuang, 1985) as observed by Thornton (1979).

Irregularity of the Cooper Basin floor can be appreciated from examination of an isopach of the basal strata (Merrimelia Formation – Tirrawarra Sandstone) and a Bouguer gravity map at the same scale, as shown in Figure 5.2a. If the top of Tirrawarra Sandstone approximates a time plane (top of palynozone PP1.2), then the isopach can be viewed as a crude topographic map and on this basis a number of features are notable, namely:

- a linear trough filled with sediments up to 500 m thick striking east–west in the southern part of the basin
- an arcuate chain of asymmetric, elongate troughs trending northeast–southwest
- relatively thin strata (<250 m) in the northwest and southeast



**Fig. 5.1** Late Palaeozoic sedimentary basins on the Australian portion of Gondwana; Late Carboniferous latitudes have been taken from palaeomagnetic data.



**Fig. 5.2** (a) Bouguer gravity map of the Cooper Basin and adjacent Birdsville Track Ridge. (b) Isopach map of the combined thickness of Merrimelia Formation and Tirrawarra Sandstone. Locations denoted by letter in each figure are: **A**, margin of Patchawarra Trough; **B**, Moomba structure; **C**, flank of Wooloo Trough; **D**, Bulyeroo structure; **E**, Toolachee South and Munkarie area; **F**, undrilled region between Mulga and Kumbarie wells; **G**, Murteree Ridge.

- outcrop areas of irregular shape surrounded by thin (<100 m) shelves of sediments.

The areas that outcropped at that time are interpreted as highlands, some glaciated, the largest being west of the southern Cooper Basin (designated **A** in Figure 5.2), composed of Early Cambrian Mooracoochie Volcanics. The elevated areas (therefore bald of sediment and coloured pale blue) designated **B**, **C** and **D** are composed mainly of Carboniferous granite which has been intersected in more than 23 wells, notably those in Moomba and Big Lake Fields and the Nappamerri Trough (Gatehouse *et al.*, 1995). These areas are characterised by pronounced negative anomalies on the gravity map and thus the negative gravity anomalies labelled **E** and **F** are also interpreted to be granite plutons buried beyond the reach of the drill.

The shape of the elevated area labelled **G** in Figure 5.2 has been altered by structural reactivation in the late Early Permian and Triassic and thus the shape of the original landform is partly obscured. Faults on the margins of the asymmetric troughs have also been reactivated and thus the 'landscape' depicted in Figure 5.2b should not be taken too literally. Nevertheless, the figure is useful in showing that original depocentres were elongate, narrow features and that topographic extremes varied from at least 600 m (the maximum thickness of basal strata) to possibly 5000 m (emplacement depth of granite uplifted to be exposed on the basin floor), although this upper limit would have been reduced considerably by erosion. For comparison, peaks in the modern Transantarctic Mountains range from 2700 to 4300 m in elevation.

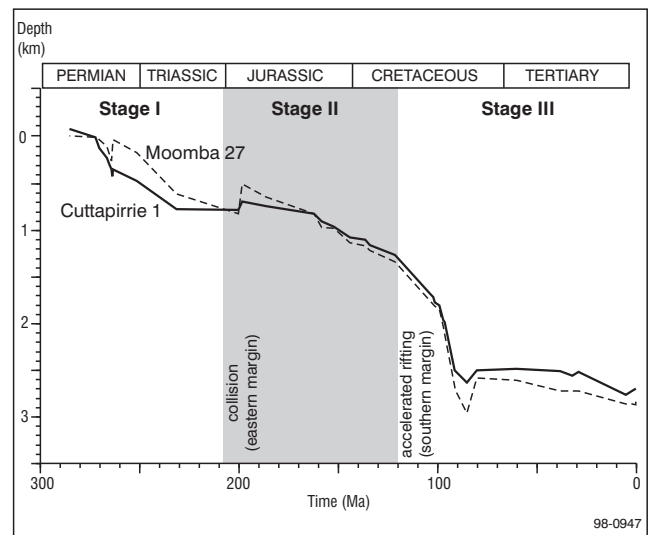
## BASIN-FORMING MECHANISM

The 10 million year prehistory of the Cooper Basin was an epoch of granite emplacement, uplift and glaciation. The first two phenomena are clearly associated with high thermal activity in the upper crust and it was the cessation of heat flow which caused the Cooper and Eromanga Basins to subside. Cooling has resulted in thermal contraction characterised by exponential decay of heat flow with time. Tectonic subsidence curves are thus pseudo-exponential or linear as shown by Gallagher (1988) for the Cooper Basin and Gallagher and Lambeck (1989) for the overlying Eromanga Basin using data from 40 wells.

Burial history analysis of 14 wells (Moussavi-Harami, 1996a) yielded subsidence curves which indicate a three-stage burial history from the base of the Cooper Basin to the present day. Curves for Moomba 27 (representing relatively thick Permian and thin Triassic) and Cuttahirrie 1 (representing relatively thin Permian and relatively thick Triassic) are shown in Figure 5.3. They have been generated using BURY software (see Ch. 9).

Stage I is characterised by pseudo-exponential subsidence curves in both wells between 285 and 208 Ma, an epoch which spans Late Carboniferous to Triassic deposition in the Cooper Basin.

The portions of the burial history curves labelled Stage II represent non-marine Jurassic to Early Cretaceous subsidence of the Eromanga Basin (see e.g. Alexander and Hibbert, 1996). The curves are initially linear, then pseudo-exponential, generally in agreement with the thermal decay model of Gallagher and Lambeck (1989).



**Fig. 5.3** Interpretive burial history of Moomba 27 and Cuttahirrie 1. Permian and Triassic strata in Moomba 27 are 561 m and 195 m respectively; compare Cuttahirrie 1 where Permian strata are 243 m thick and Triassic 267 m thick (after Moussavi-Harami, 1996a).

The curves which represent Stage III subsidence are initially steep during the remaining Cretaceous and relatively shallow from Late Paleocene to present day. Gallagher and Lambeck (1989) suggested that the steep portions of the curves are due to increased sedimentation rates as global sea-level rise increased accommodation. The Tertiary to Recent portions of the curves correspond with a thermal decay model.

The burial history of the Cooper Basin region was interrupted between the Late Triassic and Early Jurassic (~212–190 Ma) and again during the late Barremian stage of the Early Cretaceous (~118 Ma), giving rise to the three-part subsidence curves shown in Figure 5.3. The interruptions appear to arise from intraplate tectonic responses to plate margin stresses, followed by extended periods of relative tectonic quiescence. Thus, the partition between Stage I and Stage II is attributed to large-scale tectonics (collision) on the eastern plate margin (Veevers, 1984; Gallagher, 1988) and the partition between Stage II and Stage III is attributed to accelerated rifting on the southern margin of Australia prior to the separation of Antarctica 95 million years ago. A review of the wider events on the Australian continental plate is provided in Chapter 6.

## COOPER BASIN STRUCTURAL STYLE

Authors from the time of Kapel (1966a) to Apak *et al.* (1997) have stressed the importance of fault reactivation in the structural evolution of the Cooper Basin. This was foreshadowed by Sprigg (1958, p.2475) who commented prior to discovery of Permian strata beneath the Mesozoic: 'persistent structural lineaments in the form of major transcurrent faults have also exerted strong influence on basin configuration and upon the development of fold patterns since earliest geological history'. Interpreters of parts of essentially the same seismic data set have proposed extension (e.g. Stanmore, 1989), compression (e.g. Sun, 1997; Apak *et al.*, 1997), and a range of extension, strike slip and compression (Kuang, 1985) as mechanisms of Cooper

Basin deformation. Such differing viewpoints would appear to be irreconcilable but they can be accommodated by considering the orientations of faults in an applied stress field.

Wopfner (1985) was the first to examine the structural geometry of northeastern South Australia under the influence of a regional compressive stress field and he also speculated on variation of the stress regime through geologic time as well as on possible causative mechanisms. An approximate model of the present day stress field of the Australian plate has been devised by Hillis and Sandiford *et al.* (1997) who pointed out that the orientation of horizontal stresses governs the probable geometries of reactivated faults — extensional if the fault plane dips in the direction of minimum horizontal stress, compressional if the fault dips in the direction of maximum horizontal stress, and strike slip if the fault strike is rotated  $\sim 30^\circ$  with respect to the maximum horizontal stress vector. By appropriate selection of seismic lines, arguments for the full range of fault geometries can be sustained. The differing views on the structural style of the Cooper Basin in effect point to an anisotropic regional stress field and indicate that no single mechanism of deformation has predominated.

The maximum present day horizontal stress of the Nappamerri Trough and surrounding regions has been recently deduced from borehole breakout and fracture analysis, and is approximately east–west (Hillis, Meyer and Magee, 1997). The same authors pointed out that in the Nappamerri Trough at depths exceeding 2700 m, the minimum horizontal stress may equal the overburden in overpressured zones, indicating a compressional regime at depth.

Faults which displace the Cooper Basin are vertical and mostly of small ( $\sim 10$  m) displacement. Anticlines are characteristically coaxial, indicating vertical structural reactivation from the time subsidence began in the Late Carboniferous. The Cooper Basin, the Jurassic to Cretaceous Eromanga and the Tertiary Lake Eyre Basin thus share the same major structural elements as pointed out in an early paper published on the Cooper Basin (Kapel, 1966a). Vertical reactivation is typical of intracratonic basins and it is only Australian convention which separates and names stratigraphically stacked depocentres, even though they are demonstrably a single entity in a structural sense.

Three depth structure contour maps are shown in Figure 5.4a–c: the base of the Cooper or top of Warburton Basin (Z seismic horizon), near top of Toolachee Formation (P seismic horizon) and near top of Cadna-owie Formation (C seismic horizon). The limit of the P horizon (Fig. 5.4b) is interpreted to mark the subcrop margin of the Cooper Basin. Although Triassic rocks extend north beyond this margin and are also assigned to the Cooper Basin, they are not underlain by Permo–Carboniferous strata and thus the exterior of Figure 5.4b is blank. The outline of the Cooper Basin subcrop margin is also shown superimposed on the Z and C regional structure contour maps to assist with recognition. Names of the main structural elements are shown in Figure 5.5.

## Ridges

Elevated features up to 30 km long by 10 km wide are called ‘ridges’ regardless of whether they are structural or

topographic in origin. Thus, ‘ridge’ is a non-genetic term which replaces inappropriate nomenclature (‘high’, ‘horst’, ‘trend’, etc.). The most prominent are the Gidgealpa, Merrimelia, Packsaddle and Innamincka Ridges (Fig. 5.5) which are arranged partly in-line, partly *en echelon* to form an arcuate ridge complex (shortened here to GMI Ridge; = GMI Trend in previous publications). Each ridge is asymmetric with major faults bounding the north margin and minor faults on the south margin; some are known to be cored by deep thrust faults in the underlying Warburton Basin (Roberts *et al.*, 1990; Sun, 1997).

Further south there are the broader, symmetric (faulted on both margins), flat-topped Dunoon and Murteree Ridges and, parallel to them, the Della–Nappacoongee Ridge with a major bounding fault to the north. The fault extends southwest between Moomba and Big Lake Fields. Together, the Dunoon, Murteree and Della–Nappacoongee Ridges trend east to northeast (= Murteree–Nappacoongee or MN Trend in many publications).

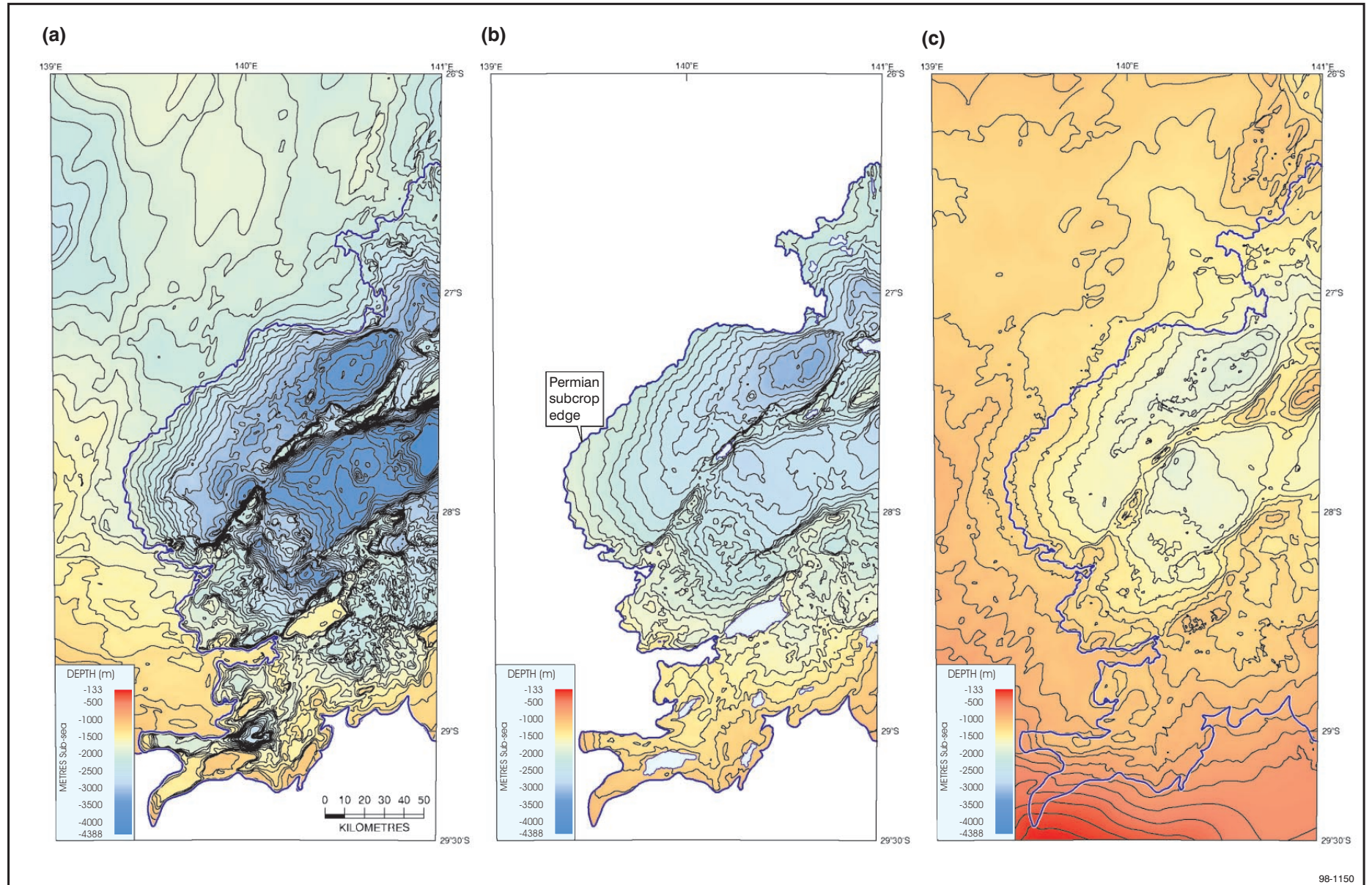
From the southern margin of the Cooper Basin the Tinga Tingana Ridge strikes northwards until terminated by the Dunoon Ridge. Although seismic coverage is sparse, the Tinga Tingana Ridge becomes less well defined on successively younger structure contour maps suggesting it is an ancient (?Proterozoic), structurally dormant feature. Also poorly defined seismically is the Birdsville Track Ridge which lies beyond the Cooper Basin margin and consists of large Neoproterozoic domes partly delineated by gently upwarped Cretaceous outcrops (Alexander and Jensen-Schmidt, 1996).

The tops of larger ridges are complex and composed of several domal culminations (anticlines) which may be grouped in clusters or chains separated by saddles. Often the Permian is eroded and the Triassic is thin on individual culminations. The Dunoon and Murteree Ridges are devoid of both Permian and Triassic and are overlain unconformably by Jurassic strata. Names of smaller ridges have been adopted from unpublished company maps (see e.g. Callen and Gravestock, 1994; Tectonic Sketch) but scale does not permit their inclusion in Figure 5.5.

## Troughs

Major depressions are called ‘troughs’ regardless of whether they are structural or topographic in origin. ‘Trough’ is thus a non-genetic term which replaces inappropriate nomenclature (‘low’, ‘graben’, ‘rift’, ‘syncline’, etc.).

Between the two major ridge complexes lies the Nappamerri Trough which contains the deepest and thickest Cooper Basin sediments illustrated on the P–Z isopach in Figure 5.6. The giant Moomba gas field lies at the southern end of the Nappamerri Trough which appears to be crudely compartmentalised by north–northwest to northwest-trending structural culminations. They may mark the locations of wrench faults which accommodated differential movement between thrust faults in the underlying Warburton Basin (Kuang, 1985; Apak *et al.*, 1997). The Wooloo Trough west of Moomba is a parallel feature which also has a northwest strike, suggested by Boucher (1991) to have marked the passage of a Cambrian rift splay, perhaps related to the major Koonenberry Fault in western New South Wales. The Patchawarra Trough, situated northwest



**Fig. 5.4** (a) Top of Warburton Basin (Z horizon) depth structure contour map. (b) Near top of Permian (P horizon) depth structure contour map. (c) Near top of Cadna-owie Formation (C horizon) depth structure contour map. Edge of Cooper Basin (Permian subcrop edge) is shown on each map.

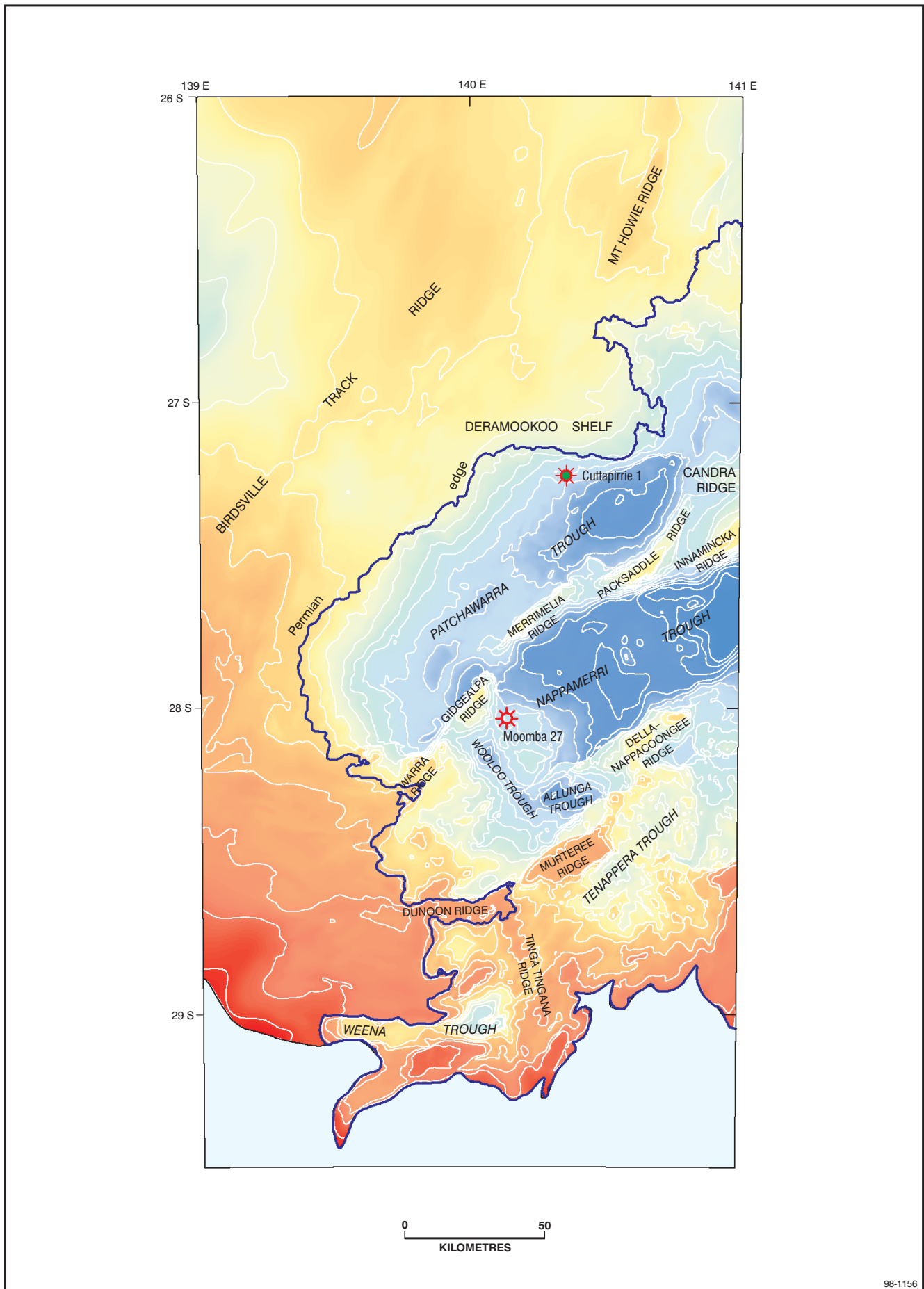


Fig. 5.5 Nomenclature of principal structural elements of the Cooper Basin.

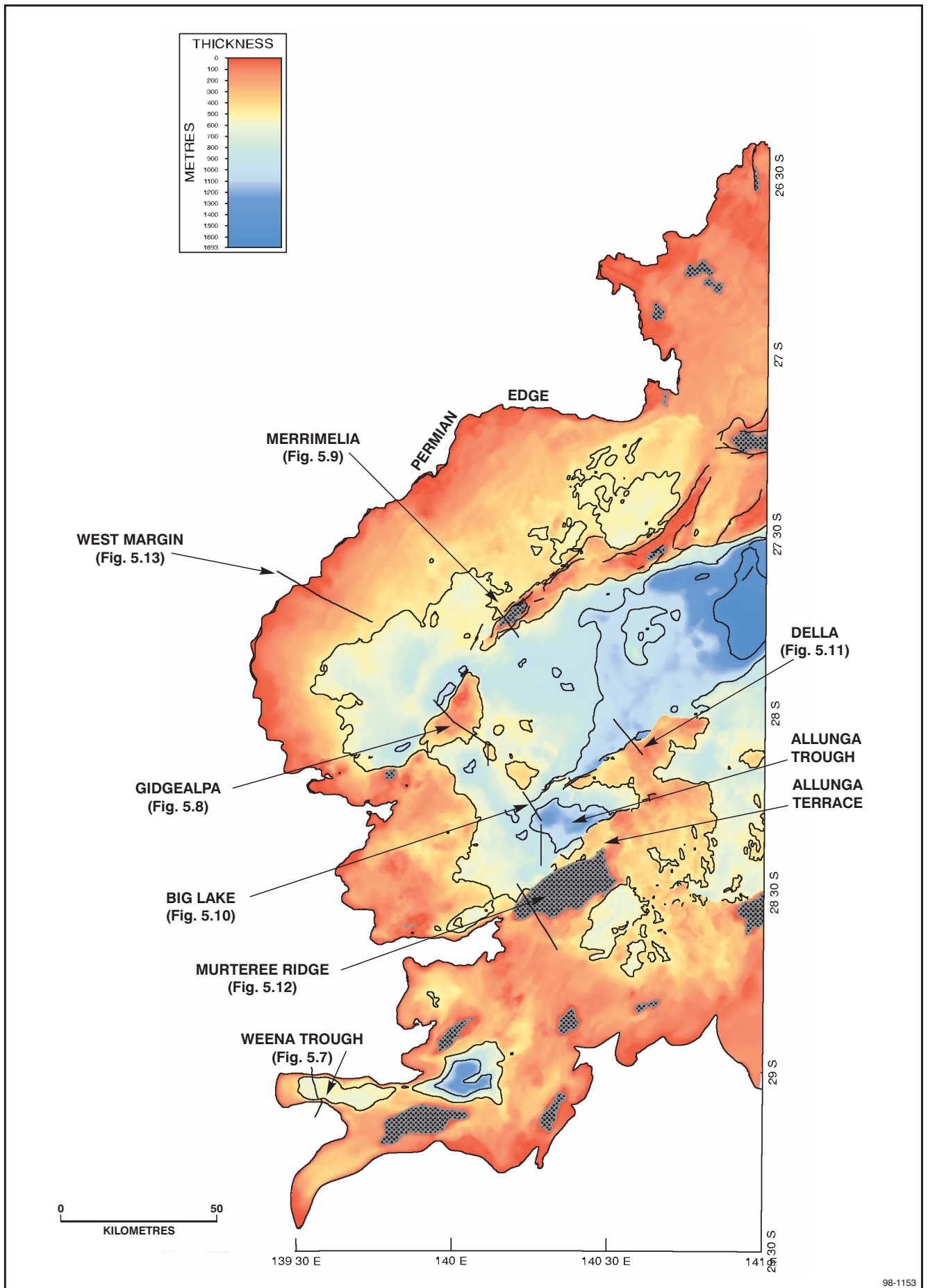


Fig. 5.6 Permo-Carboniferous (P-Z) isopach map. The locations of seismic lines described in Figures 5.7–5.13 are also shown.

of the Gidgealpa, Merrimelia and Packsaddle Ridges, is also a complex depocentre as shown by gravity, structure contour and isopach data (Figs 5.2, 5.4, 5.6). It too is crudely compartmentalised by northwest-trending structures interpreted by Roberts *et al.* (1990) to mark the passage of a wrench fault assemblage through the Warburton Basin. Examination of Figure 5.6 shows that northwest-trending structural features, though usually short and discontinuous, are quite pervasive.

Thickness of Permian sediments in the Patchawarra Trough is less than half that in the Nappamerri Trough because the southwestern Patchawarra Trough was topographically higher to begin with and much of the Permian is missing due to non-deposition or erosion at the Daralingie unconformity (R seismic horizon; see below). Despite this, the thickest coal seams (to 20 m) occur in the Patchawarra Trough, suggesting prolonged tectonically stable conditions prior to uplift.

The Tenappera Trough, like the Patchawarra and Nappamerri Troughs, was first delineated by a gravity survey (Kapel, 1966a). However, the negative anomalies which were originally assumed to outline the Tenappera Trough are now interpreted as shallow granitoids (Fig. 5.2) and the trough is not well defined seismically. It appears on structure contour and isopach maps (Figs 5.4, 5.6) as a pair of embayments which flank the Toolachee gas field, and a structural depression south of the Murteree Ridge. An east–west trough, considered part of the Tenappera Trough by Thornton (1979) is regarded as a separate entity (see below).

The Allunga Trough lies south of Big Lake gas field and north of the Murteree Ridge, and contains a considerable thickness of Permo-Carboniferous strata (Fig. 5.6). The Wooloo and Allunga Troughs merge in the west. Unlike Big Lake Field and the Wooloo Trough which are underlain by granite, there is no gravity anomaly associated with the Allunga Trough.

One of the most distinctive features near the southern boundary of the Cooper Basin is the Weena Trough (new name), which is sufficiently covered by seismic data to distinguish its flat-bottomed, steep-sided geometry (Fig. 5.7). The trough is also associated with an elongate, negative gravity anomaly and contains a very thick Merrimelia Formation – Tirrawarra Sandstone section (Fig. 5.2). Weena is the only trough in the Cooper Basin to strike east–west and it is interpreted by the authors as a Late Carboniferous glacial valley.

Callen and Gravestock (1994) named several embayments of troughs (e.g. Mettika and Tarwonga Embayments of the Tenappera Trough) and a number of depressions not connected with the deeper troughs. These names have been adopted from unpublished company maps but are not shown in Figure 5.5 for reasons of scale.

## EXAMPLES OF COOPER BASIN STRUCTURES

Seismic sections across some of the larger Cooper Basin structures are illustrated in Figures 5.8–5.12. The lines cross the Gidgealpa, Merrimelia, Murteree and Della–Nappacoongee Ridges and also cross the fault between the Moomba and Big Lake gas fields. Seismic line locations are shown in Figure 5.6. Sections are normal polarity compressed stacks, principally from 1990 to 1992 surveys. Each figure comprises four frames levelled on successive seismic horizons:

- a Early Permian V seismic horizon (near top of Patchawarra Formation)
- b Late Permian P horizon (near top of Toolachee Formation)
- c Early Cretaceous C horizon (near top of Cadna-owie Formation)
- d present day.

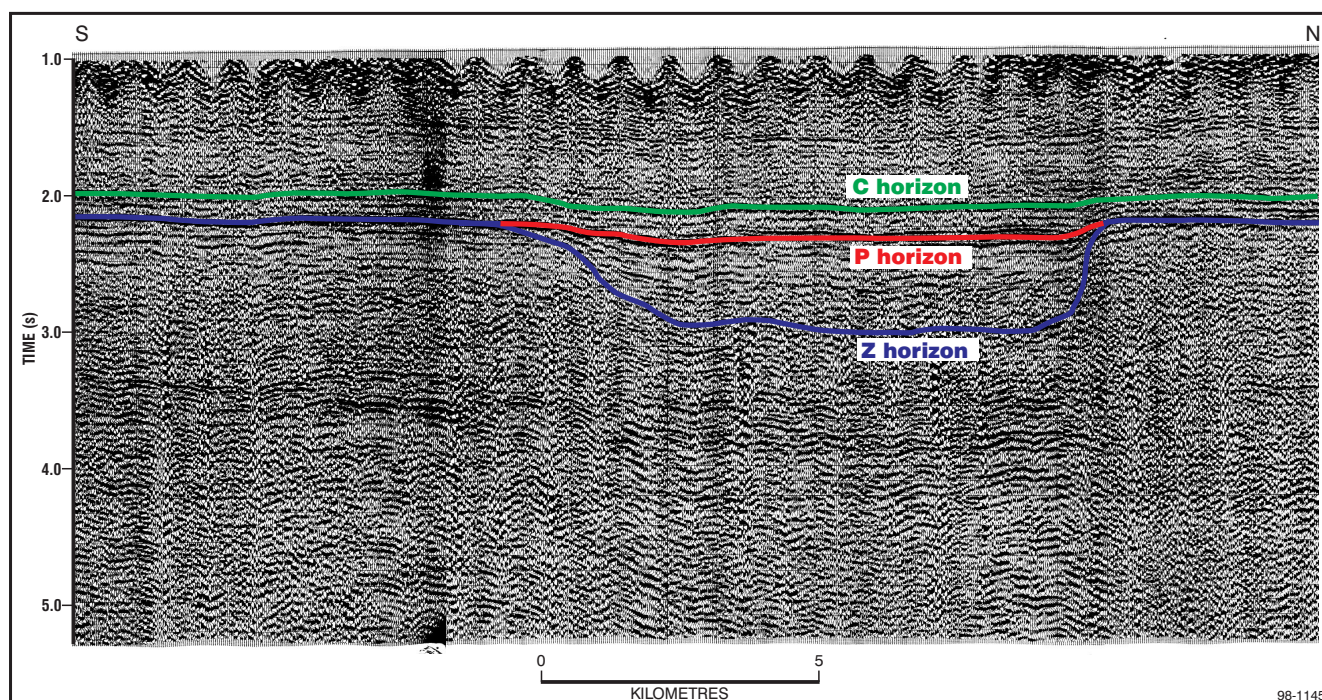


Fig. 5.7 Composite seismic section (lines 64-CN and 65-PE) showing morphology of the Weena Trough. Line of section is located in Figure 5.6.

## Gidgealpa

Gidgealpa 2 was the Permian gas discovery well on New Year's Eve of 1963. The structure is composed of two southwest–northeast elongated domes initially delineated by aeromagnetic, refraction and reflection seismic surveys (Greer, 1965). The core of the north dome is composed of Middle Cambrian to Early Ordovician Kalladeina Formation carbonates resting on Early Cambrian Mooracoochie Volcanics. The Kalladeina Formation has been overthrust to the northwest (Greer, 1965; Sun, 1997), presumably during the Alice Springs Orogeny. Gidgealpa field geology is described by Battersby (1976) and McIntyre *et al.* (1989).

The seismic section shown in Figure 5.8 is a composite of three lines (90-CRF, 90-CRW, 83-M004) which trend southeast to south and record sediments in the Patchawarra Trough, the northern flank of the Gidgealpa Ridge, northern Wooloo Trough and Moomba flank.

The first frame (Fig. 5.8a) has been levelled on the V horizon to show the relationship between the Late Carboniferous to Early Permian strata and the underlying structure. The Z horizon represents the base of the Cooper Basin. The asymmetry of the ramp-like basement has caused the V–Z package of sediments to onlap the structure from the southeast and fill a flat-floored depression in the northwest to abut the western scarp of the feature. The crest of the dome south of this section is bald of Early Permian strata. Slight upturning of the reflectors (marked X in Fig. 5.8a) may represent sedimentary dip or may indicate very slight structural growth. The absence of significant drag or rollover into the escarpment precludes growth faulting on the western side. Likewise, the absence of folding or buckling indicates a lack of compressive stress over this period.

The second frame (Fig. 5.8b) has been levelled on the P horizon, and the P–V sediment package incorporates the Daralingie unconformity (see below). After deposition of the Patchawarra Formation, subsidence became significant in the Wooloo and Nappamerri Troughs. Strata away from the established ridges maintained their horizontal aspect. Fault blocks tilted on the southeastern margin of the Gidgealpa Ridge, causing the accumulated strata to dip into the Wooloo Trough. The faults (marked F in Fig. 5.8b) define the western edges of these tilted blocks.

The third frame (Fig. 5.8c) shows continued subsidence and deposition in the flat-floored Patchawarra Trough adjacent to the western scarp of the Gidgealpa Ridge, reactivation of a second fault to enhance tilt and accumulation in the Wooloo Trough, and absence of significant faulting in the Cooper Basin (P–Z) package. The seismic section above the C horizon datum has not been cropped in this frame to illustrate a system of layer-bound faults at two levels in the Cretaceous marine section. On 3D seismic surveys, these faults enclose polygonal blocks resembling 500–1000 m scale mudcracks and are Cretaceous in age (Oldham and Gibbins, 1995). A model proposed by Cartwright and Lonergan (1997) for similar polygonal faults in the North Sea Basin suggests that they are not tectonic but related to compaction and expulsion of pore fluids.

The final frame, representing present day (Fig. 5.8d), illustrates a broad, low-amplitude fold pattern caused by early Tertiary east–west compression and compaction of previously deposited strata. This has tightened the existing Gidgealpa and Moomba structures but has introduced no major faults. It is clear that no significant faults occur in the Permian or Mesozoic section even on the steep western scarp of the Gidgealpa structure. The major offsets are between Permian and basement strata but there are no major displacements within the Permian section. It is worth noting that the flat basin floor west of the scarp has remained unchanged since the earliest Permian. In conclusion, the only evidence of deformation on this section is basement tilt, mild uplift and truncation at the end of the Early Permian, and broad Tertiary folding.

## Merrimelia

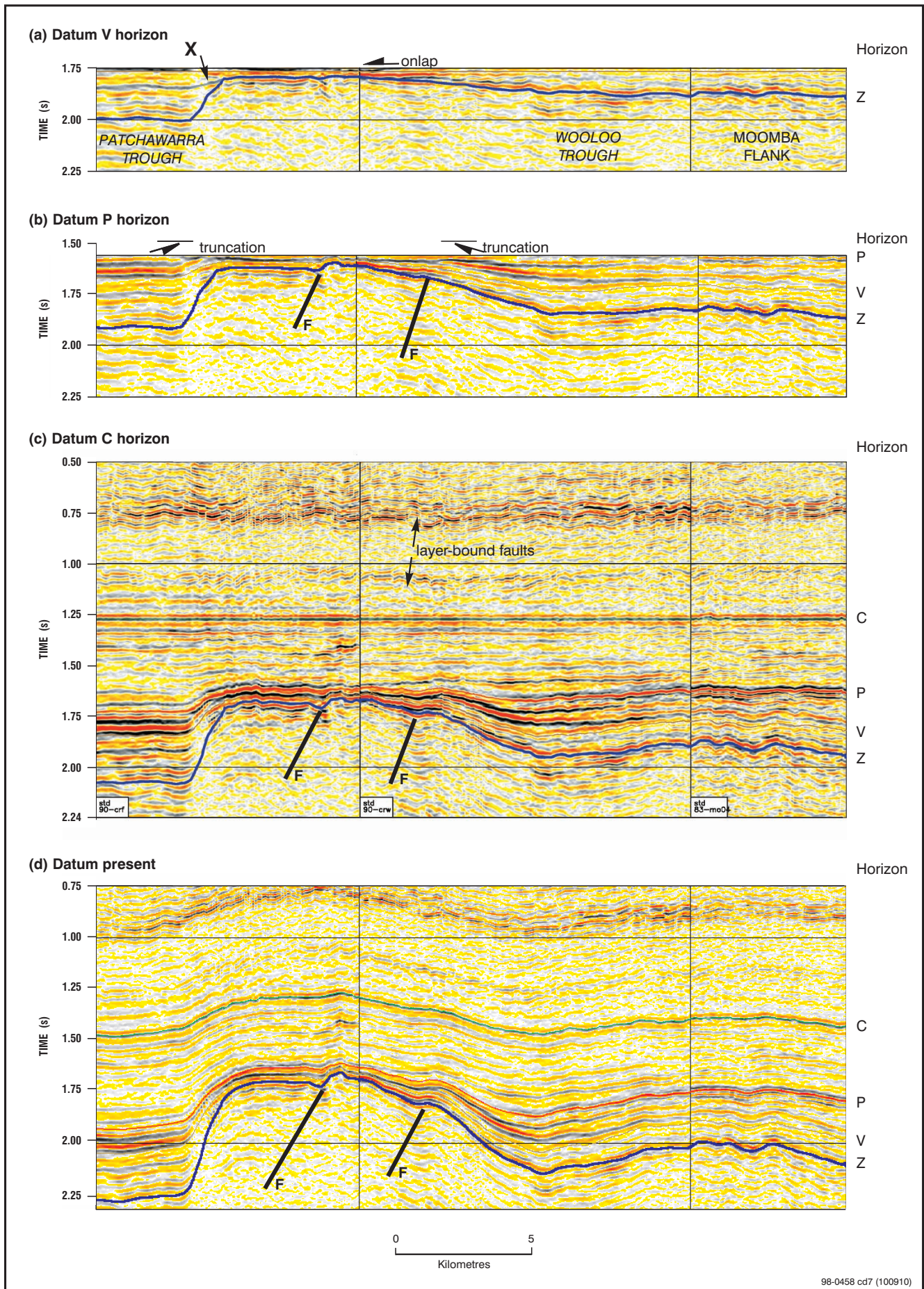
The Merrimelia structure lies on-trend from the Gidgealpa Ridge and was also first detected by aeromagnetic surveying; single-fold reflection seismic and gravity surveys delineated the structure. Merrimelia 1 was drilled in 1964 shortly after the Gidgealpa 2 discovery but was dry; it was not until 1970 that Merrimelia 5 tested commercial gas from the Late Permian and Triassic (Battersby, 1976). Smith (1983) has outlined the exploration history of the Merrimelia field to the drilling of Merrimelia 12.

The Merrimelia structure is depicted in Figure 5.9. Seismic line 90-CLW passes southeasterly through part of the Patchawarra Trough, over the Merrimelia Ridge and onto the northwestern flank of the Nappamerri Trough. The core of the structure beneath the Z horizon is composed of flat-lying to gently dipping Ordovician redbeds and quartzites (Innamincka Formation). The redbeds appear undeformed but may be thrust faulted at depth in a manner similar to the Wantana locality further northeast on the same trend (Sun, 1997).

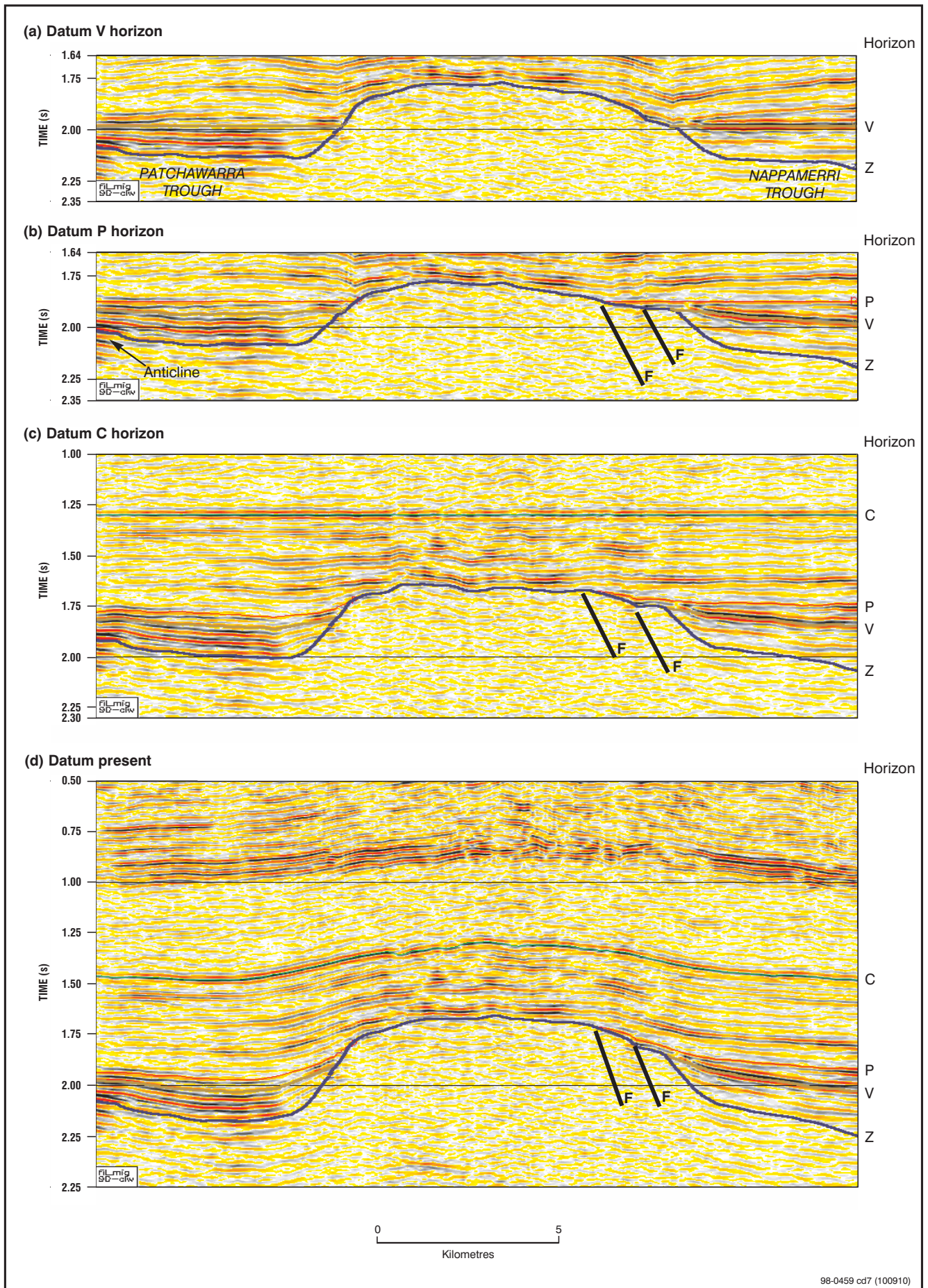
Figure 5.9a depicts the Merrimelia–Tirrawarra–Patchawarra (V–Z) seismic package. The high-amplitude glacio-lacustrine and coal reflectors in the Patchawarra Trough contrast with the low-amplitude outwash and aeolian deposits on the opposite, Nappamerri Trough side of the structure, an indication of palaeotopographic relief during the Early Permian. Smith (1983) recognised the structure was a basement high and proposed a period of structural growth during Patchawarra time. Slight upturning of V–Z reflectors on the northwestern side of the structure may indicate either depositional dip or mild structural growth, but there is no evidence of pronounced structural movement.

Figure 5.9b, levelled on the P horizon, illustrates the geometry of the Daralingie unconformity at the end of the Early Permian. This resulted in tilt and truncation of Early Permian strata, notably the gas-bearing Tirrawarra Sandstone which is sealed by post-unconformity shale and coal units (Stanmore, 1989). Angular tilt of the southeastern side of the Merrimelia structure resulted from fault reactivation (faults labelled F in Fig. 5.9b) and variation in subsidence of the fault block relative to that of the main basement massif.

An anticline beyond the northwestern margin of the seismic section has affected strata in the illustrated portion



**Fig. 5.8** Gidgealpa Ridge and adjacent troughs levelled on successive seismic horizons. See text for details. Line of section is located in Figure 5.6.



**Fig. 5.9** Merrimelia Ridge and adjacent troughs levelled on successive seismic horizons. See text for details. Line of section is located in Figure 5.6.

of the Patchawarra Trough. This anticline was an Early Permian growth structure since seismic reflectors converge in that direction.

The third scene (Fig. 5.9c) is levelled on the C horizon. Topography of the Merrimelia structure probably influenced fluvial drainage patterns during the early Mesozoic until it was covered by onlapping Early Jurassic strata. Subsidence was uniform during the remaining Jurassic and Early Cretaceous, as shown by the parallel reflectors.

The final scene (present day, Fig. 5.9d) shows the open fold pattern imposed by early Tertiary compression as well as drape compaction of Permian and Mesozoic strata over the Merrimelia Ridge.

### **Big Lake – Allunga Trough**

The third example comprises seismic sections 91-DDW and 77-JKT which cross the Big Lake structure from northwest to southeast and the Allunga Trough from north to south. Big Lake Field, discovered in 1971, is an elongate northeast-trending anticline separated from the complex Moomba structure by a fault downthrown to the northwest. Geology of the Big Lake Field is described by Battersby (1976) and details of tight gas reservoir stimulation are presented by Stanley and Halliday (1984).

The first frame (Fig. 5.10a) has not been levelled on the V horizon but on the U seismic horizon which approximates the top of the Murteree Shale (this conformably overlies Patchawarra Formation; Fig. 6.1). Early Permian strata thicken from the northwest and south into the Allunga Trough and no structure is discernible at Big Lake.

The second frame (Fig. 5.10b), levelled on the P horizon, reveals that a fault has developed with a downthrown block on the northwestern side. Minor thickening of Early Permian strata towards the fault is evident on the downthrown side. This fault is one of the few which are interpreted here to propagate through the Early Permian section. This view contrasts with those of other workers (e.g. Battersby, 1976) who interpreted significant fault displacements. Taylor *et al.* (1991) considered the throw on the Big Lake Fault to increase from 80 m on the southwestern side of Big Lake Field, to 150 m on the northwestern side.

What appears to be happening here is a general subsidence in both the Nappamerri and Allunga Troughs, with a sub-Cooper Basin ridge maintaining its elevation, or simply subsiding less than the two troughs. This is causing crestral thinning on the Big Lake structure whilst maintaining a more or less complete stratigraphic sequence. The dip on the beds increases into the Allunga Trough as does their thickness, due to a combination of uneven accumulation and differential compaction. Erosion in the trough during the Daralingie uplift was minimal and possibly non-existent. On the downthrown side of the fault, original minor structuring due to topographic variations has been enhanced by rollover into the fault.

The third frame (Fig. 5.10c) also shows continued relative subsidence in the trough as shown by thickening of Triassic seismic events directly above the P horizon. Subsidence due to differential compaction of the thicker Permian section may also be a factor. After Triassic time, the sediments are effectively horizontal up to and through

the Cretaceous Cadna-owie C horizon, denoting a period of tectonic quiescence.

Representing the present day, the final frame (Fig. 5.10d) illustrates the low relief Big Lake structure as a slab of sediments tilting to the southeast with only minor later deformation which can be attributed to compaction.

### **Della**

Della, an elongate domal structure on the Della–Nappacoongee Ridge, is a major gas field discovered in April 1970. It contains some of the best quality fluvial sandstone reservoirs in the Cooper Basin (Pyecroft, 1973; Battersby, 1976).

The first frame (Fig. 5.11a) has been levelled on the V horizon and has not been cropped at this level so as to display the extreme topography of the Della Ridge. The sediments to the northwest, in the Nappamerri Trough, show a remarkable degree of horizontal conformity down to and including the pre-Carboniferous basement. This is attributed to a stable low-energy sedimentary environment during a period of tectonic inactivity. No sediments were deposited on the crest of the ridge, and it can be safely assumed that the ridge was being eroded at this time.

The second frame (Fig. 5.11b) is flattened on the P horizon and thus effectively encompasses the entire Permian section, including the Daralingie unconformity. Within the Nappamerri Trough, sediments are still remarkably horizontal and conformable denoting consistent sediment deposition. A slight dip and discontinuity of sediments on the ridge shows that the Nappamerri Trough began subsiding after Patchawarra time, approximately during deposition of the Epsilon Formation. This subsidence activated a fault marked X at the top of the section. Subsidence was regular, maintaining the remarkable horizontal nature of the beds, and is interpreted to originate by reactivation of a fault in the deep Warburton Basin.

The third frame (Fig. 5.11c) shows subsidence continuing into the Jurassic with what appears to be rollover into the fault or escarpment edge within the Nappamerri Trough. Sedimentation on the ridge was reduced considerably and, in a small area of the Della field at the far right of the section, the Toolachee Formation unconformably overlies basement.

The final frame representing present day (Fig. 5.11d) dramatically illustrates the effect of later structural reactivation. As with previous figures, the Della Ridge has been enhanced by early Tertiary east–west compression and sediment compaction with all the appearance of a thrust-faulted structure. The absence of compression folds is noted in the still sub-horizontal beds within the Nappamerri Trough.

### **Murteree Ridge**

The Murteree Ridge is a large flat-topped structure, composed of Ordovician black shale and Cambrian basic volcanics, and is bald of Permian sediments on top. Along the northeastern flank, the ridge is bounded by a downthrown fault block — the Allunga Terrace (Fig. 5.6) — for much of its length, and abuts the Allunga Trough proper to the southwest on the same flank. The southern edge meets the Tenappera Trough with several structural configurations. Placed at the southern end and bypassing the Allunga

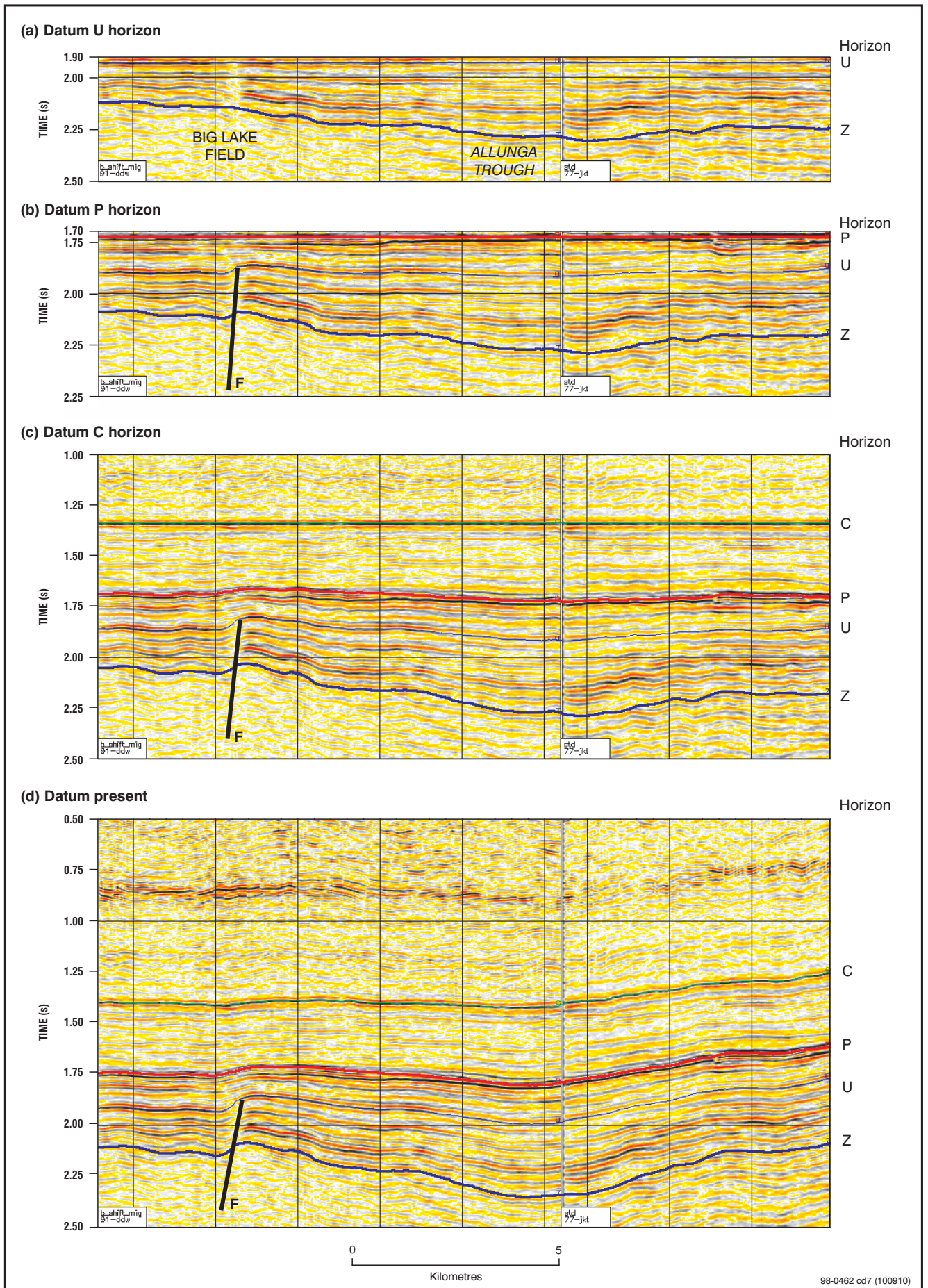
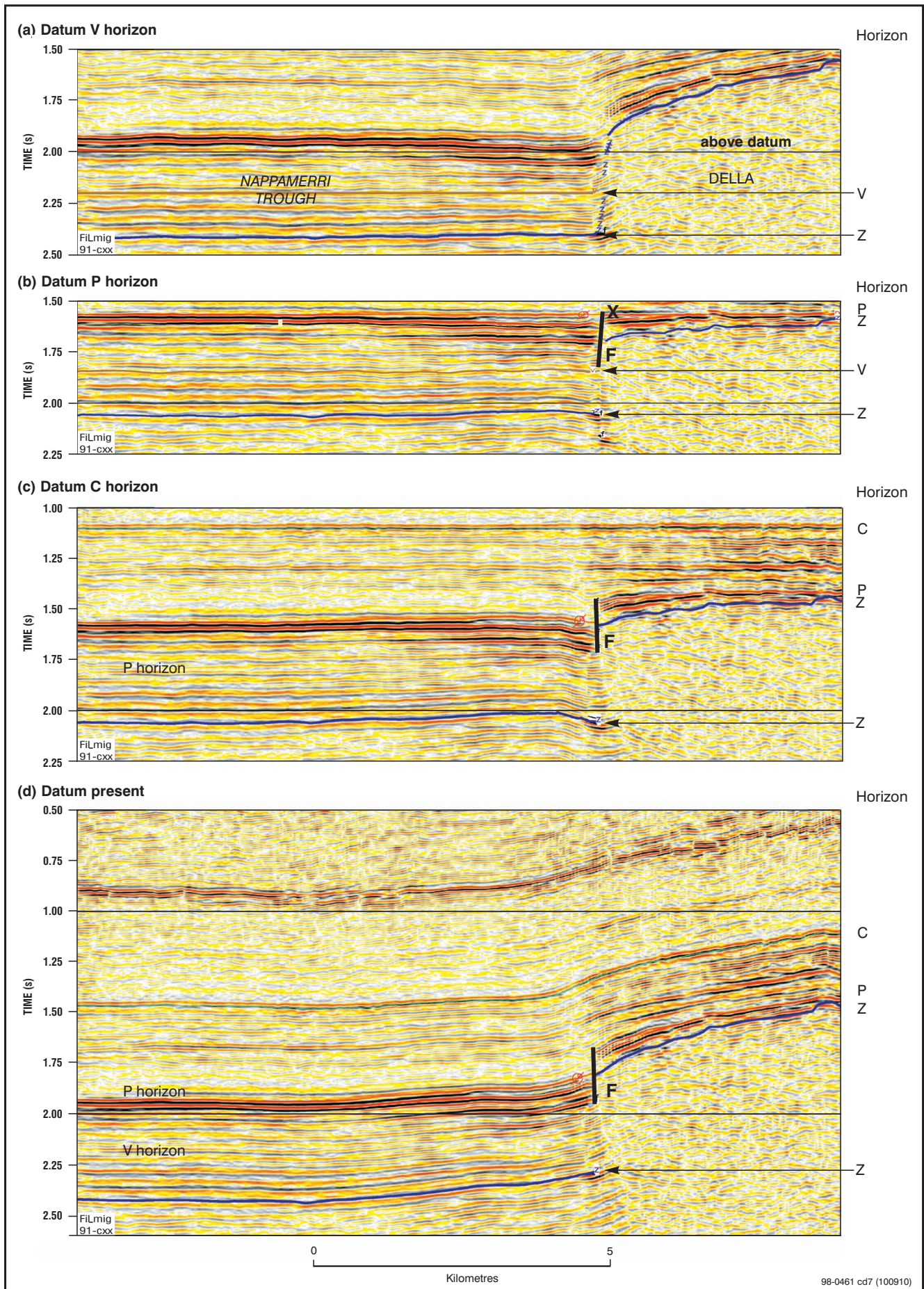


Fig. 5.10 Big Lake structure and adjacent Allunga Trough levelled on successive seismic horizons. See text for details. Line of section is located in Figure 5.6.



**Fig. 5.11** Della structure and adjacent Nappamerri Trough levelled on successive seismic horizons. See text for details. Line of section is located in Figure 5.6.

Terrace, the seismic section in Figure 5.12 trends north-westerly directly into the Allunga Trough. To the southeast, the section enters the Tenappera Trough.

As with other sections, the first frame (Fig. 5.12a) has been levelled on the V horizon. To the southeast, the sediments are typically horizontal, indicating that the Early Permian was tectonically quiescent or evenly subsiding. To the northwest, on the left of the frame, the seismic horizons dip slightly into the Allunga Trough. This may be due to compaction in the thicker trough sediments, seismic velocity effects or, most probably, minor subsidence in this area during the Early Permian. The slope on the crest of the ridge is a visual effect of the flattening process and is not real.

The second frame (Fig. 5.12b), levelled on the P horizon, maintains the horizontal aspect of the rocks in the Tenappera Trough. Only minor truncation at the Daralingie unconformity, between the P and V horizons, is apparent. In the Allunga Trough, beds have tilted in a mirror image of the Big Lake sections (Fig. 5.10). Major truncation at the Daralingie unconformity is evident, overlain by the horizontal Toolachee Formation.

The third frame (Fig. 5.12c), flattened at the C horizon, displays only minor structuring within the Permian sediments through to Cretaceous times. Increasing dip into the Allunga Trough can be explained by sediment compaction. On the southeastern side, apparent rollover into the ridge escarpment may be caused by downward structural movement on an inferred Warburton Basin fault zone. In general, this period can be considered tectonically quiescent with minimal effect on Cooper Basin geometry.

The present day seismic frame (Fig. 5.12d) shows the extremely flat-topped ridge overlain by Jurassic and younger sediments. Tertiary compression has had little effect here and very mild deformation is attributed to differential compaction.

## STRUCTURAL EVOLUTION

The structural history of the Cooper Basin interpreted here differs from other accounts in several major aspects. The most important of these is the emphasis placed on an early fill history dominated by glacial geomorphology rather than by fault growth. In other words, the major basement ridges were not 'grown' but were part of a pre-existing landscape. Structural growth appears to the authors to have commenced in the Early Permian, about the time of deposition of the Epsilon Formation, and culminated in the Daralingie unconformity. This tectonic episode appears to have caused varying amounts of uplift and erosion, ranging from negligible in the deep troughs to 100–350 m on various ridges (Moussavi-Harami, 1996a). This uplift conveniently separates the structural evolution of the Cooper Basin into two parts described below.

### Early Permian

Orogenesis may have triggered glaciation (Powell and Veevers, 1987) but it is difficult to distinguish tectonic from geomorphic control on the glaciogene deposits at the bottom of the Cooper Basin succession (see Ch. 6). These glaciogene deposits comprise the Merrimelia Formation and/or Tirrawarra Sandstone and the top of these corresponds to the W seismic horizon. The following discussion focuses on the

succeeding deposits of the waning glacial to post-glacial epoch, a time of widespread peat swamp deposits of the Patchawarra Formation which spanned ~15 million years (Fig. 6.1).

Palynological evidence for two breaks in deposition led Apak *et al.* (1993, 1995, 1997) to suggest two episodes of Sakmarian tectonic uplift preceded by 'gentle down-warping' followed by tectonic stability. Apak *et al.* (1997) ascribed this uplift to mild compression as a response to convergence on the eastern margin of the Australian Plate. The same authors noted the presence of the basal Patchawarra Formation (Unit 5 of Apak *et al.*, 1997) in structurally low areas and, long after Thornton (1979), also noted 'Moomba North Dome and South Dome were positive features with Unit 5 beds onlapping granitic terrains' (Apak *et al.*, 1995, p.196). This recognition that there were elevated terrains in the Sakmarian landscape is important. The exposed Warburton Basin rocks, and especially the granitoids in the Moomba area, have been weathered to depths locally exceeding 50 m (Boucher, 1996, 1997). It is unlikely that this weathered mantle would have been as widely preserved if there had been an episode of tectonic instability between basal Patchawarra Unit 5 and the overlying Unit 4 since there would be evidence of erosion, with Cooper Basin strata resting unconformably on fresh Warburton Basin rocks. The only known intersections of fresh Warburton Basin rocks (black shale of the Dullingari Group) are beneath Jurassic deposits on the Murteere Ridge, indicating uplift and erosion of the weathered zone at the Triassic–Jurassic boundary. The second uplift episode reported by Apak *et al.* (1995) is between Unit 3 and Unit 2 of the upper Patchawarra Formation. This does appear to be of tectonic origin as pinch-outs are evident at this level on seismic sections and Unit 2 locally rests unconformably on Unit 4 of the Patchawarra Formation or on weathered Warburton Basin rocks (see e.g. Apak *et al.*, 1995, figs 11, 12). The remaining Patchawarra Formation (Unit 1) and overlying lacustrine units attest to widespread tectonic quiescence through most of the remaining Early Permian. However, thin conglomerate beds in the Epsilon Formation in the northern Patchawarra Trough are interpreted here to reflect tectonic instability on the northwestern basin margin.

A significant hiatus is recorded palynologically on the crests and mid-flank areas of major ridges at the boundary between the Early and Late Permian (Paten, 1969). This hiatus, known as the Daralingie unconformity (e.g. Heath, 1989), represents an episode of tectonic activity which caused uplift and widespread erosion (Battersby, 1976; Stuart, 1976; Stanmore and Johnstone, 1988; Kuang, 1985; Apak *et al.*, 1993, 1995, 1997). Reverse faulting associated with this uplift has been attributed to renewed compression (Kuang, 1985) and correlated with deformation of the eastern Australian marginal basins (Apak *et al.*, 1997). The uplift appears as a mild angular unconformity between early Permian strata which pinch-out on the flanks of major ridges and late Permian to Triassic strata which overstep the ridges. This overlapping geometry is also evident locally on the southern and western margins of the Cooper Basin but, as Battersby (1976) has pointed out, the overlap sequence is more often missing, having been eroded in the Late Triassic or earliest Jurassic. Thus the early Permian section is overlain disconformably by Eromanga Basin strata, and the

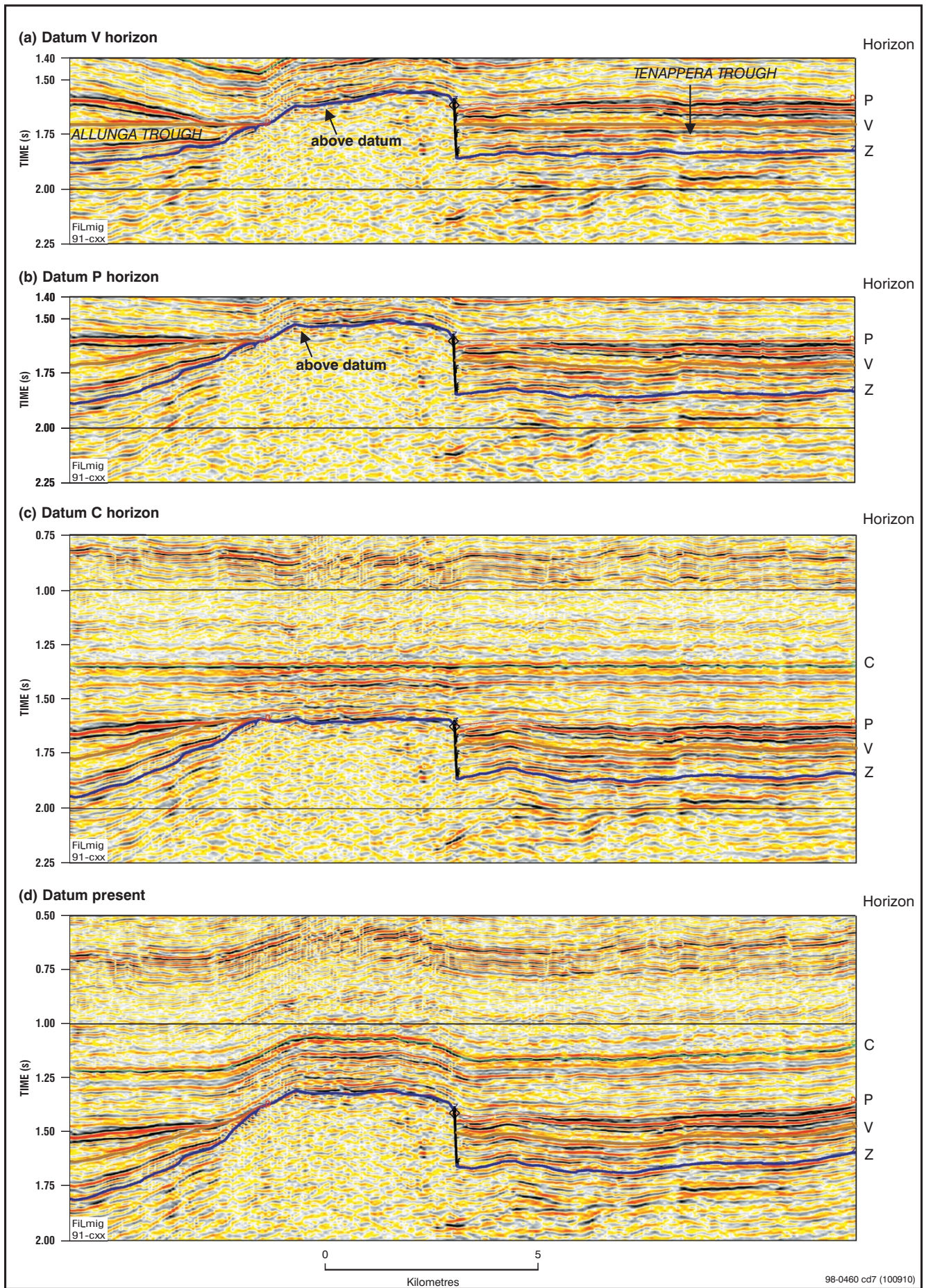


Fig. 5.12 Murteree Ridge, adjacent Allunga Terrace and Allunga Trough to the north, and Tenappera Trough to the south, levelled on successive seismic horizons. See text for details. Line of section is located in Figure 5.6.

Cooper Basin margin in this region is erosional (Fig. 5.13). Effects of the Daralingie unconformity in the northern Cooper Basin of South-West Queensland are more severe; there the Late Permian Toolachee Formation disconformably overlies the Early Permian Patchawarra Formation with intervening units eroded or not deposited (see e.g. Wecker *et al.*, 1996).

An isopach of Cooper Basin strata underlying the Daralingie unconformity is shown in Figure 5.14a. From this it is evident that the thickest sediments are in the Nappamerri, Allunga and Weena Troughs (the last containing predominantly glacial deposits). Comparison with a depth structure map of the Daralingie unconformity surface (Fig. 5.14b) shows that pre-existing structures were enhanced and a number of culminations on the major ridges (except Dunoon and Murteree) were 'bald-headed'. Despite the fact that the original hilly topography had been extensively eroded and progressively buried, the original morphology of the basin floor was still evident at the end of the Early Permian (compare Figs 5.2b and 5.14a).

### Late Permian – Triassic

The interpreted depth of erosion at the Daralingie unconformity ranges from 75 m at Bulyeroo 1 on a ridge within the Nappamerri Trough, to 350 m in Jena 1 on the Murteree Ridge (Moussavi-Harami, 1996a). The latter may be an overestimate since Warburton Basin Cambro-Ordovician rocks on the Murteree Ridge are unconformably overlain by Jurassic strata, the Permian having been removed by uplift at the Triassic–Jurassic boundary. It is

difficult to judge which parts of this ridge were uplifted and which were pre-existing topographic features.

Even though Warburton Basin rocks were exposed on the crests of some structures at the Daralingie unconformity surface, the succeeding Late Permian Toolachee Formation was generally deposited throughout the basin on a surface of low relief. It is likely that deposition in the deeper troughs was continuous from the Early to Late Permian (Battersby, 1976; Stuart, 1976; Thornton, 1979; Morton and Gatehouse, 1985).

Occasionally, channel conglomerates in the basal Toolachee Formation contain angular weathered clasts of the underlying basement and rare exotic clasts from further afield. The lack of fresh basement rock in these conglomerates suggests that the top Warburton Basin weathered zone was not fully breached. Interestingly, the base metals Fe, Mn and Zn are markedly depleted across the Daralingie–Toolachee Formations boundary (Shackleton, 1989), which may indicate greater sediment maturity in a tectonically quiescent setting. Meandering fluvial to floodbasin lake environments dominated the slow (~14 million years) accumulation of the Toolachee Formation.

The coal-bearing Toolachee Formation is overlain conformably by siliciclastics of the Nappamerri Group which also appear to have been deposited in a tectonically quiescent setting that persisted to Middle Triassic time. A depth structure contour map of the Toolachee Formation is shown in Figure 5.4b, and an isopach of the combined Toolachee Formation and Nappamerri Group is shown in Figure 5.15a. The maximum thickness of 600 m is assigned

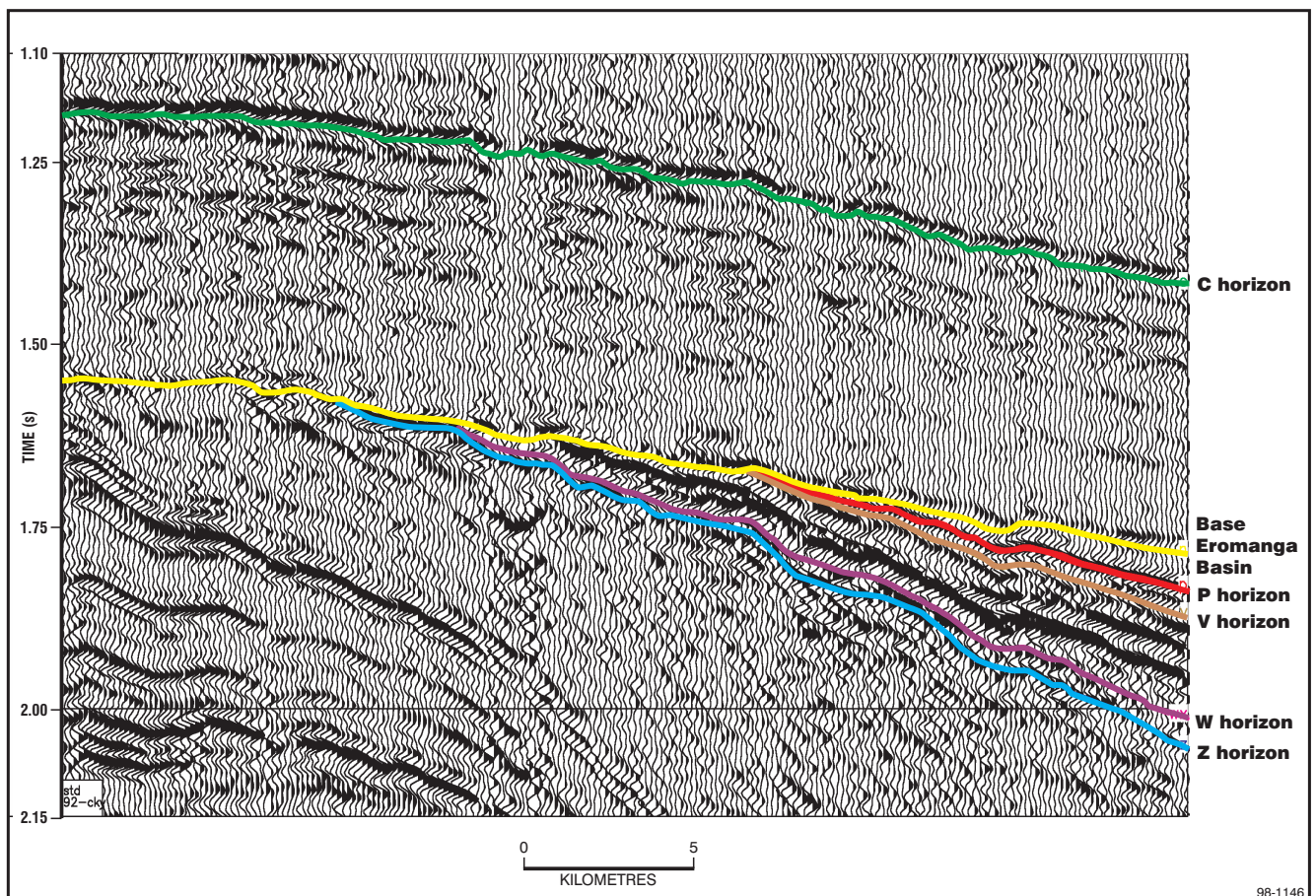


Fig. 5.13 Seismic line 92-CKY showing truncation of Permian strata by Mesozoic erosion. Line of section is located in Figure 5.6.

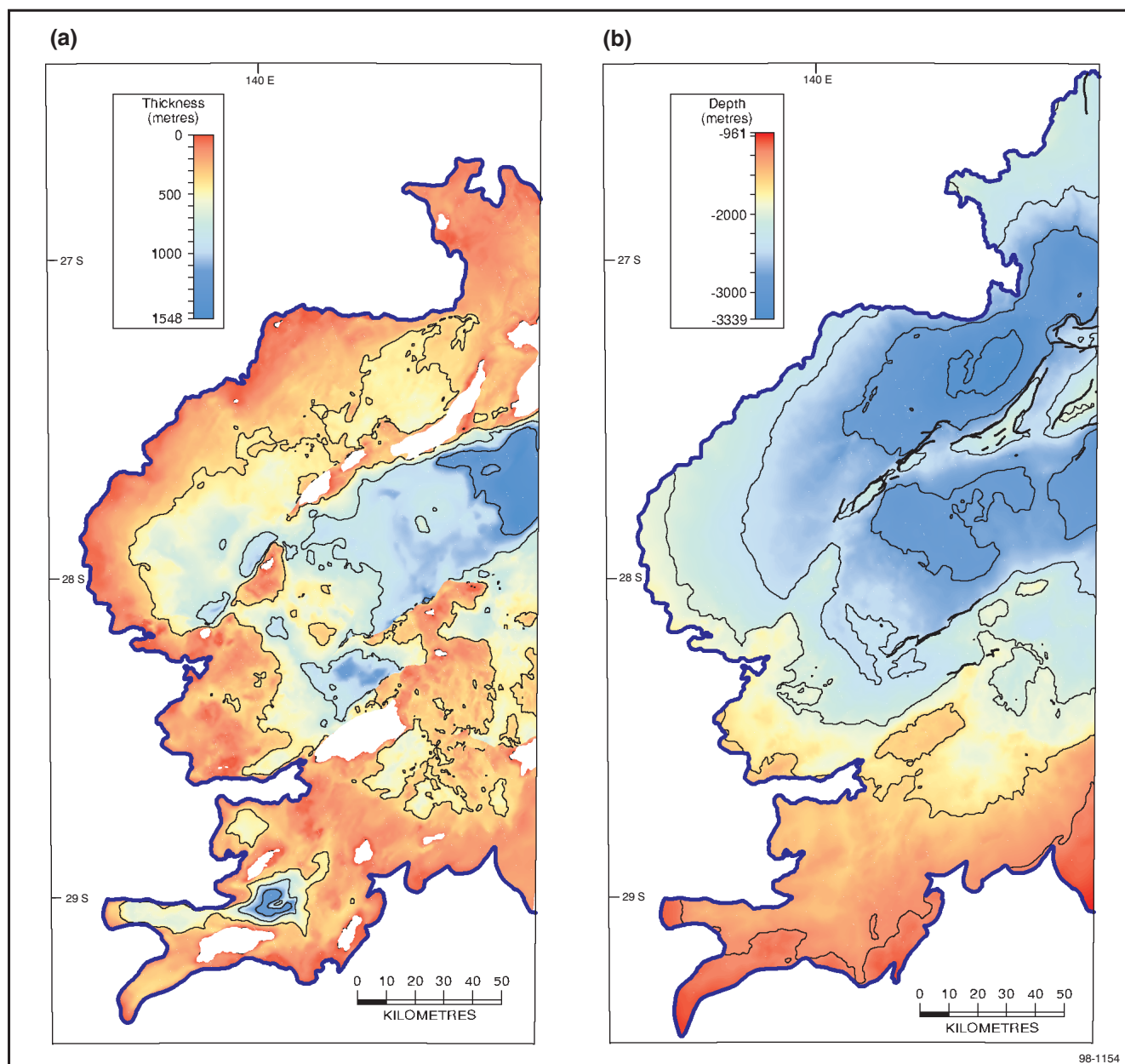


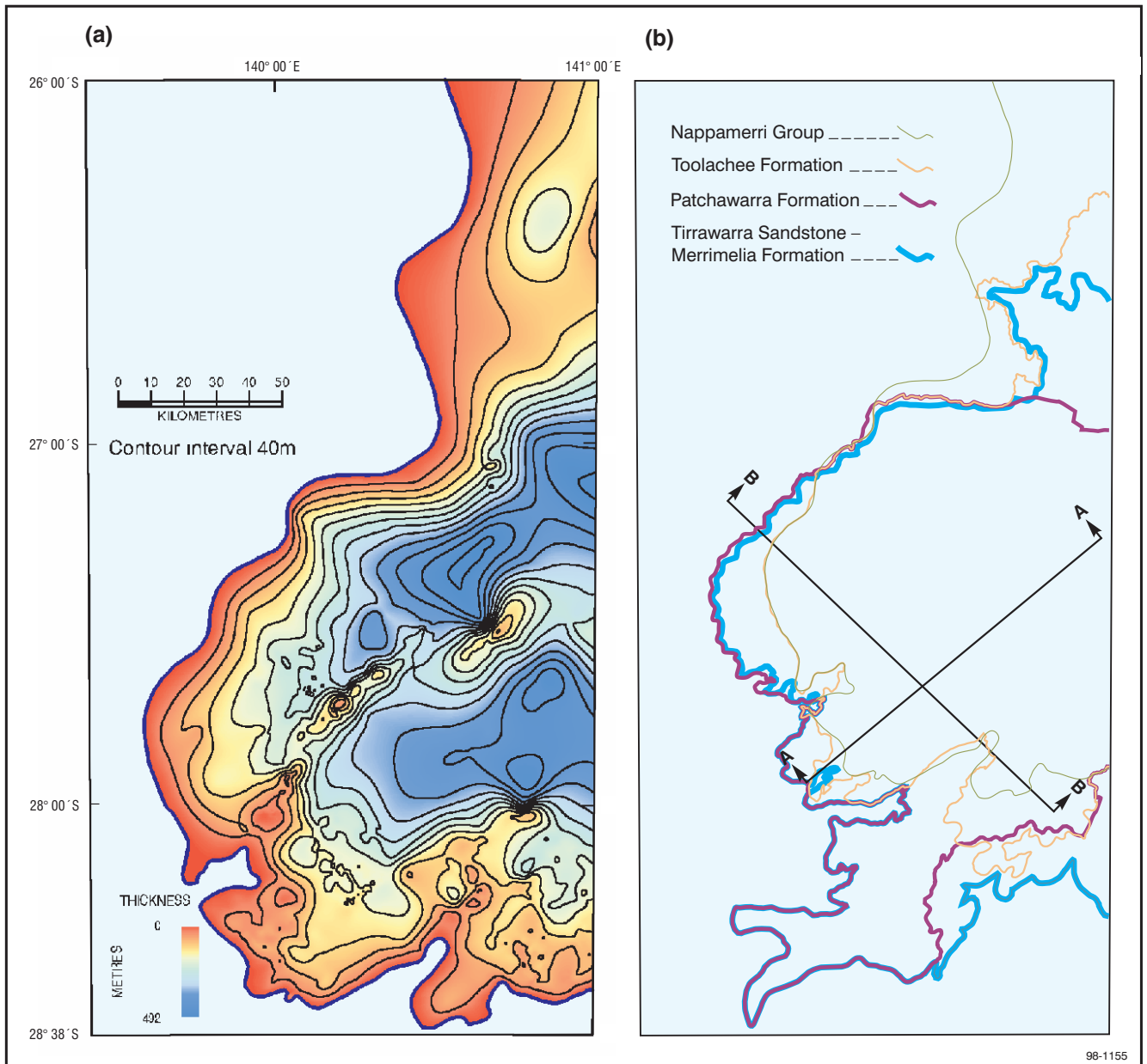
Fig. 5.14 (a) Isopach map of Early Permian strata (R–Z) from Daralingie unconformity surface to top of Warburton Basin. (b) Daralingie unconformity depth structure contour map.

mainly to the Nappamerri Group in the Nappamerri and eastern Patchawarra Troughs where subsidence rates were greatest (Moussavi-Harami, 1996a; Ch. 9). Subsidence also resulted in deposition of the Triassic Walkandi Formation in the Simpson Basin on the western side of the Birdsville Track Ridge (Moore, 1986).

The top of the Nappamerri Group (J seismic horizon) is a basin-wide erosional unconformity which marks the top of the Cooper Basin and the end of the Permo-Triassic depositional phase (i.e. end of Stage 1 burial history in Fig. 5.3). Nappamerri Group sediment distribution reflects slight (~20 minutes of arc) down-to-northeast structural tilting of the basin and attendant uplift of the regions to the south. Kuang (1985, p.246) ascribed this to ‘wrench induced northeast–southwest compressional stress’ while Wopfner (1985) ascribed uplift to isostatic compensation following a compressional Permo-Carboniferous regime.

Tilt of the Cooper Basin is shown in Figure 5.15b which depicts the seismically determined limits of the major units. The combined Merrimelia Formation – Tirrawarra Sandstone zero edge coincides more or less with the Patchawarra Formation zero edge. Likewise, the Toolachee Formation and Nappamerri Group zero edges coincide but are ~20 km east of the older unit limits in the Patchawarra Trough. In the south however, the Nappamerri Group does not extend as far as the Toolachee Formation due to uplift and erosion. In the north it extends further than the Toolachee Formation, demonstrating the tilt in that general direction.

The top Nappamerri Group unconformity is ‘a coeval feature in all basins, marking the end of the Hunter–Bowen Orogeny’ (Wiltshire, 1982, p.64), this orogeny marking a major phase of compression and uplift in the Sydney, Gunnedah and Bowen Basins (e.g. Tadros, 1993). Thus the



**Fig. 5.15** (a) Isopach map of Late Permian Toolachee Formation and Late Permian to Middle Triassic Nappamerri Group. (b) Zero edges of the Merrimelia Formation – Tirrawarra Sandstone, Patchawarra and Toolachee Formations, and Nappamerri Group.

slight northward tilt possibly represents some form of flexural response of the lithosphere at the plate interior to loading at the plate's eastern margin.

There is an additional, late Triassic unit (Cuddapan Formation) which, though separated disconformably from the Nappamerri Group and limited in extent, deserves mention. Wiltshire recognised in 1982 that this 'Ipswich Assemblage sequence' (Cuddapan Formation, Ch. 6) had extended over a vast area from the Northern Territory southwards to Leigh Creek in the Flinders Ranges prior to erosion in the earliest Jurassic. Wiltshire (1982), Veevers, (1984) and Wopfner (1985) all recognised this new succession, best summarised by Wopfner (1985, p.367): 'The deposition of these upper Triassic sediments was a new event. It was no longer subjected to the control of the Permian depositional phase but was the forerunner of events

which ultimately spread their sedimentary blanket over the Great Artesian Basin and beyond'.

In the Cooper Basin, the Cuddapan Formation is limited to the eastern Patchawarra Trough in South Australia and the Windorah Trough in South-West Queensland (Powis, 1989), where only 90 m have been preserved. This contrasts with an expanding depocentre in the Simpson Basin where up to 190 m of equivalent Peera Peera Formation were deposited (Alexander and Sansome, 1996). These units are very thin compared to the 1200 m thick Late Triassic deposits on the eastern margin of the Australian Plate but nevertheless point to minor subsidence. Widespread renewed uplift terminated the Late Triassic depositional phase. The preserved strata are currently regarded as belonging in neither the Cooper nor Eromanga Basins because of the bounding unconformities. They are more

likely related to the earliest Jurassic depositional phase of the Eromanga Basin as first pointed out by Wiltshire (1982).

### Jurassic–Recent

Mesozoic deformation was relatively weak and consisted of regional tilt, drape and compaction with progressive burial. Tilt into the Nappamerri Trough is illustrated on the southwest–northeast section A–A in Figure 5.16 (line of section A–A is located in Fig. 5.15). The section is displayed as a series of frames levelled on successive stratigraphic surfaces ranging from top Merrimelia Formation and/or Tirrawarra Sandstone (Fig. 5.16a) to present day (Fig. 5.16e). Each datum surface is assumed to have been horizontal originally; there has been no attempt to restore eroded section and no compaction corrections have been applied. Each frame therefore approximates a regional section from the southwestern Cooper Basin margin into the Nappamerri Trough after successive stratal packages have accumulated.

By the Late Permian (top Toolachee Formation), more than 1500 m of sediments had accumulated in the Nappamerri Trough to produce a triangular wedge of strata which thickens from the southwestern Cooper Basin margin into the trough (Fig. 5.16b). Differential subsidence persisted to the top Cooper Basin unconformity (top Nappamerri Group, Fig. 5.15c) causing the sediment wedge to thicken into the trough, but subsidence was more uniform by the Early Cretaceous (top Cadna-owie Formation; Fig. 5.15d). A present-day view of the section (Fig. 5.15e) shows that post-Early Cretaceous strata had again accumulated preferentially in the Nappamerri Trough and relief over existing structures had been enhanced.

The average angle of tilt of stratal surfaces from the southwestern margin of the basin into the Nappamerri Trough has been calculated to range from 0.25°, which is the present-day angle of tilt of the Cadna-owie Formation, to 1.1°, which is the present-day angle of tilt of the base of the Cooper Basin (Z horizon). Even the shallowest tilt of 0.25° along section A–A represents a gradient of 1:230 which is considerably greater than the regional Eromanga Basin gradient of 1:2000 to 1:6000 employed by Bowering (1982) and Williams and Moriarty (1986) in their palaeo-hydrological calculations. More recent mathematical modelling by Toupin (1993) suggested that uplift and erosion at the end of the Triassic did not noticeably alter the thermal regime of the groundwater at that time. However, erosion removed the regional Cooper Basin seal which facilitated mixing of Permian and Mesozoic pore water during the early Tertiary.

A northwest–southeast section allows a different view in a direction perpendicular to the axes of the major troughs. Such a section is illustrated in Figure 5.17 which shows the Patchawarra, Allunga and Tenappera Troughs separated by the Gidgealpa and Murteree Ridges. As in the previous figure, this section (B–B) is displayed as a series of frames levelled on successive stratigraphic surfaces. The striking asymmetry of the Patchawarra Trough by the Late Permian (Fig. 5.17b) is a consequence of uplift of the western margin of the Cooper Basin during the Early Permian which culminated in the Daralingie unconformity. The differing rates of subsidence of the Tenappera, Patchawarra and Allunga Troughs allowed the accumulation of 600, 800 and

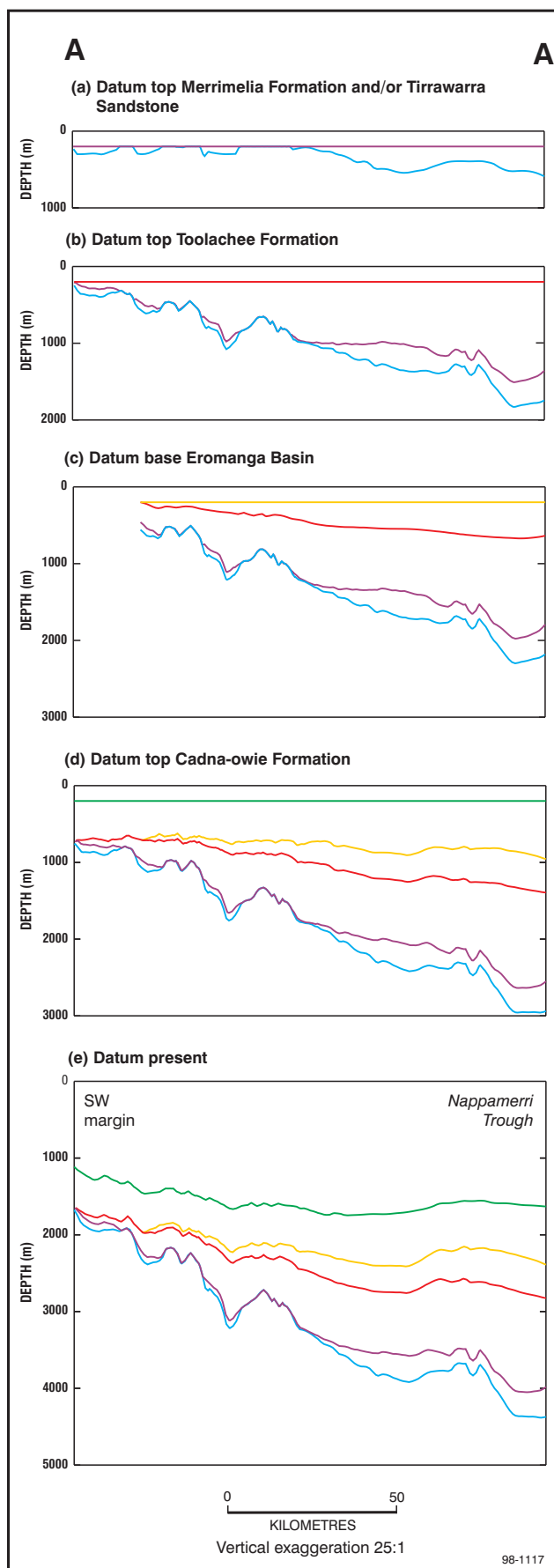


Fig. 5.16 Southwest–northeast section A–A through the Cooper and Eromanga Basins from the Weena Trough to the deepest part of the Nappamerri Trough. See Figure 5.17 for legend. Line of section is shown in Figure 5.15b.

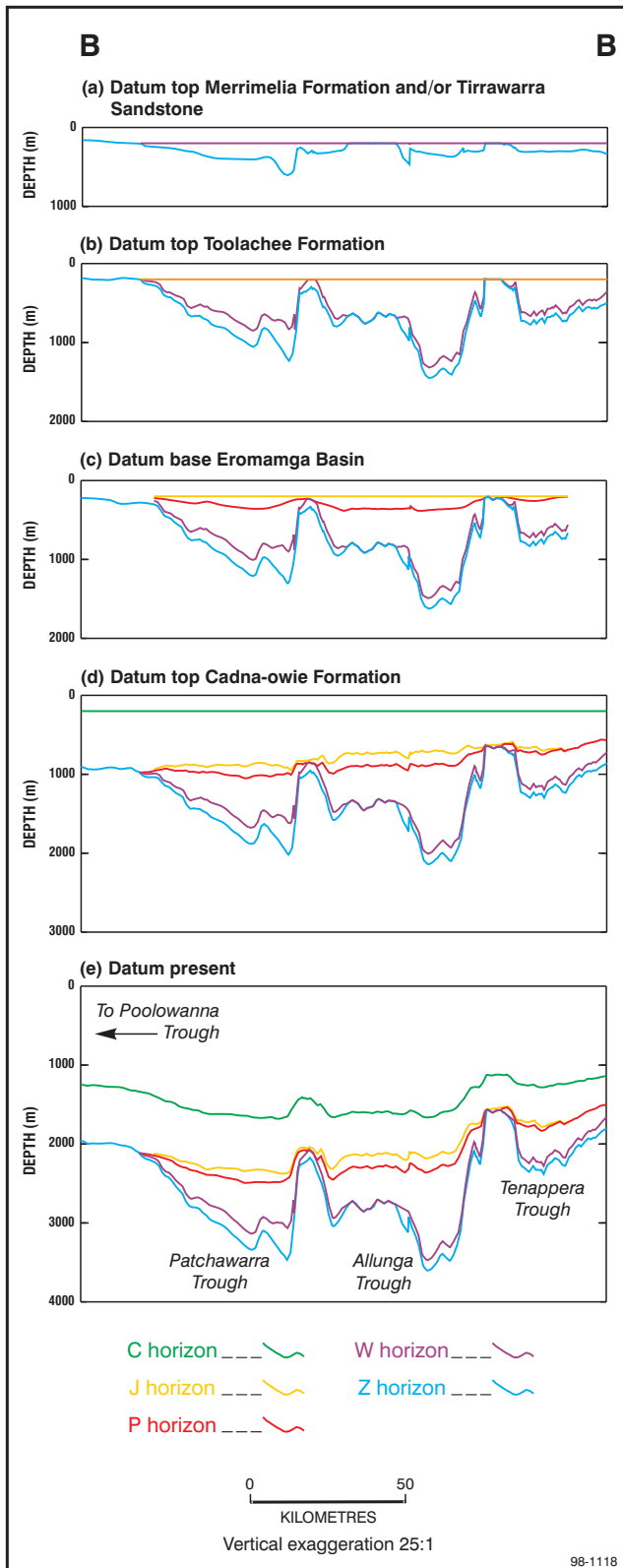


Fig. 5.17 Southeast-northwest section B-B through the Cooper and Eromanga Basins from the Tenappera Trough to the Patchawarra Trough. Line of section shown in Figure 5.15b.

1200 m of Early Permian sediments, respectively, along this line of section. In contrast, preserved Triassic sediments were thin, amounting to no more than ~200 m (Fig. 5.17c). Between the Early Jurassic and Early Cretaceous, Eromanga Basin strata had become thicker in the northwest, i.e.

towards the Poolowanna Trough (Fig. 5.17d). As noted by Kuang (1985), the Poolowanna Trough, located ~300 km northwest of the Cooper Basin, had become a more important depocentre than the Cooper region itself during the Jurassic. During the Early Cretaceous however, the Cooper Basin region again actively subsided providing enough cover for oil generation in the Permo-Triassic source rocks.

Early Tertiary compression enhanced closure on pre-existing structures and created other structures independently (Fig. 5.17e). The significance of this deformation was clear to Sprigg (1958, p.2475), who commented: 'Of principal interest are the reverberations of Cretaceous-Tertiary forces directed against the Australian continent from the east. These have deformed Mesozoic-Tertiary formations in the deeper basin areas themselves and developed a system of gentle folds of great importance in the search for commercial oil in this great basin area.'

Kuang (1985) considered Tertiary east-west compression to be probably the most severe compressional event affecting the Cooper Basin, as demonstrated by the regional cross-sections (Figs 5.16e, 5.17e) and seismic sections across specific structures (see above). Toupin (1993) pointed out that early Tertiary groundwater flow had a significant impact as a result of uplift of the intake beds in Queensland. This elevated temperatures by up to 30°C in the Patchawarra Trough and forced meteoric waters into southern parts of the Cooper Basin system as indicated by salinity data (Dunlop *et al.*, 1992). Geothermal gradients, already high due to subcrop of uraniferous granite on the floor of the Nappamerri Trough, have been elevated still further in the past 2-5 million years. Gallagher (1988) considers this process to be acting in the crust rather than the lower lithosphere but the cause of the Pliocene heating event is unknown. Effects on hydrocarbon maturation are discussed in Chapter 9.



# LITHOSTRATIGRAPHY and ENVIRONMENTS of DEPOSITION

E.M. Alexander  
with contributions from  
D.I. Gravestock,  
C. Cubitt<sup>1</sup> and A. Chaney<sup>2</sup>

## Chapter 6

### COOPER BASIN

#### INTRODUCTION

During the mid-Carboniferous the Australian Plate (then part of Gondwana) drifted from low to high latitudes (Veevers, 1984) and the region which was to become the Cooper Basin was located at 70°S (Figs 6.1, 6.2a, 7.7). At this time, Gondwana and Laurussia collided to form the supercontinent Pangea, producing worldwide orogenesis (Baillie *et al.*, 1994). Deformation along the eastern Australian Plate is thought to have produced uplift in central Australia, which triggered formation of a major continental ice sheet.

The ice sheet reached a maximum volume during the Westphalian to Stephanian, then retreated during the Asselian to Sakmarian (Veevers and Powell, 1987). Remnant ice masses were left on highlands such as the Musgrave Block and locally in the Cooper Basin (Fig. 6.2b). Decay of the ice-sheet released enormous volumes of sediment and basal diamictites overlain by non-marine and marine sediments form typical successions in Gondwanan basins (Gilby and Foster, 1988; Hobday, 1987).

The Australian Plate lay at high latitudes throughout the Early Permian to Early Triassic and peat swamp and floodplain facies were deposited during the waning stage of glaciation. Post-glacial deposition included two lacustrine units with intervening regressive fluviodeltaic sediments. Uplift late in the Early Permian led to erosion of the Daralingie Formation and underlying units from basement ridges. Peat swamp and floodplain deposits were again deposited above the unconformity during the Late Permian and passed conformably into Early Triassic organically lean, oxidised lacustrine and fluvial deposits.

During the Early Triassic the south magnetic pole was located over southeastern Australia (Fig. 6.2c), however there is no record of ice formation and a dry climate is assumed — in part because there are no significant Early Triassic coals. In contrast, Retallack *et al.* (1996) proposed a humid climate based on the occurrence of non-calcareous, kaolinitic paleosols developed within Australian Permo-Triassic non-marine sediments. Evidence from the Middle Triassic Lashly Formation (Beacon Supergroup, Antarctica) also indicates a humid, cold temperate palaeoclimate existed at high latitudes (Retallack and Alonzo-Zarza, 1998). The presence of broadleaf plant fossils and non-calcareous paleosols, and absence of permafrost features indicate that the climate was not as frigid

as expected from the Middle Triassic palaeolatitude, and was analogous to the modern climate in the Australian Alps and New Zealand (Retallack and Alonzo-Zarza, 1998).

Plant productivity was anomalously low during the Early to Middle Triassic, and although coal-forming conditions

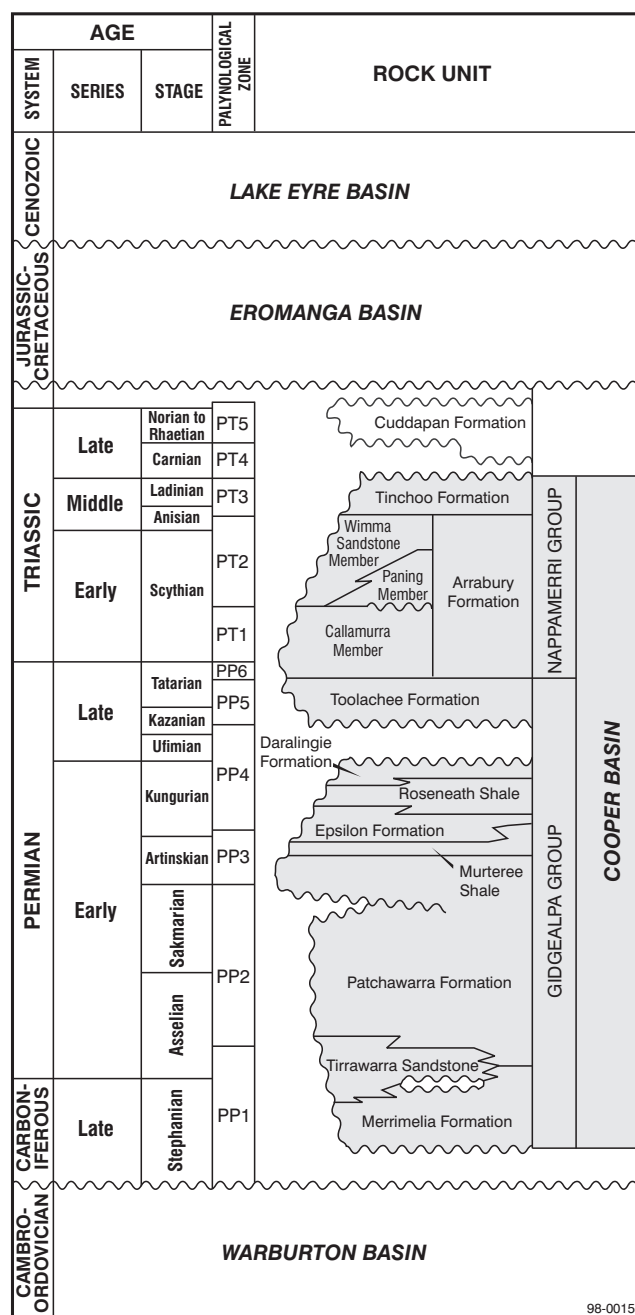


Fig. 6.1 Stratigraphic summary of the Cooper Basin, South Australia.

<sup>1</sup> National Centre for Petroleum Geology and Geophysics; present address Santos Ltd, GPO Box 2319, Adelaide, SA 5001.

<sup>2</sup> Amerada Hess, London; formerly University of Aberdeen.

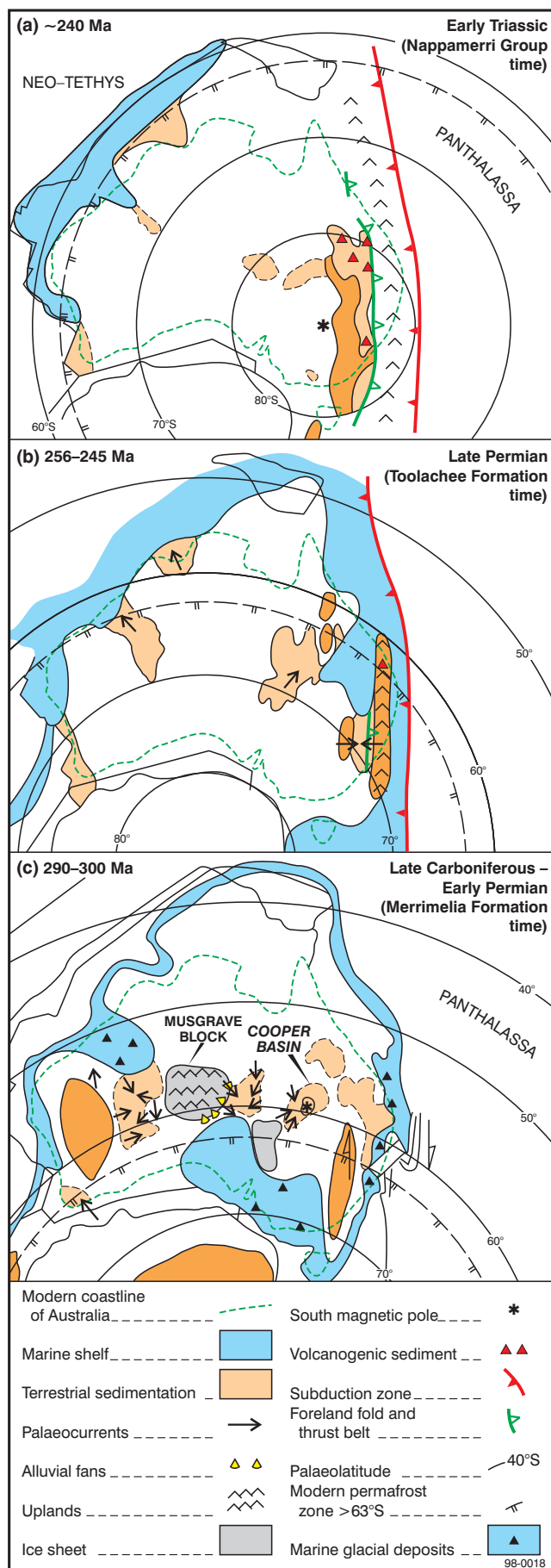


Fig. 6.2 Palaeogeographic reconstructions of the Australian Plate through the Late Carboniferous to Early Triassic (after Veevers, 1984 and Baillie et al., 1994).

existed no Early Triassic coals developed. This worldwide ‘Early Triassic coal gap’ (Veevers *et al.*, 1994) was produced by the extinction of peat-forming plants such as the *Glossopteris* flora rather than climate change at the end of the Permian (~245 million years (Ma); Retallack *et al.*, 1996).

The terminal Permian extinction was the greatest crisis faced by living creatures. Other terrestrial organisms affected by extinctions were many reptiles and insects. In the marine realm, some corals and bryozoans and all trilobites and fusuline foraminifera became extinct at the Permian–Triassic boundary during the ‘Early Triassic reef gap’ (Retallack *et al.*, 1996). A number of causes of the Permian–Triassic terrestrial and marine mass extinction have been proposed, including palaeoclimatic change, environmental acidification, low sea level, asteroid impacts and massive eruptions of basalt (Retallack *et al.*, 1996).

It took ~10 Ma for new peat-producing plants to develop a tolerance to the acidic dysaerobic conditions in peat swamp environments, and globally only thin, discontinuous coals occur in the Middle Triassic. Thick and widespread coal seams, comparable with those of the Permian, only developed during the Late Triassic in the Cooper and Simpson Basins, mirroring the worldwide trend.

A major change in basin architecture in central Australia occurred, possibly as early as the Middle Triassic. For the first time deposition of sediment spread widely across the craton beyond the margins of the Cooper Basin, independently of the long-acting controls on Permian deposition (Wopfner, 1985). This heralded a phase of widespread intracratonic deposition in the Early Jurassic to Late Cretaceous Eromanga Basin.

## GIDGEALPA GROUP

### Definition and nomenclature

The Gidgealpa Formation was proposed by Kapel (1966a, p.73) for ‘a sequence of Permian sediments intersected in petroleum exploration wells’. Martin (1967b) recognised that Gidgealpa Formation could be subdivided into three subunits (lower, middle and upper members) but he excluded the underlying Merrimelia Formation. Kapel (1972) elevated the Gidgealpa Formation to group status and divided the Gidgealpa Group into the Tirrawarra, Patchawarra, Moomba and Toolachee Formations.

Gatehouse (1972, p.11) formally defined Gidgealpa Group as the ‘succession of formations in the subsurface Cooper Basin which is conformably overlain by the Triassic Nappamerri Group and unconformably (?) underlain by the Permian Merrimelia Formation’. In addition, Gatehouse replaced ‘Moomba Formation’ by naming and defining its components: Murteree Shale, Epsilon Formation, Roseneath Shale and ‘Daralingie beds’.

Following the recommendations of Williams and Wild (1984), Merrimelia Formation is included in the Gidgealpa Group which Gravestock *et al.* (1995, p.14) redefined as ‘the succession of formations in the Cooper Basin which unconformably overlies Middle Carboniferous and older sedimentary, igneous and metamorphic rocks and is conformably overlain by the Late Permian to Triassic Nappamerri Group or disconformably by younger sedimentary rocks’ (Fig. 6.1).

The Gidgealpa Group is entirely non-marine. Constituent formations range in age from Late Carboniferous to Late Permian and a widespread unconformity intervenes between the Early and Late Permian sediments (Paten, 1969).

## Coal deposition

The Gidgealpa Group is characterised by coal measures, especially within the Patchawarra, Epsilon and Toolachee Formations. Coals typically have low sulphur content (<1%) indicating an absence of marine influence (Hunt and Smyth, 1986). Traditionally coal forming conditions are interpreted to be low-lying peat swamps developed on the floodplain away from active channels. An alternative sedimentological model of peat formation developed by McCabe (1984, 1987) is worth outlining below because it challenges the orthodox method of sandstone reservoir mapping.

### Modern peat forming environments

Peat now covers ~3% of the earth's land surface (Clymo, 1987) and occurs in tropical (coast of Malaysia and Indonesia) to sub-polar environments (Canada, Siberia and northern Europe). Modern sub-polar or boreal peats are analogous to the peats which formed the Permian coals of Australia (Clymo, 1987) and are vegetated by bog-mosses (*Sphagnum*), sedges, low heather shrubs and pine and spruce trees.



Example of a present-day peat-forming environment, Alpine Moor, Tor wilderness, Tasmania. (Courtesy of Rob Blakers; photo 46494)

Peat swamp waters are poorly oxygenated and rich in humic acids, preventing decomposition of organic tissue. For peat to be preserved and to ultimately form coal, it must be drowned by rapid subsidence or downstream damming of the fluvial system, then rapidly buried. There are three types of modern peat swamp which may follow an evolutionary sequence (McCabe, 1984, 1987). These are illustrated in Figure 6.3 and described below.

'Floating swamps' form on the margins of lakes as a floating mass of peat develops. The floating peat can develop to totally cover the lake. The lake floor typically consists of organic-rich muds (gyttja). Floating swamps do not form thick coal seams as the lakes are generally shallow. A modern example is Okefenokee Swamp in Florida, United States.

In 'low-lying swamps' peat is deposited over an existing topography and built up to a near-horizontal surface. These swamps are generally acidic (pH 4.8–6.5), rich in nutrients and contain a high diversity of plants. Low-lying swamps are commonly incorporated into meandering fluvial models on the floodplain and produce proximal coal seams that are split by crevasse splays and levee deposits. Where fluvial avulsion into a low-lying peat swamp occurs, ribbon splits and ribbon washouts form in coal seams. These seams are split by ribbon shaped sandstone and siltstone bodies, elliptical in section, up to several kilometres wide and tens of kilometres long (McCabe, 1984). Thicker, high quality coals form away from sites of active clastic deposition. Swamps of the Gulf Coast region of the United States are a modern example (McCabe, 1984).

'Raised swamps' or 'mires' have a convex upper surface with a relief averaging 2 m (Moore and Bellamy, 1974), but ranging up to 5 m (McCabe, 1984). Water and peat accumulate to form a raised bog, impeding drainage of rainwater and producing a near-hemi-elliptical mound of water supported by the vegetation mass (Ingram, 1982). Most of the mound is permanently water-saturated. The upper surface is independent of the underlying topography, and raised swamps can form on uplands, diverting and controlling streams (Fig. 6.4). Raised swamps are very acidic (pH 3.3–4.6), low in plant nutrients (McCabe, 1984) and occur in both temperate and tropical climates where rainfall is greater than evaporation (modern examples occur in Canada, Siberia and northern Europe and coastal Malaysia and Indonesia). The acidic, oxygen-poor and low nutrient environment results in low plant diversity because only specially adapted plants can thrive in this environment. The watertable is elevated across the swamp by capillary pressure within the peat. Diessel (1992) estimated that the high watertable had to be maintained over an epoch ranging from 5 to 10 thousand years for each metre of clean bituminous coal produced. During drought, the peat can dry out and burn by spontaneous combustion. Shallow flooding and drying of peat swamps causes oxidation, which can produce inertinite-rich coals (Hunt and Smyth, 1986). Raised swamps produce low ash peats because they are elevated above flood levels and do not receive clastic input. The acidic water leaches minerals such as feldspar and lithics to form kaolin. In the Carboniferous coalfields of the United Kingdom, 'ganisters' (leached sandstone composed of quartz grains and quartz cement) form under coal seams.

### Influence of peat on fluvial architecture

Peat consists of flexible mats of intertwined fibrous plant material, often strengthened by interlocking branches, and very resistant to erosion. Channels tear away large mats of peat and typically form sub-vertical cuts in coal seams, but only rarely do they cut down through an entire coal seam (Diessel, 1992). In coal mines it is often observed that channels cut down through other roof sediments but rest on coal seams. The significance of raised swamps lies in their ability to hold streams to fixed channels, preventing avulsion and leading to the development of stacked channel sandstones, i.e. potential hydrocarbon reservoirs (Fig. 6.5).

### Gidgealpa Group coals

Hunt and Smyth (1986) used high-latitude blanket mires as an analogue for Cooper Basin coals due to their lateral

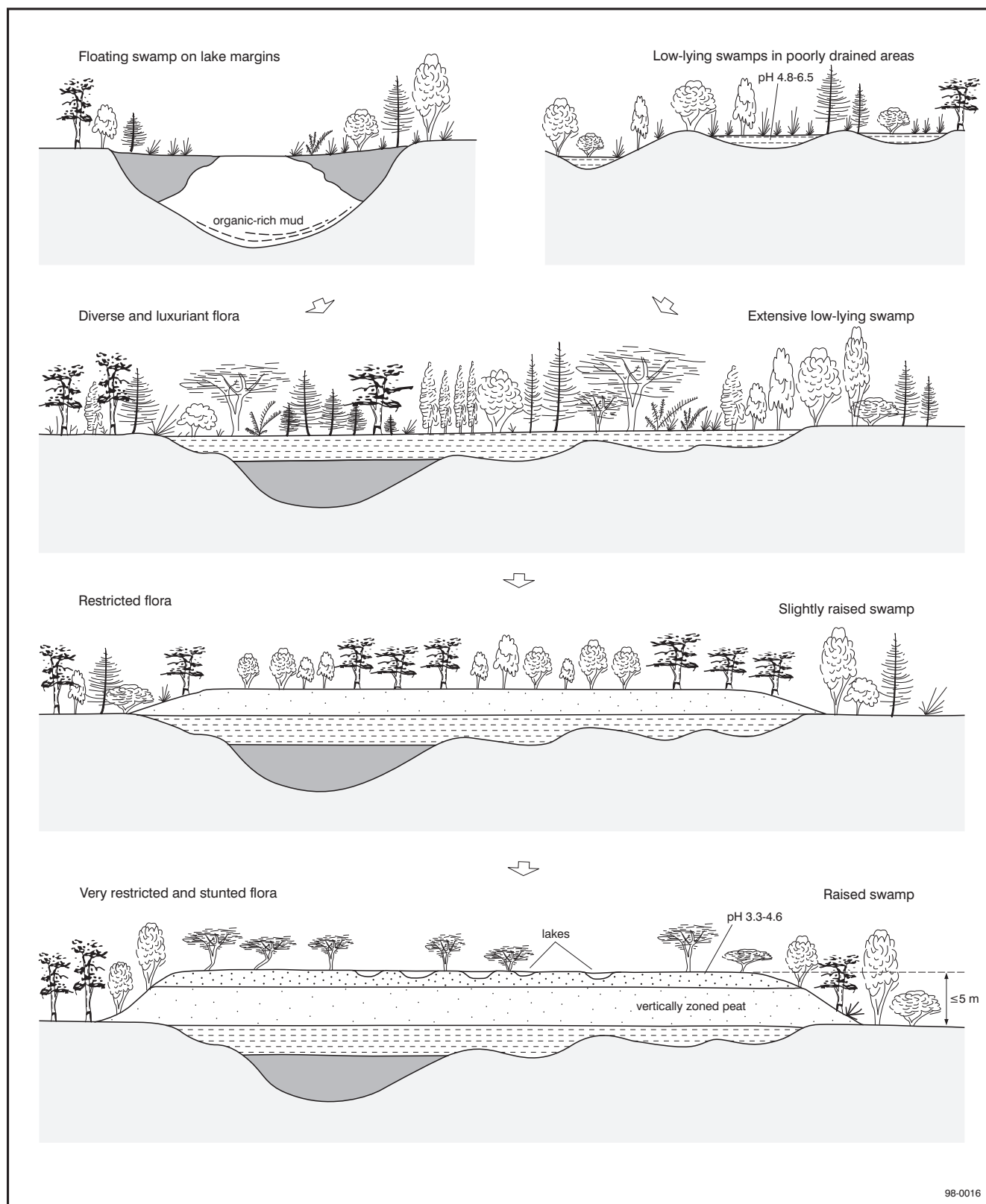
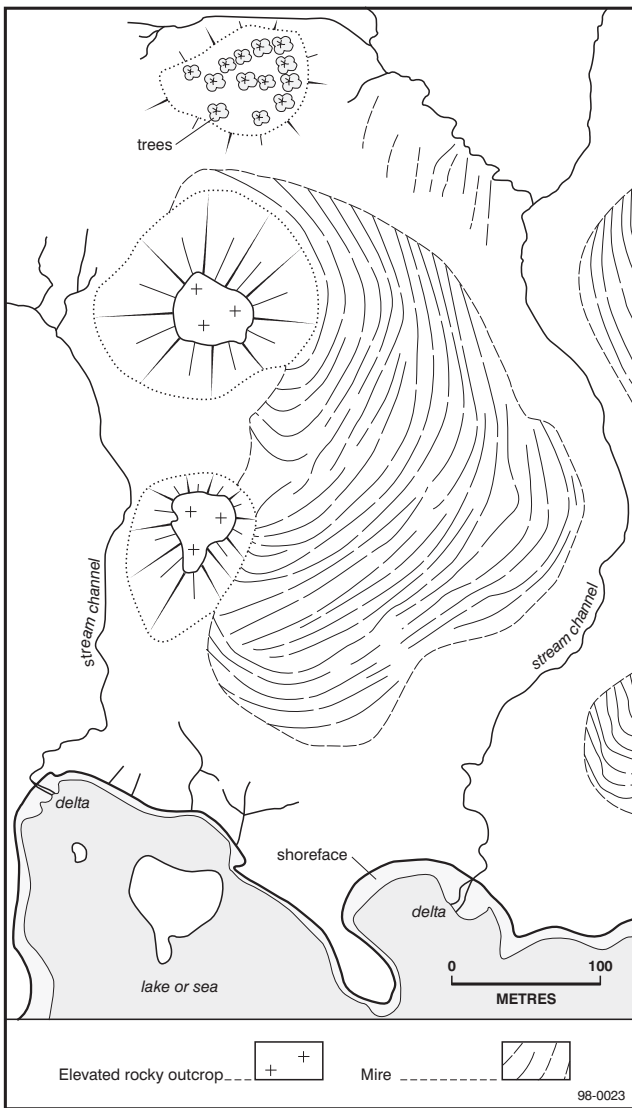


Fig. 6.3 Evolutionary sequence of swamp types (after McCabe, 1984, based on Romanov, 1968).

extent, thickness and low ash content. The lipid-rich material associated with inertinite in Permian coals is interpreted to have originated from algal mats that covered the surface of the peat (Taylor *et al.*, 1988). In addition, as there is no evidence of botanical structure within inertinite from Patchawarra Formation coals, Taylor *et al.* proposed that it formed from the seasonal desiccation (freeze-drying)

of a homogeneous gelified peat precursor. Leaf cuticles are often densely packed in Gondwanan coals and are interpreted as autumn leaf falls from the Glossopterid flora (Diessel, 1992).

Figures 6.6a and b show variations in coal thickness within the Toolachee and Patchawarra Formations respectively. Coal content for selected formations was



**Fig. 6.4** Eccentric domed mire, Clais Moss, Argyll, Scotland (from Moore and Bellamy, 1974). Note that the mire is developed between the upland and the lake or sea, and appears to have diverted a nearby stream.

derived from log analysis of over 400 wells and defined on logs over intervals where sonic transit time exceeds 120  $\mu\text{sec}/\text{ft}$  (McLean and Hill, in prep.). Coal seam thickness distributions were also derived for the Patchawarra and Toolachee Formations from sonic logs for

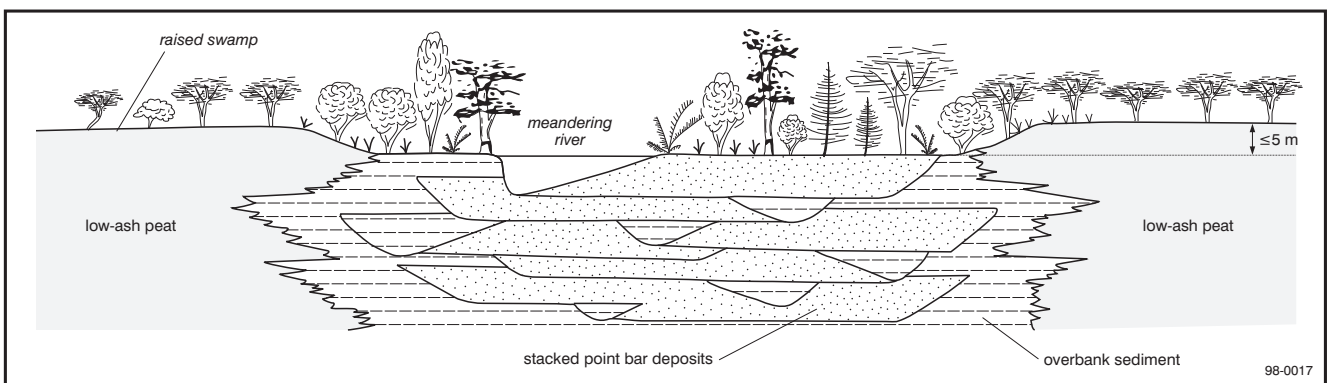
eight widely distributed wells, using the same coal cut-off. Results are summarised in Figure 6.7 and Table 6.1.

**Table 6.1** Analysis of coal seam thickness, based on eight Cooper Basin wells (Wimma 1, Bulyeroo 1, Bungee 1, Lake Macmillan 1, Beanbush 1, Kumbarie 1, Battunga 1, Tinga Tingana 1).

Thickness (m)	Patchawarra Formation	Toolachee Formation
Average	2.1	4.3
Maximum	22.3	21.9
Minimum	0.3	0.3
% seams >2 m	29.8	42.4

Patchawarra coal seams are thinner on average than those in the Toolachee (Fig. 6.7), however they are more numerous. Patchawarra Formation is usually considerably thicker than the Toolachee Formation (compare Figs 6.21 and 6.30), and thus total coal thickness is comparable in both formations. The chief difference between the two formations is the distribution of areas with thick coal deposits (Fig. 6.6). The Patchawarra Trough was an area of thick peat accumulation for both formations — preserved Patchawarra coals are thickest in the southwestern part (the formation has been eroded to the northeast) and Toolachee coals in the northeastern part. In contrast the Nappamerri Trough is dominated by overbank siltstone and channel sandstone rather than peat, as shown by Thornton (1979). The Tenappera Trough was also a site of peat accumulation in both formations, however Patchawarra coals thicken southwards into the Weena Trough where the Toolachee Formation was either eroded or not deposited. Patchawarra coals are also thick in the Woloo and Allunga Troughs, while Toolachee coals are thick only in the Allunga Trough.

Stavrakis and Smyth (1986) and Hobday (1987) observed that Early Permian Karoo Basin (South Africa) coal seams (e.g. Dwyka Coal Seam, No. 4 Seam) rest directly on paraglacial topographic features such as benches and valley sides. Palaeotopographic control on the No. 4 Seam is shown in Figure 6.8. Hobday (1987) noted that the lowermost seams pinch out on the flanks of basement highs because oxidation would have destroyed peat in updip areas. In addition, the No. 4 Seam does not occur in depressed areas too deeply inundated for peat growth. The optimal location for peat accumulation was on the flanks of topographic highs, on sloping basement surfaces where a stable platform for peat accumulation occurred (Hobday, 1987).



**Fig. 6.5** Theoretical model of fluvial architecture in an area of raised swamps. The elevated swamp restricts overbank flooding and prevents avulsion, leading to the development of stacked channel sandstones (from McCabe, 1984).

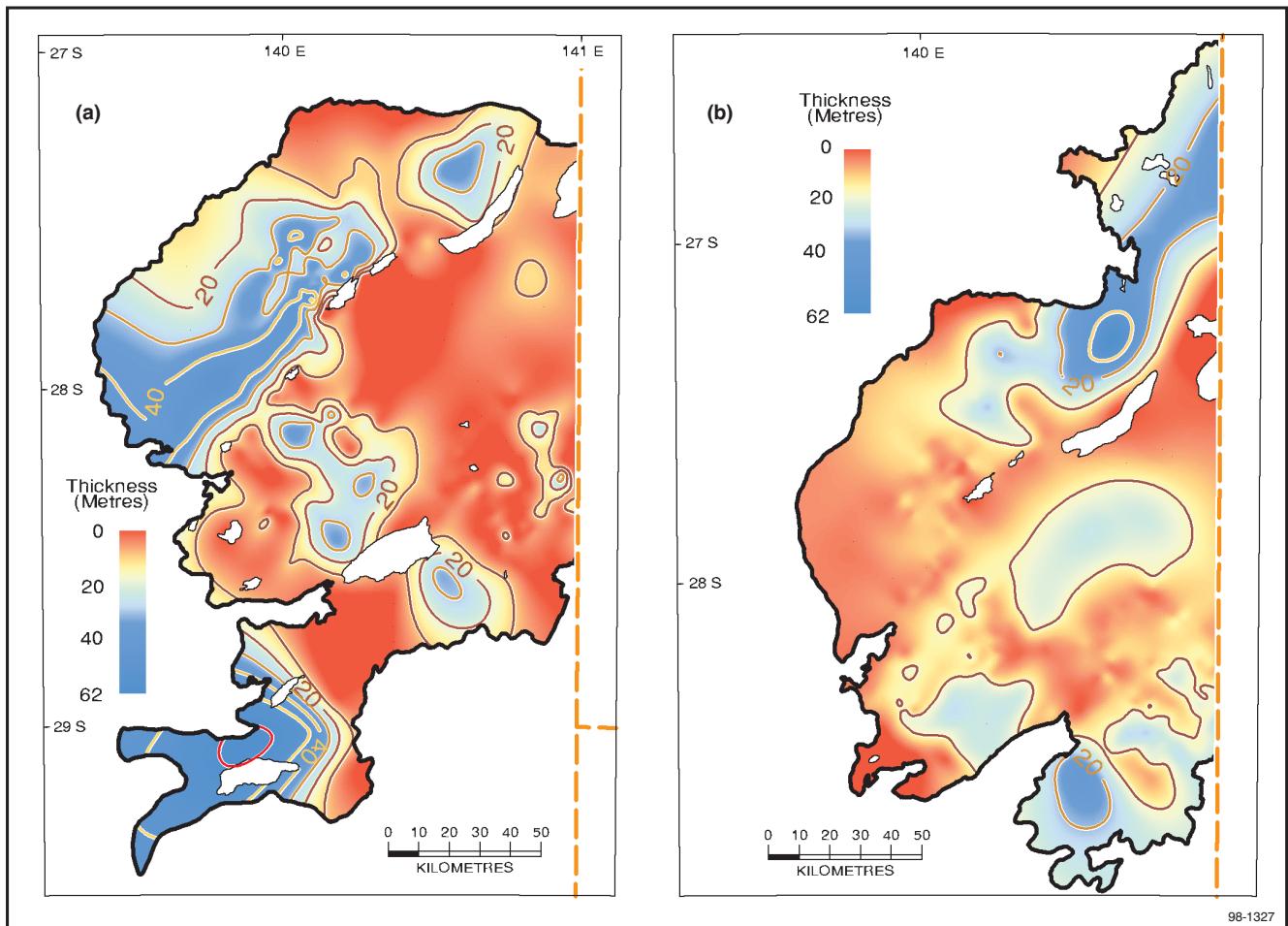


Fig. 6.6 Total coal thickness maps: (a) Patchawarra Formation, (b) Toolachee Formation.

The relatively thick Patchawarra coals mapped on the western margin of the Cooper Basin by Stanmore and Johnstone (1988) may be analogous to both the Karoo Basin

coals and modern raised swamps forming on uplands (Fig. 6.4). It is possible that raised swamps accumulated near the western depositional edge of the Cooper Basin adjacent to the Birdsville Track Ridge in Early Permian time and in the northern Patchawarra Trough during the Early and Late Permian.

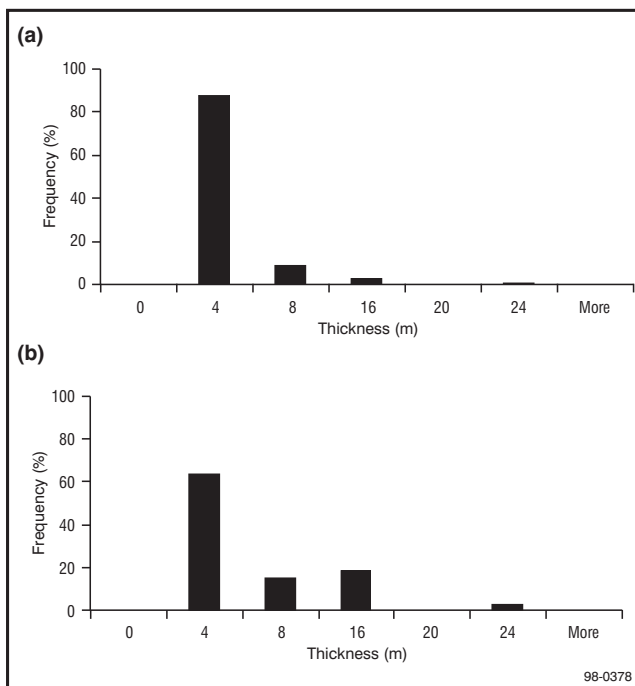


Fig. 6.7 Coal seam thickness distribution in (a) Patchawarra Formation and (b) Toolachee Formation.

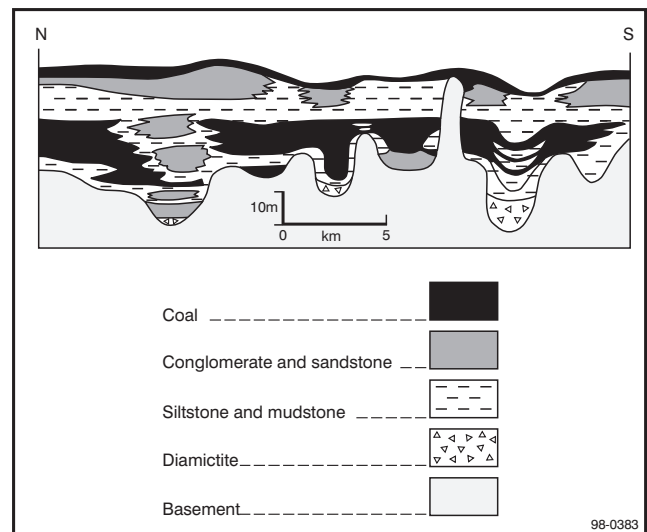


Fig. 6.8 Palaeotopographic influences on the No. 4 seam, northern Karoo Basin, South Africa. (from Hobday, 1987, after Cadle, 1982).

## Merrimelia Formation

C. Cubitt, A. Chaney and D.I. Gravestock

### Definition and nomenclature

Originally described in well completion reports as 'Permo-Carboniferous', the name Merrimelia Formation was applied by Martin (1967b, p.35) to 'a heterogeneous rock formation deposited between the unconformity surface which developed after the Bowning (?) orogeny and the overlying Permian Gidgealpa Formation'. Following the recommendation of Williams and Wild (1984) the Merrimelia Formation is now defined as the suite of glacial rocks which comprises the lowest formation of the Gidgealpa Group. The name is from the Aboriginal word Merrimelia, meaning a rocky place (Martin, 1967b).

### Type section

The type section was originally designated as 2624–2987 m in Merrimelia 1 (latitude 27°47'5.49"S, longitude 140°6'48.85"E) by Martin (1967b). However this interval includes a sandstone which was subsequently named 'Tirrawarra Formation' by Kapel (1972) and is described below. Merrimelia Formation (*sensu stricto*) is the interval 2644–2987 m in Merrimelia 1.

### Lithology and distribution

The Merrimelia Formation is a complex unit of conglomerate, diamictite, sandstone, conglomeratic mudstone, siltstone and shale; each lithotype may be thin or thick, monofacial or characterised by rapid facies transitions. Core from the type section is shown in Figure 6.9. Petrologically the Merrimelia Formation contains sedimentary, metamorphic, igneous and pyroclastic lithologies (Cubitt in Chaney *et al.*, 1997). These are described in a later section.

The formation occurs in troughs and onlaps topographic rises to the mid-flank regions of ridges throughout the Cooper Basin in South Australia. The most southerly intersection is in Weena 1 (thickness 175 m) and the most northerly is in Kenny 1 (thickness 64 m).

### Relationships and boundary criteria

The Merrimelia Formation unconformably overlies flat-lying to vertical eastern Warburton Basin strata and can be confused with weathered upper levels of the latter (Boucher, 1997a). The most common sources of error are weathered Dullingari Group (Ordovician shale) and weathered Big Lake Suite (Carboniferous granite). In uncored wells these units are often mistaken for Merrimelia Formation which was not deposited, the basal Permian unit being usually the Patchawarra Formation. The weathered zone is distinguished most readily on wireline logs by its low resistivity response compared with the underlying fresh rock (if enough was penetrated to log), and by a change from the fresh to the weathered zone, e.g. from black, firm pyritic shale to grey-white soft, sticky claystone. The black shale is unmistakably Ordovician Dullingari Group but the white claystone has commonly been mistaken for Merrimelia Formation. The weathered zone had been correctly identified in Moomba Field as long ago as 1967 (Martin, 1967b).



Rainout diamictite overlying subaqueous tunnel mouth clastics in the Merrimelia Formation, Kenny 1, 2943–2946 m. (Photo 46495)

There is no basin-wide unconformity at the top of the Merrimelia Formation. The Merrimelia Formation interfingers with and is overlain by Tirrawarra Sandstone which typically has a low gamma ray log. Williams and Wild (1984, pp.381, 384) have described and illustrated two relationships between these units. The first is a 'transitional' sequence characterised by an upward evolution from Merrimelia-type facies into Tirrawarra-type facies (e.g. from flow till and outwash sands into braided channel sands (Williams and Wild, 1984, fig. 4). The second is a widespread 'interface' sequence 'demonstrated by the inclusion of 'typical' Tirrawarra-type facies states and transitions embedded in 'typical' Merrimelia lithotypes.' An example from Goyder 1 (Fig. 6.10) illustrates on wireline logs the repetition of three interface sequences each of which consists of a 40 m thick upward-fining (?upward deepening) lacustrine suite punctuated by 3–4 m thick, relatively clean

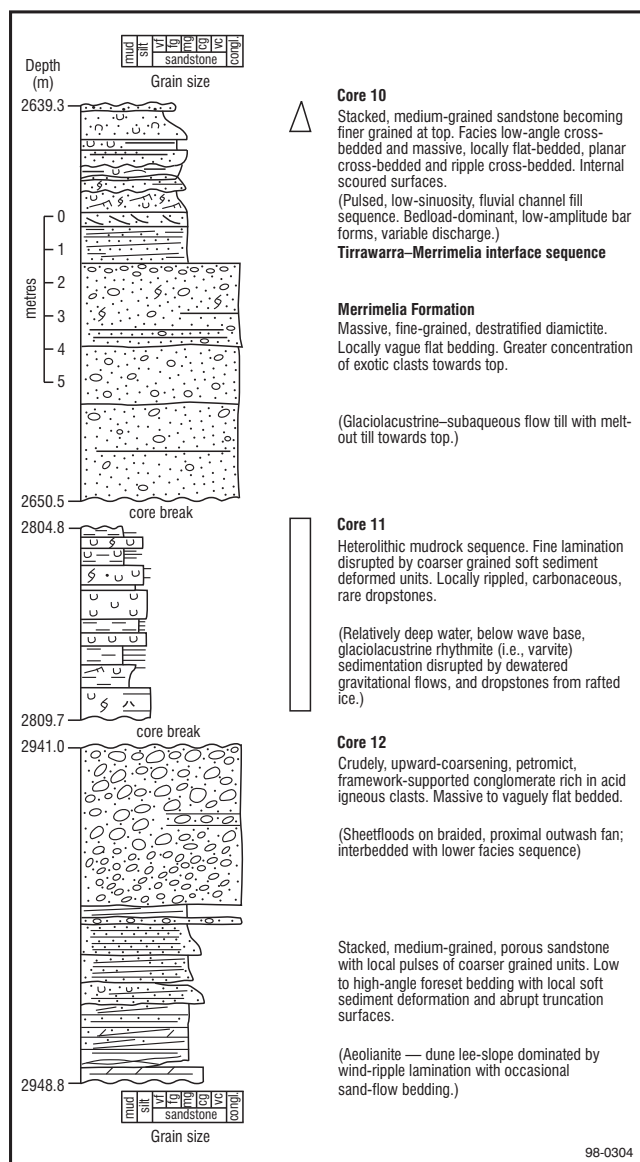


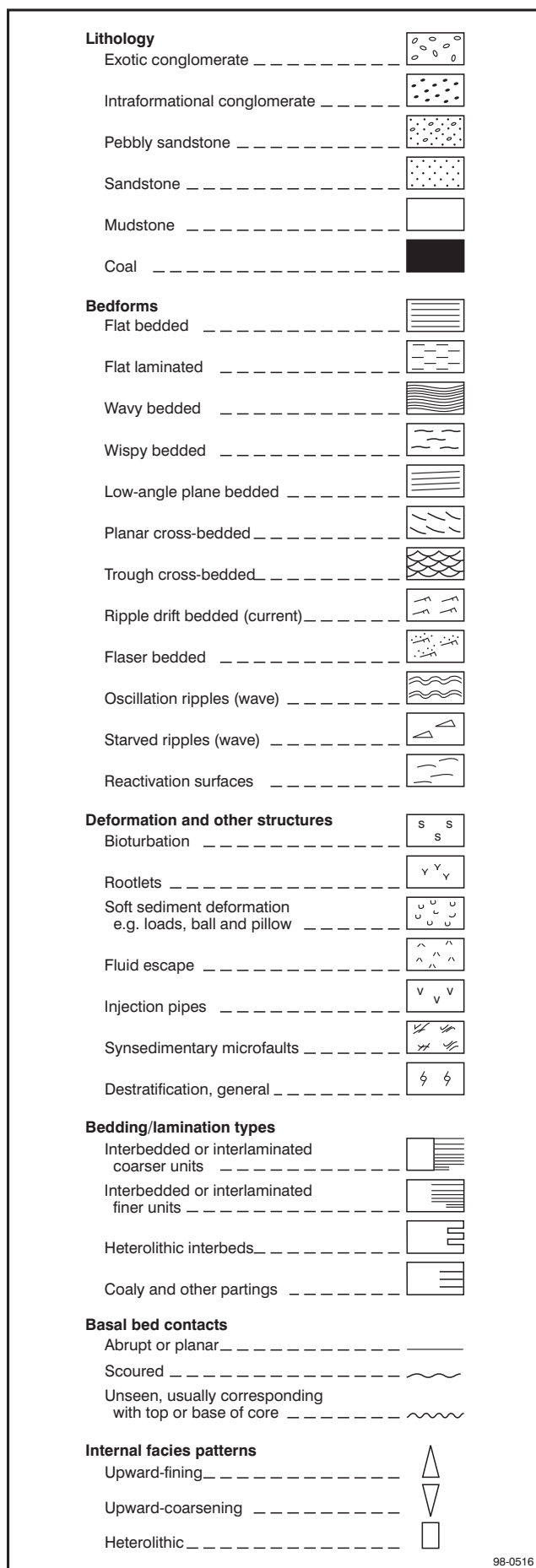
Fig. 6.9 Sedimentary facies log of part of the Merrimelia Formation type section, Merrimelia 1 (after Williams 1995). Legend adjacent.

fluvial channel or delta distributary sands overlain at 2124 m by Tirrawarra-type facies.

The top of the Merrimelia Formation in the interface sequence (or the top sequence if there are more than one), is commonly marked by deep-water glaciolacustrine mudrock which Chaney *et al.* (1997, p.172) interpret to mark the 'end of the depositional phase of the Merrimelia Formation (*sensu stricto*)' in the Moorari, Fly Lake and Tirrawarra Fields. This facies was first recognised by Seggie *et al.* (1994) to represent a flooding surface which could be correlated across the Tirrawarra Field (see Ch. 7). The same shale or one very similar to it occurs as far east as the Pondrinie Field implying widespread flooding of the region now occupied by the Gidgealpa, Merrimelia and Packsaddle Ridges. A section through some Pondrinie wells (Fig. 6.11) illustrates this shale and the rapid lateral and vertical facies changes typical of the Merrimelia Formation.

**Thickness**

The Merrimelia Formation and Tirrawarra Sandstone are difficult to separate in terms of thickness owing to their



Legend to Figures 6.9, 6.16, 6.19, 6.22, 6.25 and 6.28.

complexly interfingering association. An isopach of the combined formations is shown in Figure 5.2. As discussed in Chapter 5 the thickest sediments accumulated in the Weena Trough, the southern Patchawarra Trough and northern Nappamerri Trough where up to 600 m may have been preserved. Areas devoid of Tirrawarra Sandstone and Merrimelia Formation are interpreted either as glaciated uplands such as Moomba, Daralingie and Toolachee, or as structures subsequently uplifted and eroded (e.g. the culminations of Gidgealpa, Merrimelia, Pondrinie). Thornton had observed in 1979 that the presence of glaciolacustrine sediments on structural ridges indicated uplift of formerly low-lying areas. Thus the isopach shown in Figure 5.2 does not accurately reflect the original thickness on such reactivated structures.

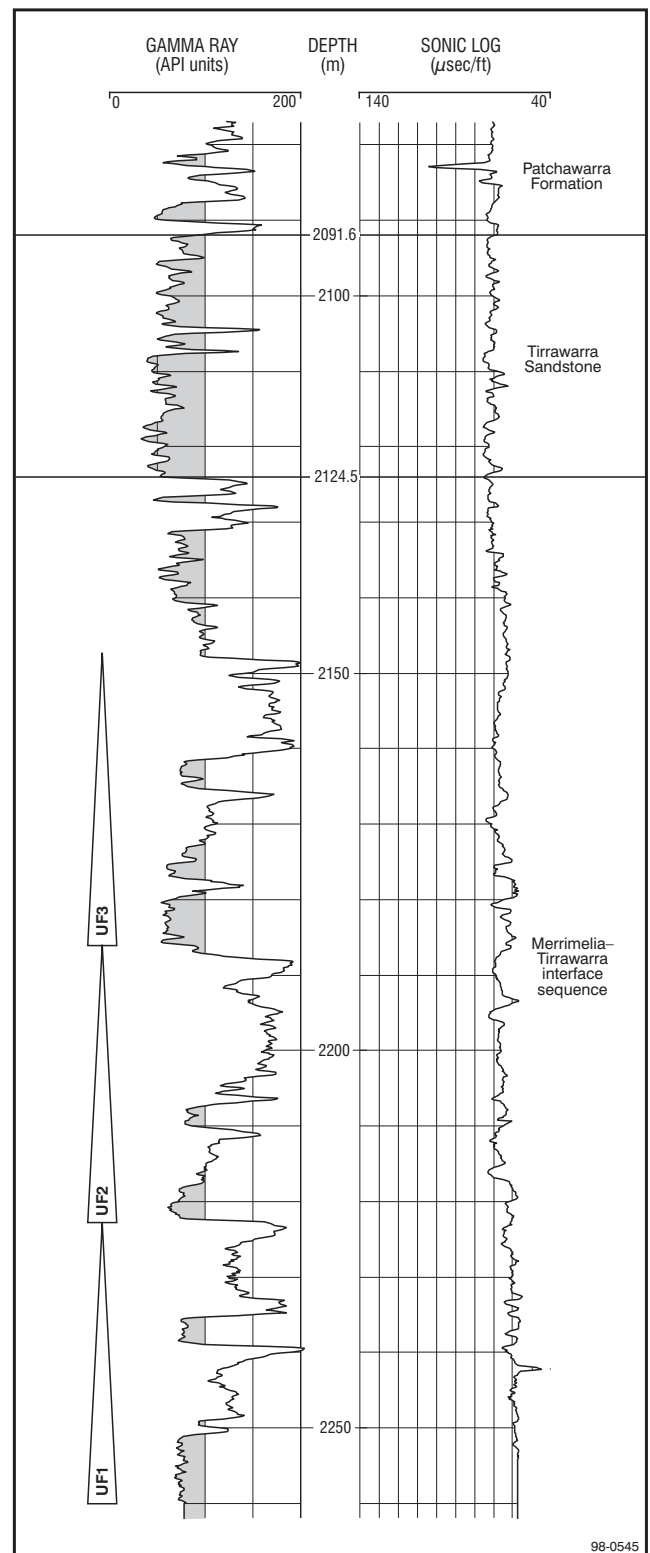
**Age**

Late Carboniferous (Stephanian) to Early Permian (Asselian), PP1 palynozone of Price *et al.* (1985).

**Sedimentology and environments of deposition**

The Merrimelia Formation is a complex mosaic of glacial facies in which the Tirrawarra Sandstone (*sensu stricto*), and Merrimelia Formation (*sensu stricto*) exhibit an interfingering relationship (Williams and Wild 1984). Recent work by Chaney *et al.* (1997) defined this relationship further, indicating that the Tirrawarra Sandstone should be included in the Merrimelia Formation as a ‘facies type’ as both units form an integrated suite of sediments. Within this context, Chaney (1998) has described the Tirrawarra Sandstone (*sensu stricto*) as a sequence of stacked braidplain sediments<sup>3</sup> and is but one of twenty facies types delineated within the Merrimelia glacial suite of rocks. Chaney *et al.* (1997) have therefore suggested that all such glaciofluvial braided outwash sandstones be called ‘Tirrawarra type’ sandstones. By retaining the name ‘Tirrawarra Sandstone’, the traditional economic importance attached to this term is maintained, since the largest Cooper Basin oil reservoir is in this unit.

The kaleidoscope of facies which forms the Merrimelia–Tirrawarra glacial complex has been deposited directly from the action of glacial meltwater and sediment output. Merrimelia (and Tirrawarra) sediments were deposited in both terminoglacial and proglacial depositional realms (Fig. 6.12) depending on the relative position of glaciers and the Merrimelia ice sheet. Initially the Gondwanan glaciers were dominant, such that only Merrimelia Formation (*sensu stricto*) sediments were deposited within this glacial complex (Fig. 6.13e). As the glacial influence started to wane, Merrimelia sedimentation began to fluctuate (Fig. 6.13b, c), to the point where both ‘Tirrawarra type’ and Merrimelia sediments were deposited in an interfingering manner (Williams and Wild, 1984; Chaney *et al.*, 1997). The glaciers retreated further until only Tirrawarra Sandstone (*sensu stricto*) sedimentation dominated (Fig. 6.13a). This evolving deposition was controlled by the action and position of Gondwanan



**Fig. 6.10** Wireline logs of the Merrimelia Formation – Tirrawarra Sandstone interface sequence, Goyder 1. Three stacked upward-fining packages (UF1–UF3) are illustrated.

glaciers, as they passed through cycles of ice advance and retreat.

No single controlling factor can account for the formation of continent sized icecaps over the Gondwana landmass. Visser (1993) has suggested that high rates of

<sup>3</sup> In this section only the sedimentology of the Merrimelia Formation will be discussed in detail with cursory mention made as to how the Tirrawarra Sandstone formed in relation to Merrimelia sediments (*sensu stricto*) and within the Merrimelia–Tirrawarra glacial complex as a whole.

plate motion resulted in the exposure of continental shelves and contributed to a drop in sea level. The net effect of this was to increase the albedo of the earth's surface which, along with the nearly south polar position of Gondwana and localised tectonic uplifts, triggered ice sheet growth. Crowell and Frakes (1971) envisaged that similar mechanisms induced icecap formation on the Gondwana landmass, and in particular on the uplifted margin of southern Australia during the Stephanian. The restriction of global ocean currents, controlled by the collision of Gondwana and Laurentia had the effect of reducing transfer of warm equatorial waters into southern polar regions. This, coupled with the very low levels of atmospheric CO<sub>2</sub> (Caputo and Crowell, 1985), further contributed to the extensive growth of ice sheets on Gondwana. Perhaps however, the single greatest controlling factor in the development of Gondwanan ice sheets and glaciers was plate movement relative to the south pole. Caputo and Crowell (1985) concluded that glaciation flourished on Gondwana when the supercontinent lay in polar regions and that glaciation disappeared when Gondwana moved to place the south pole in oceanic or coastal regions.

On the Australian portion of the Gondwanan land mass, alpine glaciers on the eastern seaboard formed at first in the mid-Carboniferous (Late Visean to Early Namurian). Continental icecap formation, which culminated in the deposition of Merrimelia and Tirrawarra sediments, formed later in the Stephanian (Late Carboniferous), spreading from the south and moving northwards (Crowell and Frakes,



Modern glaciated terrain, Larsemann Hills, Antarctica. (Courtesy of D.J. Alexander; photo 45698)

1971). Merrimelia Formation deposition (*sensu stricto*) coincided with the Gondwanan glacial maximum when the Cooper Basin was situated in southern polar latitudes (Veevers and Powell, 1987; Fig. 7.1). In this polar position, the most extensive development of the Gondwanan ice sheet on the Australian continent, according to Crowell and Frakes (1971), was on upland positions. This period of Merrimelia–Tirrawarra glaciation corresponds with scenarios (d) and (e) in Figure 6.13.

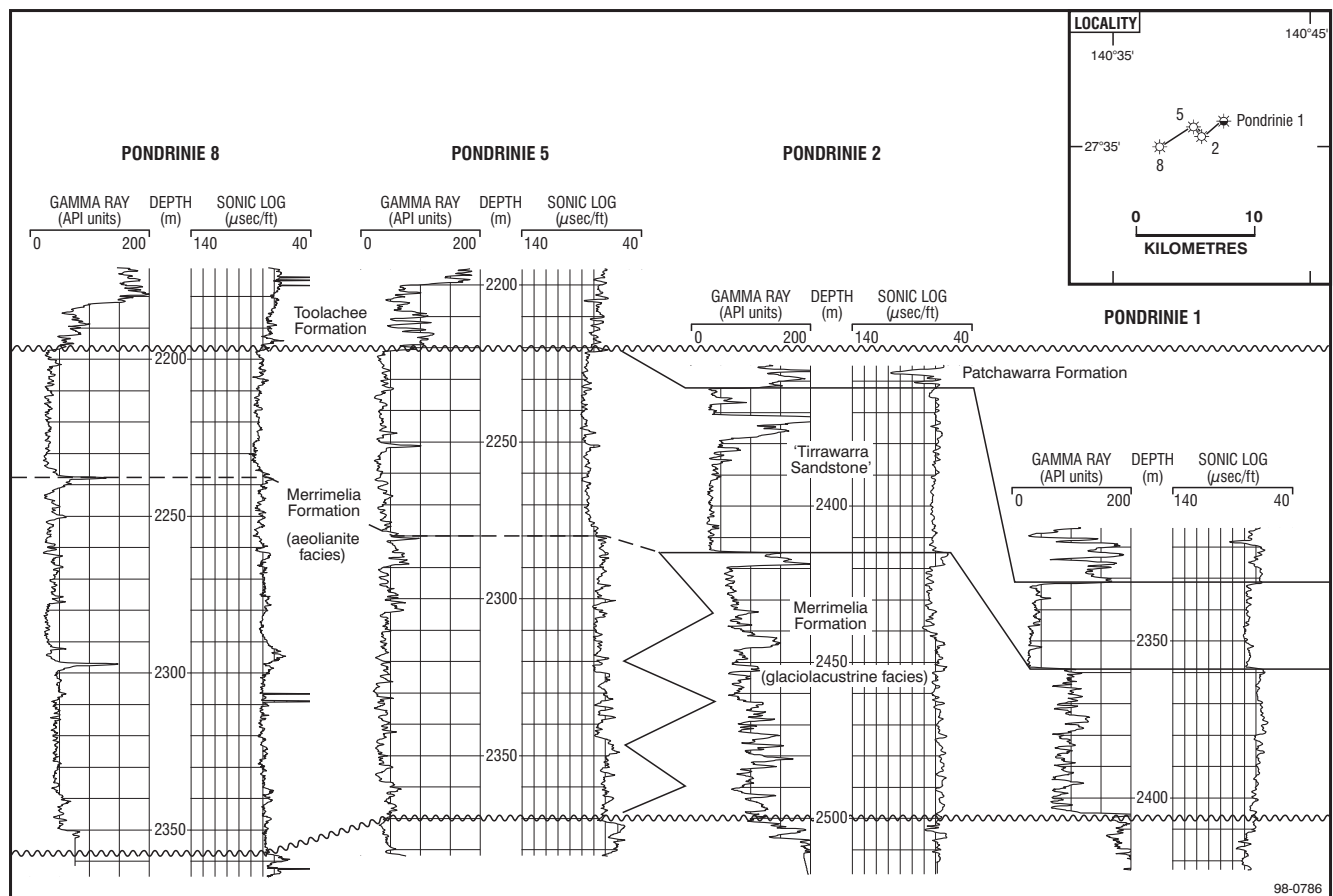


Fig. 6.11 Wireline logs illustrating glacio-lacustrine mudrock at the top of the Merrimelia Formation in Pondrinie 2 and intraformational facies changes, Pondrinie Field.

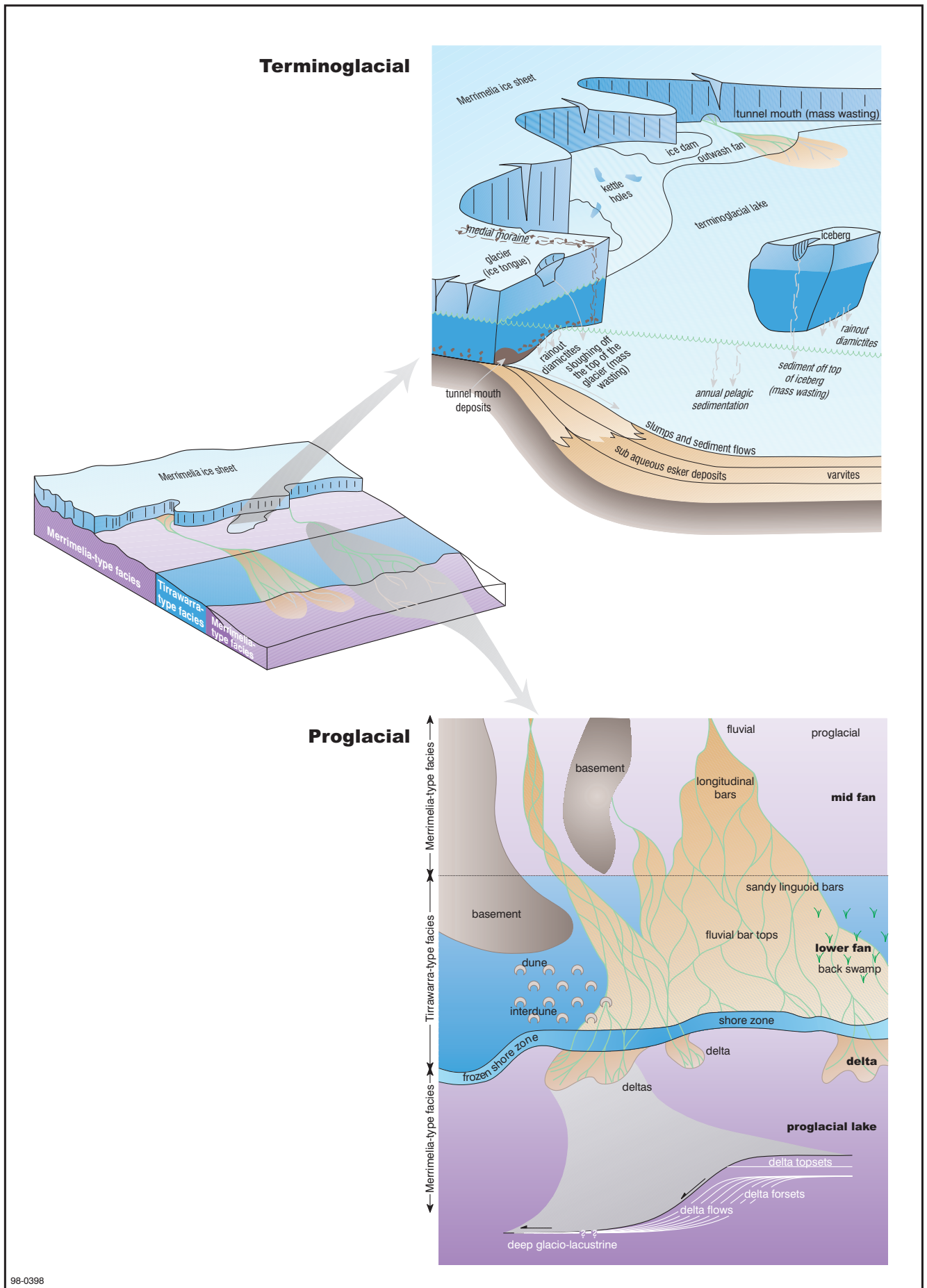


Fig. 6.12 Block diagrams of terminoglacial and proglacial realms represented by the Merrimelia Formation.

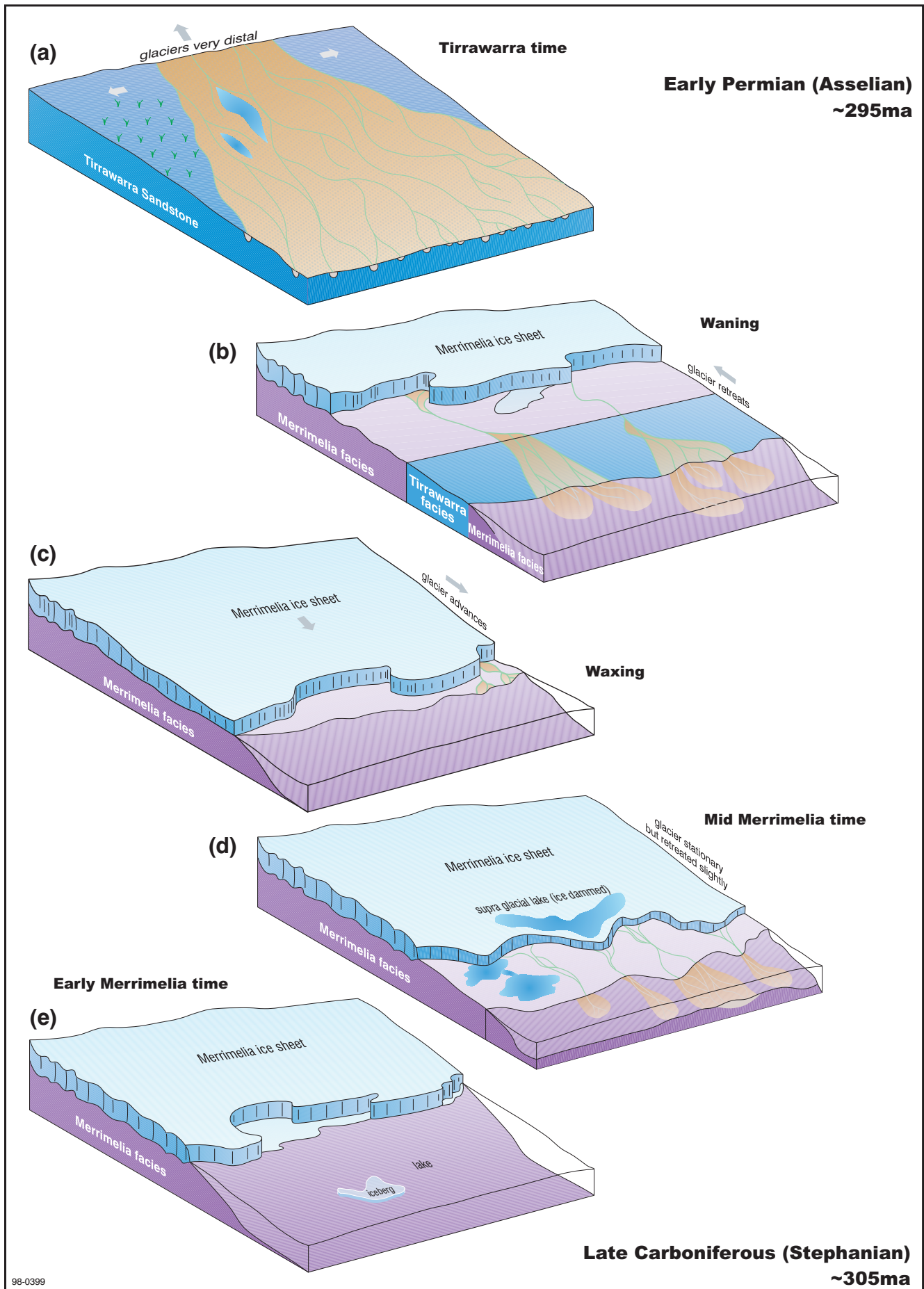


Fig. 6.13 Block diagrams illustrating five stages of palaeo-environmental evolution of the Tirrawarra-Merrimelia complex.

Towards the end of the Sakmarian, the Cooper Basin, whilst still in polar latitudes, began to experience milder conditions (Alley, 1995a). This, coupled with the reorientation of the Gondwanan supercontinent in the Early Permian, saw waxing and waning glacial conditions prevail to deposit Tirrawarra and Merrimelia sediments in an interfingering relationship (Fig. 6.13b, c). As glaciers continued to retreat, the area of Tirrawarra Sandstone deposition increased. Finally glacial influence gave way to extensive cold climate fluvial and peat swamp deposition (Patchawarra Formation, see below).

All observations indicate that glacial forces, centred on the southern Australian continent in the Permo-Carboniferous, dictated the composition and sedimentology of both the Tirrawarra Sandstone and Merrimelia Formation. The complexity of Merrimelia sediments is hard to decipher in places because of a lack of cored information. Only the most common facies types are discussed here; a full list of facies and wells is given in Table 6.2.

**Table 6.2** Location of major facies of the Merrimelia Formation.

FACIES	WELL	
<b>Deltaic deposits</b>	Bimbaya 1	Mudrangie 1
	Coonatie 1	Packsaddle 1
	Fly Lake 1, 2	Tirrawarra 2, 6, 7,
	Gidgealpa 5, 7	8, 9, 14, 22
	Kanowana 1	Tirrawarra West 1
	Merrimelia 1, 4, 7	Welcome Lake 1
	Merupa 1	Yanpurra 1
	Moorari 2, 4, 6, 7, 9	
<b>Deep-water lacustrine deposits</b>	Beanbush 1	Moorari 1, 2, 3, 4,
	Bimbaya 1	6, 7, 9
	Boxwood 1	Mudrangie 1
	Brolga 1	Packsaddle 1
	Coonatie 1	Tirrawarra 2, 3, 6,
	Fly Lake 1, 2	7, 8, 9
	Gidgealpa 5	
	Merrimelia 1	
<b>Shorezone deposits</b>	Boxwood 1	Tirrawarra 2, 3, 6,
	Brolga 1	8(?), 9, 14, 22
	Fly Lake 1, 2	Tirrawarra West 1
	Merrimelia 4	Welcome Lake 1
	Moorari 2, 3, 9	
<b>Rainout diamictites</b>	Jack Lake 1	Moorari 2
	Kenny 1	Paning 1
	Kudrieke 1	Tindilpie 2
	Merrimelia 3,18	Welcome Lake 1
<b>Terminoglacial fluvial deposits</b>	Gidgealpa 3	
	Malgoona 1, 4	
<b>Subaqueous tunnel mouth deposits</b>	Kenny 1	Moorari 2
	Merrimelia 18	Packsaddle 1
<b>Terminoglacial varvites</b>	Gidgealpa 5	
<b>Glacial aeolianites</b>	Merrimelia 1, 5, 13	
<b>Delta front debris flows</b>	Gidgealpa 5	Panning 1
	Merrimelia 1	Yanpurra 1
<b>Terminoglacial kettle holes</b>	Gidgealpa 3	
<b>Proglacial fluvial outwash deposits</b>	Coonatie 1	Lake Hope 1
	Coongie 1	Malgoona 1, 4
	Coopers Creek 1	Merrimelia 1
	Kenny 1	Moorari 2, 3, 4, 6, 9

The proximity of the ice sheet and/or glaciers ensured terminoglacial environments were dominated by high energy conditions (Fig. 6.12). As a result, deposits are coarse grained and show exceptionally rapid lateral and vertical changes, due to variation in meltwater volume and strength (Chaney *et al.*, 1997). This zone of deposition thus shows a wide variety of sedimentary structures and facies. Most of the sediments in the terminoglacial environment were deposited in meltwater rivers and streams but can also have been caused by ice melt, lacustrine, deltaic and mass flow depositional processes (Chaney, 1998).

Fluvial sediments range from coarse-grained, poorly sorted conglomerates to an array of variably sorted sandstones, siltstones and conglomerates. In most cases, the conglomerates are clast supported, with the interstitial matrix ranging from medium to very coarse sand; however some do show a high proportion of mud. These rather chaotic rocks are interpreted as high energy meltwater floods deposited after a dam burst within the glacier, or in the terminoglacial environment itself (Chaney, 1998).

Slack water deposits are rarely preserved in such an environment, overshadowed by the erosive capacity of major flood events. Kettle hole deposits represent a quiet-water facies of the terminoglacial realm, having formed by the melting of buried dead ice. As the ice melts, the overlying sediments collapse leaving a large hole where later ponded water settles in quiet conditions (Chaney, 1998). Lacustrine facies exhibit a wide variety of subaqueous deposits ranging from those released directly from the ice to those deposited from settling of surge flows (Chaney *et al.*, 1997). Rainout diamictites are common and show a wide range of clast sizes. The matrix in these sediments is composed of homogeneous silty mud within which dropstones appear to float. Chaney *et al.* (1997) state that some of the diamictites are stratified. These diamictites show faint sandy laminations and sandy layers, usually not more than 20 mm thick, that commonly contain rip up clasts. Often they are disrupted by dropstones, and occasionally exhibit isoclinal folding (Chaney, 1998). Such diamictites have been described by Evenson *et al.* (1977) as sub-aquatic flow tills which have moved downslope as coherent viscous blocks of sediment. Subaqueous tunnel mouth deposits, bottomsets and varvite mudstone were also observed and described by Chaney *et al.* (1997) within the terminoglacial environment.



Rainout diamictite in the Merrimelia Formation, Welcome Lake 1, 2830 m. (Photo 46496)



Framework-supported conglomerate of proglacial fluvial bar in the Merrimelia Formation, Lake Hope 1, core 4, 2487 m. (Photo 45945)

The proglacial environment is a short distance from the ice sheet (Fig. 6.12). The size and character of facies within this locale are dependent on meltwater volumes. Compared to the terminoglacial depositional realm, the proglacial environment is much greater in area. Accordingly there are more numerous facies in the proglacial zone (14) than in the terminoglacial zone (6). This is partly a function of erosion and reworking of the terminoglacial deposits by ice advance and continued meltwater release.

Proglacial environments are dominated by fluvial and lacustrine processes (Fig. 6.12). There is no permanent ice cover within this region, but river ice and lake ice may prevail locally (Chaney, 1998). As there is no direct glacial contact with these facies, proglacial sediments look similar to those beyond the glacial setting (Chaney *et al.*, 1997), which can make recognition difficult, particularly from wireline logs.

There are parallels between braided fluvial systems in glacial and non-glacial environments, but there are also differences, such as the freezing action of ice and seasonal as well as catastrophic discharge of glacial meltwater. Fluvial sediments generated in mid to lower reaches of the braided outwash fan, tend to be composed of well sorted, medium-grained, relatively clean sandstone. This type of



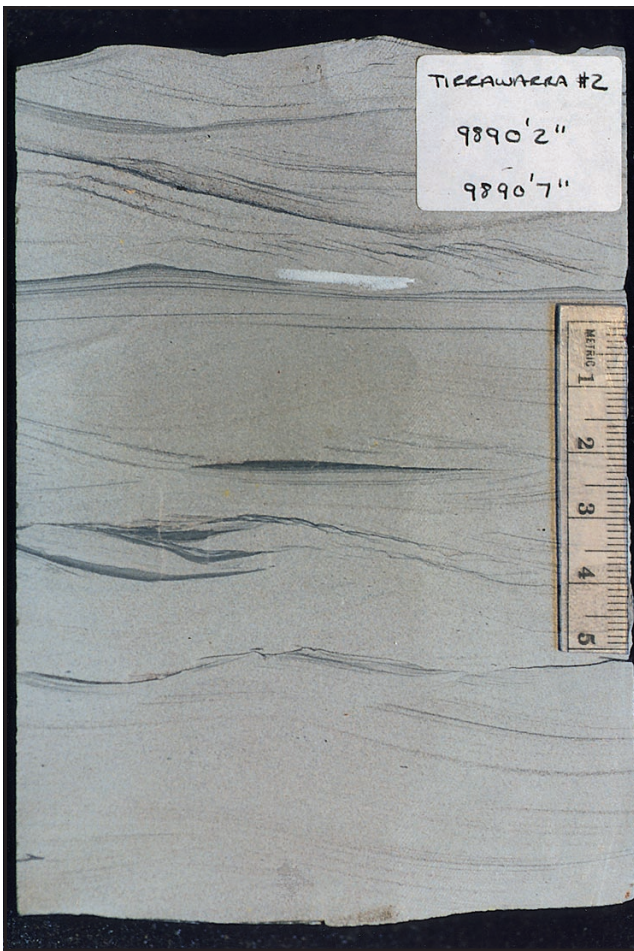
Wind ripple laminations ('pinstripes') on aeolian dune in the Merrimelia Formation, Merrimelia 5, 2624 m. (Photo 46497)

sandstone is common within the Merrimelia Formation and displays average porosity having been commonly deposited as sandy linguoid bars (Fig. 6.12). Gravelly longitudinal bar deposits, formed in the mid to upper fan, consist of very coarse-grained, reasonably well sorted conglomerates which frequently show crude low-angle bedding, often indicated by changes in grain size (Chaney *et al.*, 1997). The conglomerates are clast supported and are moderately well rounded, although this may depend on composition. The interstitial matrix is generally fine to medium-grained sand.

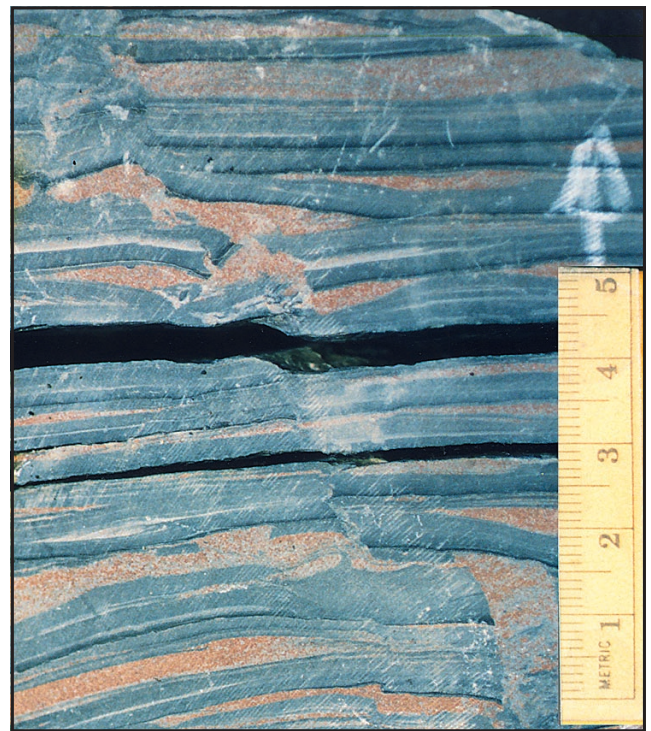
One of the more unusual environments, from a preservation viewpoint, is the glacio-aeolian regime. The best development of glacio-aeolian sandstones found to date is in the Merrimelia (Williams *et al.*, 1985, 1987) and Pondrinie Fields, where they reservoir hydrocarbons (Fig. 6.14). Glacio-aeolian sandstones are well sorted, contain very well rounded grains, lack fine-grained matrix and contain rare rock fragments. This sandstone is characterised by distinctive steep to low tabular cross-bedding which contains abundant wind ripple laminations, grain flows and inclined bounding surfaces (Chaney *et al.*, 1997). Dune areas are separated by interdunes whose deposits contain much finer sand 'stuck' to abundant green mud laminae, which show some distortion, perhaps due to the passage of the over-riding dune. Chaney *et al.* (1997) state that, within some of the dune sands, well rounded pebble lags can be found. These indicate ephemeral floods and the interdigitating nature of the aeolian and the fluvial environments. The proximity of these two environments can be observed in Figure 6.12.

As the proglacial lacustrine environment is not in contact with ice, detritus is brought into the lacustrine regime via fluvial depositional processes (Chaney, 1998). The fluvial load of the meltwater, sourced from outwash fans, slows drastically as it enters the lacustrine realm, thereby forming deltas (Fig. 6.12). The coarsest sand fractions are released first onto the proximal delta topsets whilst the finer sand fractions are deposited down slope to form delta foresets and bottom sets. Further down the delta slope the bottom sets and mud-dominated varvite sequences grade into each other. Turbiditic sand flows are also a feature of this environment. The stacked deposits in Goyder 1 may be of this type.

The proglacial lacustrine environment is dominated by cyclic, deep-water varvites and turbiditic couplets. Varvites are seasonal whilst turbidite sediments are formed from surge flows onto the lake floor (Ashley *et al.*, 1985). Chaney



Shorezone wave ripples in proglacial lacustrine sandstone, Merrimelia Formation, Tirrawarra 2, 3015 m. (Photo 46498)



Microfaulted rhythmite of deep proglacial lake in the Merrimelia Formation, Moorari 2, 3078 m. (Photo 46499)

*et al.* (1997) state that occasionally quiet water sedimentation is interrupted by clean sand flows, or poorly sorted sandy deltaic debris flows where the mud content has been washed out by reworking. Such subaqueous flows can be up to a metre in thickness (Chaney, 1998).

Both the proglacial and terminoglacial environments interfinger laterally and through time and, as a result, rapid changes in facies occur throughout the sedimentary architecture of the Merrimelia Formation. The diagrams in Figures 6.12 and 6.13 therefore are not palaeogeographic reconstructions, but simplified cartoons depicting the action of glaciers on sediment formation and facies distribution at representative time intervals.

#### Clast provenance

Merrimelia Formation sediments contain up to 76 different rock fragment species (Chaney *et al.*, 1997). Sedimentary rock fragments comprise 42%, igneous rock fragments 29%, metamorphic rock fragments 26% and pyroclastic rock fragments 4% of the observed total. Rock fragments in Merrimelia (and Tirrawarra) sediments are intrabasinal and extrabasinal. Intrabasinal rock fragments are mainly derived from the underlying eastern Warburton Basin units, whereas extrabasinal rock fragments have been sourced from outside the Cooper Basin and transported via the action of glaciers and glacial meltwaters.

The most distinctive intrabasinal Merrimelia Formation rock fragments are rhyodacites, basalts and pyroclastics derived from the Mooracoochie Volcanics. According to the classification outlined by Sun (1996), these represent three volcanic facies associations. Intrabasinal rock fragments account for 87% of the total observed in the Merrimelia Formation (Chaney *et al.*, 1997).

Extrabasinal rock fragments in the Merrimelia Formation are dominated by metamorphic rocks, of which twenty-five lithologies (Chaney *et al.*, 1997) have been observed. There is, however, no dominant metamorphic rock type. Unlike sedimentary and volcanic rock fragments, metamorphic rock fragments came from intra- and extrabasinal provenance areas. Recrystallised and schistose-polycrystalline quartz, gneiss, and pyroclastic clasts were sourced from extrabasinal regions whereas metasandstone, meta-acid volcanic and metasiltstone rock fragments are thought to have been derived from recrystallised Warburton Basin lithologies. Sixty-nine percent of metamorphic rock fragments observed within the Merrimelia Formation (*sensu stricto*) have been derived from extrabasinal sources (Chaney *et al.*, 1997).

Granite rock fragments with graphic and myrmekitic textures, although rare, suggest that transport into the basin has occurred over a considerable distance. No graphic-textured granite has been reported from the Big Lake Suite granodiorite, whereas granite exhibiting this texture is known from Mount Painter and the Willyama Supergroup to the south, and the Arunta Block to the north. There remains a possibility that undrilled granitoid plutons beneath the far southern Cooper Basin may have sourced graphic granite clasts. The majority of granite clasts in Merrimelia sediments are however granular in nature, and

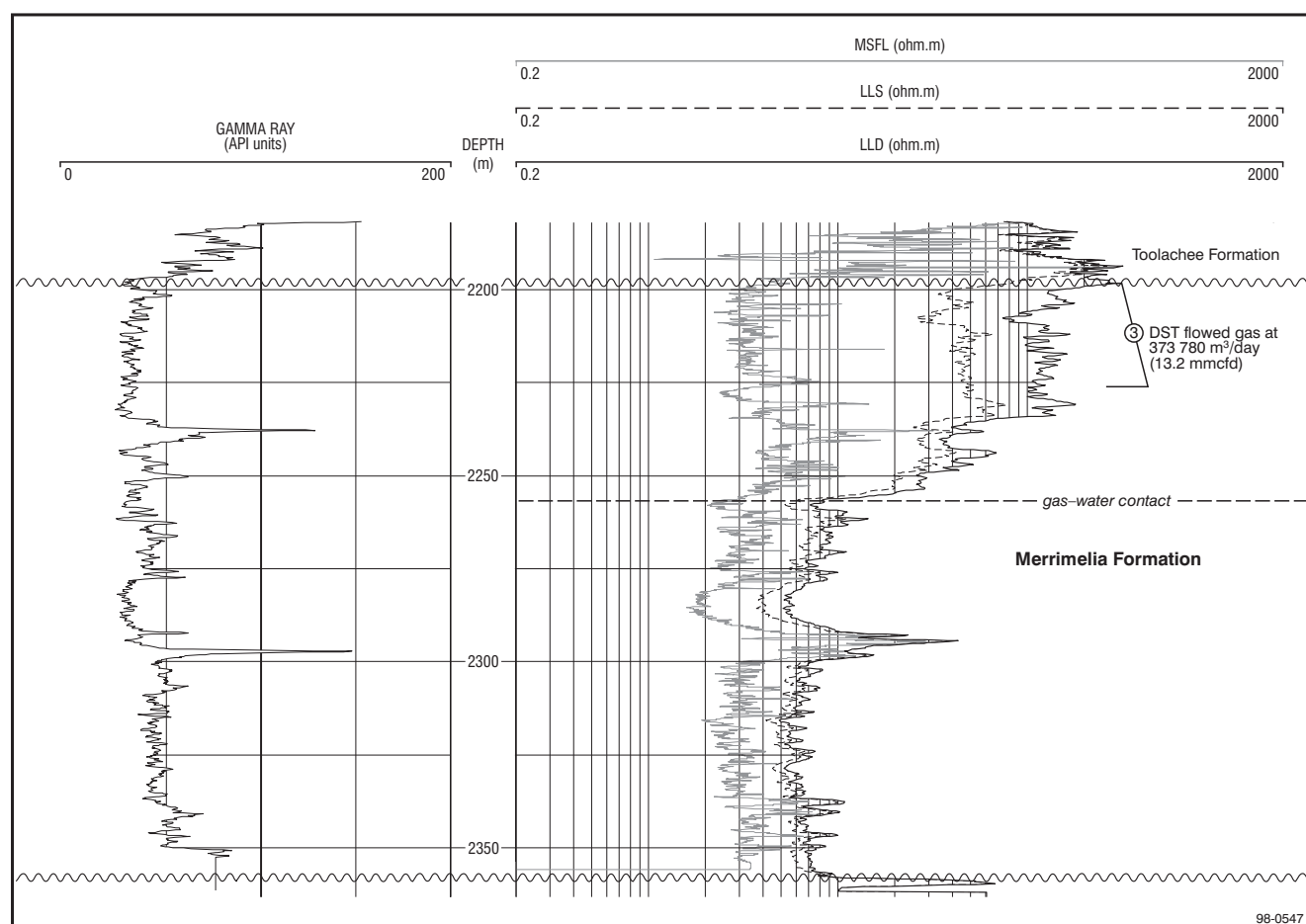


Fig. 6.14 Wireline logs of the Merrimelia Formation illustrating the low gamma ray values of the aeolianite facies, Pondrinie 8.

do not exhibit graphic or myrmekitic textures. Such granitic rock fragments are observed in abundance in the Queensland border region of the Cooper Basin at Tallalia 1. It is postulated that the fresh granite rock fragments in this well have been sourced from the Big Lake Suite which was locally exposed at that time. This implies an eastward movement of rock fragments along what is now the Gidgealpa–Innamincka Ridge complex within the Cooper Basin. An isopach (Fig. 5.2) illustrates that this ridge complex was in part a trough at that time, deepening towards the Queensland border in the direction of Tallalia 1. The movement of both graphic-textured and granular granite rock fragments indicates movement of clasts into and within the Cooper Basin. The rock fragment pathways illustrated in Figure 6.15 have been deduced from provenance and facies architecture analysis. A comparison with Figure 5.2 shows that the rock fragment movements mirror the depositional pathways indicated on this independently constructed isopach map.

In addition to graphic granite, silicic metamorphic rock fragments also indicate likely provenance regions that have supplied the Cooper Basin with sediment. Their silicic nature suggests transport over long distances by potentially destructive glacial and/or fluvial depositional processes without a high proportion being destroyed. These rock fragments can therefore, like graphic granite, be used as indicators of the directions of sediment movement through the Cooper Basin. Metamorphic rock fragments are

consistently observed within the Tirrawarra Sandstone (*sensu stricto*), on a region by region basis, in proportions that are slightly lower or consistent with the proportions of metamorphic rock fragments observed in the Merrimelia Formation. The percentage of metamorphic rock fragments is not constant over the basin in either the Tirrawarra Sandstone or Merrimelia Formation.

Three rock fragment domains have been recognised. The distribution of metamorphic rock fragments in the Merrimelia Formation and subsequently the Tirrawarra Sandstone in these domains is best explained by five extrabasinal sources (Fig. 6.15). The northern rock fragment domain was possibly sourced from the Arunta Block while the western and southern rock fragment domains were possibly sourced from the west, southwest (Mount Painter region) and the south (Benagerie Ridge, Willyama Inliers) respectively. There is also a zone corresponding with a deep trough (Fig. 5.2) where rock fragments from all three domains moved east towards Tallalia 1 (Fig. 6.15). This area is akin to a mixing zone where, according to facies architecture analysis (Chaney, 1998), glacial packages from the north and south merged.

The southerly input of extrabasinal sediments persisted throughout Merrimelia Formation deposition, whereas westerly and northerly sediment input fairways waned with time. This possibly indicates the retreat of glaciers from the northern margin of the Cooper Basin during Sakmarian time.

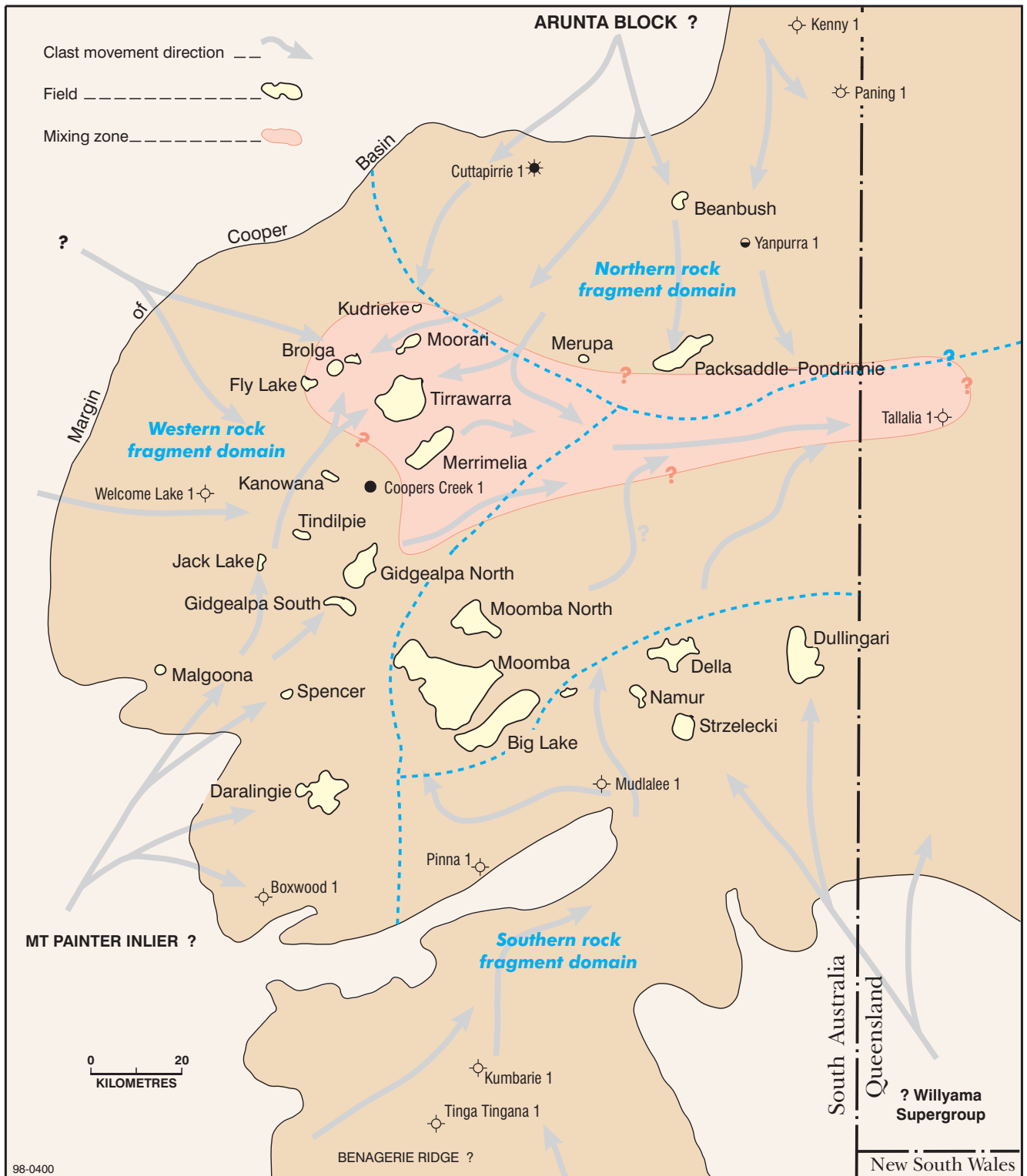


Fig. 6.15 Provenance map indicating suggested rock fragment domains and pathways of clast transport (modified from Chaney et al., 1997).

## Tirrawarra Sandstone

D.I. Gravestock

### Definition and nomenclature

The name 'Tirrawarra Formation' was first used by Kapel (1972) for a sandstone in the lower part of the Gidgealpa Formation. In the same year, and following Kapel's recommendation, Gatehouse (1972) elevated the

Gidgealpa Formation to Group status. In so doing he revised the name Tirrawarra Formation to Tirrawarra Sandstone. The name is taken from Tirrawarra Swamp and is translated from Aboriginal words meaning 'wild fight' (Kapel, 1972).

### Type section

Kapel (1972) proposed Tirrawarra 1 (latitude 27°40'36.01"S, longitude 140°7'17.86"E) as the type section of the Tirrawarra Sandstone. However, as noted

above, Martin (1967b) had previously included a major proportion of the Tirrawarra Sandstone (then unnamed) in his definition and type section of the Merrimelia Formation. It is proposed that the type section of the Tirrawarra Sandstone be returned to Merrimelia 1 (2586–2644 m) where it is represented by cores 8, 9 and part of core 10, which contains the contact with the underlying Merrimelia Formation (Williams, 1995). Kapel’s Tirrawarra 1 intersection (2911–2955 m) is designated here as a reference section. In this well, Tirrawarra Sandstone is represented by core 6, but the Merrimelia Formation contact has not been cored.

**Lithology and distribution**

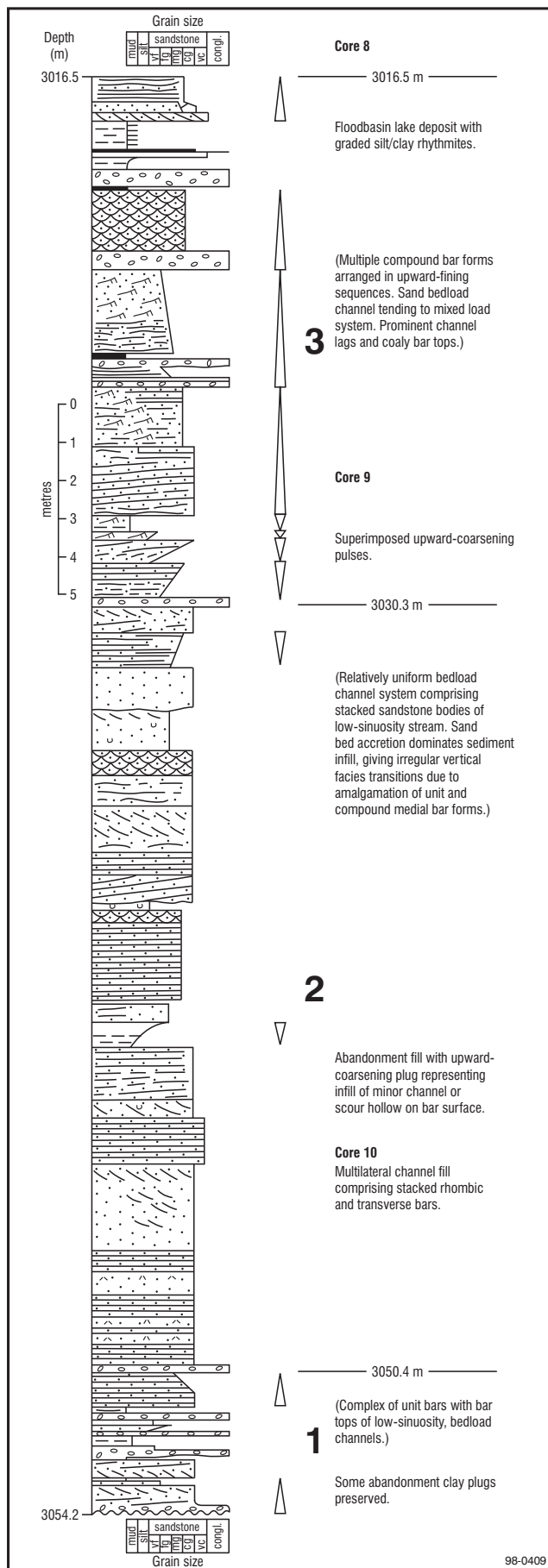
Tirrawarra Sandstone is composed chiefly of brown and white, fine to coarse-grained, moderately well sorted sandstone (sublitharenite) with minor shale interbeds and rare, thin coal seams and stringers. Conglomerate beds are locally well-developed, notably in Gidgealpa and Big Lake Fields. A core log from Tirrawarra 5 is shown in Figure 6.16. Tirrawarra Sandstone is the principal Cooper Basin oil reservoir with most reserves held in the Tirrawarra Field (26 x 10<sup>6</sup> kL (163.2 mmstb) original oil-in-place, 6.68 x 10<sup>6</sup> kL (42 mmstb) recoverable oil; Skilbeck *et al.*, 1991; Seggie *et al.*, 1994).

**Relationships and boundary criteria**

Lack of diagnostic palynomorphs in early wells led to the notion that an unconformity existed either between the Merrimelia Formation and Tirrawarra Sandstone or within the Tirrawarra Sandstone. The possibility of an intraformational hiatus led Thornton (1978) to speculate that the Tirrawarra Sandstone may have two parts: a pre-unconformity part associated with the Merrimelia Formation and a post-unconformity part associated with the Patchawarra Formation. Sufficient palynologic data now exist, in spite of a scarcity of facies amenable to spore and pollen preservation, to indicate that, except locally, the upper and lower boundaries of the Tirrawarra Sandstone are conformable.

Williams and Wild (1984) and Chaney *et al.* (1997) have demonstrated the interfingering relationship of the Tirrawarra Sandstone and Merrimelia Formation as outlined above. Chaney *et al.* (1997) and Chaney (1998) regard the Tirrawarra Sandstone as one of 20 facies types within the glacial suite of rocks embraced by the Merrimelia Formation. Removal of the type section to Merrimelia 1 reflects this association. This facies type is referred to as Tirrawarra Sandstone (*sensu stricto*; Chaney, 1998; Chaney *et al.*, 1997).

The upper part of the Tirrawarra Sandstone is locally diachronous and intertongues with the Patchawarra Formation. This time-transgressive boundary was considered regional by Thornton (1978) whereas Williams and Wild (1984, p.379) suggested the interface was locally well-developed ‘in the vicinity of early structural highs’. Gravestock *et al.* (1995, fig. 9) illustrated tongues of Tirrawarra Sandstone alternating with Patchawarra Formation in Tarwonga 1. The intertonguing boundary is best developed at two widely separated locations in the Cooper Basin. The most southerly is a diffuse region ranging from the eastern Allunga Trough towards the Toolachee gas field and the southeastern margin of the



**Fig. 6.16** Sedimentary facies log of the Tirrawarra Sandstone, Tirrawarra 5 (after Williams, 1995). Legend adjacent to Figure 6.9. Refer to Figure 6.17 for well location.

basin, as shown in Figure 6.17. Lepena 1 is an extreme example of intertonguing (see Patchawarra Formation below, Fig. 6.20). The second location is in the Fly Lake–Brolga and Moorari–Woolkina area which has been described in detail by Seggie (1997). This small field with relatively high structural (or palaeotopographic) relief is quite complex as regards the Merrimelia–Tirrawarra–Patchawarra interfaces.

Independently of Thornton (1978), Seggie (1997, p.72) considered a ‘major basin-wide unconformity’ to have separated the glaciogene Merrimelia Formation from the paludal Patchawarra Formation. This unconformity divided the Tirrawarra Sandstone in two, a lower part associated with the Merrimelia Formation and an upper part with the Patchawarra Formation (Seggie, 1997). The unconformity is considered here to be local rather than regional in extent but the sequence stratigraphic or chronostratigraphic approach proposed by Seggie (1997), Seggie *et al.* (1994), Hamlin *et al.* (1996) and Chaney *et al.* (1997) is adopted. Thus the glaciogene Tirrawarra Sandstone (*sensu stricto*) is distinguished from the ‘Tirrawarra Sandstone-like’ facies of the Patchawarra Formation (see Patchawarra Formation in next section).

### Thickness

The formation is widespread but relatively thin, reaching only 75 m in thickness. Because of their interfingering relationship the Tirrawarra Sandstone and Merrimelia Formation are difficult to separate and thus the isopach shown in Figure 5.2 is of the two units combined.

### Age

Late Carboniferous (Stephanian) to Early Permian (Asselian), PP1 palynozone of Price *et al.* (1985) for Tirrawarra Sandstone (*sensu stricto*). The ‘Tirrawarra Sandstone-like’ facies of the Patchawarra Formation is Early Permian (Asselian to Artinskian), PP2–PP3.1 palynozones of Price *et al.* (1985).

### Sedimentology and palaeoenvironment

A fluvialite ‘valley-fill’ setting was originally interpreted for the Tirrawarra Sandstone by Kapel (1972). A three-part subdivision of the formation was recognised by Gostin (1973) in Tirrawarra Field: a basal unit of erosional channel conglomerate, a middle unit of uniform well-bedded sandstone of probable braided stream origin and an upper unit of channel conglomerate, sandstone and floodplain siltstone with occasional coal beds. The first to associate the Tirrawarra Sandstone with glacial processes appears to have been Battersby (1976, p.328) who commented ‘a more likely possibility [for a Tirrawarra Sandstone source] is that as glaciers retreated to the south, meltwater streams flowing north carried sediment from the glaciers and also reworked unconsolidated Merrimelia sediments’. As stated in the previous section and illustrated in Figures 6.12 and 6.13, the action and location of glaciers through cycles of ice advance and retreat determined the interplay of facies types and the evolution of the Tirrawarra–Merrimelia complex. Thus Battersby (1976) envisaged a similar scenario to the current interpretation.

Williams (1982) and Williams and Wild (1984) established four facies associations from detailed sedimentological study of cores. Associations 1 to 3 are

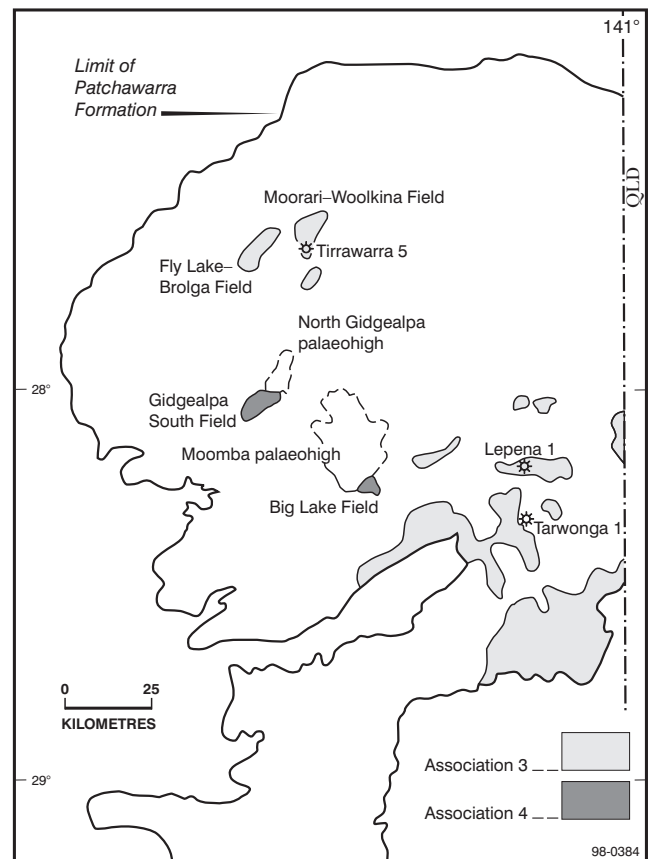


Fig. 6.17 Areas of intertonguing of Tirrawarra Sandstone and Patchawarra Formation (after Williams, 1982). See text for the explanation of Associations 3 and 4.

illustrated for Tirrawarra 5 core in Figure 6.16 and a wireline log from the same well is shown in Figure 6.18.

Association 1 consists of medium to coarse-grained sandstone and framework-supported conglomerate often of reworked Merrimelia or Warburton Basin lithotypes. This association was deposited as longitudinal gravel bars within a bedload-dominated low-sinuosity fluvial channel system. Williams (1982) has also noted rare sheet flood and debris flow gravels, suggesting unconfined floods on the distal reaches of alluvial fans.

Association 2 is considered to be the most characteristic of the Tirrawarra Sandstone and is the principal net pay facies association (Williams, 1982; Williams and Wild, 1984; Chaney *et al.*, 1997). It is composed of medium to coarse-grained, variably lithic sandstone with rare conglomerate, mudrock and coal beds. Plane, low-angle and planar cross-bedded units are ubiquitous and stacked in poorly-defined upward-fining or upward-coarsening patterns. This uniformity is typical of low-sinuosity bedload channels with a reasonably well-established discharge pattern and high width to depth ratios, similar to the modern Platte River of Nebraska in the United States (Williams, 1982).

Both Associations 1 and 2 may be found in the Tirrawarra–Merrimelia interface sequence where they are interbedded with typical Merrimelia Formation lithotypes. Commonly, however, Association 2 dominates the main part of the Tirrawarra Sandstone above the interface sequence. Associations 3 and 4 differ by representing evolution of the fluvial system towards a moderate sinuosity, mixed-load

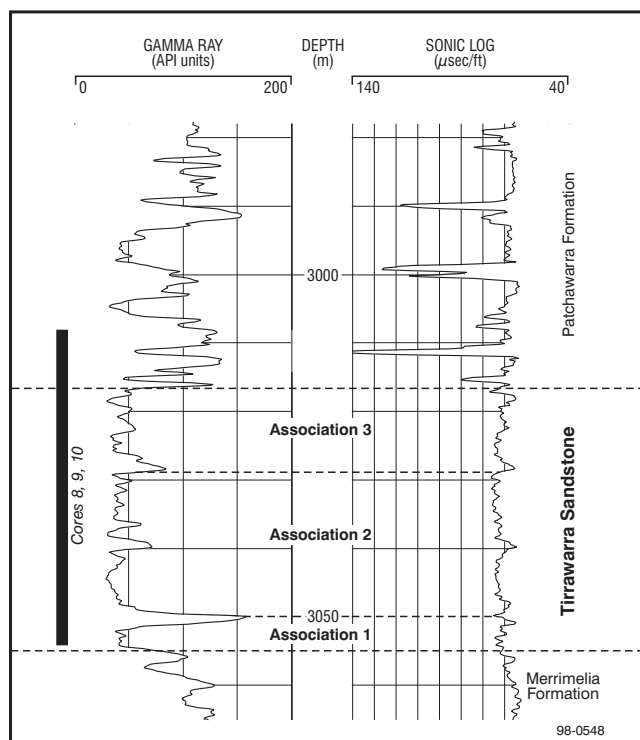


Fig. 6.18 Wireline logs illustrating Williams' (1995) Tirrawarra Sandstone facies associations, Tirrawarra 5.



Naturally fractured, braided fluvial Tirrawarra Sandstone, Big Lake 27, core 8, 2897 m. (Photo 45944)

category which grades into and is locally coeval with the Patchawarra Formation (Fig. 6.20).

Association 3 is dominated by sandstone with prominent, thin lag conglomerates, rare mudrocks and coal stringers. Stacked upward-fining sequences are characteristic of single and compound lateral and linguoid bar forms. Association 3 also contains thin floodbasin lake deposits composed of graded silt-clay rhythmites (Fig. 6.16).

Association 4 (which may coexist with Association 3; Williams, 1982) contains relatively thick conglomerates with exotic clasts reworked from the Merrimelia Formation (which contains intra- and extrabasinal clasts; see above). These conglomerates were deposited in longitudinal gravel bars which have been recognised in Gidgealpa and Big Lake Fields (Williams, 1982; Gravestock *et al.*, 1995) and may have been sourced from adjacent palaeohighs (Fig. 6.17).

Detailed studies of the Merrimelia Formation and Tirrawarra Sandstone were carried out in the Tirrawarra Field using a sequence stratigraphic approach by Seggie *et al.* (1994) and Hamlin *et al.* (1996). These authors recognised and mapped four major facies:

- Facies 1, delta front to glaciolacustrine fine-grained rippled to rhythmically-laminated clastics
- Facies 2, fine to coarse-grained distributary channel, mouth bar and interdistributary deposits
- Facies 3, fine to coarse-grained sandy braid-delta plain deposits
- Facies 4, upward-fining sandstone to mudrock and coal deposits of an evolving bedload to mixed-load fluvial system

Facies 1 and 2 are 'typical Merrimelia' glaciogene lithotypes. Facies 3 is equivalent to Williams' (1982) Association 2, i.e. 'typical Tirrawarra', and Facies 4 is equivalent to Williams' (1982) Association 3.

In the Tirrawarra Field Facies 3 is bounded above and below by unconformities subdividing the four facies into two cycles of decreasing then increasing accommodation space (Hamlin *et al.*, 1996). Seggie (1997) has traced the same cycles and their component facies from Tirrawarra to Woolkina-Moorari Field, noting that the upper unconformity has completely removed Facies 3 and part of Facies 1 in a northerly direction — a distance of only 10 km. Erosion of this magnitude (~40 m) is attributed here to the interplay of episodic floods associated with glacial melting and ice-sculpted high relief, with syndepositional tectonism playing a minor role.

## Patchawarra Formation

### Definition and nomenclature

Patchawarra Formation was named after Patchawarra Bore by Kapel (1972) and defined as the interbedded sandstone, siltstone, shale and coal beneath the Murteree Shale and above the Tirrawarra Sandstone, Merrimelia Formation or pre-Permian rocks (Gatehouse, 1972). Kapel (1972) suggested that basal sandstones (equivalent to Williams' (1982) Association 3) within the Patchawarra Formation should be named 'Moorari beds', however this term was not widely adopted and has been discarded.

### Type section

The type section is 2741.4–2913.9 m in Moorari 1 (latitude 27°34'20.88"S, longitude 140°34'15.3"E; Kapel, 1972).

### Lithology and distribution

Patchawarra Formation consists of interbedded grey, buff or brown, fine to medium-grained, locally coarse-grained and pebbly sandstone, grey to black siltstone, shale and coal. Sandstones are dominated by monocrystalline quartz with common polycrystalline quartz and minor chert and sedimentary rock fragments (Almon and Davies, 1981). Feldspar is present in trace amounts. Quartz overgrowths together with kaolinite and dickite cements are common; minor illite–smectite, chlorite and carbonate (dolomite and siderite) cements have also been observed (Almon and Davies, 1981; Schulz-Rojahn and Phillips, 1989).

Kapel (1972) and Williams (1995) recognised three facies assemblages within the Patchawarra Trough, where the formation reaches its maximum thickness. Kapel's lowest assemblage consists of carbonaceous siltstone, with minor sandstone and thin coal seams. The middle assemblage is dominated by sandstone, with grey-black shale interbeds and thick coal seams. The top of the thickest (up to 30 m) and most laterally extensive coal corresponds to the Vc seismic horizon; Hunt and Smyth (1986) informally named this the Malabine Coal. The upper assemblage consists of siltstone and shale with minor sandstone interbeds. Apak *et al.* (1993) subdivided the formation into five chronostratigraphic units, however correlation of these units over the entire region is difficult owing to a lack of detailed, published palynological data. A typical intersection is shown in Figure 6.19.

Locally a sandy facies, consisting of planar cross-bedded sandstone with carbonaceous siltstone interbeds and conglomerates (a Tirrawarra Sandstone-like lithofacies) has developed in the basal Patchawarra Formation. In the Sturt, Big Lake and Gidgealpa Fields a basal Patchawarra conglomerate consisting of reworked Warburton Basin volcanics occurs (Fig. 6.17). Wireline logs from widely separated wells (Fig. 6.20) illustrate variations in facies and thickness.

Coal, mudrock and sandstone isolith maps (Fig. 6.21) provide a general picture of Patchawarra Formation source and reservoir distribution. Isolith maps have been compiled from simple log analysis of 400 Cooper Basin wells for key formations (McLean and Hill, in prep.). Mudrock was defined from the gamma ray (GR) log where  $GR \geq 100$  API units and coal from the sonic log (DT), where  $DT \geq 120$   $\mu\text{sec}/\text{ft}$ . The remaining intervals were assigned to sandstone. No allowance has been made for other lithologies (e.g. 'hot sands') or drilling mud composition in the log analysis routine. Furthermore, contours were constructed as if structural ridges were absent in an attempt to simulate the geomorphology at the time of deposition. Although crude, these maps nevertheless provide reasonable regional data.

Patchawarra Formation is the thickest and most widespread Permian unit and its preserved limits generally correspond to the limits of the Cooper Basin, in South Australia (Fig. 6.21). It occurs in the southern Cooper Basin in the Tenappera and Weena Troughs but has been eroded off crests on the Gidgealpa–Merrimelia–Packsaddle–Innamincka Ridge complex and the Della–Nappacoongee, Dunoon and Murteree Ridges.

### Relationships and boundary criteria

Patchawarra Formation overlies either the Tirrawarra Sandstone or Merrimelia Formation, or has progressively overlapped Warburton Basin sediments and volcanics (Gravestock *et al.*, 1995). Although a basin-wide unconformity separating the Merrimelia and Patchawarra Formations and subdividing the Tirrawarra Sandstone has been interpreted (Seggie, 1997), the lower Patchawarra Formation locally intertongues with sandstone which is lithologically similar to the Tirrawarra Sandstone (Thornton, 1979). The example from Lepena 1 in Figure 6.20 shows that 80% of the Patchawarra Formation is composed of sandstone, with minor shale interbeds providing good palynological control (PP2.1–PP3.2). Genetically, this is a fluvial sandstone deposited in the post-glacial phase of Early Permian deposition. In the same manner that the Merrimelia Formation contains a 'Tirrawarra Sandstone facies type', so also does the Patchawarra Formation contain a 'Tirrawarra Sandstone facies type', at least locally as the Lepena 1 example shows.

Strictly, lithostratigraphic mapping codes would separate the Tirrawarra Sandstone from both the Merrimelia and Patchawarra Formations. However, a genetic or chronostratigraphic approach leads to a far greater understanding of the units in question, especially when seismic interpretation (a chronostratigraphic approach) is most heavily relied upon for mapping.

In this work, Tirrawarra Sandstone (*sensu stricto*) is regarded as genetically inseparable from the Merrimelia Formation, and 'Tirrawarra Sandstone-like' intervals of the post-glacial epoch (nominally PP2.1 and younger) are regarded as genetically inseparable from the Patchawarra Formation. The isopachs included in this book (Figs 5.2 and 6.21) reflect these two associations.

Patchawarra Formation is usually overlain by the Murteree Shale, however towards the edge of the Cooper Basin where intervening units were removed by erosion at the end of the Early Permian, it is overlain by Toolachee Formation or by Eromanga Basin sediments (Poolowanna Formation and Hutton Sandstone).

Two localised internal breaks occur within the Patchawarra Formation in the PP2.1 (lower Patchawarra unconformity) and PP2.2 subzones (mid-Patchawarra unconformity; Apak *et al.*, 1995). The biostratigraphic basis for these breaks has not yet been published.

### Thickness

The Patchawarra Formation is the thickest formation of the Gidgealpa Group, ranging up to 680 m thick in the Nappamerri Trough (Fig. 6.21).

### Age

Early Permian (Asselian to Artinskian), PP2 to PP3 palynozones of Price *et al.* (1985).

### Sedimentology and palaeoenvironment

Upward-fining packages from sandstone to carbonaceous siltstone and coal beds are common within the Patchawarra Formation. In Sturt, Big Lake and Gidgealpa Fields, basal Patchawarra conglomerates consisting of

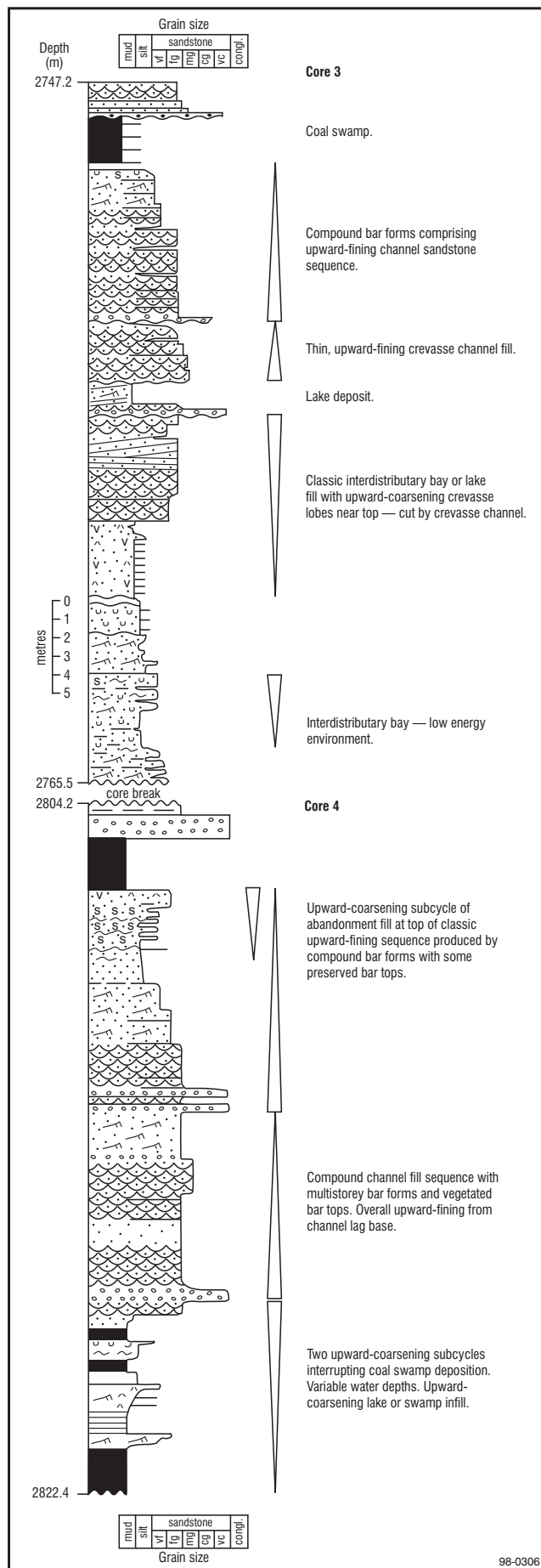


Fig. 6.19 Sedimentary facies log of the Patchawarra Formation, Fly Lake 2 (after Williams, 1995). Legend adjacent to Figure 6.9.

reworked Mooracoochie Volcanics are equivalents of Association 4 of the Tirrawarra Sandstone and are interpreted as longitudinal gravel bars (Williams and Wild, 1984). This association is interpreted to be genetically a part of the Patchawarra Formation as conglomerates at the base of relatively well ordered upward-finings packages are sometimes capped by coal seams.

Typically channel sandstone overlies a scoured base and may have a bank collapse conglomerate. Sandstone beds pass upward from trough cross-bedded, to planar and ripple cross-bedded varieties which are overlain by ripple cross-bedded and horizontally-laminated siltstone (sometimes with rootlets and pedogenically disturbed horizons) and coal seams (Stanmore and Johnstone, 1988; Williams, 1995). These upward-finings packages are interpreted as point bars, which are often stacked to form compound bars with internal scours (e.g. Williams, 1995). Devine and Gatehouse (1977) mapped north-south oriented sandstone channels >20 km long and ~5 km wide in the Toolachee Field.

Upward-coarsening packages comprise thin coal stringers and carbonaceous siltstone with wave ripples and bioturbation, grading upward into thin current-ripple cross-bedded sandstones. These upward-coarsening packages are interpreted as crevasse splay deposits (Williams, 1995). Floodplain deposits include pedogenic horizons, lacustrine deposits, extensive elevated peat swamps and distal crevasse splays.

Thick and extensive coal seams in the Patchawarra Formation have been traditionally interpreted as low-lying swamp deposits, however alternatively coals may have been deposited in high-latitude blanket raised swamps. This interpretation may apply to the thick coals mapped in the Patchawarra Trough by Stanmore and Johnstone (1988). Raised swamps may also have formed adjacent to the Birdsville Track Ridge and elsewhere in the Cooper Basin. Peat swamps would have been resistant to fluvial erosion and would have been elevated above all but major flood levels. The peat swamps in the Patchawarra Formation may have controlled fluvial architecture by restricting avulsion and overbank flooding (McCabe, 1984).

Palaeogeography during Patchawarra Formation deposition is interpreted to have been dominated by high-sinuosity fluvial systems flowing northward over a floodplain with peat swamps, lakes and gentle uplands (Stuart, 1976; Battersby, 1976; Thornton, 1979; Stanmore and Johnstone, 1988). Dipmeter data from Welcome Lake 1 and Kanowana 1 show northerly-directed palaeocurrents (Stanmore and Johnstone, 1988). Localised proximal braidplain and meanderbelt deposits occur at the base of the Patchawarra Formation in the Moorari-Woolkina area (Seggie, 1997).

The upper part of the formation reflects inundation of the Patchawarra floodplain environment from the east as a broad lake transgressed the region. Deltaic, lagoonal and lacustrine environments developed as precursors to Murteree-Epsilon-Roseneath deposition (Stuart, 1976; Gravestock *et al.*, 1995).

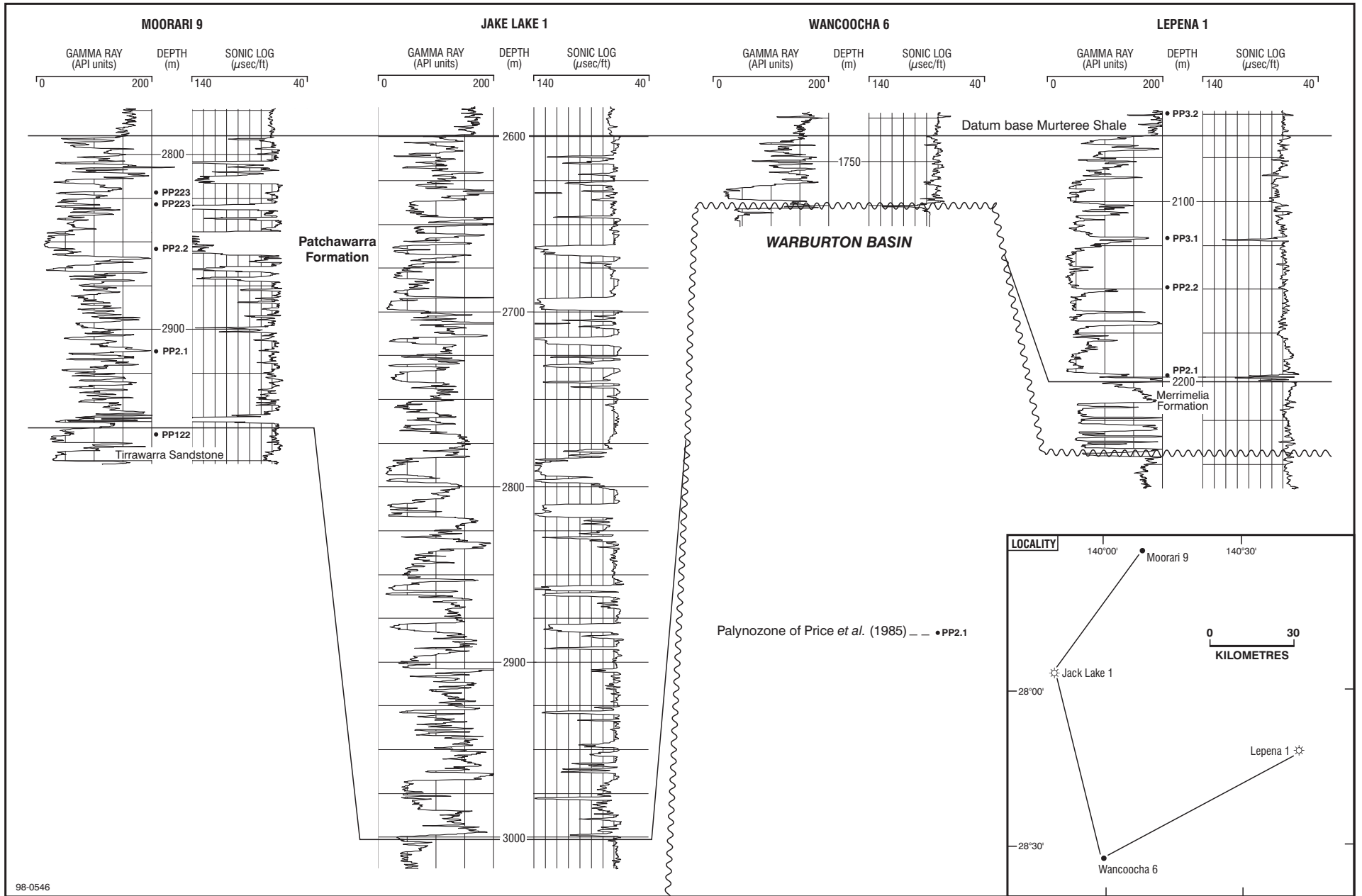
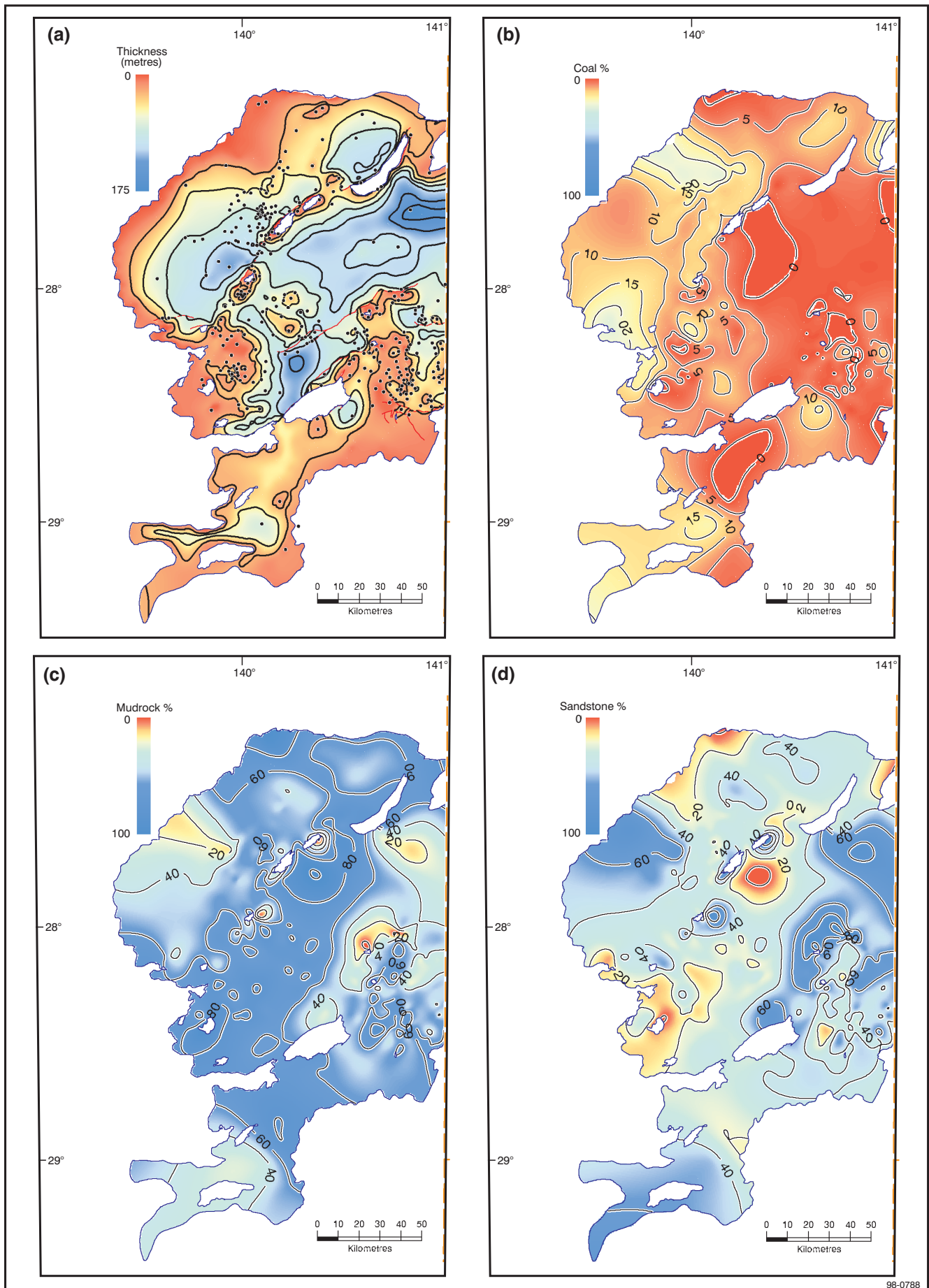
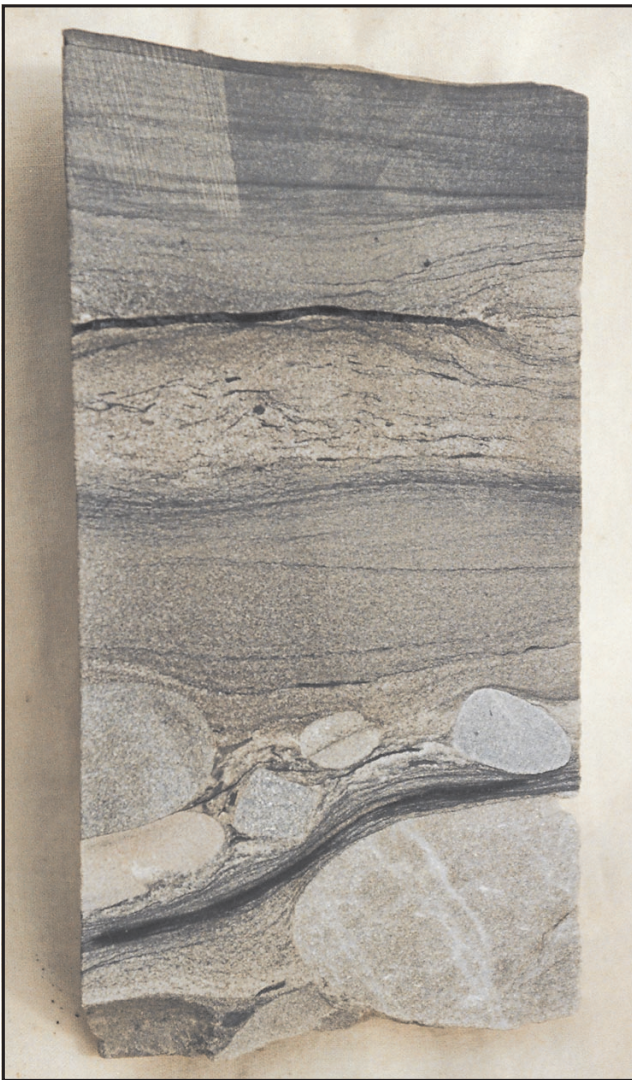


Fig. 6.20 Wireline logs illustrating variation in thickness and lithology of the Patchawarra Formation (Associations 3 and 4), Moorari 9 to Lepena 1.



98-0788

Fig. 6.21 Isolith maps of the Patchawarra Formation: (a) isopach and well data points, (b) coal percentage, (c) mudrock percentage, (d) sandstone percentage.



Basal conglomerate consisting of exotic quartzite clasts in the Patchawarra Formation, Fly Lake 1, 2714.0–2714.2 m. (Photo 45939)

## Murteree Shale

### Definition and nomenclature

Murteree Shale was defined by Gatehouse (1972) as the series of shales overlain by Epsilon Formation and underlain by Patchawarra Formation. The name was derived from Lake Murteree on Strzelecki Creek. Murteree Shale was originally included as one of three units in the 'Moomba Formation' by Kapel (1972); Gatehouse (1972) raised it to formation status.

### Type section

The type section is 1922.9–1970.8 m in Murteree 1 (latitude 28°23'48.3"S, longitude 140°34'15.3"E; Gatehouse, 1972).

### Lithology and distribution

Murteree Shale consists of black to dark grey-brown argillaceous siltstone and fine-grained sandstone. It becomes sandier in the southern Cooper Basin. Fine-grained pyrite and muscovite are characteristic and carbonaceous siltstone occurs.



Climbing ripples in the Patchawarra Formation, Fly Lake 2, 2763 m. (Photo 45943)

Murteree Shale is widespread within the Cooper Basin in both South Australia and Queensland, but has been eroded from structural highs such as the Murteree and Dunoon Ridges and from crestal areas of other ridges.

### Relationships and boundary criteria

Murteree Shale conformably overlies and intertongues with the upper Patchawarra Formation and is conformably overlain by Epsilon Formation. Where Epsilon Formation, Roseneath Shale and Daralingie Formation were eroded at the end of the Early Permian, Murteree Shale is unconformably overlain by the Toolachee Formation. Where conformable, the top of the Murteree Shale is picked on wireline logs where the gamma ray log drops below the shale baseline into the Epsilon Formation.

### Thickness

Murteree Shale is relatively uniform in thickness, averaging ~50 m. It reaches a maximum thickness of 80 m in the Nappamerri Trough.

### Age

Early Permian (Artinskian), PP3 palynozone of Price *et al.* (1985).

### Sedimentology and palaeoenvironment

Murteree Shale is composed of horizontally-laminated siltstone, with minor linsen bedding, rare wave ripples and



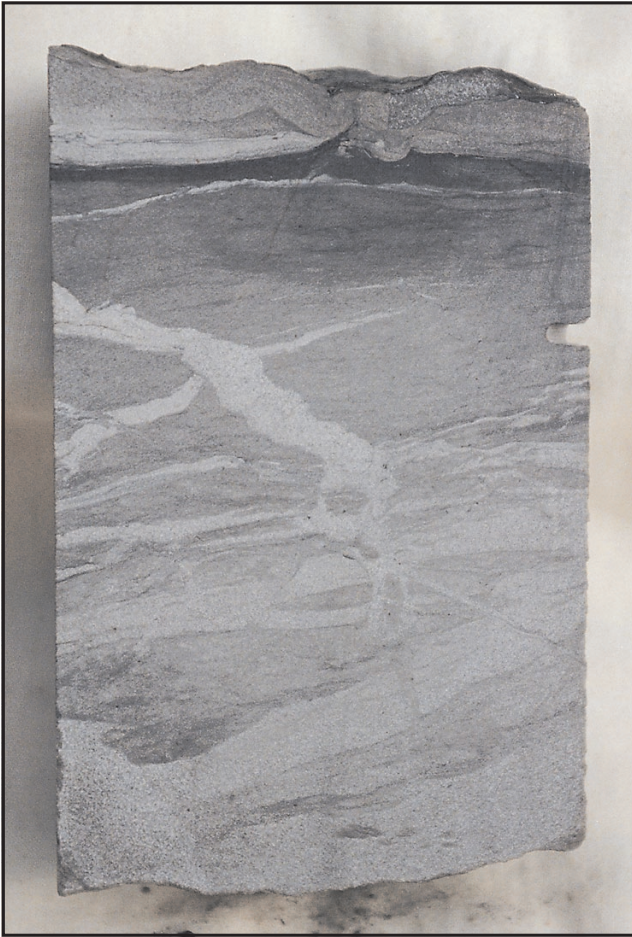
Compound bar form with internal scours and basal lags in the Patchawarra Formation, Kujani 2, 2046–2054 m. (Photo 46500)

wavy bedding and occasional turbidites and rhythmites (Williams, 1995). Slump folds and microfaults occur, indicating slope instability or possibly, seismic activity (Gravestock and Morton, 1984). Bioturbation and destratification of some beds has occurred. Dropstones are locally abundant — these are either related to ice or vegetation rafting.

Lack of marine microplankton and invertebrate fossils (e.g. foraminifera, brachiopods, bivalves) and evidence that rare glauconite pellets are reworked from the underlying Warburton Basin led Gravestock *et al.* (1995) to conclude that the Murteree Shale was deposited in a broad, fresh water lake. This is in contrast to previous interpretations of an

open basin with access to the sea in the east (Stuart, 1976) or a restricted sea with access to open sea from the south (Thornton, 1979) for both the Murteree and Roseneath Shales.

A relatively deep lake environment is interpreted, as wave ripples and other evidence of storm reworking is rare. A broad lake would have significant fetch and frequent high latitude (60–70°S) storms could be expected. Williams (1995) has interpreted lake shoreface (beach–barrier), lake delta slope and prodelta environments in core. Rhythmites are deposited by episodic gravity flows, which may be related to seasonal influences, such as spring thaws in the hinterland.



*Water escape structures in the Patchawarra Formation, Fly Lake 2, 2806.5 m. (Photo 45942)*



*Carbonaceous fragments in a fine to medium-grained sandstone in the Patchawarra Formation, Fly Lake 4, 2709 m. (Photo 45940)*

## Epsilon Formation

### *Definition and nomenclature*

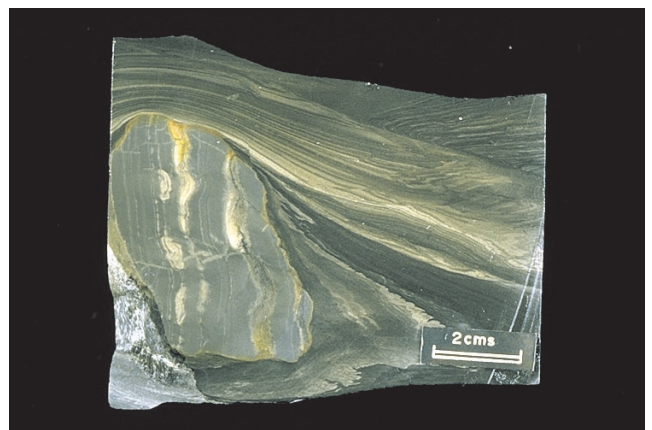
Epsilon Formation was defined by Gatehouse (1972) as the series of sandstones, shales and minor coals overlain by Roseneath Formation and underlain by Murteree Shale. The name was derived from Epsilon Parish in Carruthers County, South-West Queensland. Epsilon Formation was originally included as one of three mappable units in the ‘Moomba Formation’ by Kapel (1972), however Gatehouse (1972) raised it to formation status.

### *Type section*

The type section is 2095.2–2136.9 m in Epsilon 1, Queensland (latitude 28°8’48”S, longitude 141°9’11”E; Gatehouse, 1972).

### *Lithology and distribution*

Epsilon Formation consists of thinly bedded, fine to medium-grained, moderately to very well sorted, quartzose sandstone with dark grey-brown carbonaceous siltstone and shale, and thin to occasionally thick (<2–20 m) coal seams. Sandstone consists of monocrystalline quartz with minor chert, sedimentary rock fragments and polycrystalline quartz. Authigenic minerals include quartz, kaolinite (dickite) and siderite and dolomite (Taylor *et al.*, 1991).



*Dropstone in Murteree–Epsilon transition, Wancoocha 1, 1776.6 m. (Photo 46501)*

Fairburn (1992) described three major depositional stages — a lower stage which consists of a sandy upward-coarsening cycle capped by shale and coal, a coal-dominated middle stage and an upper stage consisting of upward-coarsening sandstone. A core log of the Murteree Shale – Epsilon Formation transition is shown in Figure 6.22. Wireline log signatures characteristic of the Epsilon Formation are shown in Figure 6.23.

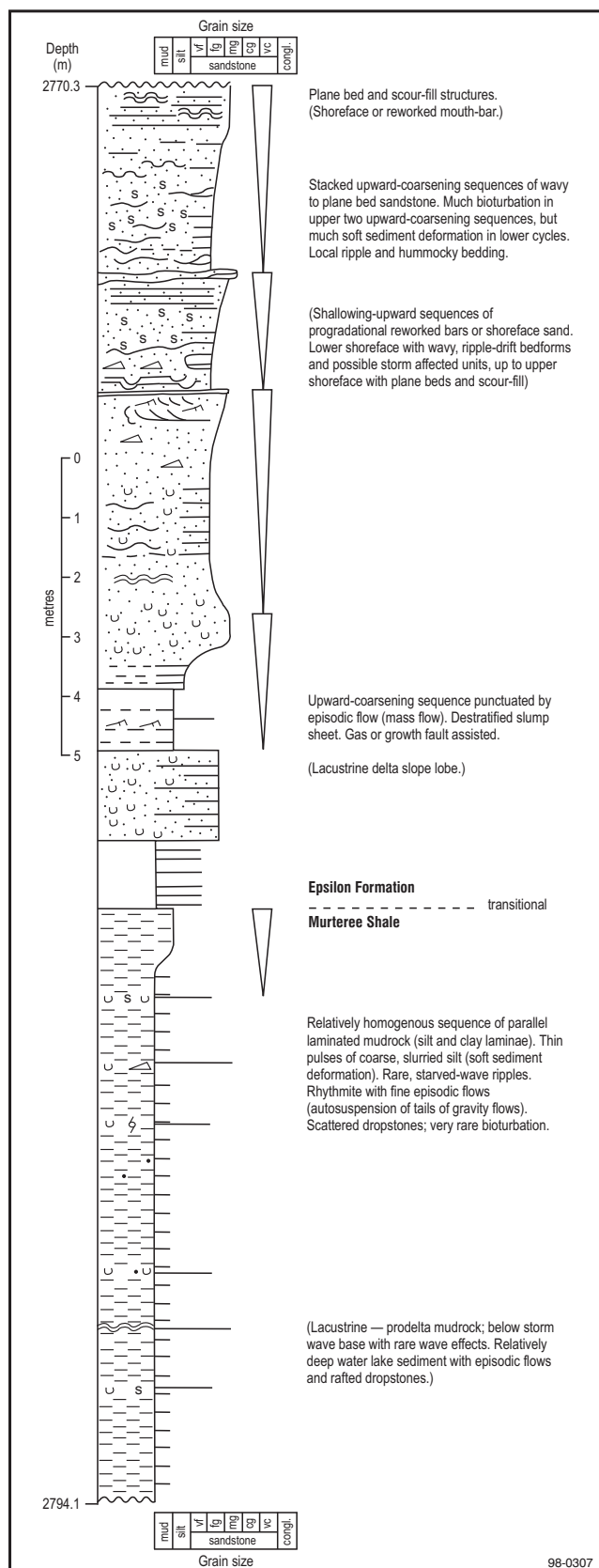


Fig. 6.22 Sedimentary facies log of the Murteree Shale – Epsilon Formation transition, Mudrangie 1 (after Williams, 1995). Legend adjacent to Figure 6.9.

‘Glaucinitic illite’ described in the 79-4 sand by Taylor *et al.* (1991) was interpreted by Gravestock *et al.* (1995) as being reworked from the Pando Formation (exposed at that

time to the southwest of Moomba) rather than providing evidence for marine influence.

Epsilon Formation is widespread across the Cooper Basin and occurs from the Tenappera Trough in the south to the Patchawarra Trough in the north. It was eroded from the Dunoon and Murteree Ridges and crestal areas of other ridges during late Early Permian uplift. Coal and sandstone isolith maps (Fig. 6.24) illustrate regional variations in Epsilon Formation composition.

### Relationships and boundary criteria

Epsilon Formation intertongues with and is conformably overlain by Roseneath Shale and conformably overlies Murteree Shale. Where Roseneath Shale and Daralingie Formation have been eroded, Epsilon Formation is unconformably overlain by Toolachee Formation.

### Thickness

Epsilon Formation reaches a maximum thickness of 156 m in the Nappamerri Trough.

### Age

Early Permian (Artinskian to Kungurian), PP3 palynozone of Price *et al.* (1985).

### Sedimentology and palaeoenvironment

Both Thornton (1979) and Stuart (1976) recognised the influence of regional transgressions and regressions on deposition of the Murteree–Epsilon–Roseneath package and proposed an open basin setting with restricted access to the sea. During deposition of the Epsilon Formation, deltas prograded westward as the lake or sea retreated to the east. The upper Epsilon Formation reflects a transgression from the east which peaked during deposition of the overlying Roseneath Shale. Thornton (1979, fig. 39) also postulated that the eastern Cooper region in Queensland was last to be subaerially exposed as Epsilon deltaic facies prograded eastward and was the first region to be transgressed as Roseneath lacustrine–marine facies developed westward.

Morton (1983, fig. 40) mapped sandstone reservoirs within the Epsilon Formation in Toolachee Field, and interpreted prograding barrier-bar, delta mouth-bar and shoreface sands from log signatures and core in the area. Log signatures characteristic of shoreline sandstone facies occur in a crude belt around the margin of the ‘Murteree Lake’ (Fig. 6.23). Fairburn (1992) divided Epsilon Formation in the southern Cooper Basin into three broad depositional stages — a lower unit interpreted as a lake shoreline facies, a deltaic middle unit and a second lake shoreline upper unit. Fairburn used regional coal markers to further subdivide the formation into subunits (S1 to S6). The lower and upper depositional stages are related to regressions at the Murteree and Roseneath Shale contacts respectively (Stuart, 1976; Fairburn, 1992). In the middle Epsilon Formation stillstands produced strandline deposits around the lake margin and fluviodeltaic facies prograded into the lake during regressions.

The lower depositional stage (S1, Fig. 6.22) is a relatively thin upward-coarsening package of siltstone grading upward into ripple and planar bedded or slumped sandstone (Fairburn, 1992). It is interpreted as a lacustrine

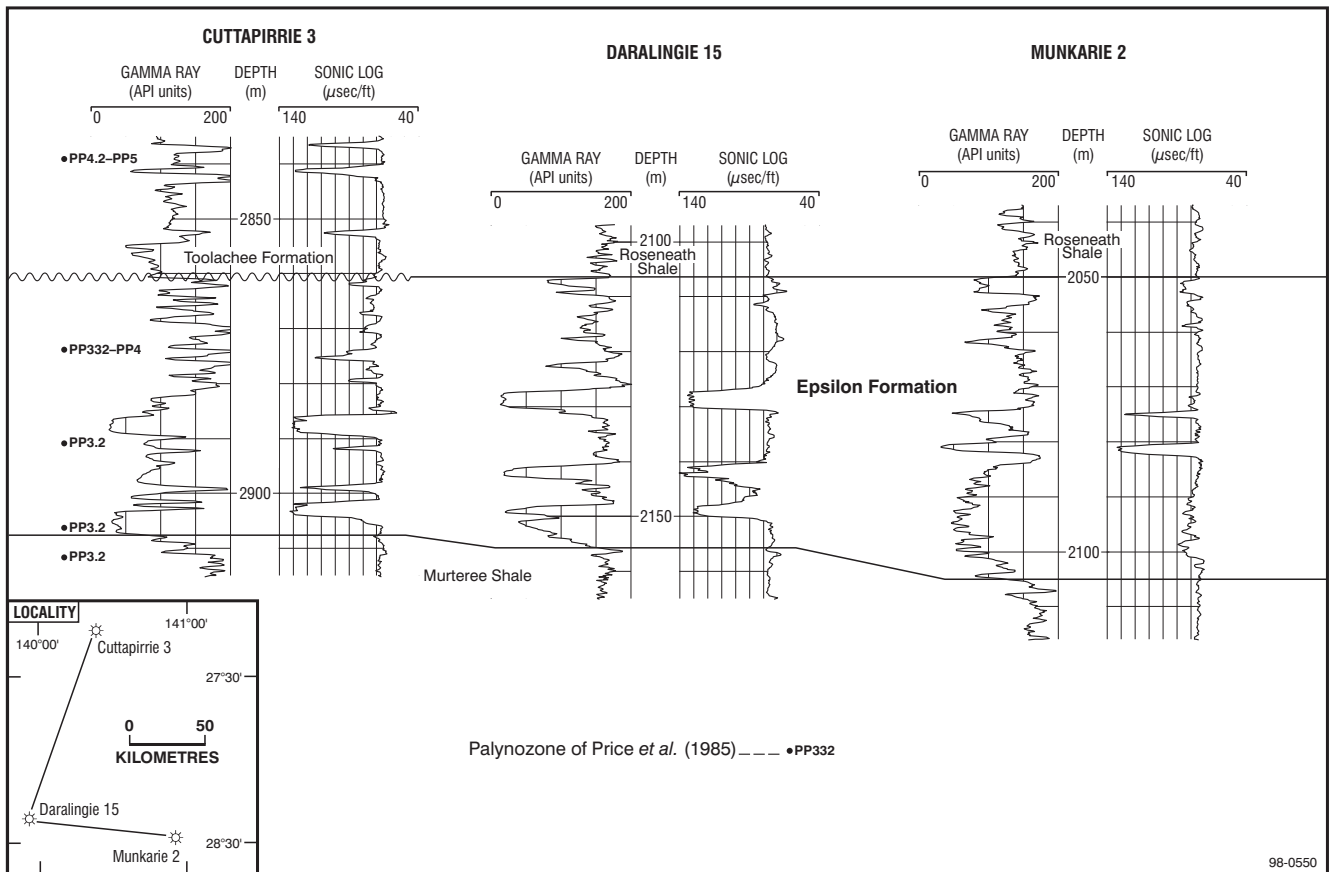


Fig. 6.23 Wireline log correlation of the Epsilon Formation, Cuttairrie 3 to Munkarie 2.

delta fill and delta slope sequence with development of beach, beach barrier and shoreline deposits (Williams, 1995) which form sandstone sheets and strandlines parallel to the shoreline of ‘Murteree Lake’.

The middle depositional stage (S2, S3 and S4) is a thicker, more coaly package with ribbon sandstones up to 12 m thick and at least 2 km long (Fairburn, 1992, fig. 20). Sandstone ribbons are interpreted as distributary channels developed on a prograding delta plain and are oriented perpendicular to the lake shoreface. Crevasse splay and backswamp facies also occur (Williams, 1995). Raised peat swamps are interpreted in the northern Patchawarra Trough (see also Ch. 10).

The upper depositional stage (S5 and S6) consists of upward-coarsening sandstones with plane to low-angle beds, rare trough cross-lamination, ripples and destratified beds (Fairburn, 1992). Bioturbation and soft sediment deformation disrupt bedding. The S5 and S6 sandstones correspond to Taylor *et al.*'s (1991) 79-4 and 79-0 sands in Moomba and Big Lake Fields. These sandstones range up to 6 m near Moomba and Big Lake, where stacked upward-coarsening, internally scoured sandstone and flat bedded to massive sandstone with escape burrows occur (Fairburn, 1992). These sandstones are interpreted as lacustrine or back barrier lagoonal facies modified by fluvial events which produced crevasse splays and washovers (Fairburn, 1992).

## Roseneath Shale

### Definition and nomenclature

Roseneath Shale was defined by Gatehouse (1972) as the shales and minor siltstones that are overlain conformably by ‘Daralingie beds’ or unconformably by Toolachee Formation and which conformably overlie Epsilon Formation. The name was derived from Roseneath Parish in Carruthers County, South-West Queensland. Roseneath Shale was originally included as one of three units in the ‘Moomba Formation’ by Kapel (1972); Gatehouse (1972) raised it to formation status.

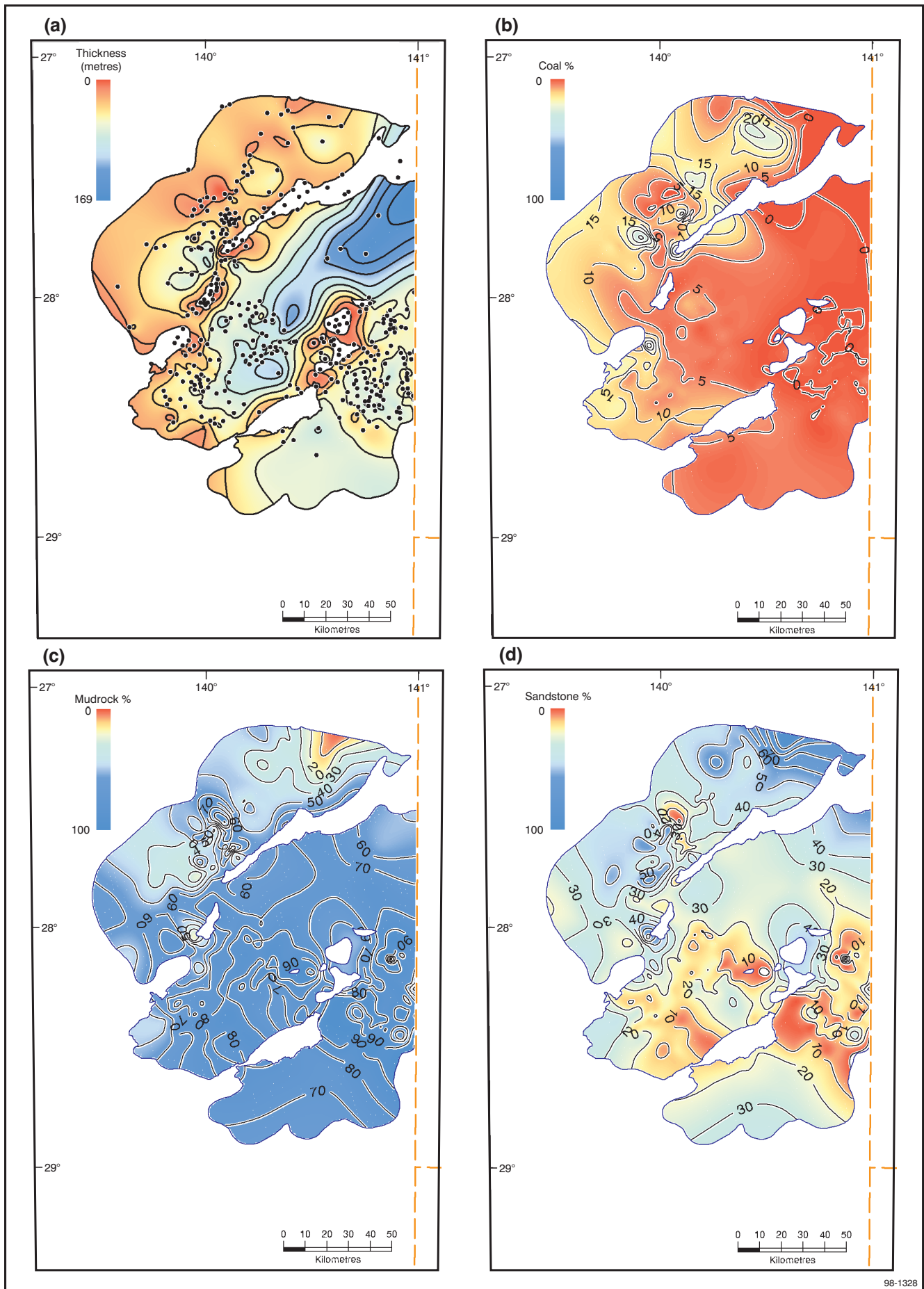
### Type section

The type section is 1956.8–2024.5 m in Roseneath 1, Queensland (latitude 28°10’10”S, longitude 141°14’E; Gatehouse, 1972).

### Lithology and distribution

The Roseneath Shale comprises light to dark brown-grey or olive-grey siltstone, mudstone and minor sandstone. Siltstones are micromicaceous with minor fine-grained pyrite. Sandstone interbeds are pale brown and fine grained.

Roseneath Shale occurs across the central Cooper region but was eroded from the Dunoon and Murteree Ridges and crestal areas of other ridges during late Early Permian uplift. The Roseneath Shale is not as extensive as the Murteree Shale.



98-1328

Fig. 6.24 Isolith maps of the Epsilon Formation: (a) isopach and well data points, (b) coal percentage, (c) mudrock percentage, (d) sandstone percentage.

**Relationships and boundary criteria**

Roseneath Shale conformably overlies and intertongues with Epsilon Formation. It is overlain by and intertongues with Daralingie Formation. Where Daralingie Formation has been eroded, Roseneath Shale is overlain by Toolachee Formation.

**Thickness**

Roseneath Shale reaches a maximum thickness of 100 m in Strathmount 1 and thickens into the Nappamerri and Tenappera Troughs.

**Age**

Early Permian (Kungurian), PP3 to PP4 palynozones of Price *et al.* (1985).

**Sedimentology and palaeoenvironment**

Roseneath Shale siltstones vary from massive to finely laminated, with minor wavy lamination and wave ripples suggesting possible storm reworking. Load marks, flame structures and slump folds indicate mass flows and slope instability. A lacustrine environment of deposition, similar to that of the Murteree Shale, is interpreted for the Roseneath Shale (Stuart, 1976; Thornton, 1979).

**Daralingie Formation**

**Definition and nomenclature**

A series of sandstones, shales and minor coals conformably above the Roseneath Shale and disconformably below the Toolachee Formation was named by Gatehouse (1972) as 'Daralingie beds'. The name was derived from Daralingie Waterhole on Strzelecki Creek. Morton and Gatehouse (1985) raised it to formation status.

**Type section**

The type section is 1963–1989 m in Daralingie 1 (latitude 28°21'40.52"S, longitude 139°58'19.64"E; Morton and Gatehouse, 1985).

**Lithology and distribution**

Daralingie Formation is dominated by light grey to black carbonaceous and micaceous siltstone and mudstone with interbedded light grey to brown fine to very fine-grained sandstone. Minor coal seams and carbonaceous partings and streaks occur. A core log of part of the Roseneath Shale – Daralingie Formation transition is shown in Figure 6.25. Coal and sandstone isoliths (Fig. 6.26) illustrate regional variation of the formation.

Daralingie Formation is restricted to the Cooper Basin area south of the GMI Ridge. Uplift at the end of the Early Permian caused erosion of the Daralingie Formation and underlying units off the crests and flanks of structural highs including the Murteree, Dunoon and other ridges.

**Relationships and boundary criteria**

The base of the formation is transitional from the underlying Roseneath Shale. Morton and Gatehouse (1985) defined it as the first coal or sandstone bed above the Roseneath Shale of Early Permian age. The top of the formation is a disconformity and may be located on wireline logs between upward-coarsening

cycles in the Daralingie Formation and upward-fining cycles in the overlying Toolachee Formation (Boucher, 1997b).

**Thickness**

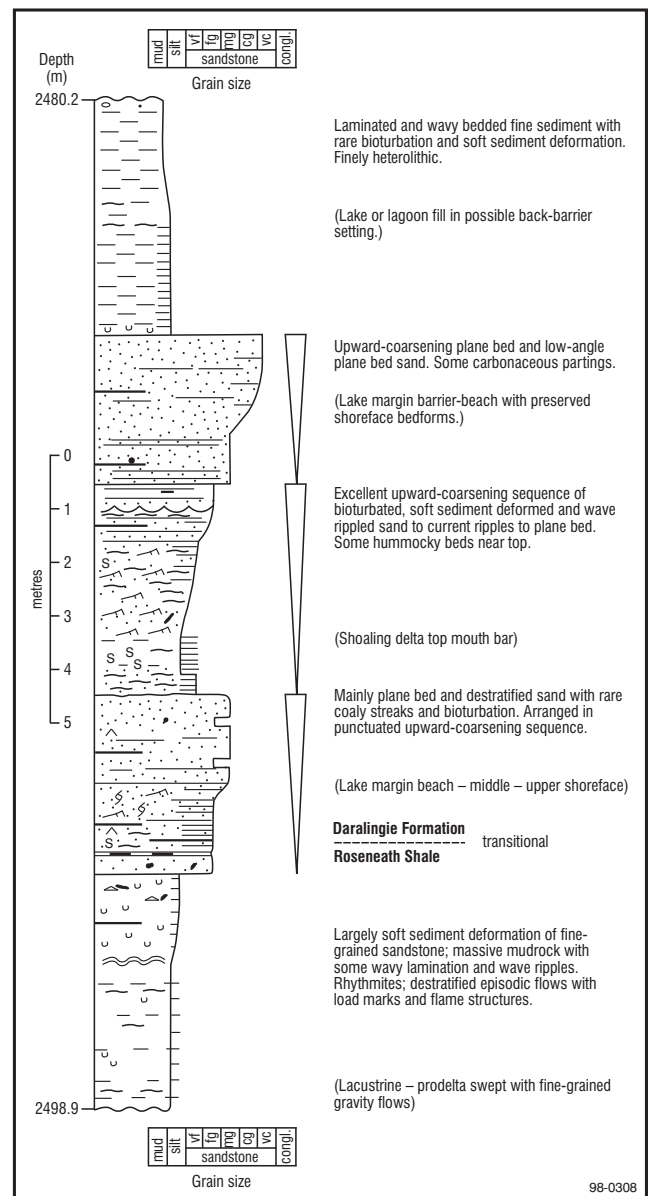
Daralingie Formation reaches a maximum thickness of >100 m in the Nappamerri Trough. An isopach from the base of the Murteree Shale (top of Patchawarra Formation) to the top of the Daralingie Formation (Daralingie unconformity) is shown in Figure 6.27.

**Age**

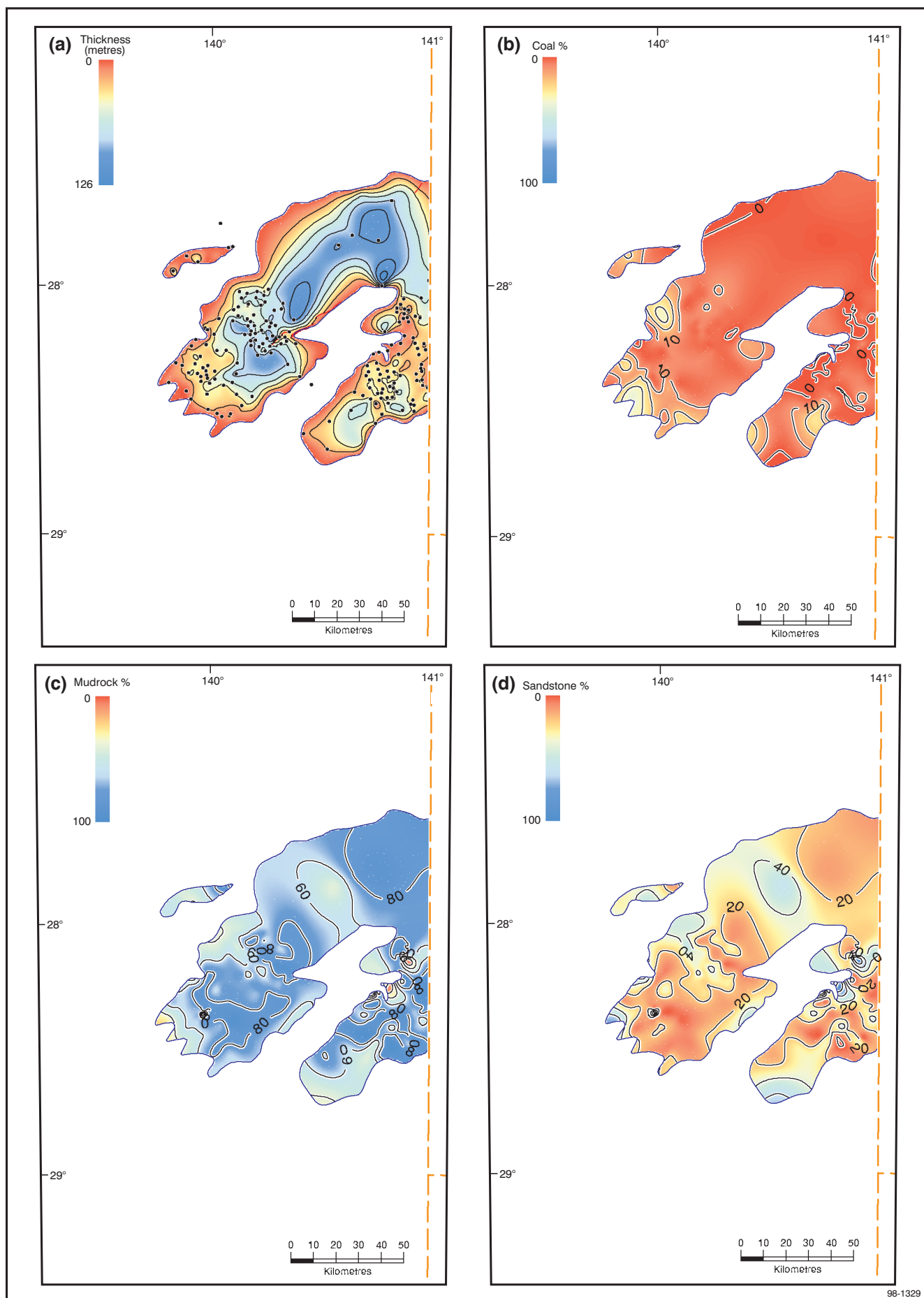
Early Permian (Kungurian to Ufimian), PP4 palynozone of Price *et al.* (1985).

**Sedimentology and palaeoenvironment**

Wave ripples, low-angle planar cross-bedding, wavy bedding, planar bedding and minor hummocky cross-bedding occur in sandstones (Williams, 1995). Siltstones and mudstones are laminated and wavy bedded.



**Fig. 6.25** Sedimentary facies log of the Roseneath Shale – Daralingie Formation transition, Moomba 45 (after Williams, 1995). Legend adjacent to Figure 6.9.



98-1329

Fig. 6.26 Isolith maps of the Daralingie Formation: (a) isopach and well data points, (b) coal percentage, (c) mudrock percentage, (d) sandstone percentage.

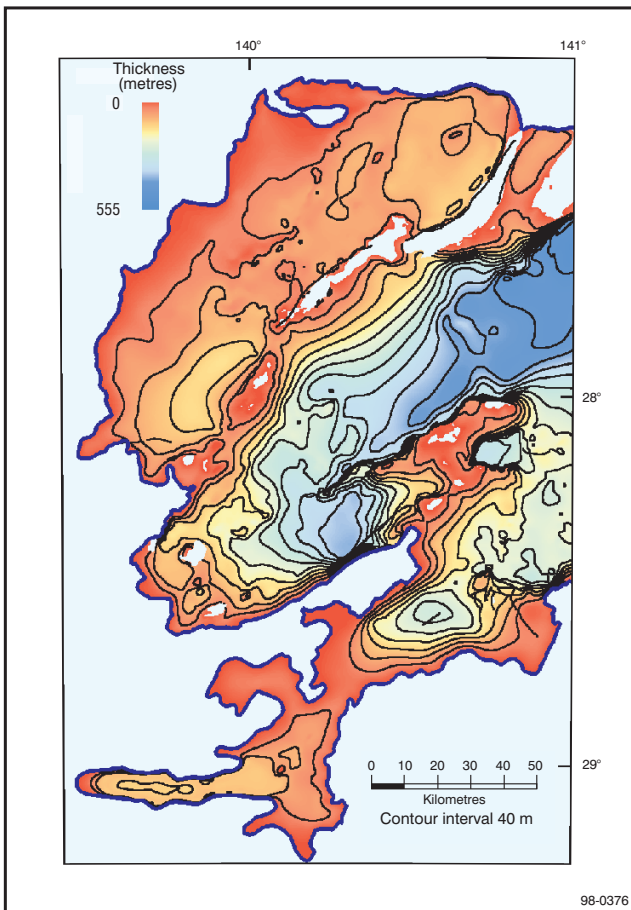


Fig. 6.27 Isopach map from top Patchawarra Formation to Daralingie unconformity (V–R seismic horizons).

Stacked upward-coarsening sand packages are common in the lower part of the formation and have been interpreted as delta front bars and lake margin beach and shoreface deposits in Moomba Field by Williams (1995). Bioturbation is also common in the lower part of the unit, which is transitional from the fully lacustrine facies of the Roseneath Shale. High-sinuosity fluvial channel, backswamp and marsh environments are interpreted for the middle and upper parts of the Daralingie Formation, with crevasse splay sandstones and coal seams.

Like the Epsilon Formation, Daralingie Formation was deposited by northeasterly prograding delta systems which developed during regression of the ‘Roseneath Lake’ (Stuart, 1976; Thornton, 1979, fig. 48).

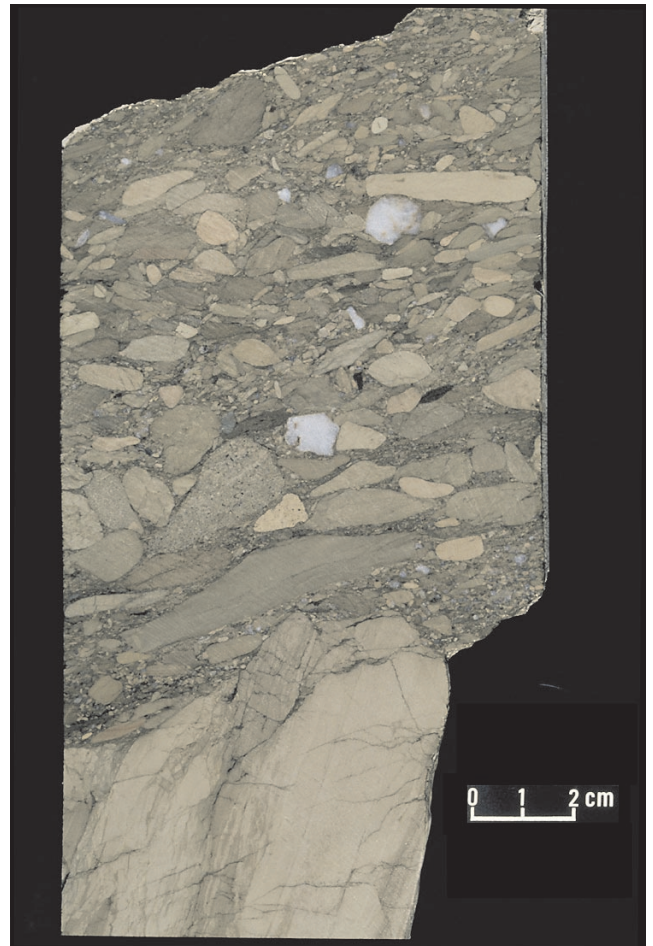
## Toolachee Formation

### Definition and nomenclature

Toolachee Formation was named by Kapel (1972) and defined by Gatehouse (1972). Morton and Gatehouse (1985) redefined the formation to exclude that part of the Daralingie Formation originally included but not recognised in the type section.

### Type section

The type section has been redefined by Morton and Gatehouse (1985) as 1792–1897 m in Toolachee 1 (latitude 28°25′59.37″S, longitude 140°46′39.83″E).



Basal conglomerate of Toolachee Formation resting unconformably on steeply dipping Dullingari Group, Della 5A, core 3, 1952.9 m. (Photo 42580)

### Lithology and distribution

Toolachee Formation consists of interbedded buff to white, fine to coarse-grained sandstone, dark grey siltstone and dark grey to black carbonaceous shale, sometimes sideritic with thin coal seams (<3 m thick), and conglomerates. Sandstone is quartzose (dominated by monocrystalline quartz), almost devoid of feldspar with minor mica and rock fragments (metamorphics and intraclasts), and traces of zircon and tourmaline (Martin, 1980; Martin and Hamilton, 1981). Authigenic quartz overgrowths, kaolinite (dickite), illite and patchy carbonate cement (mainly siderite with minor calcite) occur (Martin, 1980; Martin and Hamilton, 1981; Schulz-Rojahn and Phillips, 1989).

Basal conglomerates occur adjacent to structural ridges and may contain clasts of reworked Warburton Basin rocks. Channel lag conglomerates contain pebbles and cobble-sized quartz as well as mudstone and siderite cemented mudstone intraclasts. Abundant glossopterid leaves are well preserved on bedding planes in laminated siltstone, and laterally continuous (field-scale) coal seams are common. A core log of part of the formation in Moomba 10 is shown in Figure 6.28 and the corresponding wireline log characteristics in Figure 6.29. Coal and sandstone isoliths (Fig. 6.30) show regional variation of the formation.

The Toolachee Formation is widespread across the Cooper Basin, but has been eroded off crests of the Murteree

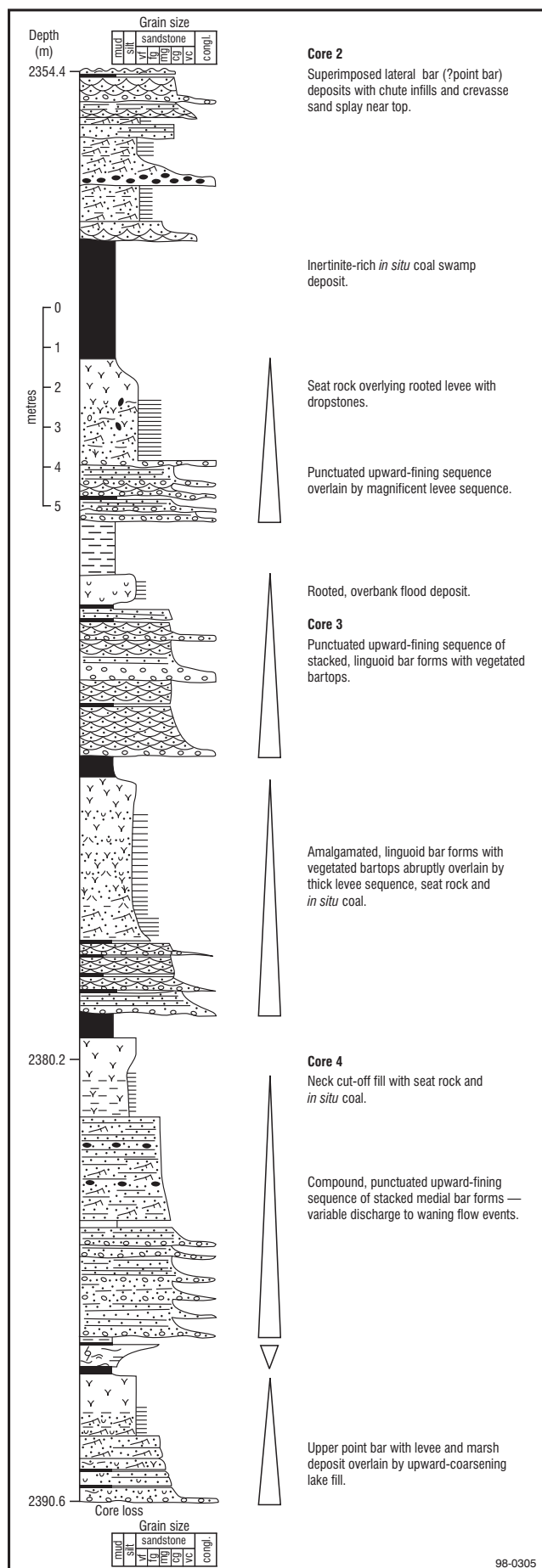


Fig. 6.28 Sedimentary facies log of the Toolachee Formation, Moomba 10 (after Williams, 1995). Legend adjacent to Figure 6.9.

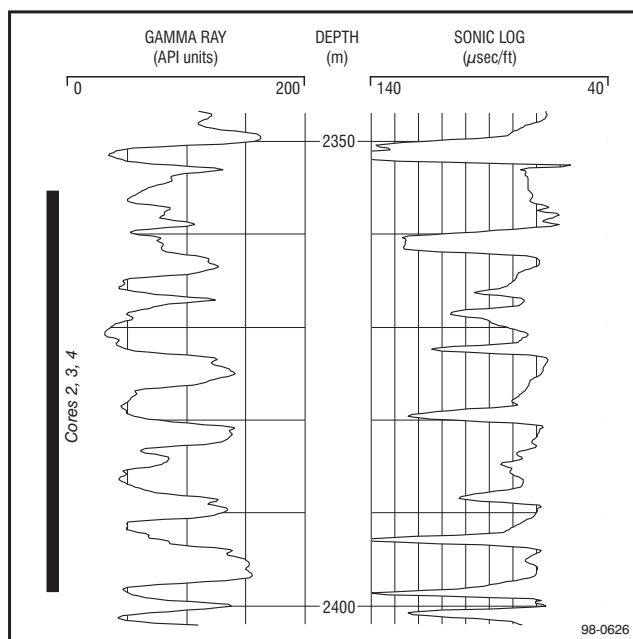


Fig. 6.29 Wireline log of the Toolachee Formation, Moomba 10.

and Dunoon Ridges. It is also absent in the southern Tenappera Trough due to Late Triassic uplift.

#### Relationships and boundary criteria

Toolachee Formation disconformably overlies Daralingie Formation and unconformably overlies older rocks including the Warburton Basin on ridges (e.g. Della 5A, Gravestock and Morton, 1984, fig. 18a). It is the uppermost unit of the Gidgealpa Group and is overlain conformably but slightly diachronously by Arrabury Formation or unconformably by Eromanga Basin sediments.

Gatehouse (1972) defined the top of the formation as the contact between the organic-rich lithologies of the Toolachee Formation, and the organic-poor lithologies of the Nappamerri Formation. However, in practice on logs (e.g. Youngs and Boothby, 1985) and especially in seismic mapping, the top Toolachee Formation is taken as the top of the uppermost coal (P seismic horizon).

#### Thickness

The Toolachee Formation forms a blanket deposit over the Daralingie unconformity surface and is thickest in the Patchawarra and Nappamerri Troughs (Fig. 6.30)

#### Age

Late Permian (Kazanian to Tatarian), PP5 palynozone of Price *et al.* (1985).

#### Sedimentology and palaeoenvironment

Stuart (1976) subdivided the Toolachee Formation into two units, C and B. Williams (1982, 1984) recognised three facies associations within the Toolachee Formation — Association 1 (which corresponds to Unit C), Association 2 (Unit B) and Association 3 (a locally developed facies). The lower Toolachee Formation (Association 1) consists of thick (up to 6 m) upward-fining packages, with minor upward-coarsening packages and coal seams. Upward-fining packages are interpreted as point bars and consist of a basal pebble lag with a scoured base which fines up into trough cross-bedded coarser grained sandstones,

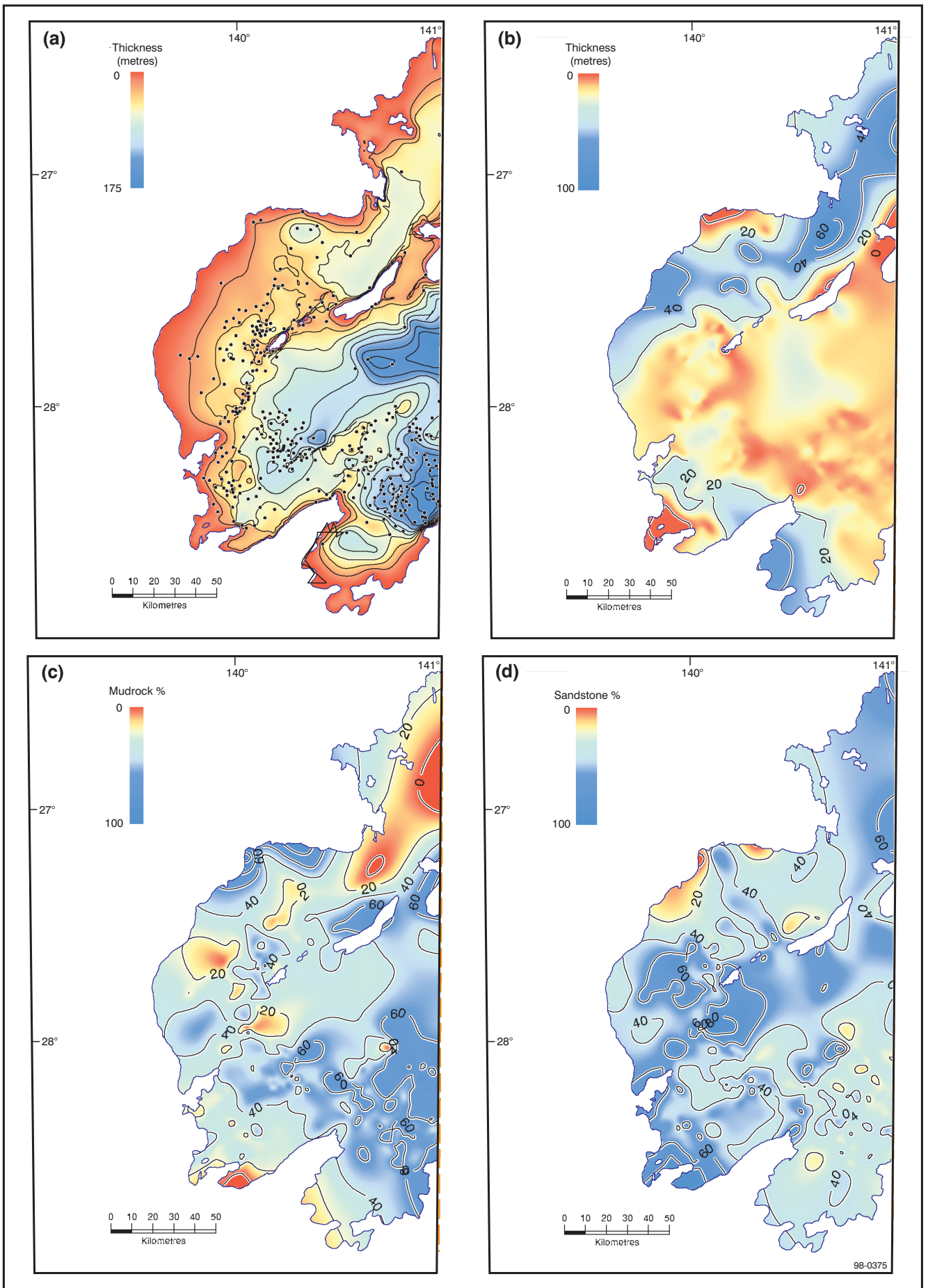


Fig. 6.30 Isolith maps of the Toolachee Formation: (a) isopach and well data points, (b) coal percentage, (c) mudrock percentage, (d) sandstone percentage.

planar and low-angle cross-bedded sandstone and fine-grained ripple cross-bedded sandstone (Williams, 1984; Fig. 6.28). These fine upward into ripple cross-bedded fine to very fine-grained sandstone and bioturbated and root mottled mudstone, deposited in ephemeral lakes and backswamps on the flood-basin. Coals formed *in situ* in swamps that were subject to flood events, as evidenced by mudstone seam splits (Mackie *et al.*, 1995). Other sandstone packages are interpreted as abandoned channels (chute and neck-cut-off) and proximal and distal crevasse splays (Mackie *et al.*, 1995). Bank collapse and basal lag conglomerates are developed locally.

Channel dimensions for Association 1 in the Moomba Field were determined by Williams (1982, 1995) and by Mackie *et al.* (1995). Both measured an average channel thickness of ~5 m from core logs. The average bank fill width was calculated as 105 m by Williams (1984), while the average channel width was calculated as 166 m by Mackie *et al.* (1995); the average meander belt width ranged from 541 m (Williams, 1984) to 1311 m (Mackie *et al.* (1995). The fluvial system flowed towards the northeast in the Moomba area (Stuart *et al.*, 1988; Mackie *et al.*, 1995) and towards the north in the Della area (Gravestock and Morton, 1984).

Association 2, in the upper Toolachee Formation is dominated by mudstone and coal seams, with multiple thin upward-coarsening packages deposited by overbank flooding and perennial flood-basin lakes (Williams, 1984). Backswamp coals and lacustrine muds are sharply overlain by crevasse splay sandstones with rooted and bioturbated tops. A high gamma ray marker bed in the Moomba–Big Lake area was described by Williams (1982) as a deep lacustrine (below storm wave-base) graded and laminated rhythmite from core.

Association 3 is locally developed (e.g. Gidgealpa Field) and consists of coarse-grained upward-fining packages, interpreted as high-sinuosity alluvial channels.

## NAPPAMERRI GROUP

### *Definition and nomenclature*

‘Nappamerri Formation’ was defined by Papalia (1969) as the Triassic sediments with ‘redbed characteristics’ conformably overlying the Gidgealpa Group (Toolachee Formation) and unconformably overlain by the Eromanga Basin (Poolowanna Formation and Hutton Sandstone). It is now recognised that in places, it is unconformably overlain by eroded remnants of the Late Triassic Cuddapan Formation (Powis, 1989). Papalia (1969) delineated four informal rock units in the ‘Nappamerri Formation’ and assigned the type section to Mount Howitt 1 in Queensland (latitude 26°37'27"S, longitude 142°28'17"E) over the interval 1713.9–2106.8 m for members I, II and III, and to Merrimelia 3 in South Australia (latitude 27°37'28.12"S, longitude 140°21'26.18") over the interval 2170.8–2306.7 m for member IV. Extensive core was cut through the ‘Nappamerri Formation’ type section in Merrimelia 3.

Youngs and Boothby (1982, 1985) interpreted the depositional environments of four different informal lithological units within the formation and commented on the correlation difficulties between South Australian and

Queensland wells. They also nominated a new reference section for the ‘Nappamerri Formation’ in Beanbush 1 (2712–3202 m, their fig. 3) where the section is more complete compared to Papalia’s composite type section. Moore (1986) correlated the Nappamerri Formation with the Walkandi Formation of the Simpson Basin to the west and noted similarities in lithology and environment of deposition.

In 1989 Santos (South Australia) and Esso Australia (Queensland; Channon and Wood, 1989 and Powis, 1989 respectively) conducted separate reviews of Triassic stratigraphy and delineated two formations, thus elevating the ‘Nappamerri Formation’ to Group status. The Late Permian to Early Triassic Arrabury Formation and the Middle to Late Triassic Tinchoo Formation were subdivided into members in South Australia and Queensland. Channon and Wood (1989) based their subdivision on the work of Youngs and Boothby (1985). Difficulty exists in correlating members between Queensland and South Australian wells, consequently, the Channon and Wood (1989) stratigraphic framework is used in this volume.

It was initially thought that the Nappamerri Group was entirely Triassic in age based on the assumed age of the lowermost palynozone. However Foster (1982) recognised the age of this zone (*P. microcorpus*) as middle Late Permian. In general, biostratigraphic zonation of Cooper Basin Triassic sediments is problematic. As Powis (1989, p.267) states ‘The Early Triassic palynofloras of the Cooper Basin are of generally low diversity, lacking key, chronostratigraphically important index species. The palynofloras are generally very poorly preserved (if present at all) due to the oxidised nature of the host sediments and their low original organic carbon content. Only occasionally are assemblages found that can be assigned confidently to either PP6, PT1 or PT2’. The low resolution of index forms (Fig. 7.2) contrasts with the large number of Early to Middle Triassic magnetic reversals (Haq *et al.*, 1987), suggesting magnetostratigraphy as a useful correlation tool (see Ch. 7).

The Nappamerri Group is widespread and best developed in the Nappamerri and Patchawarra Troughs in South Australia, where it is >500 m thick and in the Windorah Trough in Queensland. It onlaps structural ridges except the Dunoon and Murteree Ridges and has been eroded around the margins of the Cooper Basin. An isopach of the Nappamerri Group is shown in Figure 6.31.

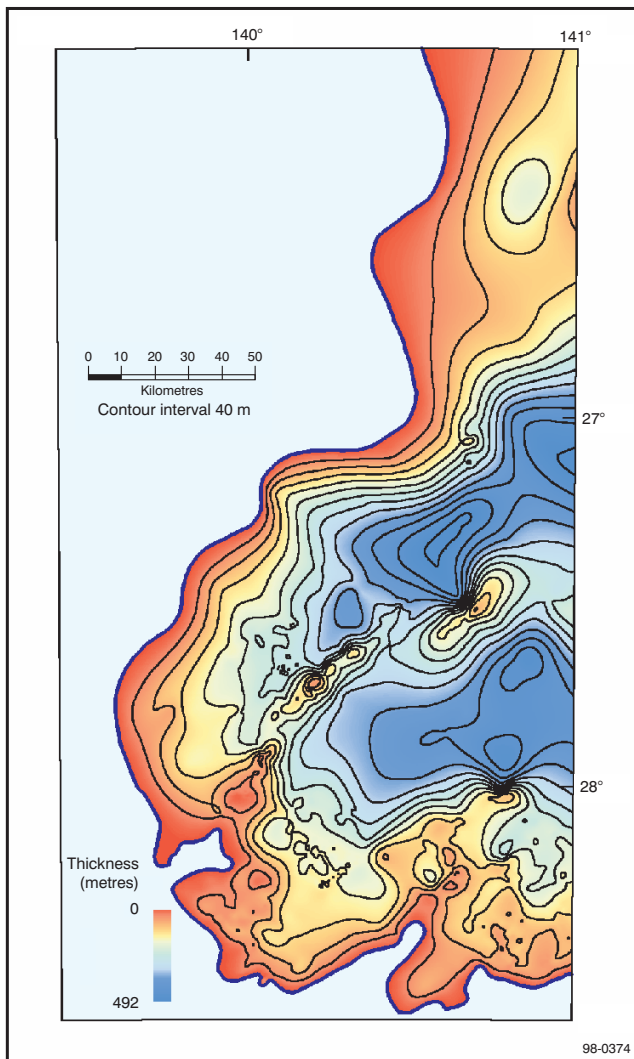
## Arrabury Formation

### *Definition and nomenclature*

Arrabury Formation was defined by Powis (1989) as the basal unit of the Nappamerri Group. In places (e.g. Patchawarra Trough) Arrabury Formation is divisible into the Callamurra, Paning and Wimma Sandstone Members which were equated with Units 1 to 3 of Youngs and Boothby (1985) by Channon and Wood (1989; Fig. 6.32).

### *Type section*

The type section was designated by Powis (1989, fig. 3) as 1917–2096 m in Mount Howitt 1 (latitude 26°37'27"S, longitude 142°28'17"E), conforming to Papalia’s (1969) member I. A reference section from 2324 to 2615 m in Arrabury 2 was also assigned. Both wells are located in South-West Queensland.



**Fig. 6.31** Isopach map of the Nappamerri Group (P–J seismic horizons).

### Lithology and distribution

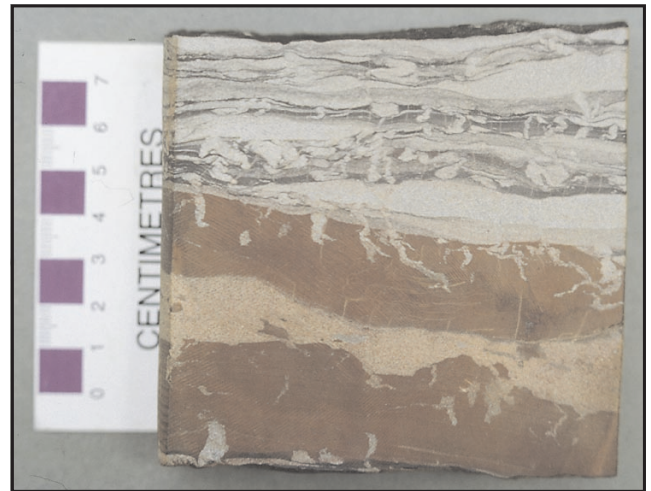
Arrabury Formation consists of mudstone and siltstone with thin fine to medium-grained quartzose sandstone interbeds (Callamurra and Paning Members) overlain by sandstone with minor siltstone interbeds (Wimma Sandstone Member).

Although this formation is commonly described as ‘redbeds’, the cored type section consists of dark to pale grey siltstone and mudstone beds with interbedded pale grey sandstone beds. Red, purple and brown colouration is patchy and is a result of variable siderite and possibly haematite content. Siderite occurs in a variety of forms — diffuse layers, patchy cement, speckles, sharp edged layers and reworked clasts. Pyrite also occurs in trace amounts. No evaporite minerals or calcite cement occur.

Arrabury Formation is widely distributed over the Cooper Basin, including the GMI Ridge, and its zero edge defines the northern limits of the Cooper Basin. Arrabury Formation is absent south of the Murteree Ridge, where it has been eroded.

### Relationships and boundary criteria

The base of the formation is defined by the abrupt change in lithology from black to dark grey organic-rich siltstone



*Sphaerulitic cracks and load casts in fine-grained sandstone of the Arrabury Formation, Merrimelia 3, 2364 m. (Photo 42457)*

and coal of the Toolachee Formation to medium to pale grey organic-lean, siltstones of the Arrabury Formation. In Merrimelia 3, this is marked by a colour change as well as a change in magnetic polarity from reversed to normal, a major negative  $\delta^{13}\text{C}_{\text{org}}$  isotope excursion and a drop in total organic carbon (TOC; Morante, 1995).

Arrabury Formation also unconformably overlies sedimentary rocks and volcanics of the Warburton Basin beyond the zero edge of Permian sediments towards the Cooper Basin margin and in places on the GMI Ridge. Where the Arrabury Formation unconformably overlies horizontal Innamincka Formation redbeds (Warburton Basin) on the GMI Ridge, distinguishing the two formations using logs and cuttings can be problematic. The Arrabury Formation is overlain unconformably by Eromanga Basin sediments in the southern Cooper Basin and conformably by Tinchoo Formation in the Patchawarra Trough and northern areas.

Undifferentiated Arrabury Formation occurs where the Wimma Sandstone Member is absent (e.g. Mount Howitt 1; Powis, 1989, fig. 6), or where the Callamurra and Paning Members cannot be distinguished. A disconformity has been interpreted within the Arrabury Formation, between the Callamurra and Paning Members and a time gap of up to 10 Ma (cf. Daralingie unconformity time break of 2 Ma depicted on unpublished palynostratigraphic charts). The duration and significance of this break is subject to debate, given the slow depositional rates interpreted during this period and the poor biostratigraphic control.

### Thickness

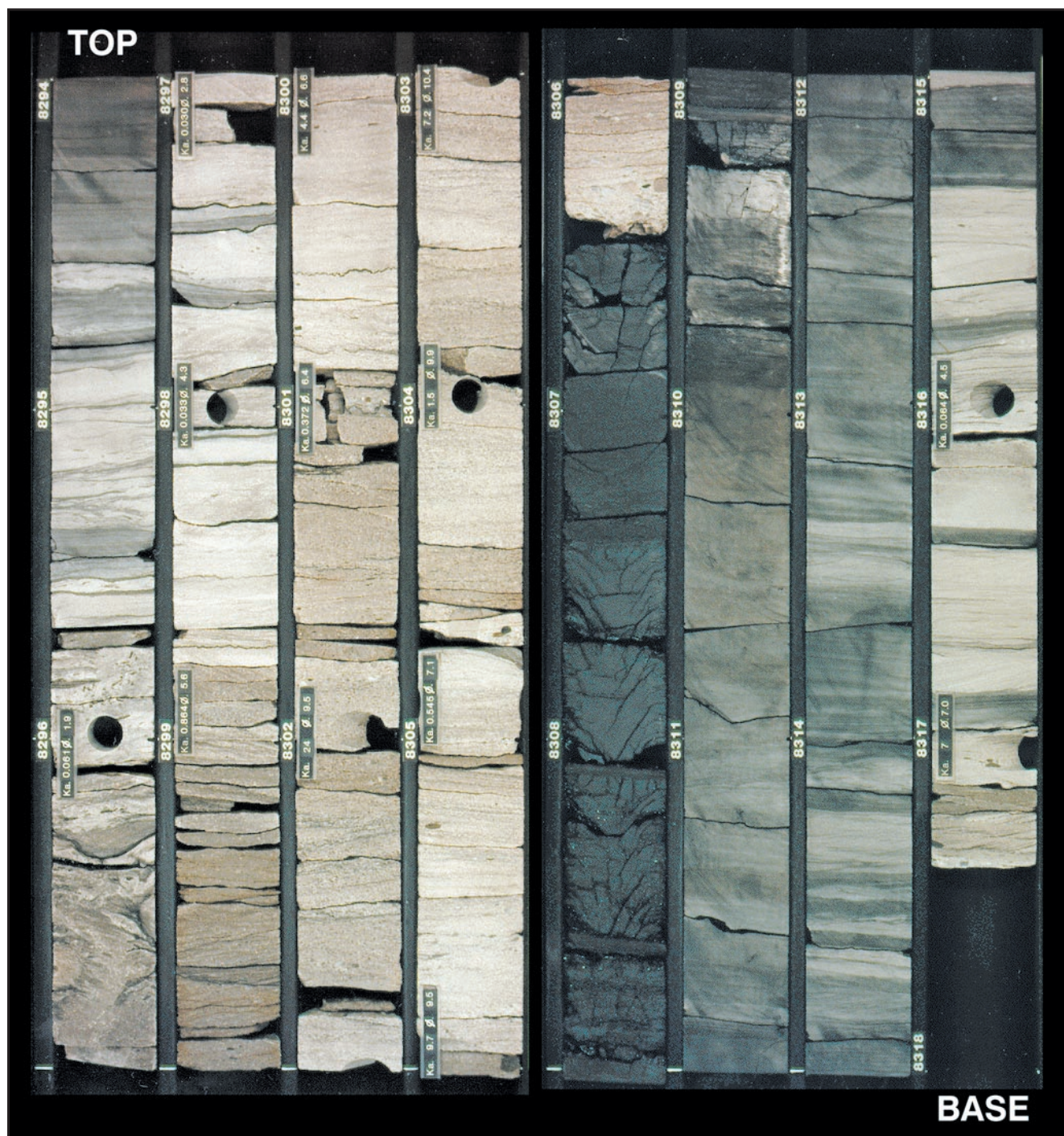
Arrabury Formation reaches a maximum thickness of 400 m in the Patchawarra Trough.

### Age

The Arrabury Formation contains sparse, oxidised palynomorphs indicative of a Late Permian to Early Triassic age (Tatarian to Anisian) corresponding to the PP6 to PT2.2 palynozones of Price *et al.* (1985).

### Sedimentology and palaeoenvironment

The Arrabury Formation is typically described as ‘redbeds’, however there is no evidence of basin-wide deposition under hot arid to semi-arid conditions, implied by



Stacked upward-fining packages (2528.0–2531.8 and 2531.8–2535.3 m) in the Toolachee Formation, Moomba 72. (Photo 46502)

usage of the term. The palaeoclimate during deposition of the Arrabury Formation was humid rather than arid (Retallack *et al.*, 1996). The palaeolatitude of the Cooper region during the Triassic was high, as it was in the Permian (Figs. 6.2, 7.7). Calcrete horizons and calcite nodules (comparable to modern caliche soils) and evaporite minerals, indicative of arid conditions have not been found in the Arrabury Formation. Carbonate occurs as siderite cement and nodules, and formed in slightly reducing conditions, possibly in a permanently saturated soil profile (Reading, 1982), implying high watertables.

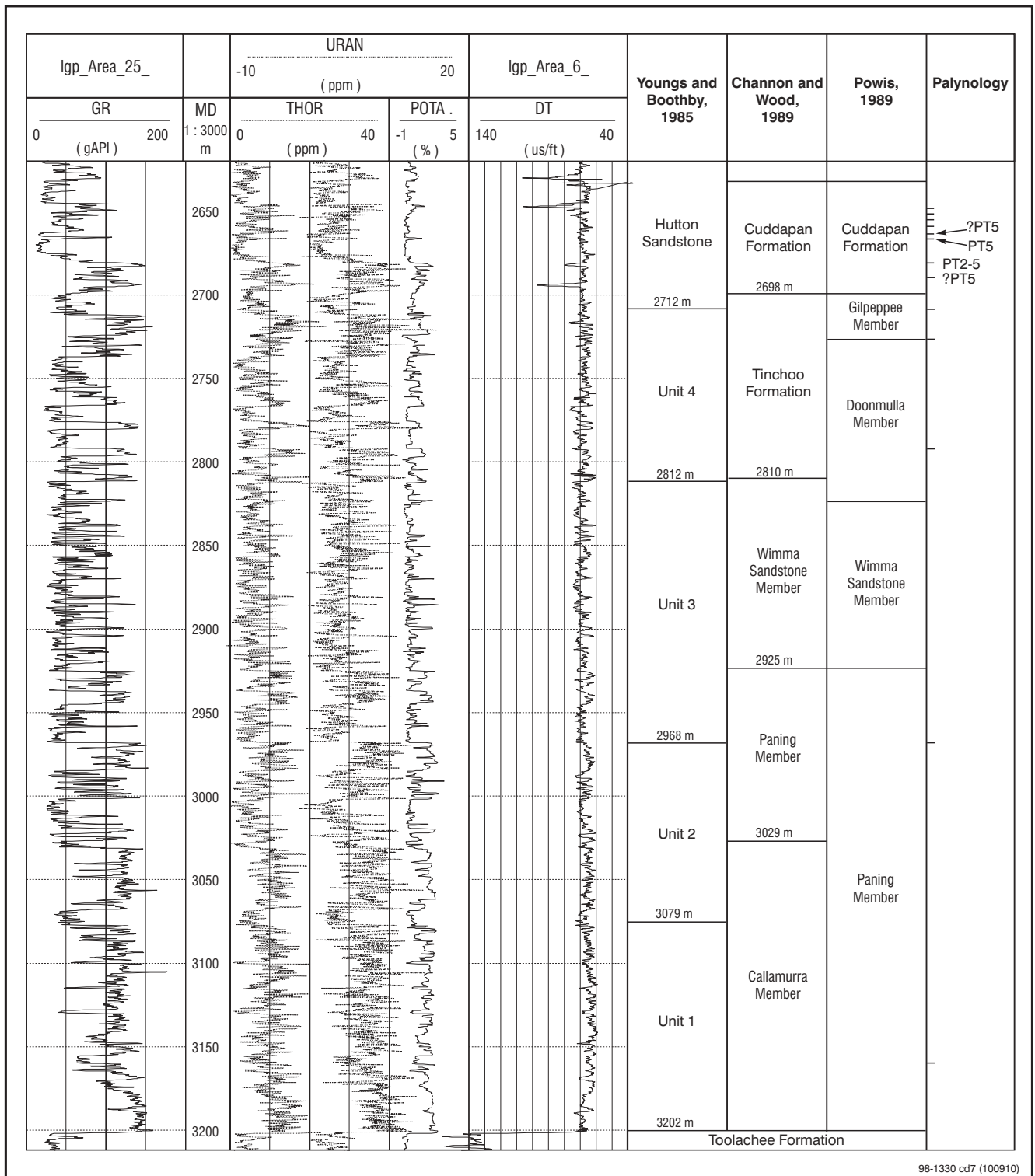
The Arrabury Formation was deposited during the worldwide ‘Early Triassic coal gap’ (Veevers *et al.*, 1994)

when peat-forming plants became extinct (Retallack *et al.*, 1996). The environment of deposition is interpreted as a vegetated floodplain with ephemeral lakes in low-lands with pedogenesis occurring on exposed areas — peat swamps did not develop. The floodplain was cut by low-sinuosity rivers, largely confined to northeast–southwest channel belts in the Patchawarra and Nappamerri Troughs.

### Callamurra Member

#### Definition and nomenclature

The Callamurra Member is the lowermost unit of the Arrabury Formation and was informally defined by Channon and Wood (1989). It is the organically lean mudstone and siltstone package overlying the Toolachee



98-1330 cd7 (100910)

Fig. 6.32 Wireline logs illustrating subunits of Youngs and Boothby (1985), Channon and Wood (1989) and Powis (1989), Beanbush 1. Barren palynological samples indicated by unlabelled tick.

Formation and encompasses Unit 1 of Youngs and Boothby (1985). Callamurra Member was not recognised in Queensland by Powis (1989).

**Type section**

A reference section was assigned by Channon and Wood (1989) from 2335 to 2673 m in Burley 2. Callamurra Member was recognised in the Mount Howitt 1 type section by Channon and Wood (1989) over the interval

2057–2096 m; but was not distinguished within the Arrabury Formation by Powis (1989).

**Lithology and distribution**

The Callamurra Member consists of a basal carbonaceous siltstone and mudstone facies (Late Permian) which grades rapidly into organically lean, mottled medium to light grey mudstone and siltstone, with minor sandstone interbeds (Early Triassic). Red, brown and purple siderite

and possibly haematite cements have formed in siltstone and sandstone beds. Sandstone beds are light grey to off-white, fine to medium grained, quartzose and cemented by silica, patchy siderite and kaolinite. Traces of mica, weathered feldspar, quartz overgrowths, lithic grains and pyrite occur. Conglomerates consist of reworked granule to cobble sized clasts of siltstone and mudstone in a sandy matrix. Coals are very rare, seams are thin, shaly and restricted in lateral extent. Carbonised branches and leaves form rare coal stringers and fine carbonaceous flecks occur.

Callamurra Member is thickest in the Nappamerri Trough, however it has been eroded north of the Patchawarra Trough and south of the Murteree Ridge. It has been eroded off the Murteree and Dunoon Ridges.

#### **Relationships and boundary criteria**

Callamurra Member conformably overlies the Toolachee Formation or unconformably overlies older rocks. The base of the member is as described above for the Arrabury Formation. It is overlain, possibly disconformably by Paning Member and the top is picked at the base of the first significant sandstone (Channon and Wood, 1989).

#### **Thickness**

The Callamurra Member reaches a maximum drilled thickness of 150 m in Moomba Field, but greater thicknesses are evident on seismic sections in the Nappamerri Trough.

#### **Age**

Late Permian to Early Triassic, Tatarian to Scythian (PP6 to PT1 palynozones of Price *et al.*, 1985).

#### **Sedimentology and palaeoenvironment**

The Callamurra Member is dominated by siltstone and mudstone beds, with minor sandstone interbeds. Three facies are identified in core. The most common is mottled siltstone and mudstone with sub-vertical water escape structures, rootlets, siderite nodules, possible clay globules and pellets, breccias associated with collapse structures and bedding disrupted by development of a strong vertical fabric. These features are associated with pedogenesis.

The second facies is best developed in the lower part of the formation and consists of finely-laminated siltstone with thin very fine-grained sandstone. Synaeresis cracks and both sheet and pillar dewatering structures occur in this facies. Swaley bedding and small scale ripples, including climbing ripples occur in sandier beds, some of which have loaded bases. This facies is interpreted to represent shallow lake deposits, reworked by wind generated wave action. Bioturbation is rare and occurs as isolated trails on bedding rather than burrows (cf. Youngs and Boothby, 1985; plate 2; synaeresis cracks).

The third facies consists of 2–3 m thick sandstone beds with siltstone interbeds. Sandstones have planar cross-bedding and planar bedding at the base, and wispy bedding, climbing ripples and small scale ripples towards the top. Systematic changes in grain size such as upward-fining or coarsening, are not common. Siltstone interbeds have sharp bases and tops and transitional boundaries are rare. Tangential toesets of bedforms up to 300 mm thick have been preserved in places, topsets have typically been truncated by reactivation surfaces. Rare carbonaceous stringers and fragments are preserved as

partings within sandstone beds. Well preserved plant impressions with needle-shaped leaves and articulated with stems, occur in thinly bedded siltstones.

The Callamurra Member was deposited in a fluvial floodplain environment, cut in the northern part of the Cooper Basin by eastward flowing meandering channels (e.g. Youngs and Boothby, 1985, fig. 6d). The presence of carbonaceous flecks, palynomorphs and coalified twigs and branches indicates that the floodplain was vegetated. However there is no evidence of significant coal swamp development. Instead, perennial lakes occurred in lowlands and pedogenesis was an important process on the floodplain away from areas of active sediment accumulation.

Stacked soil horizons are common. Each represents a condensed sequence, formed over a significant period of time, during which little or no deposition occurred on that part of the floodplain. As a result, significant hiatuses are interpreted within the Callamurra Member. Large time gaps (disconformities) depicted between it and the Paning Member can alternatively be taken up by many smaller breaks and generally slow rates of deposition.

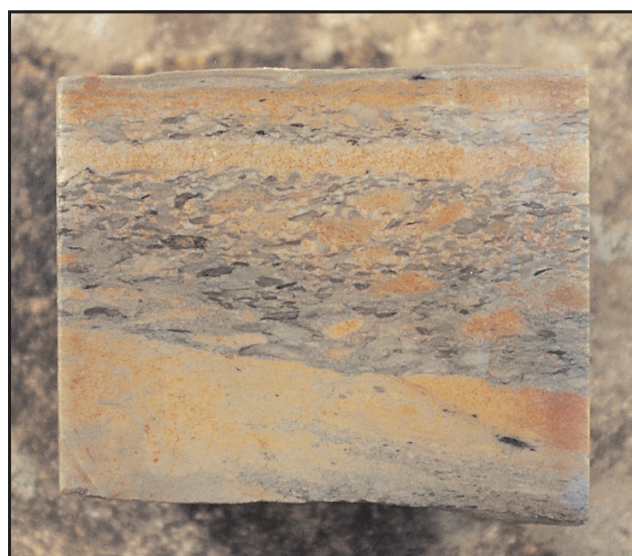
### **Paning Member**

#### **Definition and nomenclature**

The Paning Member of the Arrabury Formation was defined by Powis (1989). However, Channon and Wood (1989) used the name in a different sense (overlying the Callamurra Member) and regarded it as corresponding to Unit 2 of Youngs and Boothby (1985). It is a generally upward-fining unit which consists of smaller upward-fining sandstone and siltstone packages overlying the Callamurra Member.

#### **Type section**

The Paning Member does not occur in the Arrabury Formation type section in Mount Howitt 1; a reference section 2583–2851 m in Paning 1 was assigned by Powis (1989). Channon and Wood (1989) assigned two reference sections: 2925–3031 m in Beanbush 1 and 2757–2849 m in Lamdina 1.



*Disconformable contact between the Callamurra and Paning Members, Merrimelia 29, 2166.7 m. (Photo 45941)*



Callamurra and Paning Members, Merrimelia 29, 2164–2168 m. The upper Callamurra Member consists of a palaeosol developed in a silty mudstone. This is overlain sharply by Paning Member channel sandstone. (Photo 46503)

### **Lithology and distribution**

Paning Member consists of upward-fining cycles of buff, pale grey to off white, fine to medium-grained sandstone grading into light to dark grey and brownish siliceous mudstone and siltstone units. Sandstone beds are best developed at the base of the unit. Martin (1983) has described quartz grains (monocrystalline as well as a significant polycrystalline proportion), small amounts of feldspar and mica (much of which has been altered to clay) and rock fragments including acid volcanic flows and tuffs, mica phyllite and sedimentary clasts. Siderite occurs as irregularly distributed cement and trace amounts of leucoxene and pyrite are present. Clay minerals are composed of authigenic dickite and illite with minor chlorite. Quartz overgrowth formation has been constrained by lithics, clays and mica.

Intraclast conglomerates consist of granule and cobble sized reworked grey-brown siltstone and mudstone with quartz pebbles in a dirty sandstone matrix. Siltstone and mudstone beds become more dominant towards the top of the unit (Youngs and Boothby, 1985). In core, the bases and tops of siltstone and mudstone interbeds are blurred and grade into sandstone.

The Paning Member is the most widely distributed member of the Arrabury Formation over the Cooper Basin. It is absent south of the Murteree and Dunoos Ridges, but extends northwards towards the Mount Howie – Nappamilkie Ridge (= Haddon Dome in other reports; Channon and Wood, 1989, fig. 9).

### **Relationships and boundary criteria**

The base of the formation is picked where the frequency of upward-fining sandstone packages increases above the siltier Callamurra Member (Channon and Wood, 1989). In the Karmona area (South-West Queensland), Paning Member contains a late Early Triassic PT2 palynomorph assemblage and immediately overlies the Late Permian PP6 assemblage, thus Channon and Wood (1989) interpret a disconformity to explain the missing PT1 palynozones. However the PT1 zone is poorly defined, the low diversity assemblage only occurs in scattered wells in the South Australian part of the Cooper Basin and it may be generally unrecognised due to sparse occurrence, low sample density and/or poor preservation of palynomorphs. In Merrimelia 29 (core 1) the basal contact however is scoured, thus locally disconformable, and a conglomerate consisting of rounded brown and grey siltstone and mudstone intraclasts occurs at the base of the Paning Member. The upper Paning Member is a lateral equivalent of the Wimma Sandstone Member.

### **Thickness**

The Paning Member is >200 m thick in Moomba Field, where it has been drilled. Greater thicknesses are predicted in the central Nappamerri Trough.

### **Age**

Early to Middle Triassic, Scythian to basal Anisian (PT2.1 to PT2.2 palynozones of Price *et al.* (1985)).

### **Sedimentology and palaeoenvironment**

Sandstone is planar cross-bedded, horizontally bedded and massive. Siltstone and mudstone beds are finely

laminated, although in places have been disrupted by microfaulting and subvertical water escape structures.

Acid volcanic grains described in the Paning Member (Martin, 1983) were sourced from the east, where thick Triassic volcanics and volcanogenic sediments were deposited in a foreland basin (Fig. 6.2). This foreland basin on the eastern margin of Gondwana was active from the Late Permian to late Early Triassic, when it was deformed and uplifted (Baillie *et al.*, 1994).

The Paning Member was deposited in a floodplain environment, with development of soil profiles, localised lakes and high-sinuosity channels. Like the Callamurra Member, deposition occurred during the 'Triassic coal gap' and the Paning Member lacks significant coal seams.

## **Wimma Sandstone Member**

### **Definition and nomenclature**

Wimma Sandstone Member was defined by Powis (1989) as a clean sandstone with minor siltstone interbeds that conformably overlies Paning Member. It equates to Unit 3 of Youngs and Boothby (1985), although Channon and Wood (1989) redefined the member to include only relatively clean sandstone facies.

### **Type section**

Wimma Sandstone Member does not occur in the Arrabury Formation type section in Mount Howitt 1; a reference section was assigned by Powis (1989) as 2779–2890 m in Wimma 1. Channon and Wood (1989) selected 2811–2925 m in Beanbush 1 and 2667–2757 m in Lamdina 1 as reference sections.

### **Lithology and distribution**

The Wimma Sandstone Member consists of buff to pale grey, fine to medium-grained quartzose sandstone with minor interbeds of pale to medium grey siltstone and mudstone. It is restricted to the Patchawarra Trough in South Australia and Queensland and forms a southwest–northeast oriented belt ~70 km wide (Channon and Wood, 1989, fig. 10; Powis, 1989, fig. 11).

### **Relationships and boundary criteria**

The Wimma Sandstone Member is underlain by Paning Member and is also locally a lateral equivalent of the upper Paning Member. It is conformably overlain by the Tinchoo Formation.

### **Thickness**

The Wimma Sandstone Member is >100 m thick in the Patchawarra Trough and reaches a maximum thickness of 114 m in Potiron 1.

### **Age**

Early to Middle Triassic, Scythian to basal Anisian (PT2.1 to PT2.2 palynozones of Price *et al.* (1985)).

### **Sedimentology and palaeoenvironment**

Sandstone within the Wimma Sandstone Member is horizontally and planar cross-bedded; massive beds with water escape, slump and possible dish structures also occur. The Wimma Sandstone Member was deposited by low-sinuosity rivers which flowed across the Paning



Palaeosol overlain by channel sandstone, Wimma Sandstone Member, Potiron 1, 2168.0–2171.7 m. (Photo 46504)

Member floodplain. The main channel axis was oriented southwest–northeast along the Patchawarra Trough.

## Tinchoo Formation

### *Definition and nomenclature*

Tinchoo Formation was defined by Powis (1989, p.271) as ‘a fining upwards succession of strata with variable sandstone development at the base.... of Middle Triassic age’ conformably overlying Arrabury Formation. Powis subdivided the formation into the Gilpepee and Doonmulla Members in Queensland, however these members are not readily identifiable in South Australia where the formation has been eroded and is relatively thin. The Tinchoo Formation is partially represented in Unit 4 of Youngs and Boothby (1985) in Beanbush 1 over the interval 2712–2811 m (Channon and Wood, 1989).

### *Type section*

Powis (1989) defined Tinchoo Formation as 1714–1917 m in Mount Howitt 1 (latitude 26°37′27"S, longitude 142°28′17"E). This varies from the interval picked by Channon and Wood (1989) in the same well (1713–1878 m). A reference section was also assigned by Powis (1989) as 2267–2422 m in Tinchoo 1. Channon and Wood (1989) proposed the extensive section of PT4 age sediments in Russel 1 (2427–2648 m) as a reference section.

### *Lithology and distribution*

In Queensland, the Tinchoo Formation consists of interbedded brown-grey siltstone and light grey sandstone (Doonmulla Member) overlain by uniform dense light grey to green siltstone, with minor coal seams (Gilpepee Member) and intraclast conglomerate beds (Powis, 1989). However, in South Australia where the formation has been thinned by erosion, the members are not readily picked. In the northern Cooper Basin in South Australia, Tinchoo Formation consists of quartzose, very fine to coarse (up to granule size), predominantly medium-grained sandstone, with variable lithic content and strongly to weakly cemented by silica, clay and patchy siderite. Intraclast conglomerates consist of granule to cobble sized brown and dark grey siltstone and mudstone clasts in a coarse-grained sandstone matrix. Rare, well rounded isolated quartz pebbles occur within sandstone beds. Siltstone interbeds are light olive grey to brown and medium grey and contain layers of coarse sand grains.

The Tinchoo Formation has been cored only in Telopea 2 in South Australia (core 1, 2488.7–2507 m). The formation appears to be more coarse grained than the underlying Wimmera Sandstone Member. Tinchoo Formation is restricted to the northeastern Patchawarra Trough and area north towards the Mount Howie – Nappamilkie Ridge in South Australia (Channon and Wood, 1989, fig. 11).

### *Relationships and boundary criteria*

The base of the Tinchoo Formation cannot be simply defined on well logs due to facies variations within it and within the conformably underlying Arrabury Formation. Largely choice of the boundary depends on whether the Wimmera Sandstone Member is present or not (e.g. Powis, 1989, fig. 6). As a result, some confusion exists as to how the base is defined on well logs and both Channon and Wood and Powis give contradictory descriptions. The lower

contact is a mappable seismic marker in Queensland (Powis, 1989). Triassic stratigraphy in northern South Australia is being reviewed by PIRSA.

Tinchoo Formation unconformably overlies the Warburton Basin northwest of the Cooper Basin towards the Birdsville Track Ridge. It is unconformably overlain by Cuddapan Formation or sediments of the Eromanga Basin (Poolowanna Formation or Hutton Sandstone). Tinchoo Formation has been correlated with the Walkandi Formation from the Simpson Basin, although the latter only has poorly resolved Triassic palynomorph assemblages (Channon and Wood, 1989).

An unusual 49 m thick silty sandstone was recently identified in the Telford Basin near Leigh Creek (Shaw, 1996). It contains a superb palynomorph assemblage which has been assigned to the *Aratrisporites parvispinosus* zone (Helby *et al.*, 1987) of Middle Triassic age by Alley (1995a). Middle Triassic sediments also occur in the Springfield and Boolcunda Basins, implying that such strata may have been more widely distributed. These small basins thus may contain remnants of formerly more extensive Tinchoo Formation deposits. The Cuddapan Formation may not have been the first widely deposited blanket deposit in the region as previously thought.

### *Thickness*

Tinchoo Formation reaches a maximum thickness of ~109 m in Telopea 1 in South Australia. It has been eroded from the crest of major ridges and towards the edge of the Cooper Basin.

### *Age*

Middle to early Late Triassic, Anisian to Ladinian (PT3 palynozone of Price *et al.*, 1985).

### *Sedimentology and palaeoenvironment*

Tinchoo Formation is dominated by planar cross-bedded and planar bedded, fine to medium-grained sandstone with thin siltstone interbeds. In places, bedform topsets have been preserved. Fine-grained sandstone beds show low-angle planar cross-bedding, ripple cross-bedding and planar bedding. Carbonaceous and micaceous partings and wisps occur in the finer sands and in places have been disrupted by subvertical water escape pillars. Granule conglomerate beds are crudely planar bedded or planar cross-bedded and can occur at the base of upward-fining packages. Siltstone and mudstone interbeds are thin (<100 mm), with sharp bases and tops, and vary from slumped to horizontally laminated with very fine-grained sandstone stringers, linsen and rippled sandstone interbeds.

Youngs and Boothby (1985) interpreted a high-sinuosity fluvial environment of deposition based on upward-fining log signatures. However, in the one Tinchoo Formation core in South Australia, upward-fining packages are not common and sedimentary structures typical of point-bar and abandonment facies were not observed, rather siltstone interbeds have sharp bases and tops and are thin. A low-sinuosity fluvial environment is interpreted from the core in Telopea 1, however variation in channel type may occur across the floodbasin, as, e.g. the Travis Peak Formation, United States which contains both high and low-sinuosity fluvial facies (Davies *et al.*, 1993).



Cross-bedded sandstone with disrupted siltstone interbed (2505.8–2506.2 m) in the Tinchoo Formation, Telopea 2, 2502–2507 m. (Photo 46505)

Powis (1989) interprets a tectonically-driven northward shift in the Triassic depocentre following deposition of the Arrabury Formation. This supports the gross northeasterly palaeocurrent direction interpreted from limited data by Youngs and Boothby (1985) and is in turn supported by northerly basin tilt (Ch. 5).

## Cuddapan Formation

### *Definition and nomenclature*

Cuddapan Formation was defined by Powis (1989). Channon and Wood (1989) applied the name to replace the informal 'Beanbush beds' of Price *et al.* (1985). It is the youngest preserved Triassic formation in the region.

### *Type section*

Powis (1989) defined the type section as 2267–2319 m in Cuddapan 1 (latitude 25°41'47"S, longitude 141°40'15"E). Channon and Wood (1989) proposed an unpublished type section as 2645–2712 m in Beanbush 1, however the published type section of Powis has priority and the Beanbush section (Fig. 6.32) is proposed as a reference section. A reference section, 2321–2384 m in Paning 1, was also assigned by Channon and Wood (1989).

### *Lithology and distribution*

The Cuddapan Formation is lithologically similar to the overlying Poolowanna Formation and identification of the unit depends on palynological dating (Channon and Wood, 1989). It consists of a basal sandstone package with increasing siltstone and coal interbeds upwards. In core (Beanbush 1, core 1) Cuddapan Formation consists of interbedded grey siltstone and off-white sandstone with minor mudstone. Sandstone beds range from fine grained to granular. Siltstone intraclasts are common. Carbonaceous and micaceous films cap sandstone layers. Wiltshire (1982) considered that thin Late Triassic sediments formed an extensive veneer over and beyond the current limits of the Eromanga Basin, but were eroded during the early phases of Eromanga Basin deposition, leaving isolated remnants. Cuddapan Formation is restricted to the Patchawarra Trough in South Australia.

### *Relationships and boundary criteria*

Cuddapan Formation disconformably overlies the Tinchoo Formation of the Cooper Basin and is disconformably overlain by the Poolowanna Formation or Hutton Sandstone of the Eromanga Basin. Currently it is assigned to neither, but may be an outlier of the Simpson Basin. Powis (1989) correlated it to the Peera Peera Formation of the Simpson Basin, to the west. The base of the formation is picked as the first sandstone above siltstone and mudstone of the upper Tinchoo Formation. The base of the formation may be diachronous, younging from PT4 in Queensland to PT5 in South Australia.

### *Thickness*

In South Australia, Cuddapan Formation occurs as eroded remnants and reaches a thickness of 67 m in Beanbush 1 (Channon and Wood, 1989).

### *Age*

Late Triassic (Carnian to Norian). In South Australia, Cuddapan Formation corresponds to the PT5 palynozone of

Price *et al.* (1985), however in Queensland its base may be older and fall within the PT4 palynozone (e.g. Powis, 1989).

### *Sedimentology and palaeoenvironment*

Cuddapan Formation has been cored in one well in South Australia (Beanbush 1, 2656–2667 m). Sandstone beds are trough and planar cross-bedded, with some ripple cross-bedding and planar bedding. Upward-fining cycles occur with some granule sandstones grading to medium and fine-grained sandstones which pass upward into siltstones. Upward-fining cycles have sharp, scarred bases and are interpreted as high-sinuosity channel deposits. Intraclast breccias and conglomerates are interpreted as bank collapses, and in places imbricate clasts have been oriented by strong currents. Rootlets have disturbed one sandstone bed and may represent a vegetated bar top.

A high-sinuosity fluvial system, with flood basin coal swamp development is interpreted for the Cuddapan Formation in South Australia and Queensland. The occurrence of relatively thick and extensive coals in the equivalent Leigh Creek Coal Measures and Peera Peera Formation indicates the recovery of peat swamp flora at the end of the 'Triassic coal gap'.

## WARBURTON BASIN

The Cooper Basin is unconformably underlain by sediments and volcanics of the eastern Warburton Basin (Fig. 6.1). Recent studies of Warburton Basin geology include Gatehouse (1986), Sun *et al.* (1994), Roberts *et al.* (1990), Gravestock and Gatehouse (1995) and Sun (1997, 1998). Warburton Basin sediments range from Cambrian to Ordovician age; Devonian sediments have not been intersected in the Cooper region of South Australia. The eastern Warburton Basin is essentially a fold belt deformed during the Late Devonian to Carboniferous Alice Springs Orogeny, intruded by mid-Carboniferous granitoids (Gatehouse *et al.*, 1995) and subsequently buried to depths ranging from 1300 to almost 4000 m.

The eastern Warburton Basin contains a basal suite of acid to intermediate volcanics, tuff and agglomerate (Mooracoochie Volcanics), overlain by dolomitised shelfal limestone historically assigned to the basal Kalladeina Formation. A Middle to Late Cambrian carbonate shelf developed in the Coongie–Cuttapirie area, with a slope to the east. Several depositional sequences have been identified in the Kalladeina Formation (Gravestock and Gatehouse, 1995; Sun, 1997) typically with deep-water shales overlain progressively by shallow-water ooid grainstone, bioclastic packstone, then fine-grained ripple-laminated sands and silts with mud drapes. The Pando and Innamincka Formations continue this trend to shallow subtidal water depths as part of a deltaic complex with an extensive marine shelf sand (Gravestock *et al.*, 1995; Zang, 1993). Black shale of the Dullingari Group with rare graptolites was deposited in the deep-water Larapintine Sea which extended through the Warburton and Amadeus Basins to the Canning Basin in Western Australia (Webby, 1978).

Middle to Late Ordovician shale and siltstone constitute the last preserved deposits of the eastern Warburton Basin. Early to Middle Carboniferous granitic intrusives (Big Lake Suite) beneath the Nappamerri and Wooloo Troughs were

responsible for localised silicification and contact metamorphism of Cambrian country rock. A weathered zone up to 150 m thick has altered Warburton Basin strata, the granites in particular, immediately beneath the Cooper Basin unconformity (R. Boucher, Mines and Energy South Australia, pers. comm., 1996; Boucher 1997a, b).

### EROMANGA BASIN

The Eromanga Basin unconformably overlies the Cooper Basin and Cuddapan Formation. The stratigraphy, structural setting and hydrocarbon potential of the basin is discussed in detail in Volume 2 of *The petroleum geology of South Australia* series (Alexander and Hibburt, 1996).

The Eromanga Basin consists of a broad intracratonic downwarp with two main depocentres — the Poolowanna Trough and the Cooper region — containing up to 3000 m of sediment. These depocentres are separated by the northeast trending Birdsville Track Ridge. Deposition in the Eromanga Basin was initially controlled by the topography of the Triassic unconformity surface, especially for the Poolowanna Formation and lower Hutton Sandstone. No major depositional breaks occur in the Eromanga Basin, indicating a period of tectonic quiescence.

Eromanga Basin stratigraphy can be divided into three sequences — lower non-marine, marine and upper non-marine (Krieg *et al.*, 1995; Alexander and Sansome, 1996). In the Cooper region, (Fig. 6.33) the lower non-marine sequence consists of intertonguing, low-sinuosity fluvial sandstones (Hutton and Namur Sandstones), lacustrine shoreface sandstone (McKinlay Member) and high-sinuosity fluvial, overbank and lacustrine sandstones, siltstones, shales and minor coal (Poolowanna, Birkhead and Murta Formations).

The non-marine sequence is succeeded conformably by a sequence reflecting transition from non-marine to marginal marine and finally to open marine conditions. The basal unit, Cadna-owie Formation is of significance for petroleum exploration as the top of the unit approximates a distinctive seismic reflector — the C horizon, mappable over the entire basin (Fig. 5.4c). The marine sequence (Marree Subgroup) consists of shale and siltstone with minor shoreface sandstone interbeds with at least one organic-rich condensed sequence (Toolebuc Formation), deposited in a shallow epicontinental sea (Moore and Pitt, 1984; Krieg and Rogers, 1995). The upper non-marine sequence consists of high-sinuosity fluvial sandstone, siltstone, shale and coal of the Winton Formation (Rogers, 1995).

### LAKE EYRE BASIN

Sediments of the Lake Eyre Basin were deposited after a period of erosion and deep weathering and unconformably overlie the Eromanga Basin. The Lake Eyre Basin is composed of two sub-basins, west and east of the Birdsville Track Ridge; the Tirari Sub-basin and the Callabonna Sub-basin. Krieg *et al.* (1990) recognised three phases of deposition in the Lake Eyre Basin, interrupted by structural movements. The oldest Tertiary unit consists of fluvial sandstone with a basal conglomerate (Eyre Formation). In places it has been capped by silcrete, which forms prominent mesas. During the Early Oligocene the silcrete was gently folded and tilted and then incised by fluvial systems.

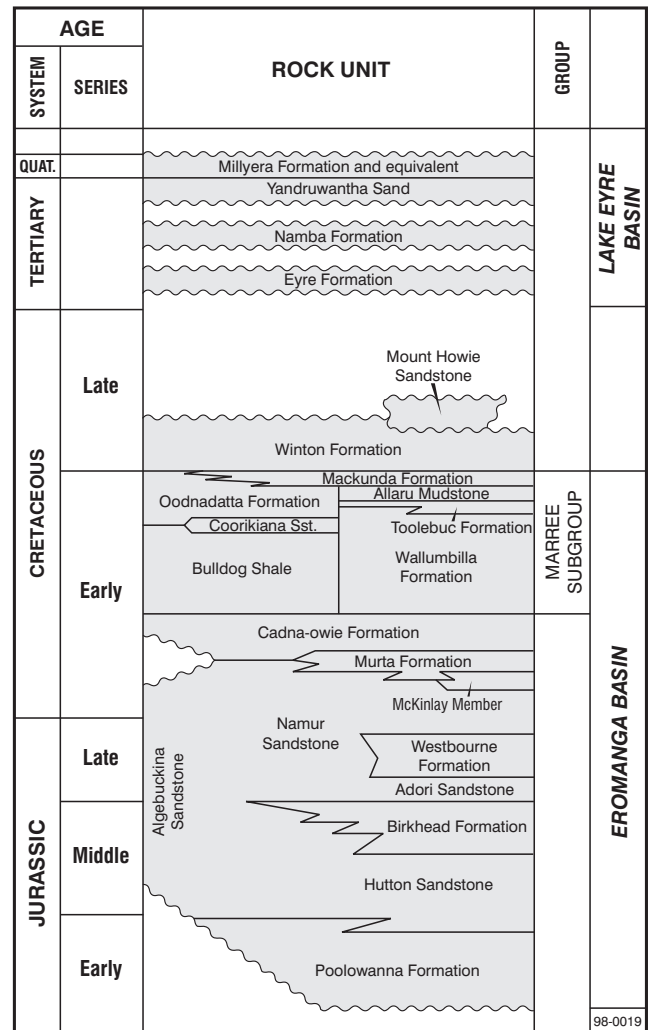


Fig. 6.33 Stratigraphic summary of the Eromanga and Lake Eyre Basins, South Australia.

Carbonates and clastics were deposited in shallow brackish to fresh water lakes during the Late Oligocene to Miocene (Namba Formation). Following this depositional phase, Miocene compression reactivated Permian and older faults and produced localised uplift and erosion. Development of extensive aeolian dunes, fluvial systems, saline lakes, gibber plains and palaeosols (Yandruwantha Sand and Millyera Formation) occurred during the Pliocene to Quaternary. The distribution and thickness of Lake Eyre Basin sediments is described in Moussavi-Harami and Alexander (1998) and Moussavi-Harami (in prep.).



# STRATIGRAPHIC FRAMEWORKS for CORRELATION

D.I. Gravestock  
Chapter 7

## INTRODUCTION

There have been three stages of refinement of Cooper Basin stratigraphic correlation brought about by a response to the changing requirements of petroleum exploration, appraisal and development. The 'exploration stage' called for broad correlation of the newly discovered Permian basin in the 1960s with distant but better known formations of the eastern States. The goal of the following 'appraisal stage' during the 1970s and 1980s was prediction of reservoir facies architecture at field scale based on comparisons with fluvial and deltaic facies models. The third or 'development stage' applies to oil fields where recovery factors can be improved from better knowledge of reservoir flow-units and the geometry of intervening permeability barriers.

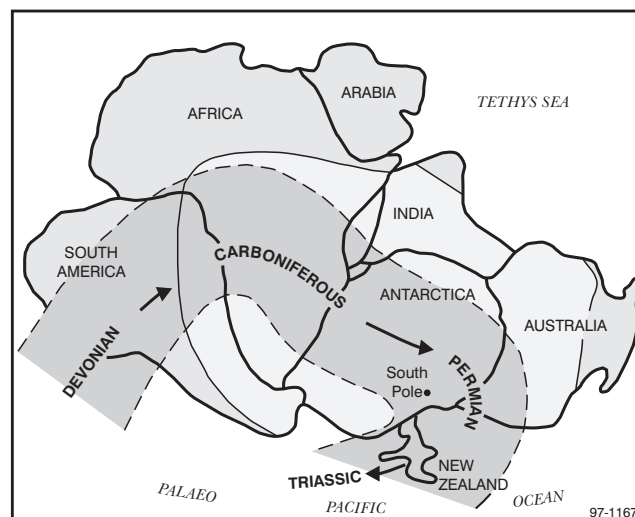
As an example of the exploration stage, wells such as Innamincka 1 and Dullingari 1 in South Australia and Orientos 1 in southwest Queensland were suggested to have Permian analogues in the New South Wales and Queensland coal measures 1000 km to the east and possibly in the Lake Phillipson Bore in the Arckaringa Basin 500 km to the southwest (Freeman, 1963). Correlation between wells up to 40 km apart was assisted by the persistence of two thick mudrock units subsequently named the Roseneath Shale and Murteree Shale (Gatehouse, 1972).

With continued drilling and the discovery of oil and gas fields over the following 30 years, there have been substantial advances in lithostratigraphic correlation by using wireline logs guided by an increasingly refined palynological framework. In addition, advances in seismic acquisition and processing have made seismic stratigraphic interpretation possible. These and other stratigraphic schemes are discussed below.

## PALYNOSTRATIGRAPHY

Glaciers advancing from the margin of a continental ice sheet reached into the Cooper Basin during the Late Carboniferous (Crowell and Frakes, 1971; Fig. 7.1). The environment of this region was non-marine, the nearest sea was about 500 km to the southwest in Early Permian time (Arckaringa Basin). The high southern latitude, late Palaeozoic Gondwanan flora was low in diversity and composed of stunted, broad-leafed seed ferns including *Glossopteris*, other ferns, horsetails and mosses adapted to severe climatic conditions.

As glaciers retreated and released vast reservoirs of fresh water, peatlands spread over hundreds and possibly several thousand square kilometres of the Cooper Basin. The climate improved but remained cool-temperate to cold in the Late Permian and in the Early to mid Triassic. Global faunal and floral extinction at the Permian-Triassic



**Fig. 7.1** Devonian to Permian migration of major ice centres across Gondwana. The position of the South Pole at the Permian-Carboniferous boundary is shown (from Alley, 1995b and references therein).

boundary included the extinction of peat-forming plants in the earliest Triassic (coal gap of Retallack *et al.*, 1996). The succeeding flora was dominated by the seed fern *Dicroidium* but also included other ferns, lycopods, cycads and primitive conifers (Thomas, 1982).

The microfossil record of the flora (chiefly fern spores) forms the biostratigraphic record of the Cooper Basin. Other Gondwanan basins have the advantage of a fossil marine fauna (foraminifera, brachiopods) as well as a microflora to achieve correlation. Variations in the original plant communities were governed by climatically controlled floristic ecology as well as evolutionary trends which ideally would be reflected in the fossil record. However, fossil yield and quality also depend on sample lithology and the degree of coalification of organic matter. Spore identification becomes difficult when vitrinite reflectance exceeds 0.8%, but spore colour alteration also provides a measure of the thermal maturity of the host rock. Despite these problems, sufficient wells have been sampled to provide a reliable palynostratigraphic scheme.

Palynological zone nomenclature spanning the Late Carboniferous to Late Triassic is shown in Figure 7.2. Absolute ages are based on zircon dates from Permian rocks in the Sydney and Bowen Basins (Roberts *et al.*, 1996). Organic carbon and magnetostratigraphic profiles across the Permian-Triassic boundary are discussed later in this chapter.

The historical development of palynological zone nomenclature for the Cooper, Bowen and Galilee Basins has

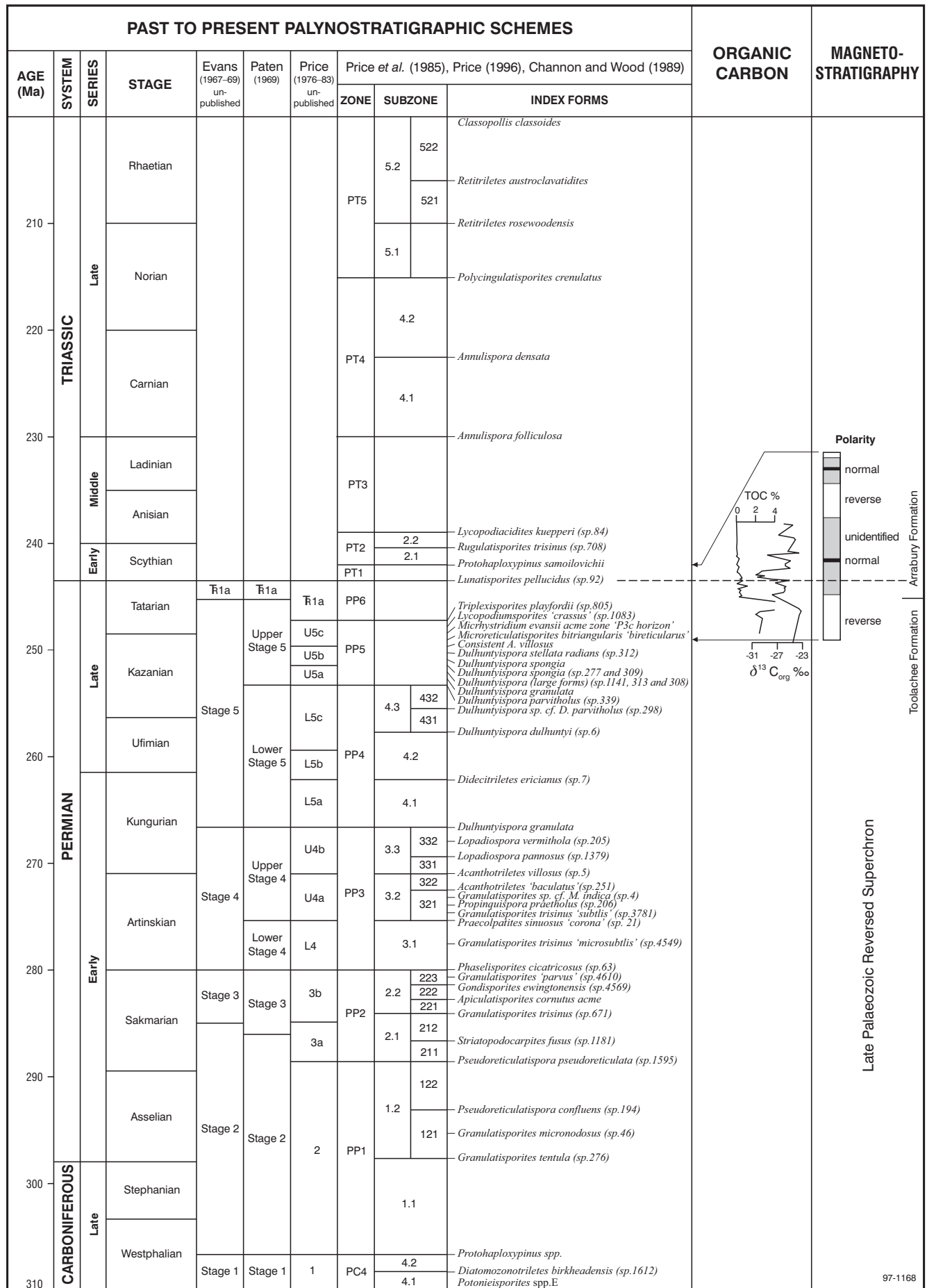


Fig. 7.2 Development of Late Carboniferous to Late Triassic palynostratigraphic zonation and organic carbon and magnetostratigraphic profiles in Merrimelia 3 (after Morante, 1995). Organic carbon and magnetostratigraphic data are provided for the Scythian–Tatarian only.

been documented in detail by Price (1983). His information and data from Price *et al.* (1985), Helby *et al.* (1987), Channon and Wood (1989) and Price (1996) form the basis of Figure 7.2. The alphanumeric zone nomenclature has been developed for the petroleum industry and replaces the older stage terminology of Evans (1969) and Paten (1969). The first character (P = spore/pollen) indicates the fossil group which defines the zone. The second character (C = Carboniferous, P = Permian, T = Triassic) denotes the geological age. The third character (numerals 1–6) indicates the broad subdivisions or zones within which 90% of samples can be placed (Price *et al.*, 1985). A second numeral after the stop identifies each of the two or three subzones which divide the succession into its finest commonly used subdivisions. Under favourable circumstances some subzones can be refined further, for instance to document hiatuses within the Patchawarra Formation (e.g. Apak *et al.*, 1995). High resolution intervals of this type are designated by a third numeral. As an example, the palynological subdivision corresponding to the seismic ‘yellow unit’ between the V6 and VU Patchawarra Formation reflectors is denoted PP223. These finer subdivisions also included in Figure 7.2, permit reasonably high resolution correlation where conditions of burial and sampling are optimal.

The tops and bases of zones and subzones (biohorizons) are determined by the oldest consistent occurrence of successive index species. Each zone is an interval zone and the same applies to each subzone. As an example, the interval between the oldest consistent occurrence of *Granulatisporites trisinus* and *Phaselisporites cicatricosus* is the PP2.2 interval subzone which is within the Sakmarian Stage of the Early Permian Series (Fig. 7.2).

The oldest Cooper Basin microflora occurs in the glaciogene Merrimelia Formation. Age is Late Carboniferous (Stephanian), PP1.2\* subzone. Apart from localised hiatuses in the PP2.1 and PP2.2 subzones (Patchawarra Formation), palynological samples and wireline logs indicate a conformable succession to the top of the Daralingie Formation in the late Early Permian. The top of the Daralingie Formation is a disconformity surface reflecting erosion on fault-reactivated structural ridges, uplift of the west flank of the Patchawarra Trough and the southern basin area. The hiatus was recognised from palynological data at an early stage (Paten, 1969). It is not certain whether the Daralingie and overlying Toolachee Formations are conformable in deeper parts of the Nappamerri Trough. In much of the southern Cooper Basin the Toolachee Formation rests disconformably on older Permian strata or unconformably on early Palaeozoic Warburton Basin rocks. The Toolachee Formation is Late Permian in age (PP4.3–PP5).

The conformably overlying Arrabury Formation spans the Permian–Triassic boundary, marked by global extinction. Palynological dating across the boundary in the Cooper Basin is hampered by low yields and high levels of oxidation of organic matter. In the Queensland Cooper Basin a disconformity within the Arrabury Formation is marked by the absence of the PT1 palynozone. However,

PT1 assemblages occur in the Nappamerri Trough (Channon and Wood, 1989) and on the Merrimelia Ridge (Wood in Morante, 1995), thus the Arrabury and Toolachee Formations are regarded as conformable in South Australia.

The Arrabury Formation is overlain conformably by the Tinchoo Formation which is of Middle Triassic age and contains oil in James 1 well. The majority of the formation is assignable to the PT3 palynozone, but where thicker Tinchoo strata are encountered (>150 m), Late Triassic PT4 assemblages have been recovered from carbonaceous siltstones and thin coals (Channon and Wood, 1989).

The top of the Tinchoo Formation is a regional erosion surface which marks the top of the Cooper Basin. However, pockets of the Late Triassic Cuddapan Formation with a PT5 palynoflora occur in the eastern Patchawarra Trough and southwest Queensland (Powis, 1989; Channon and Wood, 1989). Channon and Wood point out that palynology is required to distinguish the Cuddapan from the disconformably overlying Poolowanna Formation of the Eromanga Basin owing to the lithological similarity of the two units.

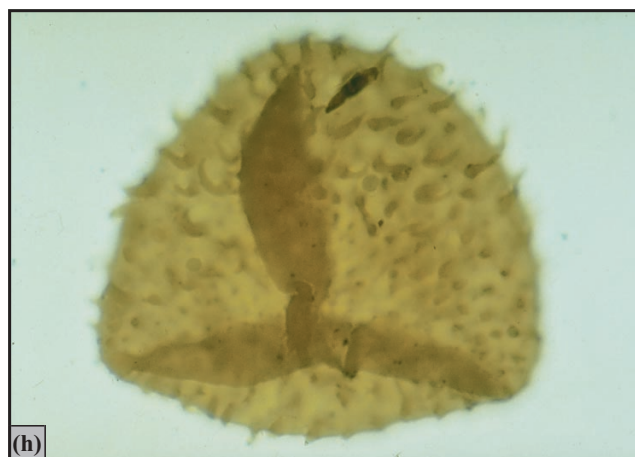
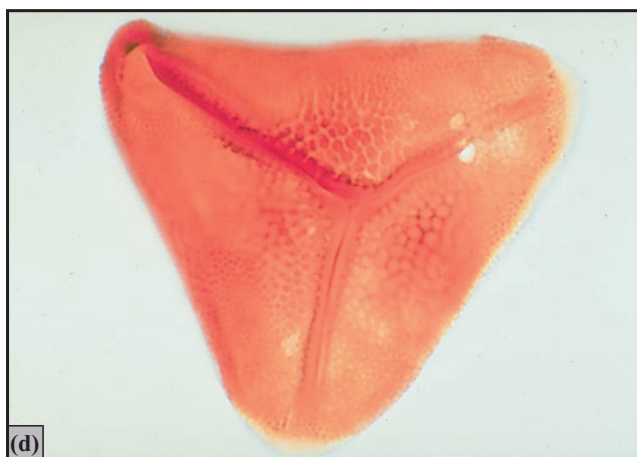
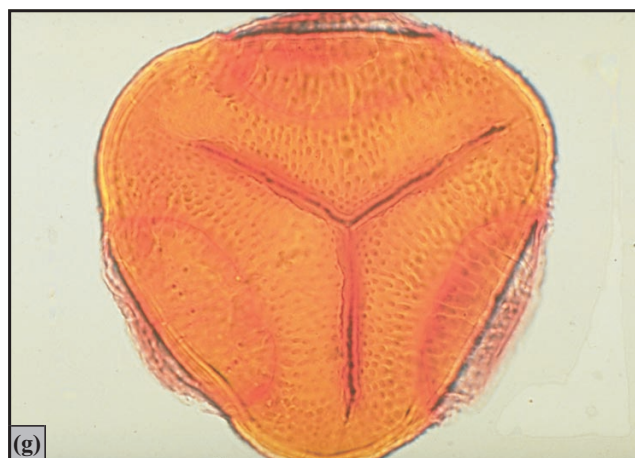
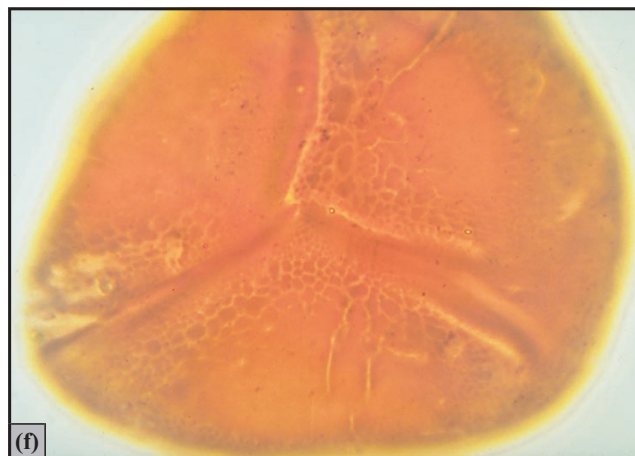
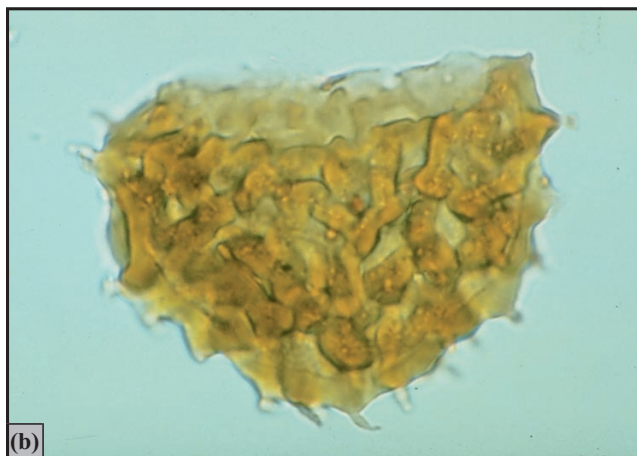
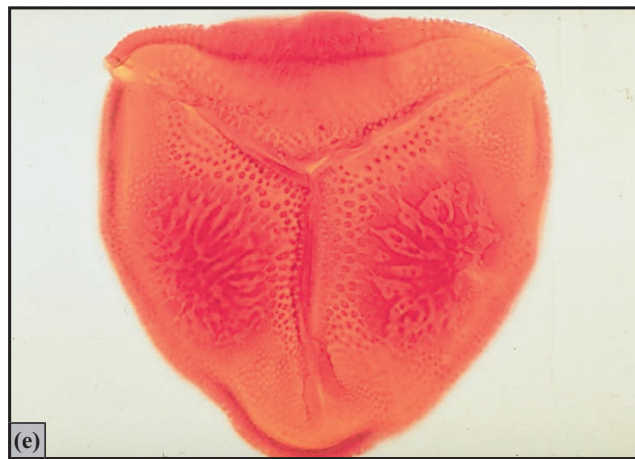
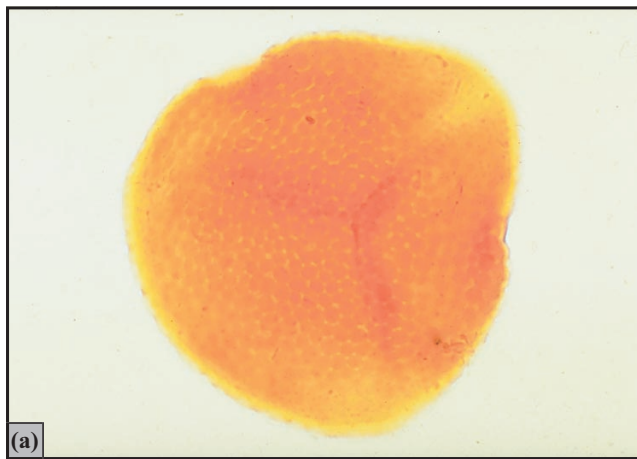
## SEQUENCE STRATIGRAPHY

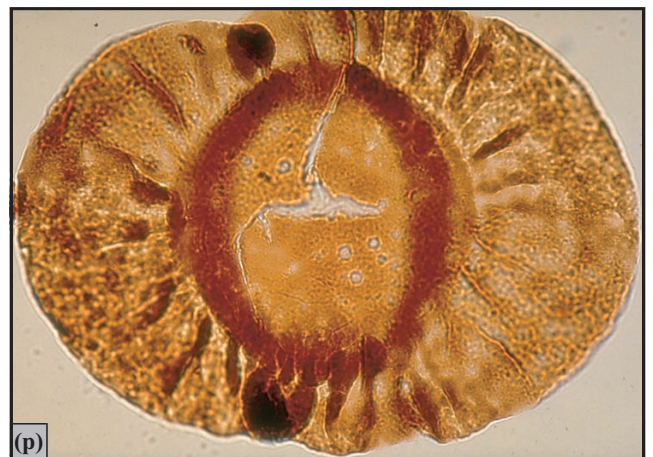
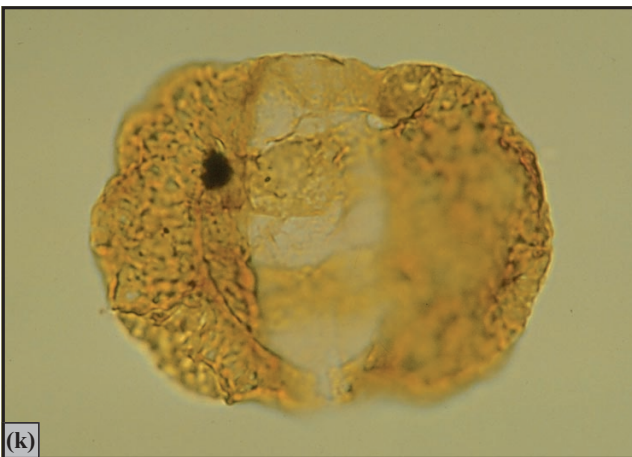
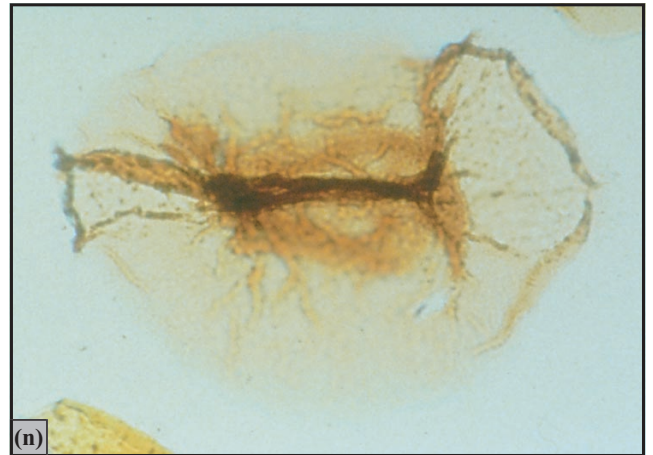
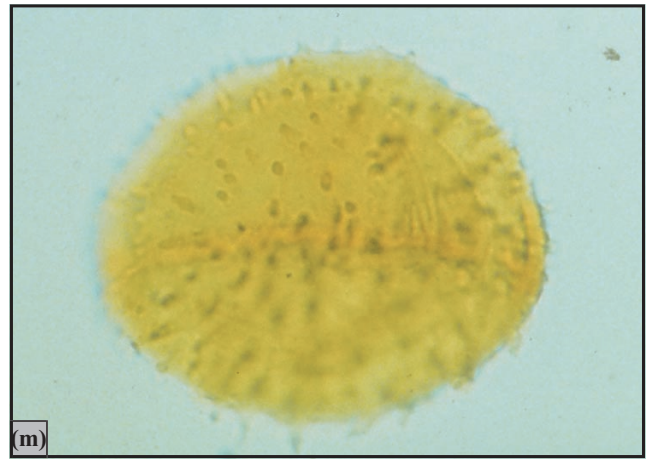
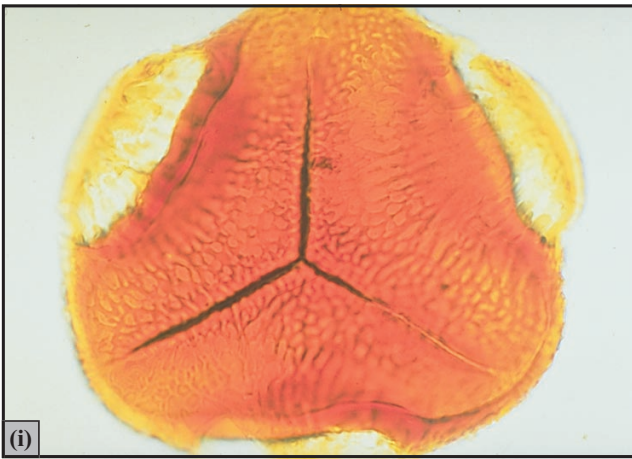
Field-scale correlations rely on the description and interpretation of facies associations or genetic depositional units from cores and wireline logs. Typically a field area may be 50–200 km<sup>2</sup> with wells nominally about 1 km apart. Examples include Toolachee (Devine and Gatehouse, 1977), Della (Gravestock and Morton, 1984) and Moomba (Fairburn, 1989); a similar approach has been applied to more regional studies beyond field boundaries (e.g. Stuart, 1976; Thornton, 1979; Fairburn, 1992). With the addition of multifold seismic data, more sophisticated mapping can be carried out beyond the limits of well control as exemplified by a study of part of the Toolachee Formation by Mackie *et al.* (1995).

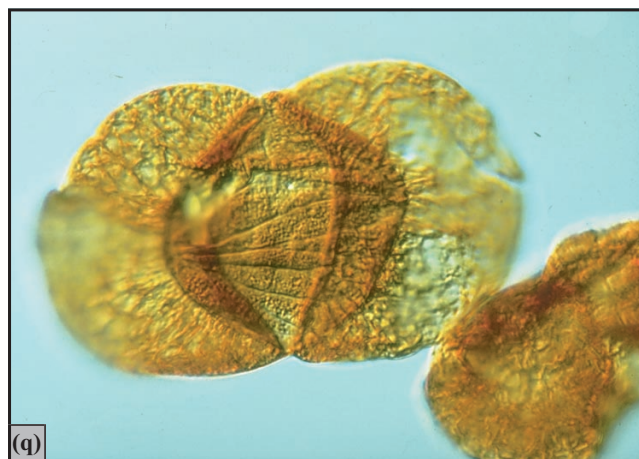
The aim of such studies is to predict the geometry and flow characteristics of reservoirs in the Gidgealpa Group. There are two principal components of each study: a facies model and a chronostratigraphically significant subdivision of the units of interest. The principal reservoirs (Tirrawarra Sandstone and Patchawarra, Epsilon and Toolachee Formations) contain only two to four palynological zones and detailed studies of reservoir sands are beyond the scope of biostratigraphic resolution. Twelve reservoir sands, representing perhaps 25% of southern Cooper Basin gas reserves, occur within the lower to middle Toolachee Formation in the Moomba and Big Lake Fields (Mackie *et al.*, 1995). Since these reservoirs all fall within the PP4.3 subzone characterised by the oldest consistent occurrence of *Dulhuntyispora dulhuntyi* (Fig. 7.2), detailed subdivision of this 40 m thick stratal succession is mainly lithostratigraphic. Coal seam correlation has been the yardstick applied to most studies of the Toolachee and Patchawarra Formations and the commonest facies model is the meandering fluvial model.

Mackie *et al.* (1995) revised correlation of the Toolachee Formation in the Moomba Field. Coal seam correlation in this formation was abandoned in favour of correlating a lacustrine rhythmite recognised as a significant datum by Williams (1982, 1984). The floodbasin lake facies is characterised on wireline logs by a prominent gamma ray

\* The P = Permian notation is carried over from earlier ideas that the PP1 zone was entirely Permian in age.







*Permo-Triassic index forms.* (a) *Pseudoreticulatispora pseudoreticulata*, (b) *Phaselisporites cicatricosus*, (c) *Praecolpatites sinuosus*, (d) *Propinquispora praetholus*, (e) *Lopadiospora pannosa*, (f) *Lopadiospora vermithola*, (g) *Dulhuntyispora granulata*, (h) *Didectritiletes ericianus*, (i) *Dulhuntyispora dulhuntyi*, (j) *Dulhuntyispora parvitholus*, (k) *Lunatisporites noviaulensis*, (l–o) *Aratrisporites spp.*, (p) *Potonieisporites balmei*, (q) *Prototaphoxypinus bharadwajii*. All x 700 except (b) and (d) which are x 1000. (Photos 45276–45289)

anomaly which was interpreted as a maximum flooding event. The example illustrated by Mackie *et al.* (1995, fig. 6) is reproduced in Figure 7.3a and extended to show the gamma ray log above the lacustrine shale marker.

The gamma ray anomaly is separated from the underlying coal by 1–4 m of shale in Moomba 54 and 56 and Moomba North 2. In Moomba 52, however, the selected gamma ray anomaly is not underlain by coal, but is sharply *overlain* by coal. This Moomba 52 shale is considered to correlate, not with the selected datum, but with a shale at a lower stratigraphic level, as exemplified by shale X in Moomba 56. This yields the alternative correlation shown in Figure 7.3b. Shale X in Moomba 52 is interpreted to have an erosional upper surface representing a hiatus. The lacustrine rhythmite intersected in the other wells was eroded or more likely not deposited at this locality, and a peat mire eventually grew on the hiatal surface.

The alternative correlations displace the Toolachee Formation in Moomba 52 about 7.3 m with respect to the other wells, a displacement beyond the limit of vertical seismic resolution but comparable with channel sand thickness. This example emphasises the point that *both shales and coals, if correctly identified, are equally good yardsticks for the correlation of fluvial successions in the Cooper Basin.*

In studies of the periglacial Merrimelia Formation and Tirrawarra Sandstone (in which coal seams are absent or rare), field-wide shales have also been interpreted to contain flooding surfaces (Seggie *et al.*, 1994; Hamlin *et al.*, 1996; Seggie, 1997). These are regarded as analogous to marine maximum flooding surfaces and mark the transition from transgressive to highstand systems tracts using the Exxon approach to sequence stratigraphy.

The Permian Sydney, Gunnedah and Bowen Basins are coastal retroarc basins with alternating marine and non-marine, coal-bearing strata, 1000 km east of the Cooper

Basin (Fig. 5.1). Because of their economic importance these coal measures have been studied in detail using both Exxon sequence stratigraphy (e.g. Diessel, 1992) and Galloway's (1989) genetic sequence stratigraphy (Hamilton and Tadros, 1994).

The formation of peat and ultimately coal depends on a number of factors including the height of the water table and in a near-coastal setting this approximates sea level; thus one may expect a link between the formation of coal measures and relative sea-level change. However, in wholly intracratonic Gondwanan basins such as the Cooper, the base level which governed the height of the water table would have depended on the geomorphology of the glaciated terrain and the impedance of drainage by glacial deposits. Growth of peat and creation of lakes in the Merrimelia Formation, Tirrawarra Sandstone and Patchawarra Formation at least would have been controlled by local base level variation rather than by glacio-eustatic sea-level oscillations.

Sequence stratigraphic models, while indispensable in marine-coastal basins should be used with caution in non-marine settings such as the Cooper Basin because relative sea-level change may be less important than other factors in the accumulation of non-marine sediments.

## SEISMIC STRATIGRAPHY

Seismic amplitude variation, when qualitatively correlated with reservoir performance in Moomba Field, has led to the mapping of potentially productive sand trends (Mackie *et al.*, 1995). However, application of seismic stratigraphy to the Cooper Basin coal measures has not been followed up since a thought-provoking early study of the Patchawarra Formation by Stanmore and Johnstone (1988).

Before examining the work of these authors a brief description of the geometry of coal-bearing sequences is worthwhile. The high latitude Permian, Cooper Basin coals were formed by the compaction of peat. Raised mire deposits in peatlands divert fluvial channels and, although tough and resistant to erosion, peat is readily compacted under the weight of sand dumped e.g. by avulsion or crevasse splay processes (McCabe, 1984). As Mallett (1986) points out, even though fluvial deposits contain the normal suite of sedimentary structures, the interaction of the fluvial system with the mire system produces bed geometries quite distinct from those normally encountered. These include pods, ribbons and steeply dipping lenses of terrigenous clastics totally enclosed by coal seams. Stacked fluvial channels in structurally stable areas are attributed by McCabe (1984) and Mallett (1986) to peat compaction under the load of dumped sands while peat continues to grow in the adjacent mire. Channel deposits may also be stacked by growth faulting (Devine and Gatehouse, 1977; Stanmore and Johnstone, 1988).

A particularly useful account of coal seam and interseam geometry on a scale comparable with that encountered in the Patchawarra Formation has been provided by Johnson (1984). Johnson studied the Permian coal measures of the Goonyella Mine in the Bowen Basin from continuous exposures on the mine highwall. His measured sections are reproduced in Figure 7.4 and characteristics of his lithofacies are listed in Table 7.1 (see Johnson, 1984, fig. 2 and table 1). Also listed are suggested seismic reflector

attributes based on lithofacies geometry and the attitude of bounding surfaces.

Johnson (1984) identified two types of sandstone; one interpreted as stacked fluvial channels and the other as crevasse splay channels. The major channels have erosional bases but the preservation of *in situ* stumps protruding from the underlying claystone indicates that erosion was contemporaneous with deposition and tree growth in the adjacent marsh. Fluvial channels, though not evident at Goonyella, often cut down through coal seams into underlying sediments forming washouts and creating a mining hazard. Such channels show that the majority of peat compaction takes place on the floodplain and continuous coal seam seismic reflectors may be disrupted by erosion.

Proximal splay sands at Goonyella exhibit mounded geometry typical of sand dumping onto peat (Fig. 7.4).

Bidirectional downlapping seismic reflectors are expected in splay channels. The marsh and lacustrine claystones are thin but extensive and closely associated with coal seams. A tuff bed interpreted to represent a single eruptive event indicates that both coals and claystones are chronostratigraphically significant marker beds. The 10 m thick Goonyella Middle Seam has been traced along strike at least 130 km and the tuff, 0.5–2 m thick, has been traced over 250 km (Koppe in Johnson, 1984).

Further south in the same basin system (Sydney and Gunnedah Basins), coal seams 0.5–6 m thick occur in association with gravelly alluvial fan and braided stream deposits. Sections through these coal measures reveal lenticular-mounded braid bars, sheet-flow sands and continuous, split or locally eroded coal seams (Hunt and Hobday, 1984).

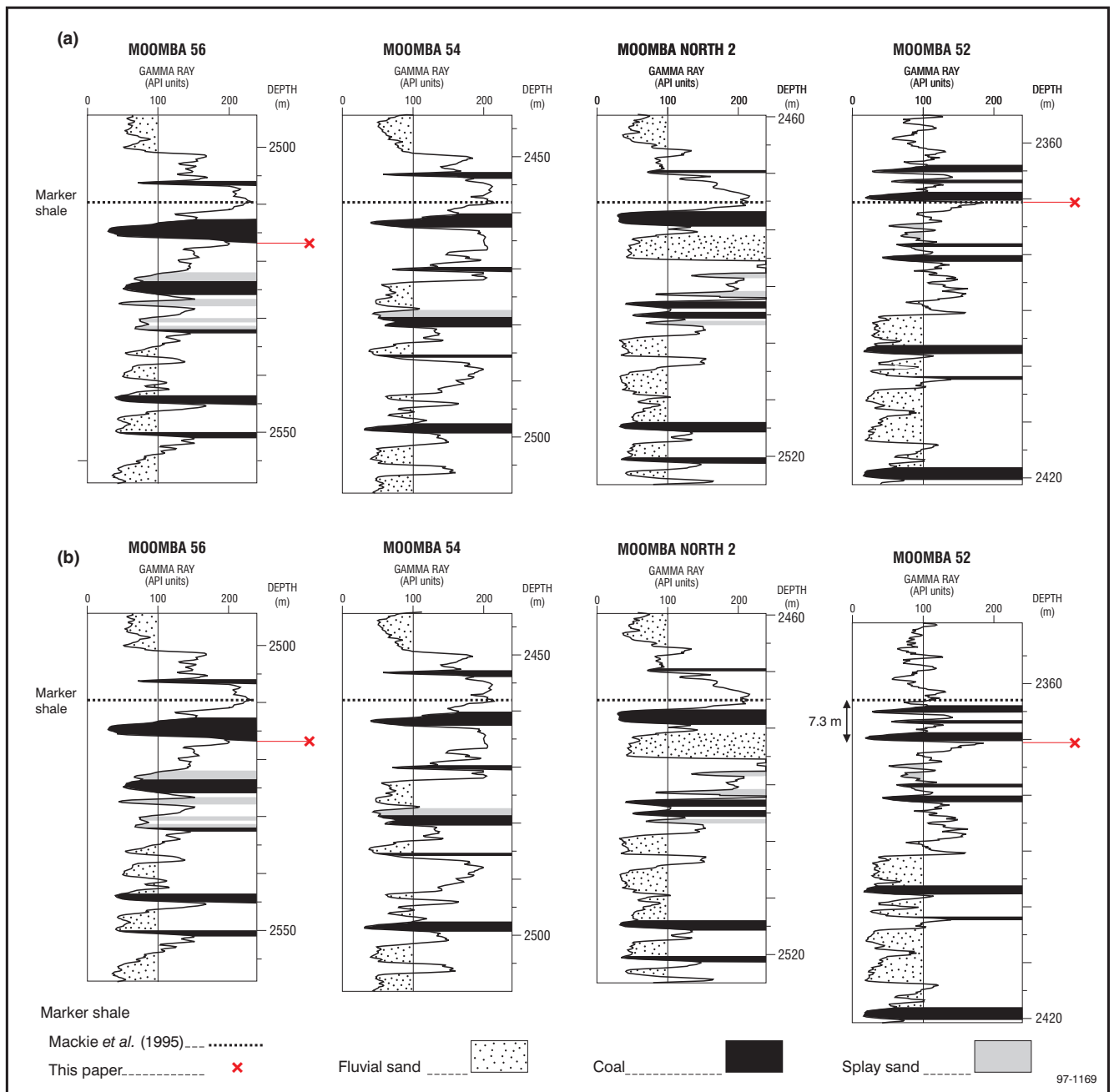


Fig. 7.3 Correlation of lower-middle Toolachee Formation in Moomba Field. (a) Using shale marker correlation of Mackie et al. (1995). (b) Showing alternative correlation of Moomba 52.

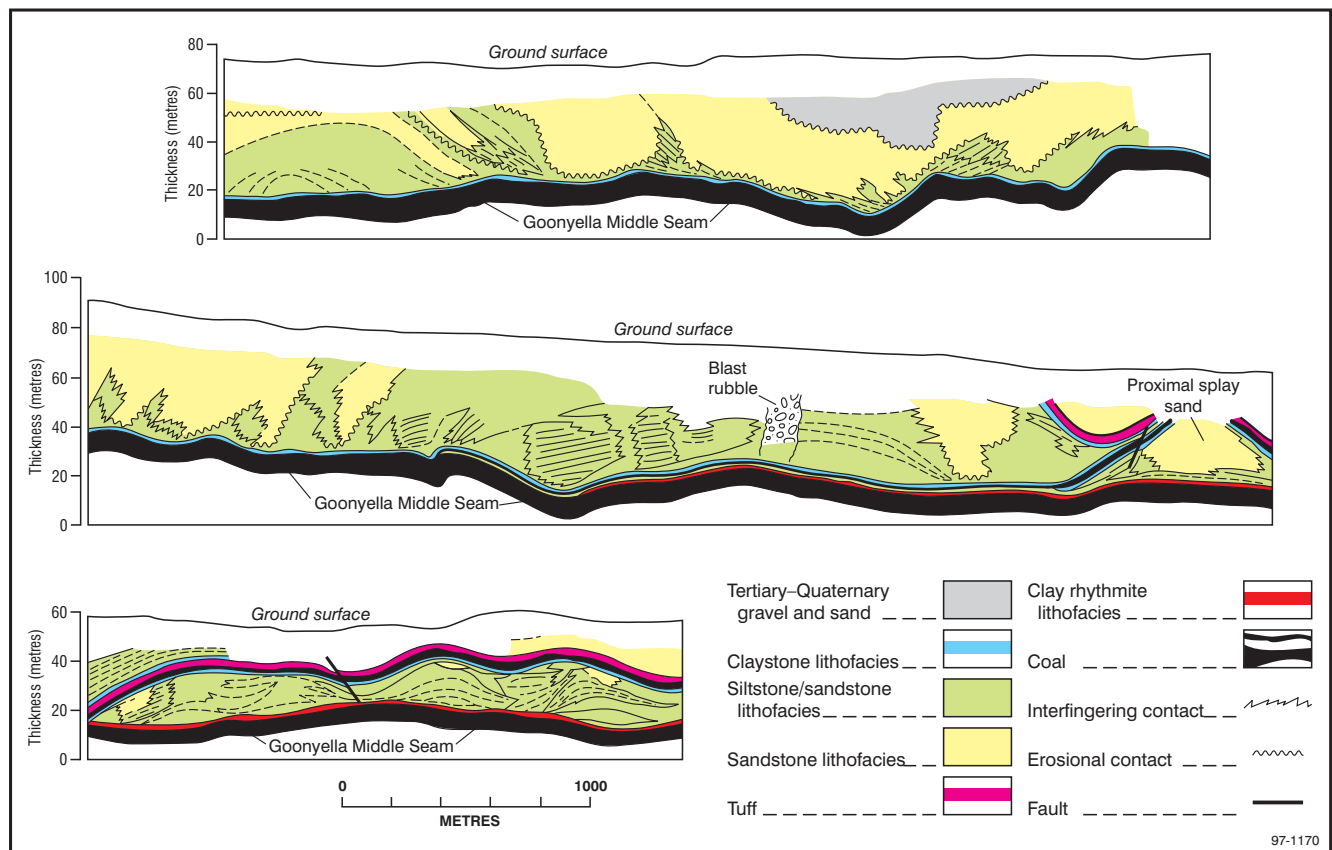


Fig. 7.4 Coal seam and interseam facies in the Goonyella Mine (after Johnson, 1984).

Despite the considerably higher rate of sediment accumulation in the east coast retroarc basins compared with the intracratonic Cooper Basin, the detailed architecture of their sandy alluvial and muddy to peat-rich marsh-mire systems forms a useful analogue for the coal measure sequences of the Gidgealpa Group.

Stanmore and Johnstone (1988) were of the same opinion when studying seismic data from the southern Patchawarra Trough, an area with reasonable seismic coverage but with little well control. Vertical seismic resolution at Patchawarra Formation depths (2000–3000 m) is 20–30 m and synthetic seismograms indicate peak reflection responses from the tops of the thicker coal seams.

Stanmore and Johnstone (1988, p.181) defined a seismic increment of strata (SIS) as an interval bounded by high amplitude seismic, peak reflection events. ‘An SIS unit is the seismic expression of an interval of strata composed of one or more cycles of sedimentation usually bounded by coals. A typical cycle of sedimentation comprises an upward fining sequence from basal lag and flood conglomerates passing to channel sandstones, to levee and overbank siltstones and shales, with coal seams forming the upper boundary.’

The authors illustrated wireline log responses and lithological profiles for channel, crevasse splay, overbank and swamp or shallow lake facies, and indicated where these may occur in a SIS. Furthermore they recognised common and recurring seismic reflector characteristics related to channels, levees (lens-shaped anomaly) and coal seam splits. Examples are shown in Figure 7.5. Boundary conditions at the tops and bases of thick coal seams may not

follow model predictions. Instead of representing conformity, the basal beds of a coal seam may rest on a surface of non-deposition of perhaps  $10^5$  years (McCabe, 1984), and the top surface of a coal seam, even though eroded by channel sands, may represent a geologically insignificant time interval.

Stanmore and Johnstone (1988) mapped eight SIS units in the Patchawarra Formation of the southern Patchawarra Trough and concluded that the main stratigraphic target is pinchout of channel sandstones due to depositional processes, with seals provided by enclosing shales, coals and/or impermeable sandstones.

In 1989, Lycium 1 was drilled to test an Eromanga Basin trap in the southern Patchawarra Trough. Stratigraphic traps in the Patchawarra Formation constituted a secondary target composed of sandstone ‘encompassed within sealing coal envelopes’ (Nugent, 1990). It was considered that gas in Kanowana 1 and Jack Lake 1 flowed from similar envelope traps.

Trace shows were recorded in the Eromanga section which was water saturated, but a number of the Patchawarra Formation sands had shows of varying quality even though the well was not optimally located for this target. A drillstem test of one sand did not flow to surface but recovered 1.5 kL (9.6 bbl) of 51° API oil, 0.3 kL (2 bbl) of mud-cut oil and 1.6 kL (9.8 bbl) of muddy water.

Kuenpinnie 1, drilled in 1991, was designed to test a Patchawarra Formation pinchout with three-way dip closure, the latter attributed to Tertiary compression (Baily, 1991a; Fig. 7.6). The seismic section shows the lenticular pattern typical of sands encased in coals of the Patchawarra

Formation but the drilled interval was shallier than expected. Multiple gas shows and spotted to solid yellow/green fluorescence prompted two drillstem tests but no fluid flowed to surface and gas-cut water and watery mud were recovered. Water resistivity ( $R_w = 0.41 \Omega m @ 24^\circ C$ ) indicates seal integrity and a lack of flushing by artesian water (assuming this recovery is not mud filtrate).

Although not commercial, the shows in Lycium 1 and Kuenpinnie 1 confirm the stratigraphic potential of the Patchawarra Formation and justify the seismic stratigraphic approach first proposed in 1988 by Stanmore and Johnstone.

### CHEMOSTRATIGRAPHY

Isotope chemostratigraphy attempts correlations using stable isotopes (of carbon, strontium oxygen, sulphur) from carbonates and sulphates deposited in essentially marine sedimentary environments. However, carbon in kerogen also yields potentially useful  $\delta^{13}C_{org}$  from plant fossils preserved in siliciclastic terrestrial as well as marine deposits. Plants preferentially store  $^{12}C$  during photosynthesis and organic matter is enriched in this isotope (hence depleted in  $^{13}C$ ), relative to carbonate carbon and carbon dioxide in the atmosphere or oceans.

Patterns of secular change of  $\delta^{13}C_{org}$  have been documented in marine and non-marine sedimentary basins, and in particular from Permian–Triassic boundary strata in Western Australian basins, the Bowen Basin (Morante *et al.*, 1994, Gorter *et al.*, 1995) and the Cooper Basin (Morante, 1995).

The Cooper Basin  $\delta^{13}C_{org}$  isotope profile shown in Figure 7.2, was constructed by Morante (1995) from kerogens extracted from cores in Merrimelia 3 which span the Late Permian and Early Triassic (his data are presented relative to driller's depth KB, which is 2.4 m high to logger). Total organic carbon (TOC) content, also shown, declines from a maximum value of 7.8% in the glossopterid coal-bearing upper Toolachee Formation to almost zero in the Arrabury Formation, consistent with the oxidised siltstone lithology of the latter. The  $\delta^{13}C_{org}$  profile begins to decline in the upper Toolachee Formation and reaches its

lowest value of -30.23‰, 15 m above the base of the conformably overlying Arrabury Formation, and about one metre above a PP6 microfloral assemblage. Early Triassic palynomorphs have been identified by G. Wood (in Morante, 1995), about 26 m above the lowest  $\delta^{13}C_{org}$  value, while intervening strata are barren. Morante interprets the negative excursion to coincide with the Permian–Triassic boundary as found in other parts of the world. However, the  $\delta^{13}C_{org}$  profile, in Merrimelia 3, instead of remaining strongly negative as in other basins, rapidly returns to values similar to those in the underlying Permian. This is attributed to the presence of detrital graphite which causes the isotope values to change. Morante (1995) and Retallack *et al.* (1996) have suggested that the abrupt global depletion of heavy carbon may have been due to catastrophic oxidation of organic matter over a short interval at the base of the Triassic, liberating carbon dioxide and creating a greenhouse atmosphere.

The ten million year global 'coal gap' which began in the Early Triassic, is attributed by Retallack *et al.* (1996) to mass extinction of plants tolerant to acidic, nutrient-poor conditions typical of high latitude peat swamps, and the slow subsequent adaptation of other plant groups to high latitude swamp environments.

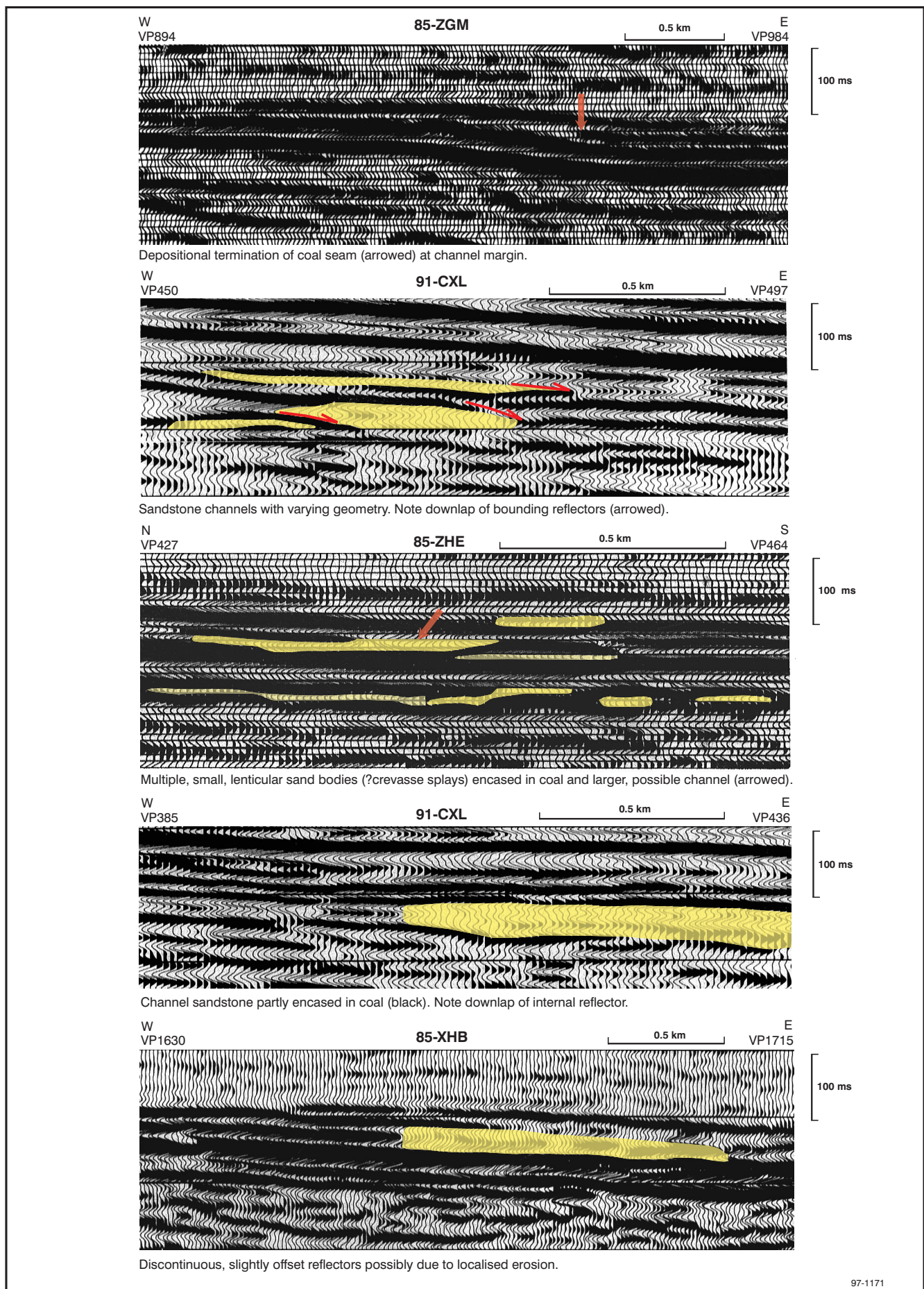
Kerogen isotope chemostratigraphy is at a preliminary stage in the Cooper Basin; kerogen data are facies dependent, at least in mixed marine and non-marine strata (Gorter *et al.*, 1995), and cored intervals are often not extensive. However, in spite of these apparent disadvantages, kerogen isotope studies are predicted to prove important, not only for correlation in strata barren of palynomorphs, but also for insights into floral distribution and hence the distribution of potential source rocks.

### MAGNETOSTRATIGRAPHY

While analysing organic carbon isotopes, Morante (1995) also documented normal and reversed palaeomagnetic intervals across the Permian–Triassic boundary in Merrimelia 3. This is the only palaeomagnetic work carried out in the Cooper Basin which is surprising

**Table 7.1** Geometry of facies in Goonyella Mine (after Johnson, 1984), with suggested seismic reflection characteristics.

Facies	Sandstone I	Sandstone II	Sandstone–siltstone	Claystone	Clay rhythmite	Coal
Height (m)	25–50	20–30	to 30	to 1.5	to 1.0	5–10
Width (km)	to 4	to 0.5	to 1.5	to 10	to 4	12
Shape	Sheet.	Lens/ribbon.	Mound, wedge, lens, sheet.	Sheet.	Sheet.	Sheet.
Depositional environment	Slightly sinuous fluvial channel.	Crevasse splay channel.	Proximal to distal splay.	Marsh.	Lake.	Mire.
Upper bounding surface	Not preserved.	Conformable, interfingering.	Gradational.	Gradational.	Gradational.	Sharp.
Lower bounding surface	Erosional but protruding stumps are preserved.	Erosional to conformable.	Conformable to sharp.	Gradational.	Sharp.	Sharp.
Internal structure	Cross-bedded.	Sheet-bedded.	Laminated to convolute bedded, common <i>in situ</i> stumps.	Laminated, rootlets, common <i>in situ</i> stumps.	Laminated, micaceous, small burrows.	Thinly bedded.
Seismic reflector attributes	Downlap, truncation, erosion.	Downlap, lensoid.	Lensoid.	Not applicable.	Not applicable.	Continuous, discontinuous, onlap.



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Fig. 7.5 Seismic reflection characteristics of Patchawarra Formation coal measures, southern Patchawarra Trough.

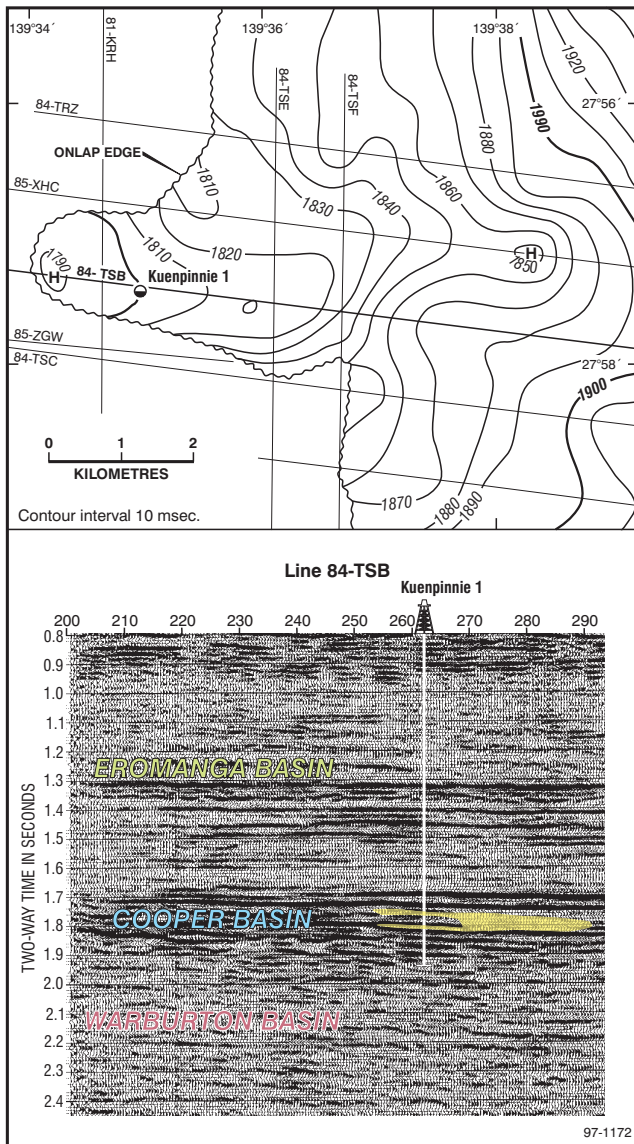


Fig. 7.6 Kuenpinnie 1, time structure contour plan near top of Patchawarra Formation coal measures, and seismic section 84-TSB, southern Patchawarra Trough.

given the abundance of cored sandstones amenable to such study.

A Devonian to Jurassic apparent polar wander path (Fig. 7.7) shows that the Cooper Basin was in high southern latitudes in the Late Permian and Early Triassic. Through much of the Late Carboniferous and Permian the geomagnetic field was reversed (the Late Palaeozoic Reversed Superchron), but there were several intervals of normal polarity chiefly in the Early Permian (Irving and Parry, 1963; Irving and Pullaiah, 1976). Numerous reverse polarity epochs are evident between the Late Permian and Middle Triassic (Haq *et al.*, 1987).

Morante's (1995) results show that polarity was mainly reversed across the Permian–Triassic boundary but there were also short intervals of normal polarity in the Early Triassic (Fig. 7.2). The close association of this polarity change with the negative organic carbon isotope spike in Merrimelia 3 is consistent with observations in China and Australia. Furthermore, overprinting which obscures this

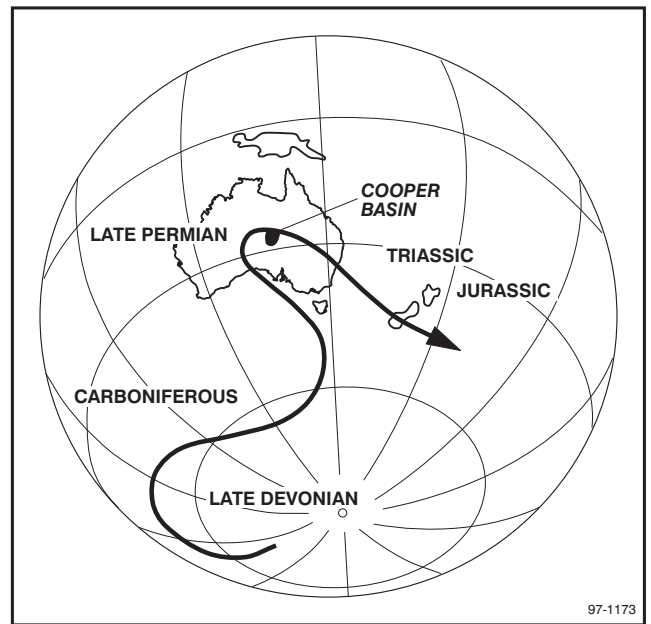


Fig. 7.7 Apparent polar wander path of Australia from Late Devonian to Jurassic (after Schmidt *et al.*, 1994).

transition in eastern Australia has not affected the Cooper Basin (Morante, 1995).

A study of the magnetic susceptibility of Cooper Basin cores and cuttings led Tucker (1992) to distinguish the Triassic Arrabury Formation from older units by virtue of that formation's distinctive susceptibility profile. An example from Packsaddle 2 is shown in Figure 7.8. Borehole logging tools have reached a stage of refinement where *in situ* magnetic measurements can now be made directly provided hole conditions are suitable, and successful trials have been reported from wells 80 km apart

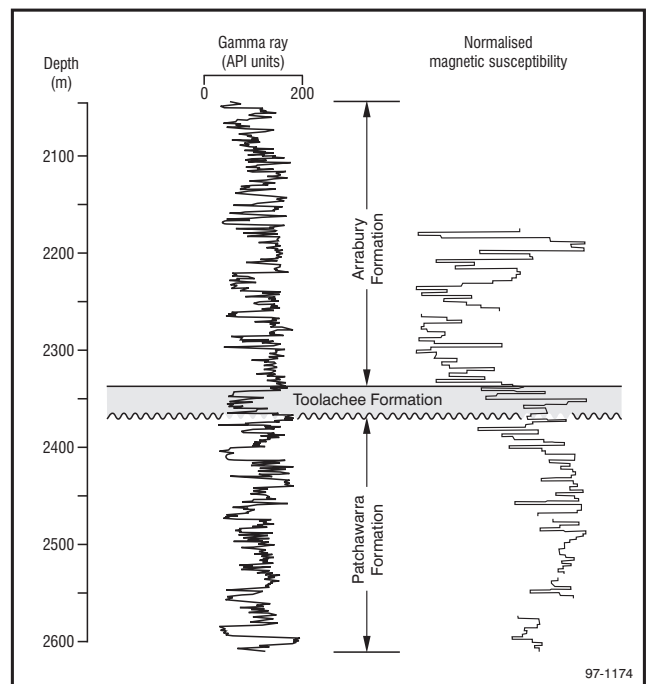


Fig. 7.8 Packsaddle 2, gamma ray log and normalised magnetic susceptibility profile of the Patchawarra, Toolachee and Arrabury Formations (after Tucker, 1992).

in the Jurassic of the Paris Basin, France (Bouisset and Augustin, 1993). It is likely that such tools will be of direct benefit in correlation of the oil-bearing Triassic succession, and may well assist correlation of the glacial succession at the base of the Permian and top of the Carboniferous.

# SOURCE ROCK DISTRIBUTION AND HYDROCARBON GEOCHEMISTRY

C.J. Boreham\*  
and A.J. Hill  
**Chapter 8**

## INTRODUCTION

Although numerous commercial and non-commercial hydrocarbon discoveries have been made in the Cooper Basin and overlying Eromanga Basin, the origin of the oil has been the subject of considerable controversy with varied views over an exclusive Cooper Basin source versus a combined Cooper and Eromanga Basins source. However, there appears to be a growing tide, particularly over the last decade, in favour of a mixed source. Recent studies by Powell *et al.* (1989), Michaelsen and McKirdy (1996), Ryan (1996) and Alexander *et al.* (1996) have provided conclusive evidence for an Eromanga Basin hydrocarbon source in the southern Cooper Basin, South Australia.

This chapter draws on existing company and Departmental data accessed from the Rock-Eval pyrolysis module of the PEPS database, recent technical reports commissioned by PIRSA (Alexander *et al.*, 1996; Michaelsen *et al.*, 1995) and results from the National Geoscience Mapping Accord (NGMA) Cooper and Eromanga Basins Project. The data have been compiled to identify potential and probable hydrocarbon source rocks, summarise the biomarker geochemistry for oils and source rocks, and establish genetic relationships between potential source rocks and hydrocarbon accumulations.

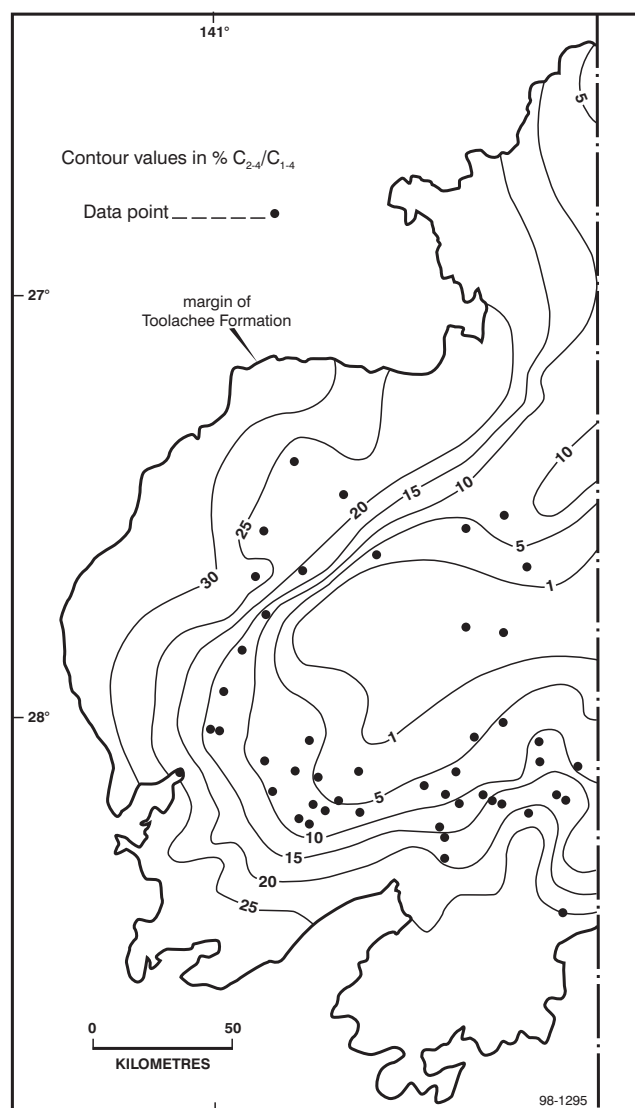
## BACKGROUND

### Cooper Basin

Numerous oil and gas fields in the Cooper Basin point to the Permian containing effective source rocks. Oil and condensate are typically medium to light (30–60° API) and paraffinic, with low to high wax contents. Most oil in Permian reservoirs contains significant dissolved gas and none shows any evidence of water washing (Hunt *et al.*, 1989). Gas composition is closely related to maturity with depth, with drier gas occurring towards basin depocentres (Figs 8.1, 8.2) although there is strong geological control on hydrocarbon composition (Hunt *et al.*, 1989). The Patchawarra Trough contains the bulk of the oil and wet gas reserves, consistent with local source rocks being in the 'oil window' while the Nappamerri Trough is overmature and contains mainly dry gas (Hunt *et al.*, 1989).

Permian source rocks have average total organic content (TOC) and S<sub>2</sub> pyrolysis yields of 3.9% and 6.9 kg of hydrocarbon per tonne, respectively (excluding coal). Locally, the Toolachee Formation is the richest source unit. The Patchawarra Formation is considered the other major source unit (Jenkins, 1989), especially the lower beds of

\* Petroleum and Marine Division, Australian Geological Survey Organisation



**Fig. 8.1** Toolachee Formation gas wetness (after Hunt *et al.*, 1989, fig. 3).

shale and coal (Hunt *et al.*, 1989). The lacustrine Murreee and Roseneath Shales appear to have little source potential (Hunt *et al.*, 1989). Permian non-marine clastics are characterised by inertinitic dispersed organic matter (DOM) with liptinite and vitrinite totalling <25% of the organic matter. On the other hand, the coal units are low in liptinite and contain subequal amounts of inertinite and vitrinite (Smyth, 1983). Sub-microscopic alginite dispersed within the inertinitic matrix of some Patchawarra coal has been suggested as a novel source for oil (Taylor *et al.*, 1988).

Together, the petrographic and geochemical evidence support coal and associated DOM as the effective source

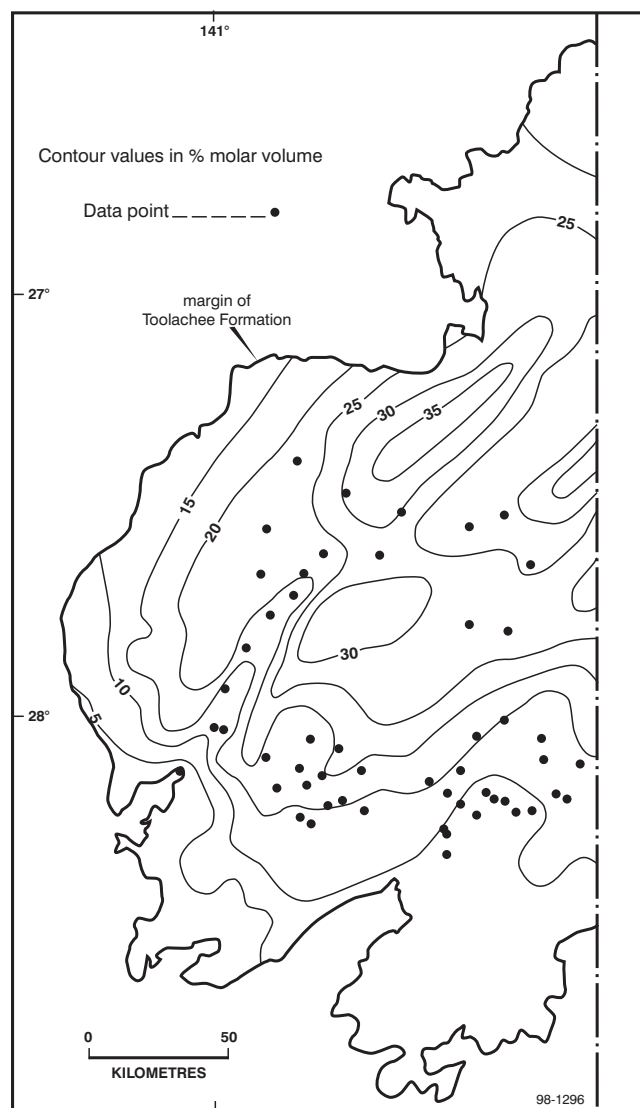


Fig. 8.2 Toolachee Formation CO<sub>2</sub> content (after Hunt *et al.*, 1989, fig. 4).

rocks capable of generating gas and minor oil, albeit in low yields (Hunt *et al.*, 1989). At maturity levels of 0.7–0.95% measured vitrinite reflectance ( $R_o$ ), initial generation from the richer facies led to partial filling of reservoirs with wet gas and oil. There is a sharp onset of significant hydrocarbon accumulation as the source reaches a maturity of 0.95%  $R_o$  (Hunt *et al.*, 1989). Faulting along anticlinal trends or basin margin pinchouts can provide migration paths for Cooper Basin-derived hydrocarbons into younger horizons (Heath *et al.*, 1989; Passmore, 1989).

## Eromanga Basin

The origin of oil in the Eromanga Basin has been attributed to a Cooper Basin source, an indigenous source or a mixture of both. Although it is recognised that Birkhead Formation and Murta Formation sources exist (Vincent *et al.*, 1985; Alexander *et al.*, 1988, 1992, 1996; Jenkins, 1989; Lowe-Young *et al.*, 1996; Powell *et al.*, 1989), there is still considerable debate as to their extent and relative contribution.

Potential source rocks of Jurassic and Early Cretaceous age contain Type II to Type III organic matter and have been shown to have maturities within the 'oil window' (onset of

oil generation between vitrinite reflectance of 0.65 and 0.7%; Kantsler *et al.*, 1983; Passmore and Boreham, 1982, 1986; Jenkins, 1989). Average TOC and pyrolysis yields are slightly lower for Eromanga Basin source rocks compared to Permian source rocks (Jenkins, 1989). However, the Birkhead Formation contains the most hydrogen-rich organic matter, has an average TOC of 2.5% and S<sub>2</sub> pyrolysis yield of 10.8 kg/t. Birkhead Formation coal is typically vitrinite rich (>50%) and inertinite poor (<10%), while the DOM is commonly more liptinitic and inertinitic (Smyth *et al.*, 1984). The Poolowanna Formation (formerly the 'basal Jurassic' unit in Queensland) shows fair to good source richness; the Westbourne Formation exhibits mainly fair source richness (Hawkins *et al.*, 1989).

Hydrocarbon extracts of Jurassic potential source rocks are paraffinic and waxy, similar to those from Permian sediments. This lack of distinction probably reflects only minor changes in organic facies and/or maturation histories (Gilby and Mortimore, 1989) or, alternatively, reflects oil contamination of Eromanga source rocks by migrating Permian hydrocarbons (Heath *et al.*, 1989). However, using age and source-specific Araucariacean conifer biomarkers, Alexander *et al.* (1988, 1992) proposed that Eromanga hydrocarbons can have both a combination from a local and Cooper Basin source or derive solely from the latter source. In addition, Jenkins (1989) suggested that the occurrence of 25,28,30-trisnorhopane, 25,28,30-trisnormoretane and 19-norisopimarane in an oil signifies an Eromanga source input. Using these criteria, a maximum Eromanga source contribution of 40% has been assigned to an individual pool (Jenkins, 1989) although an overall volumetric average of <20% can be attributable to an Eromanga source (Jenkins, 1989; Lowe-Young *et al.*, 1996).

But even this minor volumetric significance has been questioned by Tupper and Burckhardt (1990) since 19-norisopimarane occurs in Permian source rocks (Jenkins, 1989). Indeed, Heath *et al.* (1989) concluded a dominant Permian source for Jurassic oil and gas. Unlike Cooper Basin hydrocarbons, the Eromanga Basin petroleum in Jurassic reservoirs does not show regionally consistent trends in hydrocarbon type, composition and maturation. These differences have been interpreted to indicate variations in local source rock depositional environments (Vincent *et al.*, 1985; Alexander *et al.*, 1988; Powell *et al.*, 1989). The alternative model proposes that migration occurs beyond the edge of the Permian and Triassic seals and into the Eromanga aquifer system. Here, the physical and chemical properties of the Permian-sourced petroleum were significantly modified by pressure and temperature-induced migration fractionation and water washing (Heath *et al.*, 1989).

Oil in Cretaceous reservoirs is often geochemically distinct from that in Jurassic reservoirs. It is typically light (45° API), non-waxy, low sulphur, paraffinic crude (Vincent *et al.*, 1985) although waxy oil does occur (Michaelsen and McKirdy, 1989; Powell *et al.*, 1989). The Murta Formation oil is thought to be locally derived from Cretaceous source rocks (Vincent *et al.*, 1985; Michaelsen and McKirdy, 1989; Powell *et al.*, 1989). Pristane/phytane ratios (Pr/Ph = 5–9) are higher compared to those of greater reservoir age (Michaelsen and McKirdy, 1989). In addition, the Cretaceous oil shows lower levels of maturation based on

sterane isomers (Vincent *et al.*, 1985; Powell *et al.*, 1989; AGSO and GeoMark Research, in prep.) and their methylphenanthrene index (MPI-1) (Michaelsen and McKirdy, 1989; Powell *et al.*, 1989; Tupper and Burckhardt, 1990). Michaelsen and McKirdy (1989) and Powell *et al.* (1989) suggested that a major bacterial overprint of the original terrestrial organic matter has led to susceptibility to early generation of hydrocarbons. Although this may well be the case, kinetic studies on petroleum generation from potential Murta source rocks indicate that oil expulsion occurs at higher maturity levels (see Ch. 9). This discrepancy may be reconciled with the known source influence on the content of 1-methylphenanthrene (Alexander *et al.*, 1988, 1992) that will lower maturity estimates based on MPI-1. Furthermore, the results presented in Powell *et al.* (1989) show enough biomarker dissimilarities between Murta oil and the potential Murta source rocks to doubt whether a strong oil-to-source correlation has been demonstrated and the suggestion made by these authors, that migration effects could be an alternative explanation for the unusual chemistry of Murta oil, is explored further in this chapter.

Cretaceous accumulations which show reduced proportions of gasoline-range hydrocarbons ( $C_5$ – $C_{10}$ ) and low gas/oil ratios possibly reflect losses due to washing by meteoric waters, albeit to a less intense degree compared to Jurassic oil reservoirs (Vincent *et al.*, 1985; Michaelsen and McKirdy, 1989). The source for the Coorikiana Sandstone gas is less well studied, although a local Cretaceous source is highly likely (McKirdy *et al.*, 1986; Vincent *et al.*, 1985). Alternatively, an origin from an altered Permian-sourced petroleum has also been suggested for Cretaceous reservoired hydrocarbons (Heath *et al.*, 1989). The marine Cretaceous sequence contains good potential source rocks, but it is considered immature for hydrocarbon generation (Moore and Pitt, 1984). Clearly, more work needs to be done in order to distinguish local Eromanga Basin sourcing.

## SOURCE ROCK DISTRIBUTION

### Merrimelia Formation

Previous workers have concentrated on the source rock potential of DOM and coal of the Patchawarra and Toolachee Formations which represent the major source units and, to a lesser extent, the Epsilon and Daralingie Formations rather than focusing on the Merrimelia Formation and the Murteree and Roseneath Shales.

In the context of source quality and source richness of the Gidgealpa Group, shale of the Merrimelia Formation rates poorly. The formation is dominated by glaciogenic sandstone, siltstone and conglomerate with only minor amounts of mudstone, the last of which is organically lean. Thin, discontinuous coal lenses deposited as vegetated bar tops represent the best source rocks of the formation (hydrogen index (HI) average = 159; range 94–203). However, these units are infrequent and have little impact on the overall source quality.

Rock-Eval data from 13 wells (55 samples) are plotted in Figure 8.3 and selected Rock-Eval parameters for Cooper Basin shale and coal are summarised in Tables 8.1 and 8.2, respectively.

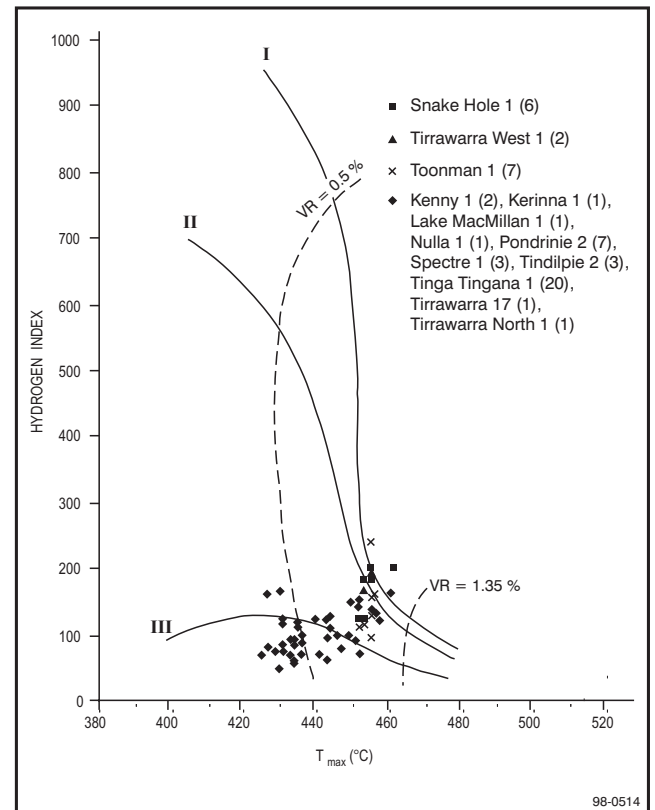


Fig. 8.3 HI versus  $T_{max}$  plot, Merrimelia Formation.

Source richness of Merrimelia Formation shale is generally very good (TOC average = 2.1) but ranges from poor to excellent (TOC = 0.03–9.9;  $S_1+S_2$  = 0.3–19 kg of hydrocarbon per tonne). Hydrogen indices are moderate (46–201) consistent with a Type III–IV gas-prone kerogen. Several wells have HI values >150, indicating potential for gas and minor light oil generation consistent with a Type II/III to III kerogen (Snake Hole 1, HI = 201; Tirrawarra West 1, HI = 163; Tinga Tingana 1, HI = 165).

### Patchawarra Formation

Coal and carbonaceous shale of the Patchawarra Formation represent the principal source rocks of the Cooper Basin, both in source richness and quality, and overall thickness. Patchawarra Formation total coal thickness is >60 m in the Weena Trough and up to 40 m in the Patchawarra Trough (see Fig. 6.6) in contrast to the Nappamerri Trough where total coal thickness rarely exceeds 10 m. Rock-Eval data are summarised in Tables 8.1 and 8.2, and plotted in Figure 8.4. Shale (<10% TOC) has the potential to generate oil (HI = 3–346;  $S_1+S_2$  = 0.04–36.6 kg hydrocarbon per tonne) and represents Type II/III kerogen, whilst carbonaceous shale and coal shale (10% < TOC < 30%) and coal (TOC > 30%) are capable of generating large quantities of oil ( $S_1+S_2$  = 2–182 kg hydrocarbon per tonne). In volumetric terms, the western Patchawarra Trough represents the most important kitchen where thick Patchawarra Formation shale and coal lie within the present-day oil window.

HI values >250 indicating good (Type II/III kerogen) to very good oil source potential (Type II kerogen) are found in Andree 2, Kurunda 1, Tibouchina 1, Snake Hole 1, Murteree 2, Gidgealpa 1 and Pondrinie 2 (Fig. 8.4).

**Table 8.1** Summary of Rock-Eval pyrolysis data for Cooper Basin shale, South Australia.

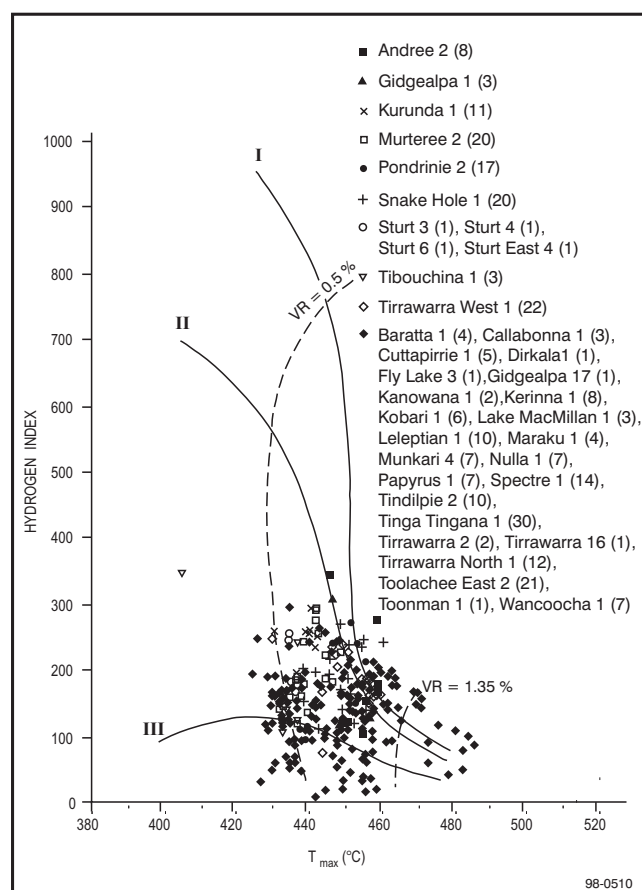
Unit	TOC (%)		Genetic potential		Hydrogen index (kg/t)		Oxygen index	
	average	range	average	range	average	range	average	range
Nappamerri Group	0.65	0.1–9.15	1.45	0.1–11.9	104	22–247	368	6–2509
Toolachee Formation	3.8	0.3–9.3	6.9	0.1–19.5	128	8–215	32	0–278
Daralingie Formation	5.3	2.1–9.0	12.7	1.6–24.4	157	66–245	20	0–82
Epsilon Formation	4.2	0.1–9.8	7.0	0.2–22.1	142	51–472	72	0–541
Murteree Shale	2.6	1.7–4.7	2.5	1.0–6.6	71	41–131	103	17–455
Patchawarra Formation	4.4	0.2–10.0	7.7	0.04–36.6	132	3–346	43	0–480
Merrimelia Formation	2.1	0.03–9.9	4.2	0.3–19	102	46–201	59	0–251

NB. Present-day Rock-Eval parameters are not corrected for maturity.

**Table 8.2** Summary of Rock-Eval pyrolysis data for Cooper Basin coal and coal-affected shale, South Australia.

Formation	TOC (%)		Genetic potential		Hydrogen index (kg/t)		Oxygen index	
	average	range	average	range	average	range	average	range
Nappamerri Group	13.6	10.7–16.4	25.9	21.3–30.5	175	175–175	10	4–15
Toolachee Formation	26.6	10.4–73.4	61.5	21.2–187	214	141–330	5	0–12
Daralingie Formation	13.1	11–15	30.3	19–40	206	151–268	4	0–8
Epsilon Formation	30.7	10.3–64.9	68.7	3.8–177.2	197	11–385	6	0–17
Patchawarra Formation	28.2	10–84.5	54	2–182	177	12–347	8	0–42
Merrimelia Formation	28.7	14.1–57.9	47.8	15.2–130.2	159	94–203	8	0–13

NB. Present-day Rock-Eval parameters are not corrected for maturity.



**Fig. 8.4** HI versus  $T_{max}$  plot, Patchawarra Formation.

### Murteree Shale

Rock-Eval data from 10 wells (27 samples) are plotted in Figure 8.5 and summarised in Table 8.1. All samples plot within the Type III/IV kerogen envelope indicating a dry gas-prone source. TOC ranges from 1.7 to 4.7% (i.e. good to

very good), but genetic potential is poor to fair ( $S_1+S_2 = 1-6.6$  kg hydrocarbons per tonne), with the richest intersection occurring in Tindilpie 2.

Although these values point to poor source potential (observed HI = 41–131 kg hydrocarbon per tonne), initial HI values would be expected to be slightly higher although still gas prone.

There are no Rock-Eval data for Roseneath Shale sediments. Based on the same environment of deposition and stratigraphic relationship to the Murteree Shale, it is safe to conclude that it would share similar geochemical properties to this unit.

### Epsilon Formation

Rock-Eval data from 18 wells (50 samples) are plotted in Figure 8.6 and summarised in Tables 8.1 and 8.2. These data point to a Type II/III to Type II kerogen (i.e. good to very good oil source potential). HI values often exceed 250, with a carbonaceous shale sample from Andree 2 (HI = 472) and coally shale sample from Toonman 1 (HI = 385) having the greatest oil source potential. No organic petrology is available for either of these wells but presumably these samples would be exinite rich. Epsilon Formation shale demonstrates highly variable source richness (TOC = 0.1–9.8%;  $S_1+S_2 = 0.2-22.1$  kg hydrocarbon per tonne). Isolith maps of coal and mudrock percentage appear in Figures 6.24b and c, respectively.

### Daralingie Formation

Only 11 samples from four wells have been analysed for Rock-Eval pyrolysis (Fig. 8.7; Tables 8.1, 8.2). Such a small data set makes it difficult to predict basin-wide source richness and quality. Based on these wells, source richness of Daralingie Formation shale is moderate to very good (TOC = 2.1–9.0%;  $S_1+S_2 = 1.6-24.4$  kg hydrocarbon per tonne) and HI = 66–245 kg hydrocarbon per tonne,

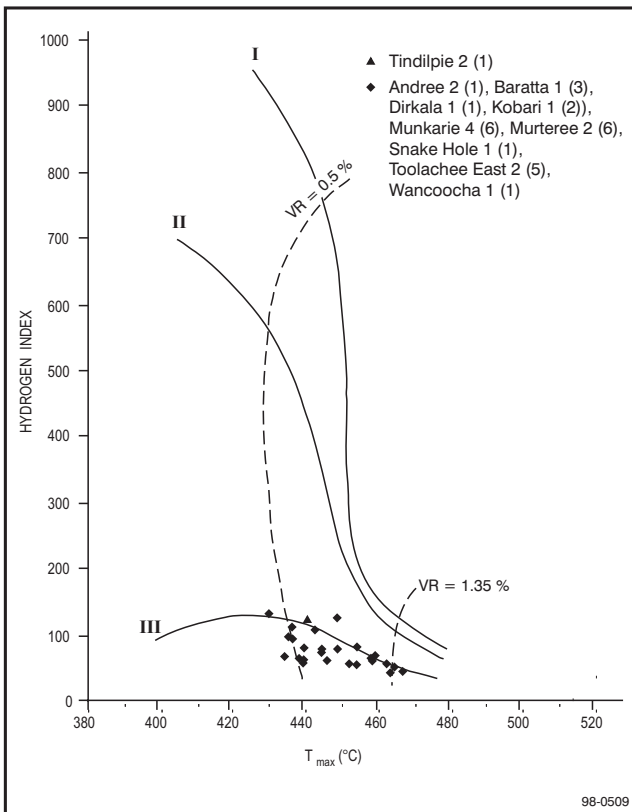


Fig. 8.5 HI versus  $T_{max}$  plot, Murteree Shale.

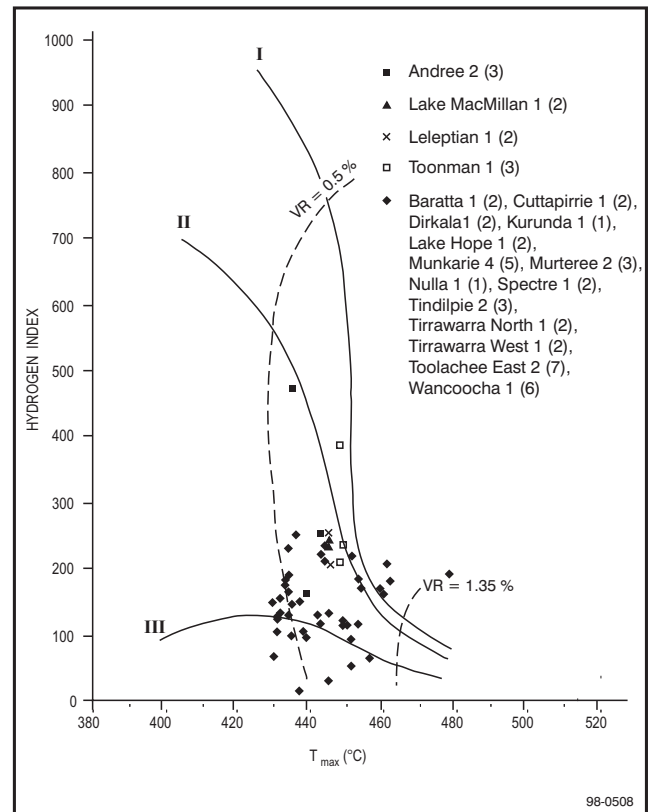


Fig. 8.6 HI versus  $T_{max}$  plot, Epsilon Formation.

indicating a moderately oil-prone source facies (Type II/III kerogen). Isolith maps of coal and mudrock percentage appear in Figures 6.26b and c, respectively.

### Toolachee Formation

Toolachee Formation coal and carbonaceous shale represent the second most important source rock unit of the Cooper Basin in terms of richness, quality and thickness. Combined Toolachee Formation coal reaches thicknesses >35 m in the northern Patchawarra Trough and 25 m in the Weena Trough, similar to regional coal thickness trends for the Patchawarra Formation. Isolith maps of coal and mudrock percentage appear in Figures 6.30b and c, respectively. Rock-Eval data from 22 wells (88 samples) are plotted in Figure 8.8 and summarised in Tables 8.1 and 8.2. They indicate a predominantly oil-prone source facies (Type II/III kerogen) with highly variable source richness (TOC = 0.3–9.3 for shale;  $S_1+S_2 = 0.1-19.5$  kg hydrocarbon per tonne). Source potential is also understandably variable given the large number of samples with HI values ranging from 8 to 330 kg hydrocarbon per tonne for the combined coal and shale data set. HI values >250 indicating good (Type II/III kerogen) to very good oil source potential (Type II kerogen) are found in Snake Hole 1, Toonman 1, Leleptian 1, Tirrawarra North 1 and Tirrawarra West 1.

In volumetric terms, the northern Patchawarra Trough represents the most important kitchen where thick Toolachee Formation shale and coal lie within the present-day oil window.

### Nappamerri Group

Thin, laterally discontinuous coal represents the best source rock of the Nappamerri Group whilst shale tends to

be organically lean. The oxidised humic-rich gas-prone nature of the kerogen is supported by Rock-Eval (Fig. 8.9; Tables 8.1, 8.2). Oxygen index (OI) for the shale averages 368 mg CO<sub>2</sub> (S<sub>3</sub>)/g TOC and range from 6 to 2509, whilst HI averages 104 kg hydrocarbon per tonne indicating an

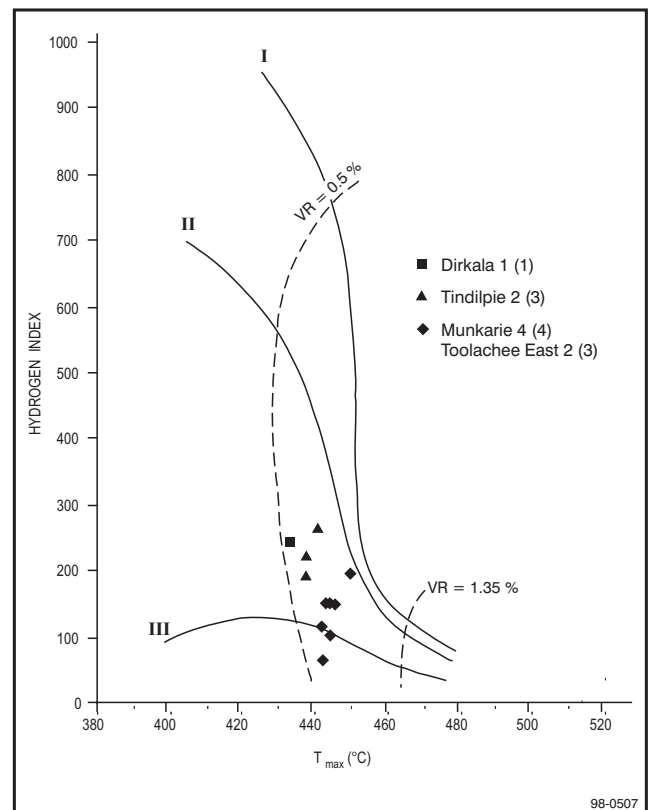


Fig. 8.7 HI versus  $T_{max}$  plot, Daralingie Formation.

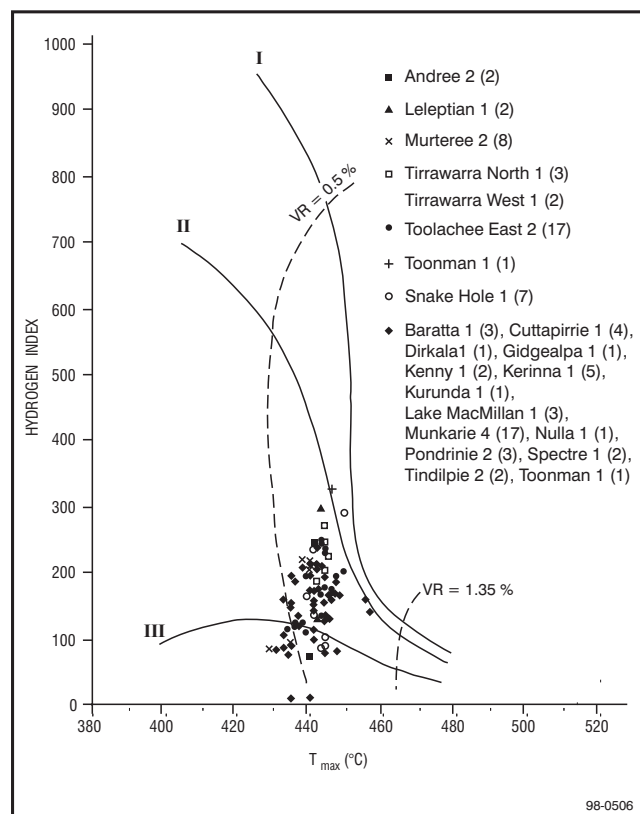


Fig. 8.8 HI versus  $T_{max}$  plot, Toolachee Formation.

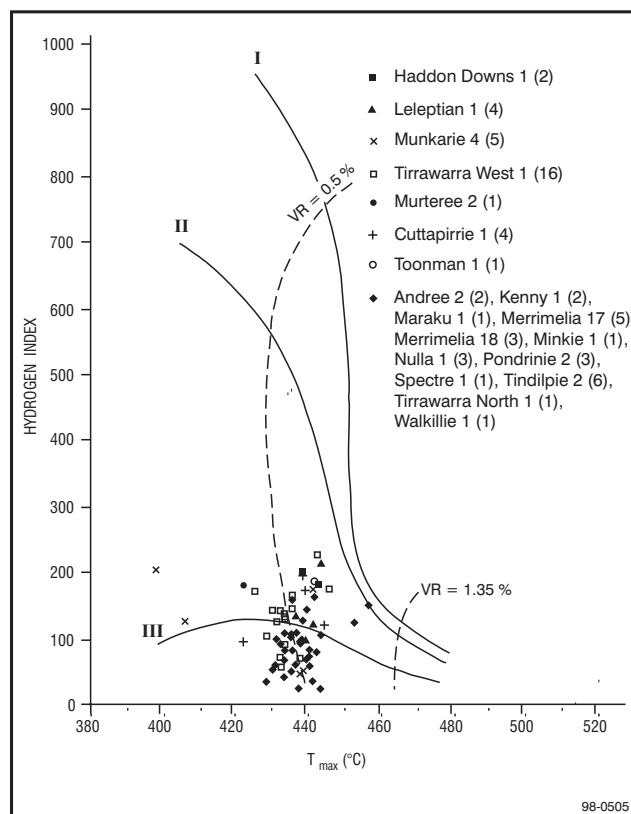


Fig. 8.9 HI versus  $T_{max}$  plot, Nappamerri Group.

oxidised Type III/IV kerogen. Wells with HI values >150 include Haddon Downs 1, Leleptian 1, Toonman 1, Cuttahirrie 1, Tirrawarra West 1 and Munkarie 4.

## PETROLEUM GEOCHEMISTRY

The following synopsis of the petroleum geochemistry of the Cooper Basin is drawn from the NGMA Cooper and Eromanga Basins Project which is due for completion in September 1999, and draws on a regionally significant data set of parameters based on bulk chemistry, gas chromatography, gas chromatography-mass spectrometry, and *n*-alkane isotope profiles of oils and condensates. The outcome of this analysis is to better understand the active source rocks of the Cooper and Eromanga Basins, and provide a reassessment of their relative contributions to oil occurrences in these basins. It was considered imperative that this product-based analysis not only address factors associated with primary source and maturity controls, as traditionally has been the case, but to understand the influence of secondary alteration processes such as migration fractionation, water washing and biodegradation on oil chemistry. Additional factors such as contamination during secondary migration and multiple charge histories may have compounded to influence oil composition. The latter two are the subjects of a separate study currently underway by the Universities of Adelaide and Cologne (Germany).

## BULK CHEMISTRY

Appendix 2 lists the API gravity and  $<C_{15}$  fraction of the whole oil. As expected, the cross-plot of the two parameters shows a positive linear relationship (Fig. 8.10), but the large 'scatter' suggests that the relationship between oil

composition and API gravity is rather complex. The API gravities range from 35 to 55, representing a medium to light oil-condensate. At the low end of the API range,  $<C_{15}$  fractions range from 0 to 15%, while up to 90% of the  $<C_{15}$  fraction is able to be lost on standing from the high API gravity light oils. In the Cooper and Eromanga Basins, it is common for vertically stacked oil reservoirs to show a progression from low API gravity oils in the deeper reservoirs to the highest API gravity oil-condensate in the shallowest reservoir (Heath *et al.*, 1989).

## SOURCE CONTROL

### Light hydrocarbons

Mango (1990) suggested that petroleum formation is mainly controlled by catalytic reactions mediated by transition metals (Mango *et al.*, 1994) and not, as traditionally believed, by thermal cracking processes (Tissot and Welte, 1984). Mango (1990) supported his views with genetic relationships between various light hydrocarbon components.

Figure 8.11a shows a strong correlation between the branched hydrocarbons 2,3- and 2,4-dimethylpentane. There is very little relationship with reservoir position and the major control is associated with the bulk parameters (Fig. 8.10) in which the oils biased towards the lower molecular weight fractions have the higher weight percent of each of the two  $C_7$  compounds in Figure 8.11a. Furthermore, there is no clear distinction between oil from the different reservoirs using the source-related parameters P3 and P2+N2 (Fig. 8.11b). This suggests that oils from the Eromanga and Cooper Basins are from a similar source or that, if there are multiple sources, secondary alteration

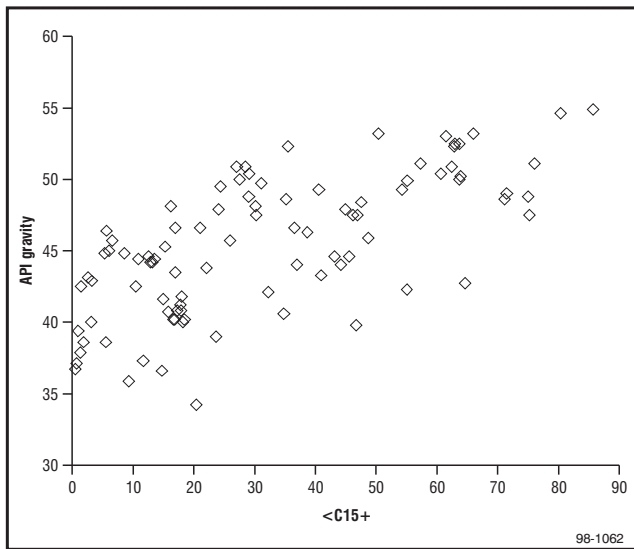


Fig. 8.10 Plot of API gravity versus  $\langle C_{15}$ .

processes are sufficiently strong to overprint the source signature.

### *n*-Alkanes and isoprenoids

Gas chromatograms of representative whole oils are shown in Figure 8.12. Appendix 2 lists a range of parameters derived from quantisation of individual compounds from the gas chromatographic traces. For the vertically stacked reservoirs (Fig. 8.12), the variation in API gravity is readily reconciled at the molecular level. Since *n*-alkanes are the major class of compounds of the oil, they can be considered representative of oil as a whole. Waxy *n*-alkanes, maximising between *n*-C<sub>21</sub> and *n*-C<sub>23</sub>, dominate the *n*-alkane profile of the deepest oil and progressively give way to lower molecular weight homologues higher in the succession. This variability is further illustrated in the ternary diagram of the relative proportion of *n*-C<sub>11</sub>, *n*-C<sub>17</sub> and *n*-C<sub>23</sub> together with colour-filled contours defining the composition limits of oil from the main reservoirs (Fig. 8.13). Light oil within the Cooper and Eromanga Basins ranges up to 90% *n*-C<sub>11</sub> whereas up to 70% *n*-C<sub>23</sub> is characteristic of the low API gravity oil. The composition of Cooper Basin oil (representatives from Merrimelia Formation to Nappamerri Group) shows two end-member groupings. One group is dominated by light hydrocarbons (*n*-C<sub>11</sub> dominant) while the other group is the high wax oil (*n*-C<sub>23</sub> dominant). Compared to this latter group, Eromanga Basin oil shows slightly lower *n*-C<sub>23</sub> content. The highest *n*-C<sub>17</sub> content is encountered in oil from the younger reservoirs (Murta, Wyandra and Cadna-owie). A secondary group of light oil is also encountered in the Murta Formation. Namur Sandstone oil shows a similar range of *n*-alkane compositions to the Murta oil, while oil lower in the section (Westbourne to Poolowanna) show a much narrower range of *n*-C<sub>17</sub> content, with the variability distributed between *n*-C<sub>11</sub> and *n*-C<sub>23</sub>.

All oil accumulations have Pr/Ph >3, indicative of a predominantly non-marine source from terrestrial organic matter (Fig. 8.14). Furthermore, the progressive change from waxy to light oil has been interpreted to indicate an increased contribution of bacterial or algal source inputs to the lighter oil (Powell *et al.*, 1989). An alternative

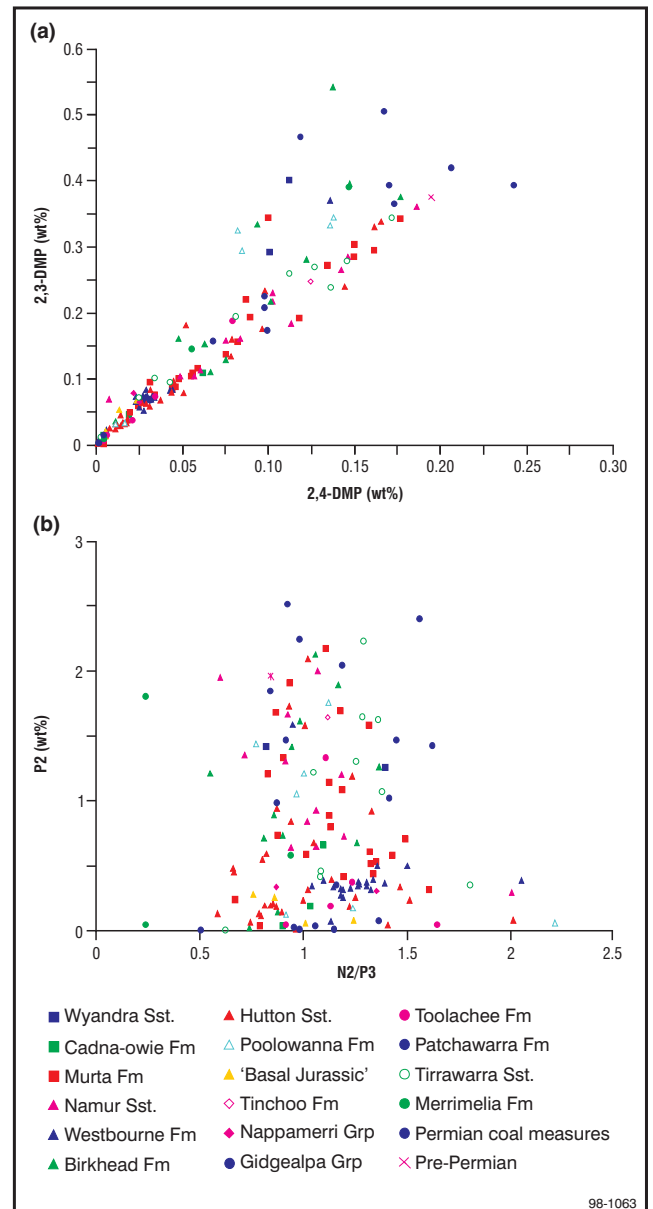


Fig. 8.11 Mango plot of (a) 2,3- versus 2,4-dimethylpentane (DMP), (b) source parameter ( $P2 = 2- + 3\text{-methylhexane}$ ;  $N2 = 1,1- + 1\text{-cis-}3 + 1\text{-trans-}3\text{-dimethylcyclopentane}$ ;  $P3 = 2,2- + 2,3- + 2,4- + 3,3\text{-DMP}$ ).

interpretation is that the original source input, although dominantly from terrestrial organic matter, has been masked by secondary alteration processes (see below).

### Biomarkers

The recognition of selective enrichment in saturated and aromatic hydrocarbons related to conifer-derived input has implied an effective Eromanga Basin source (Alexander *et al.*, 1988, 1992; Jenkins, 1989). Furthermore, this approach has enabled a semi-quantitative analysis of the proportion of Eromanga and Cooper source contribution to an oil (Jenkins, 1989). Consistent with the model, Figure 8.15 shows a clear distinction between oil reservoired in the Cooper Basin and that reservoired in the Eromanga Basin. The latter oil is characterised by enhanced relative enrichments in 1-methylphenanthrene, 1,7-dimethylphenanthrene, retene and 1,2,5-trimethylphenanthrene.

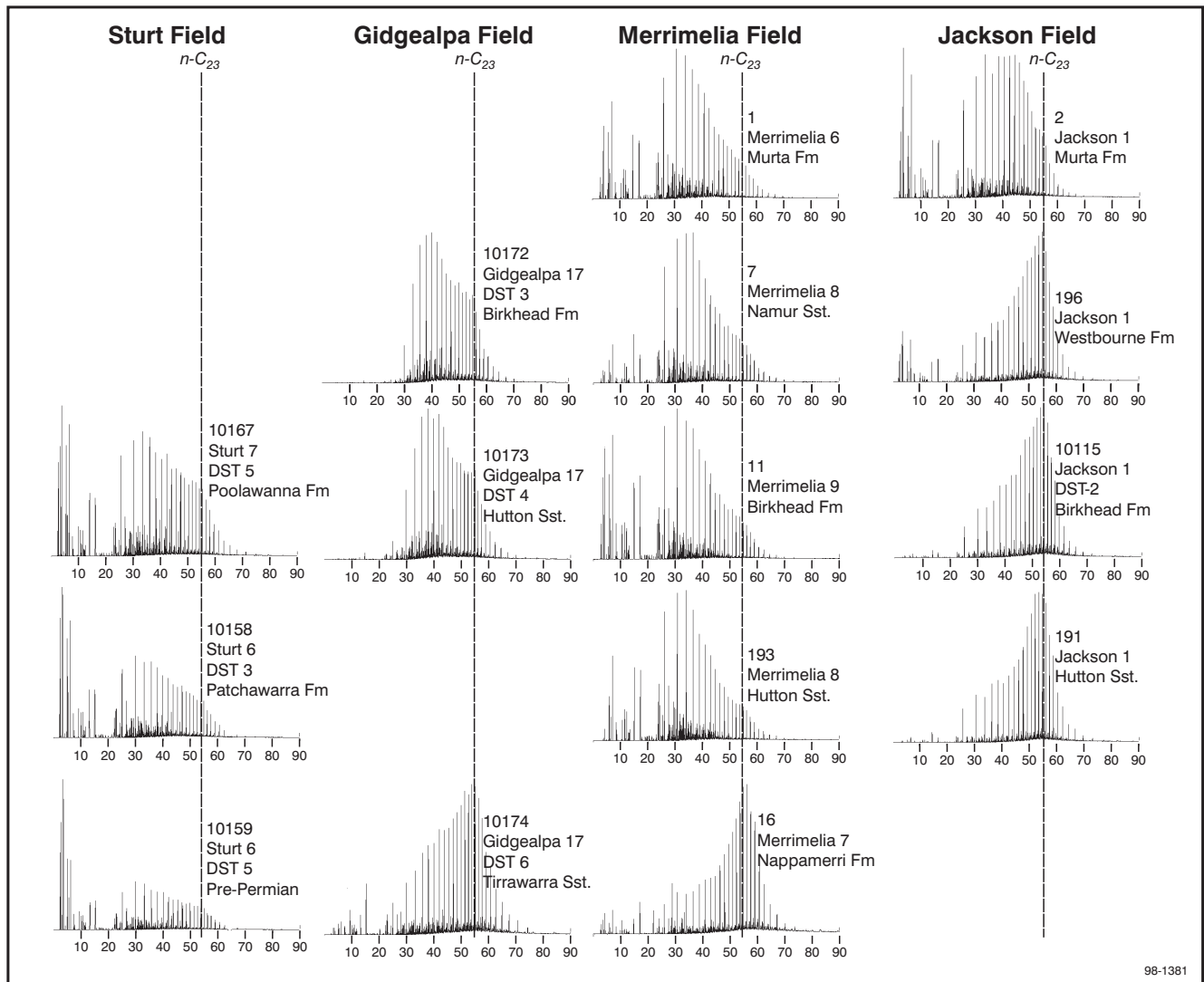


Fig. 8.12 Gas chromatograms for vertically stacked reservoirs from selected oil fields, Cooper and Eromanga Basins.

Moorari 4 shows the highest relative content of these components (Fig. 8.15) and is considered to be representative of an oil sourced predominantly from the Eromanga Basin (Alexander *et al.*, 1996). Considering its low maturity based on high Pr/n-C<sub>17</sub> and Ph/n-C<sub>18</sub>, and carbon preference index >>1 (Appendix 2), a local source from the Birkhead Formation is implied. Oil from stacked reservoirs in the Gidgealpa and Merrimelia Fields clearly show a compositional distinction between Cooper and Eromanga reservoirs. It could also be argued that the Eromanga Basin oil from these two reservoirs has a contribution from a Cooper Basin source since the Birkhead signature of this oil is not as strong as that shown in Moorari 4 (Fig. 8.15). This is consistent with the recent study by Boulton *et al.* (1998) where, using a greater range in biomarkers, the two Gidgealpa 17 oils from the Birkhead Formation and Hutton Sandstone have been attributed to a local Eromanga Basin source. It also agrees with a multi-component statistical analysis based on bulk carbon isotopes and saturated biomarkers (AGSO and GeoMark Research, in prep.; oil included in that study is shown in Appendix 2) where Cooper Basin oil at Gidgealpa and Merrimelia showed a low correlation with oil higher in the section in the Eromanga Basin. Thus, for these two oil

fields, a classical oil–oil correlation study based on biomarker and bulk carbon isotopes has implicated two main active petroleum systems (source–reservoir),

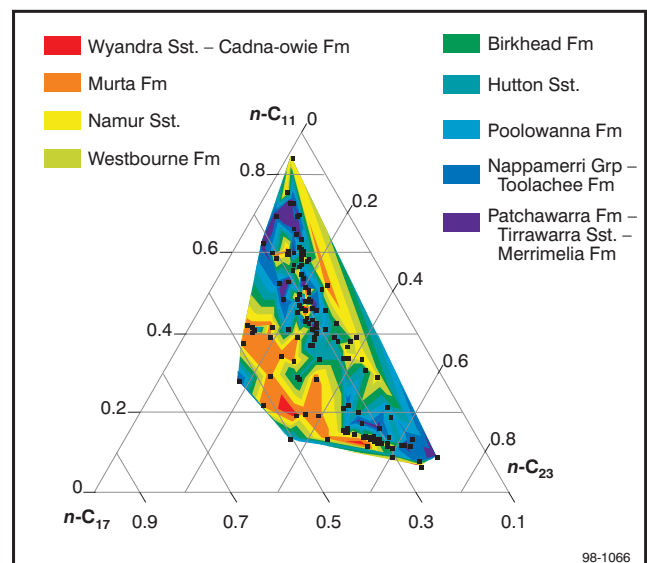


Fig. 8.13 Ternary diagram of relative proportions of n-C<sub>11</sub>, n-C<sub>17</sub> and n-C<sub>23</sub> in Cooper–Eromanga whole oil.

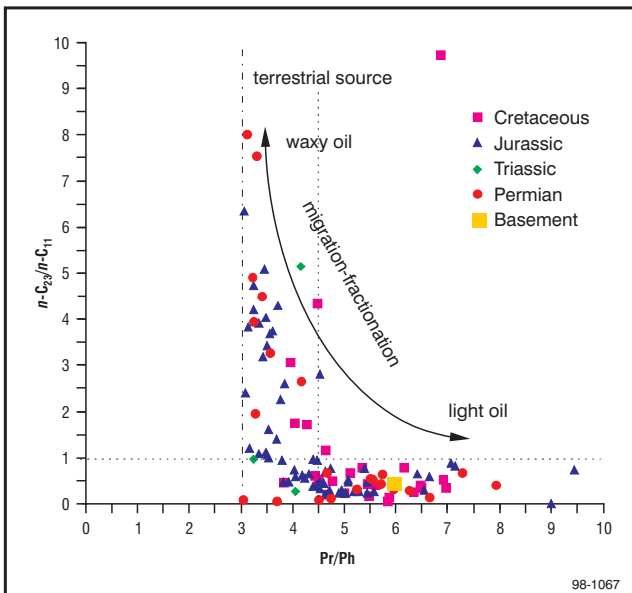


Fig. 8.14 Plot of  $n-C_{23}/n-C_{11}$  versus  $Pr/Ph$  for Cooper–Eromanga oil.

Cooper–Cooper and Eromanga–Eromanga, with latter showing variable contributions from a Cooper–Eromanga petroleum system.

### *n*-Alkane isotope profiles

Unquestionably, the biomarkers are information-rich and are an indispensable and valid component of any serious attempt in oil–oil and oil–source correlations leading to the identification of active petroleum systems (AGSO and GeoMark Research, 1996; Boreham *et al.*, 1997). However, it is debatable that quantitative analysis can be achieved by relying solely on those ‘classical’ sterane and triterpane biomarkers which are biased towards the higher molecular weight components. For example, Alexander *et al.* (1996) recently recognised that some oil in the Eromanga Basin is a composite produced by mixing of a light Permian oil with a waxy Eromanga oil of differing maturities. In this case, analysis of biomarkers would not do justice to the contribution of the former oil considering its much lower biomarker content. A similarly biased interpretation would exist for migration contamination where a light Permian oil migrates through Eromanga strata inherently enriched in biomarkers.

On the other hand, the *n*-alkanes represent the major structurally-related class of compounds in an unaltered oil. Their individual carbon isotopes have given new insights into the origins of Australian oil (Boreham and de Boer, 1998; Boreham *et al.*, 1995; Edwards *et al.*, 1997; Murray *et al.*, 1994; Summons *et al.*, 1995).

Figure 8.16 shows the *n*-alkane isotope profile for stacked reservoirs in Gidgealpa and Merrimelia oil fields together with oil from the Birkhead reservoir at Bookabourdie 8 and Moorari 4. For the Merrimelia and Gidgealpa crudes, the pronounced negative slope to the *n*-alkane isotope profile is consistent with an origin from a predominantly land plant source (Murray *et al.*, 1994). At Gidgealpa, the different slope and a wider isotopic range for the Patchawarra crude compared to the identical isotopic composition for the *n*-alkanes in Birkhead and Hutton oil

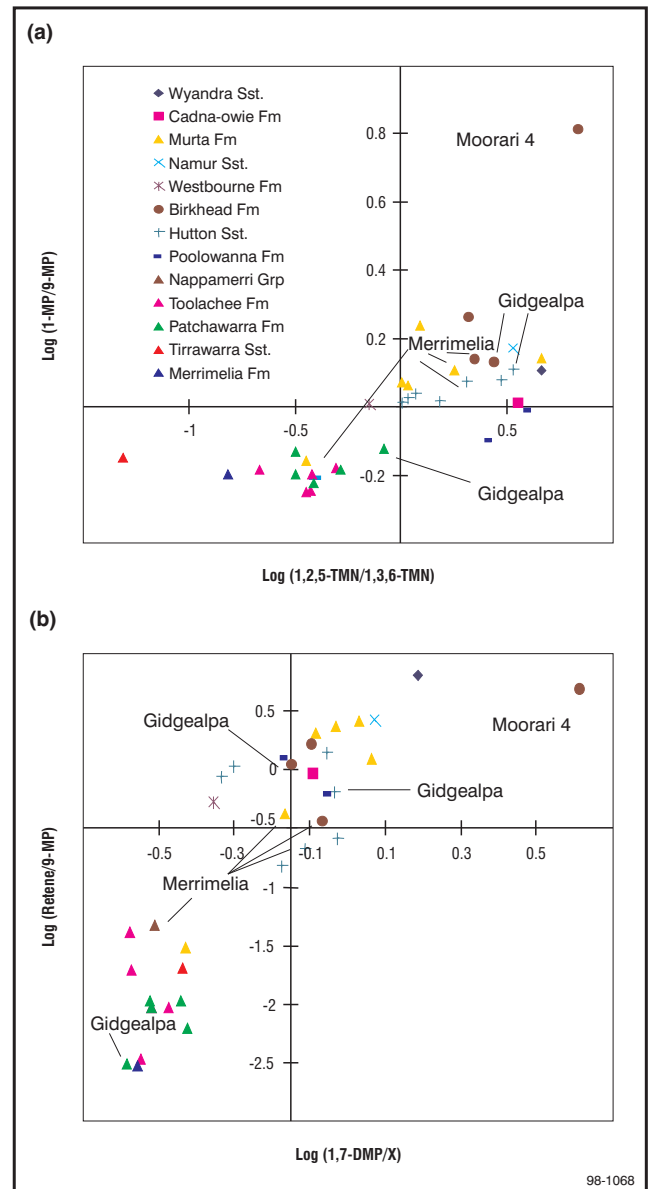


Fig. 8.15 Source indicators based on ratios of selected aromatic hydrocarbons (after Alexander *et al.*, 1988). MP = methylphenanthrene, TMN = trimethylnaphthalene, DMP = dimethylphenanthrene and X = group of other DMP isomers.

suggests a different source rock for oil from the Cooper and Eromanga Basin, in agreement with biomarker evidence (AGSO and GeoMark Research, in prep.).

A structural cross-section of the Gidgealpa Field (after Boulton *et al.*, 1998) shows possible migration pathways and source contributions to the oil accumulations (Fig. 8.17). The dissimilar *n*-alkane profiles between Patchawarra oil at Gidgealpa 17 (Fig. 8.16) and Gidgealpa 2 (not shown) indicates different source kitchens and migration pathways. On the other hand, the identical isotopic composition for Merrimelia Field oil implies a common origin (from a Permian source) for both the Cooper and Eromanga accumulations. However, a minor Eromanga source input is implied from the biomarker evidence (Fig. 8.15). Figure 8.18 shows a cross-section of the Merrimelia Field with

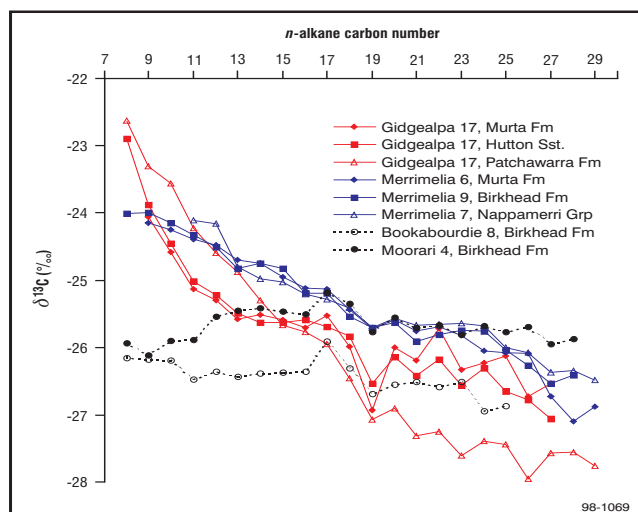


Fig. 8.16 n-Alkane isotope plot of carbon number versus carbon isotopic composition.

migration from Permian source rocks responsible for the major charge to the Eromanga Basin oil accumulations.

Birkhead Formation oil in Moorari 4 and Bookabourdie 8 shows a different isotopic profile to Birkhead Formation oil at Gidgealpa and Merrimelia. The former have a carbon isotope composition that remains reasonably constant over the range  $n-C_8$  to  $n-C_{29}$ . This isotopically ‘flat’ profile is considered a characteristic of an oil generated locally from the Birkhead Formation and establishes the existence of oil accumulations primarily from this source. The two wells are notably within the region of thickest Birkhead Formation (Paton, 1986). The isotopic difference of up to 1‰ between the  $n$ -alkanes in the Moorari and Bookabourdie oil suggests that isotopic variations of this magnitude are due to slight changes in organic facies. Indeed, Paton (1986) has shown considerable lateral variations in the coal swamp to lacustrine environments for unit 2 (highest source potential) of the Birkhead Formation.

The isotopic variability between and within formations can be readily seen in the carbon isotopic composition of the organic matter from potential source rocks (Fig. 8.19). Here, an isotopic difference of up to 3‰ occurs in organic matter from rocks of the same formation. Furthermore, the range in isotopic composition of organic matter in the Eromanga Basin (average =  $-24.7‰$ ;  $sd = 1.4‰$ ;  $n = 18$ ) is similar to that in the Cooper Basin (average =  $-24.0‰$ ;  $sd = 1.5‰$ ;  $n = 13$ ). In Moorari 4 and Bookabourdie 8, there is no clear source distinction between Late and Early Permian source rocks based on bulk carbon isotopes. Furthermore, organic matter from the Cretaceous Murta Formation and the Permian of the Cooper Basin appears to be isotopically indistinguishable. Although this may suggest that bulk isotopes offer little source differentiation, the regional isotopic variability in the Murta Formation is much less than that for any of the other formations. For the latter, organic matter in the Jackson Field of South-West Queensland is slightly lighter isotopically than in the same formations in the Merrimelia area of South Australia.

For reservoirs where multiple charging from Permian and Jurassic sources is suspected (Alexander *et al.*, 1988,

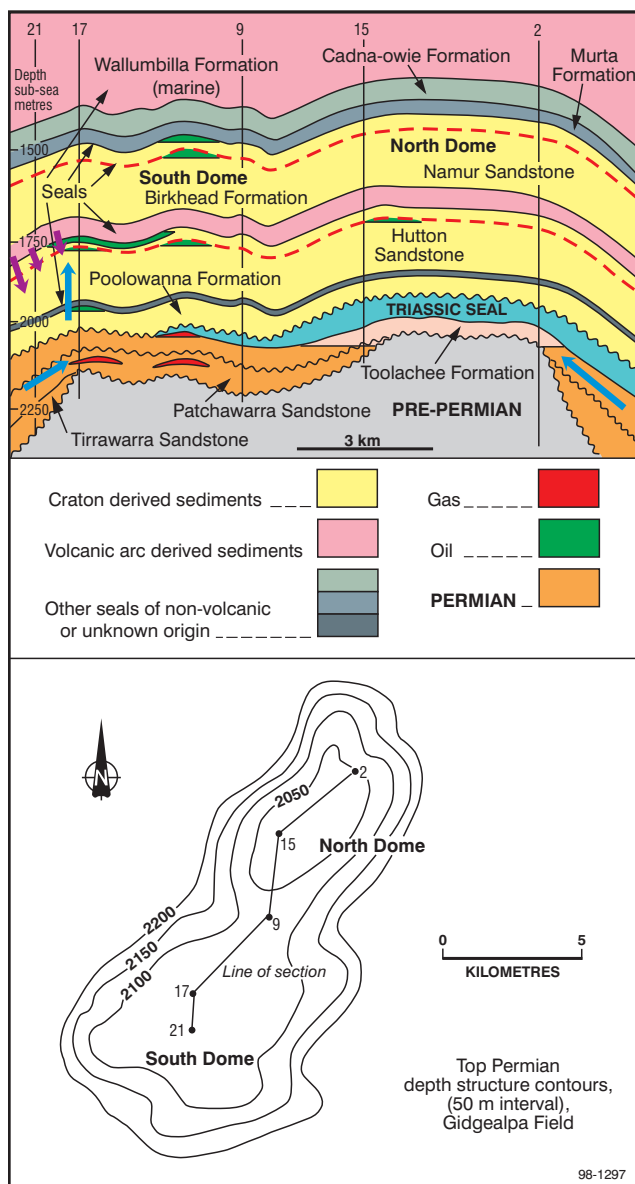
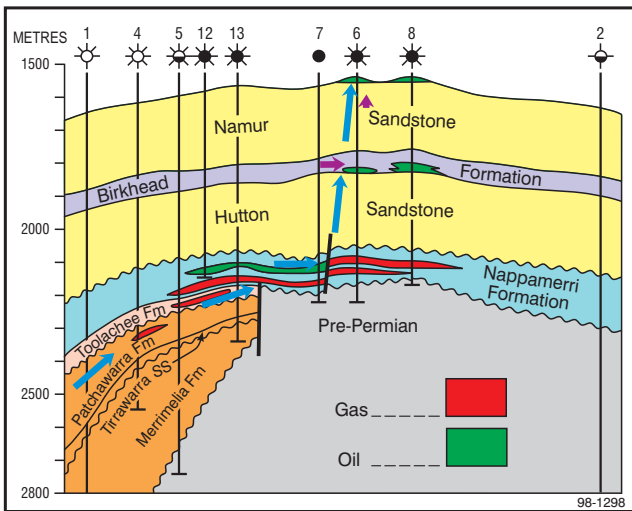


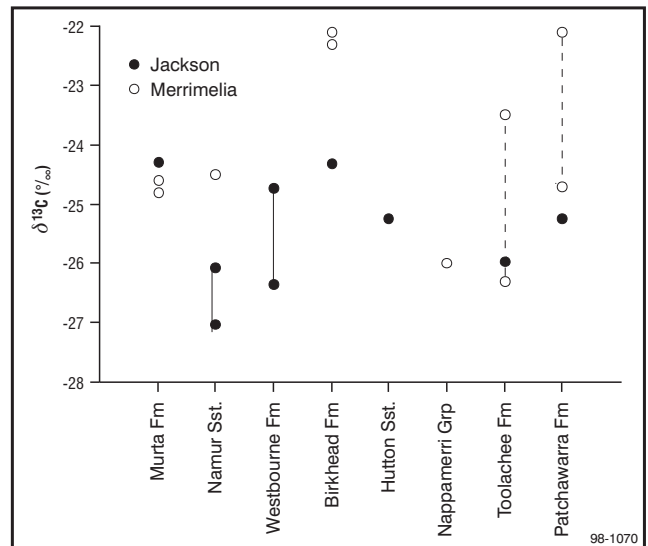
Fig. 8.17 Cross-section of Gidgealpa Field showing oil and gas accumulations and migration pathways from Cooper (blue arrows) and Eromanga (purple arrows) sources (after Boulton *et al.*, 1998, fig. 14).

1992; Jenkins, 1989; Heath *et al.*, 1989), a measure of the  $n$ -alkane ‘isotopic gradient’ may provide an estimate of the degree of mixing.

Figure 8.20 plots the isotopic difference between average isotopic composition over selected carbon number ranges between  $n-C_{10}$  and  $n-C_{25}$  for oil from Murta to Merrimelia Formations. Accumulations sourced from the Jurassic Birkhead Formation show the least isotopic differences. For the Gidgealpa 17 stacked reservoirs, a calculation based on the average isotopic difference in the range  $n-C_{10}$  to  $n-C_{20}$  of  $-1.7‰$  for a Cooper-sourced oil and an average of  $0.08‰$  for a Birkhead-sourced oil (Fig. 8.20) leads to 35:65 mixing of Permian and Jurassic sources (Fig. 8.17) in the Birkhead and Hutton oils (average isotopic difference of  $-0.54‰$ ). In this case a lower than 25% Birkhead-source contribution would not have been resolvable considering the  $0.5‰$  analytical error.



**Fig. 8.18** Cross-section of Merrimelia Field showing oil and gas accumulations and migration pathways from Cooper (blue arrows) and Eromanga (purple arrows) sources (after Bowering and Harrison, 1986, fig 6).

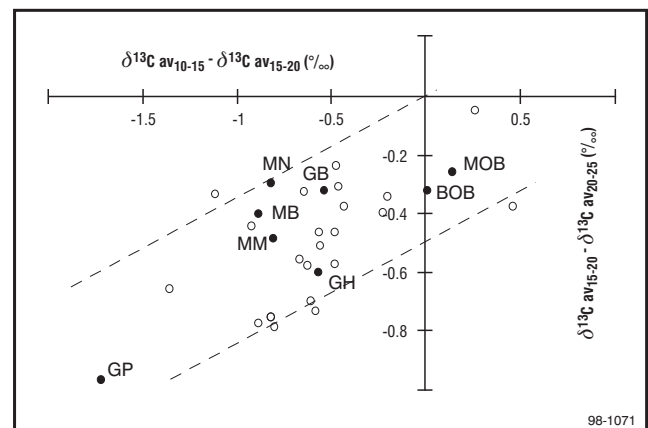


**Fig. 8.19** Carbon isotopic composition of organic matter from sedimentary rocks in the Jackson and Merrimelia wells. Data represent maximum and minimum values.

### MATURITY CONTROL

Almost every biomarker parameter is affected to varying degrees, by both source and maturity. Thus, the specificity expressed in the aromatic source parameters (Fig. 8.15) is diluted with increasing maturity and becomes unrecognisable past the main oil window. Similarly, the most commonly used aromatic maturity parameter (MPI-1) and the derived calculated vitrinite reflectance ( $R_c$ ; Radke and Welte, 1983) are source dependent for Eromanga Basin sediments by virtue of the presence of 1-methylphenanthrene in their formulae. The  $R_c$  values of the oil samples (in Fig. 8.15) are plotted in Figure 8.21 and are in the range  $0.5\% < R_c < 1.0\%$ . Oil higher in the section in the Eromanga Basin has, on average, the lowest  $R_c$ , as has been previously recognised (Alexander *et al.*, 1988; Michaelsen and McKirdy, 1989; Powell *et al.*, 1989; Tupper and Burckhardt, 1990). This  $R_c$  distribution, attributed primarily to maturity, has subsequently been used to infer migration directions from maturity gradients (Tupper and Burckhardt, 1990). An independent measure of maturity based on the highly stable, low molecular weight diamondoid structure (Chen *et al.*, 1996; methyl adamantane index (MAI) = 1-methyl adamantane/(1-methyl adamantane + 2-methyl adamantane) has proven useful in identifying maturity effects at the high maturity end (past peak oil generation; Chen *et al.*, 1996, 1998; Boreham *et al.*, 1997; Boreham and de Boer, 1998) where most hopane and sterane-based maturity parameters are ineffective. Figure 8.21 plots MAI versus  $R_c$  (based on MPI-1). The two parameters show a weak positive correlation although the oil has a higher extrapolated maturity range based on MAI ( $0.9\% < R_c < 1.2\%$ ) compared to that based on  $R_c$  ( $0.5\% < R_c < 1.0\%$ ). Despite the limited use of the MAI parameter, and uncertainties concerning its source dependency (cf. source dependency of MPI-1; Boreham *et al.*, 1988), the similar range in MAI for the Murta and Cooper oil compared to lower  $R_c$  for Murta oil may implicate a mixed origin with a high and low maturity fraction in the Murta oil.

Maturity effects are also evident in the *n*-alkane profiles. The Cooper oil from Merrimelia, Moorari and Strzelecki wells shows *n*-alkane isotope profiles with parallel negative slopes (Fig. 8.22), characteristic of oil derived from coal and associated terrestrial source rocks (Murray *et al.*, 1994). On the other hand, the Kanowana oil shows a much flatter *n*-alkane profile. Such a profile is similar to that displayed by Birkhead oil (Fig. 8.16) and is also typical of oil derived from marine source rocks (Murray *et al.*, 1994). Marine sediments are known to be present in the underlying Ordovician to Cambrian Warburton Basin (Sun, 1997), and fault-controlled migration from a deep source may be a possibility. Flat *n*-alkane profiles are characteristic of organic matter in sediments of similar age in the Officer and Amadeus Basins, but the *n*-alkanes are isotopically light (i.e.



**Fig. 8.20** Plot of carbon isotope difference between the average of ( $\delta^{13}C$  n-C<sub>10</sub> to  $\delta^{13}C$  n-C<sub>15</sub>) and the average of ( $\delta^{13}C$  n-C<sub>15</sub> to  $\delta^{13}C$  n-C<sub>20</sub>) versus the carbon isotope difference between the average of ( $\delta^{13}C$  n-C<sub>15</sub> to  $\delta^{13}C$  n-C<sub>20</sub>) and the average of ( $\delta^{13}C$  n-C<sub>20</sub> to  $\delta^{13}C$  n-C<sub>25</sub>). Oils: MM = Merrimelia 6, Murta Formation; MB = Merrimelia 9, Birkhead Formation; MN = Merrimelia 7, Nappamerri Group; GB = Gidgealpa 17, Birkhead Formation; GH = Gidgealpa 17, Hutton Sandstone; GP = Gidgealpa 17, Patchawarra Formation; MOB = Moorari 4, Birkhead Formation; BOB = Bookabourdie 8, Birkhead Formation.

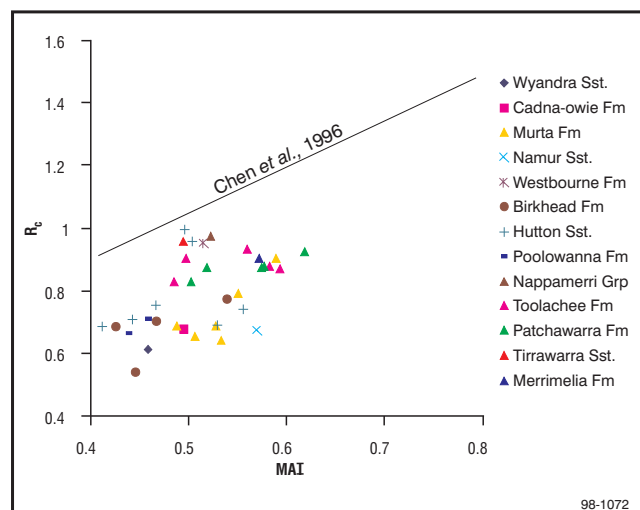


Fig. 8.21 MAI versus  $R_c$  plot (based on MPI-1 of Radke and Welte, 1983). The line of Chen et al. (1996) is the best-fit straight line for an effective vitrinite reflectance based on MAI.

depleted in  $^{13}\text{C}$ ) with  $\delta^{13}\text{C}$  mainly between  $-28$  and  $-32\text{‰}$  (Logan *et al.*, 1997), outside the range shown for any oil from the Cooper and Eromanga Basins. The isotopically heavy  $n$ -alkanes in Kanowana light oil–condensate are more likely to be high temperature products of secondary cracking reactions and the overall profile is predominantly maturity influenced.

## SECONDARY ALTERATION

### Migration fractionation

Migration fractionation (Curiale and Bromley, 1996) or evaporative fractionation (Thompson, 1987 1988) is one mechanism that can account for some of the systematic changes in composition for stratigraphically and spatially constrained oil reservoirs in the Cooper and Eromanga Basins. As upward-migrating petroleum experiences decreasing pressure, oil expands and higher molecular weight components become less soluble. Finally, as the fluid passes through the bubble point pressure, it separates into gas and oil-rich phases. Furthermore, ineffective oil seals in the deeper reservoirs can allow preferential leakage of low molecular components. In all of these processes a less mobile fluid (residual oil) becomes enriched in higher molecular components. Ultimately, in stacked reservoirs, low API gravity crude resides at the base and high API gravity light oil at the top of reservoirs (Fig. 8.12). However, there are many stacked reservoirs that do not show significant compositional differences (Fig. 8.12). This may be a function of multiple sourcing but could also reflect a phase with high gas–oil ratio (GOR) that does not undergo phase separation. For the latter, oil dissolved in gas could be an effective phase for lateral migration within the Cooper and Eromanga Basins and extending well past the Permian edge in Eromanga Basin reservoirs. Gas loss along the migration pathway will reduce the ability of the migrating phase to retain dissolved oil. Thus, an initial waxy oil leg devoid of low molecular weight hydrocarbons will be exsolved, becoming progressively enriched in light hydrocarbons with increasing migration distance from its

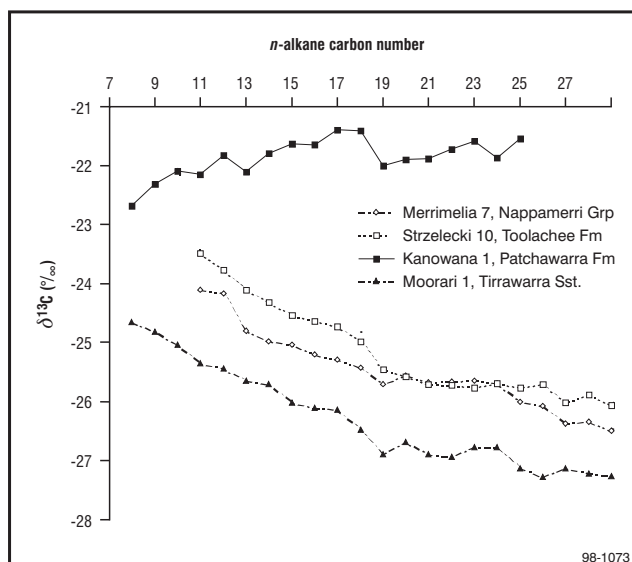


Fig. 8.22  $n$ -Alkane isotope plot of carbon number versus carbon isotopic composition.

source. Thus, the initial GOR will be critical in determining compositional variability along a migration fairway.

It would be naive to propose migration fractionation as the sole process operating in the Cooper and Eromanga Basins without considering the primary controls of source and maturity. As stated above, all oil shows Pr/Ph  $>3$ , attesting to terrestrial origin. However, Pr/Ph also shows a regular trend with  $n\text{-C}_{23}/n\text{-C}_{11}$  (Fig. 8.14), a parameter associated with the waxy to light oil character. Thus, oil with Pr/Ph  $>4.5$  and  $n\text{-C}_{23}/n\text{-C}_{11} <1$  may have experienced secondary alteration by migration fractionation. Indeed, Ph, being of higher molecular weight than Pr, will be preferentially retained in the heavier residual oil. These effects have previously been recognised in South East Asian oil, again from terrestrial sources (Curiale and Bromley, 1996).

### Water washing and biodegradation

The  $\text{C}_6\text{--C}_7$  light hydrocarbons are greatly influenced by secondary alteration processes (Thompson, 1987, 1988). For example, compared to the parent oil, the toluene/ $n$ -heptane ratio has been shown in field (Thompson, 1987) and laboratory studies (Carpentier *et al.*, 1996) to increase in the residual heavy oil and decrease in light oil (dissolved in the gas phase) through the process of migration fractionation. However, Heath *et al.* (1989) interpreted the higher toluene/ $n$ -heptane in Cooper Basin oil compared to oil in the Eromanga Basin as indicating greater water washing of the latter. This behaviour is also evident in the much larger data set (Fig. 8.23; Appendix 2). The strong positive linear relationship between toluene/ $n$ -heptane and  $n$ -heptane/methylcyclohexane (Fig. 8.24) is further evidence that water washing is the dominant factor operating on the light hydrocarbons. The trend is what would be predicted from laboratory experiments (Lafargue and Barker, 1988). There the rate of loss of light hydrocarbons from oil exposed to water washing is in the order toluene  $>$  heptane  $>$  methylcyclohexane. Again, oil from the Cooper Basin is the least affected by water washing (Heath *et al.*, 1989; Hunt, 1989) and this may suggest shorter

migration distances, being closer to the Permian source rocks.

Dibenzothiophene (DBT) is another compound that has been suggested to be highly affected by water washing (Lafargue and Barker, 1988). Phenanthrene (P) and 1,3,6,7-tetramethylnaphthalene (1,3,6,7-TeMN) are two ubiquitous compounds in crude oil and both have similar chromatographic behaviour. Water solubilities are in the order  $DBT > P > 1,3,6,7\text{-TeMN}$  (Alexander *et al.*, 1996). Indeed, a plot of  $P/1,3,6,7\text{-TeMN}$  versus  $DBT/1,3,6,7\text{-TeMN}$  (Fig. 8.25) shows a good linear correlation. However, there is no clear distinction between oil from the Cooper and Eromanga Basins, suggesting that other factors (e.g. source) have an increased influence relative to the light hydrocarbons.

The unusual oil in Figure 8.14 with  $Pr/Ph = 6.85$  and  $n\text{-}C_{23}/n\text{-}C_{11} = 9.74$  is from Cuddapan 1 (45 km north of the Permian edge in Queensland). This oil is interpreted to be severely water washed with  $C_6\text{-}C_7$  light hydrocarbons being completely lost, with the alteration effects extending past  $n\text{-}C_{11}$ . Based on  $Pr/Ph$ , the original Cuddapan oil was relatively light (Fig. 8.14).

In-reservoir alteration by biodegradation is of little importance in the Cooper and Eromanga Basins although biodegradation is a major alteration process in the adjacent Bowen and Surat Basins. The reason for the absence for biodegradation in the Cooper and Eromanga Basins is unclear since reservoirs in most regions have access to nutrient-rich connate water. However, levels of dissolved oxygen observed in the aquifer waters of the Eromanga Basin may be too low (R. Habermehl, AGSO, pers. comm., 1998) to support intense aerobic biodegradation. Furthermore, temperature of the Eromanga reservoirs is generally  $>80\text{-}90^\circ\text{C}$ , which is above the threshold for sustainable bacterial growth.

### Migration contamination

The concept of migration contamination has been largely ignored. However, it has been previously identified in the

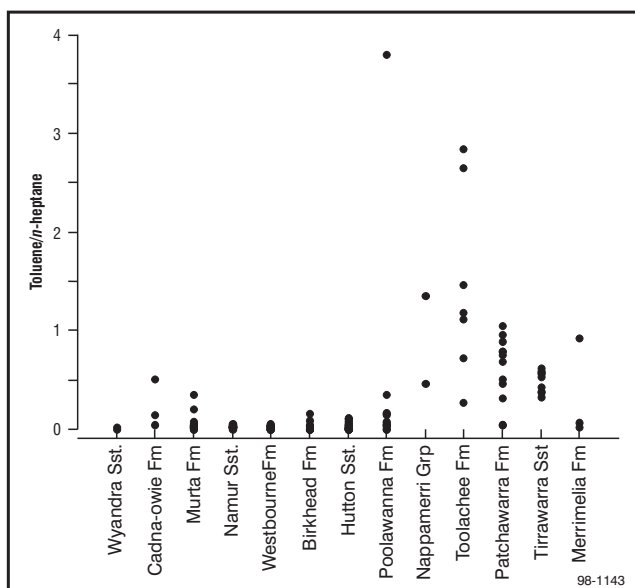


Fig. 8.23 Plot of toluene/n-heptane in whole oils grouped within their reservoir units.

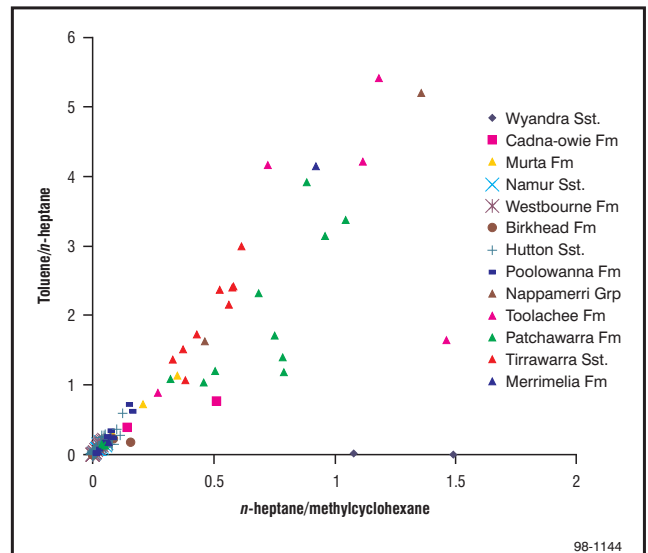


Fig. 8.24 Plot of toluene/n-heptane versus n-heptane/methylcyclohexane.

Gippsland Basin (Philp and Gilbert, 1982) and recently recognised in Birkhead oil at Gidgealpa 17 (Boult *et al.*, 1998). In principle, migration contamination is an end-member in the continuum of mixing of different oils. However, the term attracts a degree of uncertainty and can obviously be misused to ‘cover’ shortfalls in geochemical interpretations. Following expulsion from the effective source rock, the mobile oil phase finds its way through the permeable migration pathway to the reservoir. Thus, between source and reservoir there exists the possibility that the mobile oil phase can be supplemented with ‘soluble’ organics either from contact with DOM or through mixing with other mobile hydrocarbons from different effective sources at various stratigraphic levels before it reaches the trap.

All oil reservoired in the Eromanga Basin has enhanced levels of conifer-derived biomarkers compared to Cooper Basin oil (Fig. 8.15). For the Merrimelia Field stacked accumulations, this is despite a Cooper origin for the  $n$ -alkanes. Here the reliance on aromatic biomarkers would lead to a disproportionately higher level of Eromanga oil contribution than is considered the case. Studies of oil accumulations in the Bowen and Surat Basins have shown that they are predominantly from Permian source rocks and there is no contribution from Jurassic sources (Boreham,

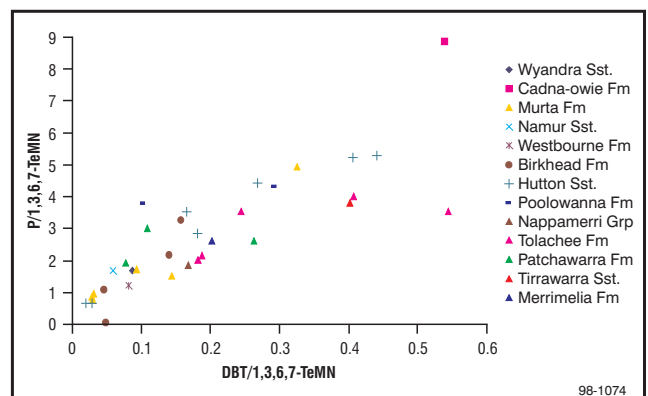


Fig. 8.25 Cross-plot of the ratio of DBT to 1,3,6,7-TeMN versus the ratio of P to 1,3,6,7-TeMN.

1995). The difference between the Surat and the Eromanga Basins is that the main Jurassic source rocks (Walloon Coal Measures in the Surat Basin, and the Birkhead Formation in the Eromanga Basin) are immature in the former but marginally mature to mature in the latter. Furthermore, oil in the Surat Basin is effectively trapped before it can come into contact with Walloon Formation sediments containing conifer-derived biomarkers (Boreham, 1994). Migration contamination of upward-migrating oil should be seriously considered when mobile hydrocarbons are expelled from Jurassic and Cretaceous source rocks, and these hydrocarbons remain pervasive throughout the Eromanga Basin succession in varying concentrations.

## SUMMARY

Both Cooper and Eromanga Basin source rocks have contributed to oil accumulations in the region. Each oil accumulation needs to be considered on its merits with respect to the extent of 'mixing' from Permian and Mesozoic sources. The ultimate 'mix' will be biased by those chemical parameters that are used since different classes of compounds respond differently to source, maturity and secondary alteration processes. *n*-Alkane isotope profiles provide a means for quantitatively assessing contributions from Cooper and Eromanga Basin sources. However, minor contributions (volumetrically <25%) from either source are difficult to access through *n*-alkane isotope profiles and other more sensitive geochemical tools are required (e.g. biomarkers).

The Cooper Basin contains both light oil–condensate and waxy oil with depleted light hydrocarbon contents. The source of the oil is Permian coal and associated terrestrial organic matter. The oil is characterised by low saturated biomarker contents, lack of conifer-derived biomarkers and an *n*-alkane isotope profile that becomes isotopically lighter with increasing carbon number.

The Eromanga Basin oil accumulations with a Birkhead source appear to be confined to the area of mature and thickest Birkhead Formation in the vicinity of Moorari and Bookabourdie Fields. This oil is characterised by high conifer-derived biomarkers (Moorari 4) and *n*-alkane isotope profiles that are 'flat' (where the isotopic composition of individual *n*-alkanes does not change significantly with carbon number).

Gas chromatographic fingerprints and parameters derived for Jurassic oil are only marginally distinguishable from Cretaceous and Cooper Basin oil. The Jurassic oil has a much narrower range of bulk compositions. The Moorari 4 oil, being the least mature, can be used to define the maturity threshold (0.65%  $R_o$  for a local source) below which no expulsion of oil can occur. Birkhead Formation oil at Gidgealpa and Merrimelia would be considered to have an Eromanga Basin source content based on biomarker evidence. However, *n*-alkane isotope data only support a strong local source contribution at Gidgealpa, whereas the Birkhead oil in the Merrimelia Field is dominantly sourced from the Cooper Basin.

A local source to the Murta Formation oil accumulation may have been overestimated since secondary alteration processes have been undervalued in previous studies. Murta oil in the Merrimelia Field in South Australia and some other accumulations in Queensland (e.g. Jackson Field) have

biomarker characteristics that set them apart from oil lower in the succession, but their *n*-alkane profiles match all others in the stacked reservoirs.

# THERMAL AND BURIAL HISTORY

I. Deighton\*  
and A.J. Hill

## Chapter 9

### INTRODUCTION

This chapter draws on preliminary results from the National Geoscience Mapping Accord (NGMA) Cooper and Eromanga Basins Project, due for completion in September 1999, and presents conclusions based on calculated maturity and source rock expulsion curves from 15 wells in the Cooper Basin, South Australia (Fig. 9.1). These wells form a subset of the overall study which encompasses 90 wells from the South Australian and Queensland portions of the Cooper Basin, and includes a number of synthetic wells in undrilled troughs.

### PREVIOUS STUDIES

Kantsler *et al.* (1983) noted that higher palaeotemperatures than present were necessary to model maturities in the Nappamerri Trough but claimed that hydrocarbon generation elsewhere in the Cooper Basin was likely to post-date deposition of the Winton Formation. They did not present any maturity cross-plot validation for this claim. Similar conclusions were substantiated by Kantsler *et al.* (1986) who found that variable palaeoheatflow regimes appeared to apply in different parts of the Cooper and Eromanga Basins. Pitt (1986) reached similar conclusions and also identified a recent rise in geothermal gradient in the last 5–10 million years. Duddy (1987) and Gallagher (1988) identified rising heatflow in the last 1–2 million years using apatite fission track analysis (AFTA) and argon spectrum analysis, respectively. Gallagher *et al.* (1994) and Tingate and Duddy (1996) have confirmed the apparently widespread nature of this Plio-Pleistocene thermal event. Toupin *et al.* (1997) modelled these heatflow variations in terms of changes in aquifer flow rates in the Great Artesian Basin. Their model suggests invasion of Permian strata by hot artesian waters in the early Tertiary, locally shifting the depth of the zone of oil generation.

### BURIAL HISTORY

Figure 9.2 shows the burial geohistory for Burley 2 in the Nappamerri Trough, constructed using standard decompaction techniques, a fluctuating sea level and palaeowaterdepths derived from sedimentological and fossil content. The plot indicates the main features of deposition in the Cooper and overlying Eromanga Basins — a thick (1500 m) non-marine Permian and Early Triassic sequence of sandstone, siltstone and shale is overlain disconformably by ~800 m of non-marine sandstone, siltstone and shale of mid-Jurassic to Early Cretaceous age. Rapid deposition of marine mudstone and siltstone took place in the late Early

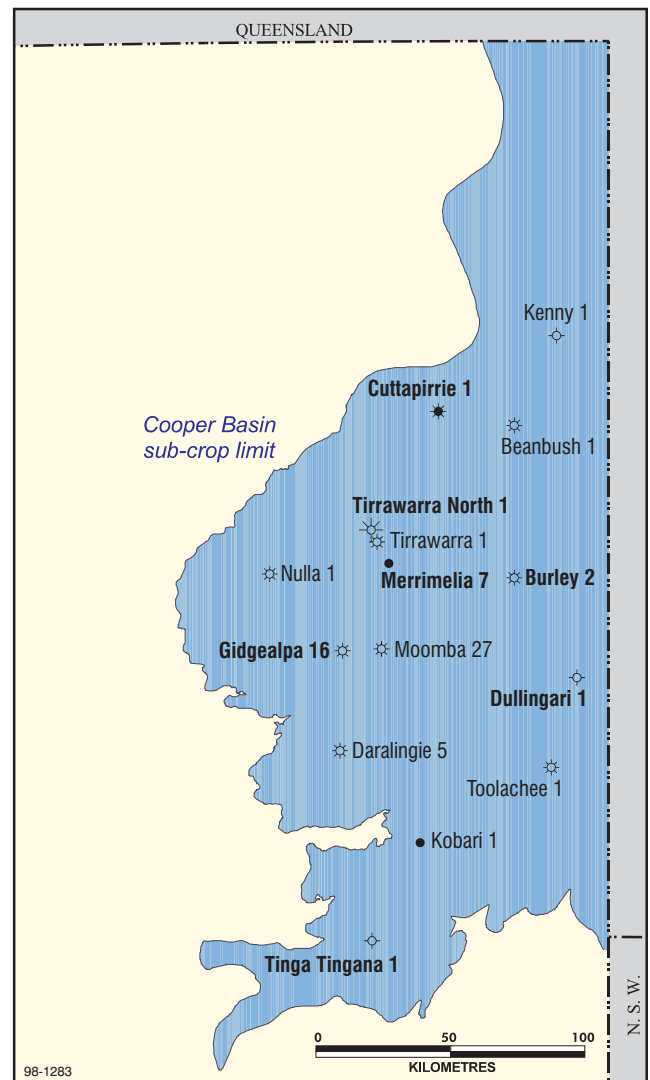


Fig. 9.1 Location of wells studied; bold indicates wells discussed in detail.

Cretaceous (shaded area in Fig. 9.2) and was followed by a thick sequence (900 m) of non-marine siltstone in the mid-Cretaceous. A minor erosional event separates this lower sequence from intermittent Tertiary deposition of thin non-marine sediments accompanied by minor compressional structuring. Interpretation of erosional events is based on Moussavi-Harami (1996b).

### TECTONIC SUBSIDENCE

Previous burial history studies of the Cooper and Eromanga Basins have concentrated on explaining the apparently anomalous rapid deposition of the Winton

\* Paltech Pty Ltd, paltech@acr.net.au

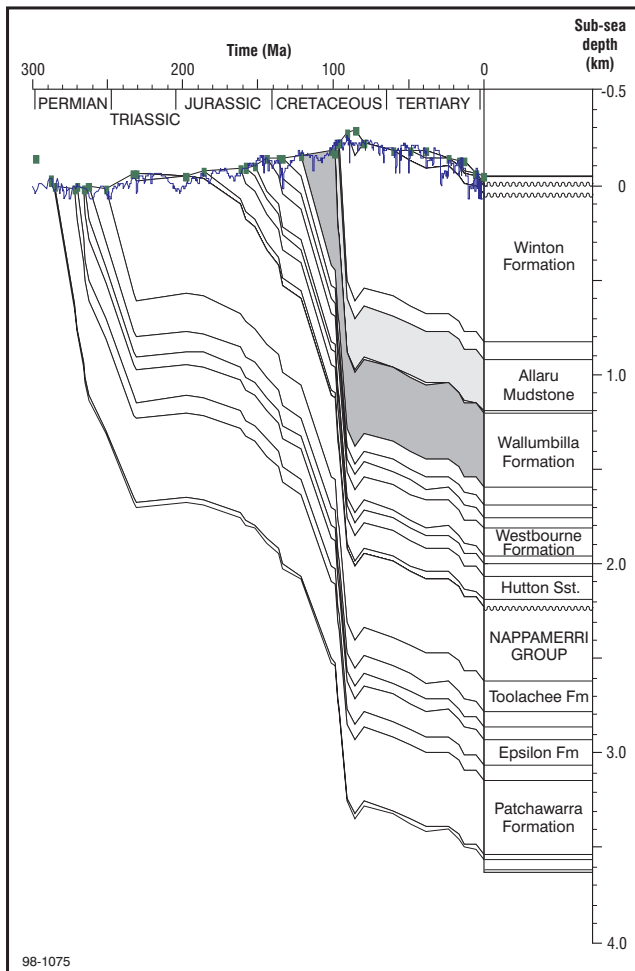


Fig. 9.2 Burial history plot, Burley 2.

Formation (Middleton, 1989; Gallagher, 1988; Zhou, 1989). In this study, the authors have modelled terrestrial compaction based on work by Nadon and Issler (1997; near-surface porosities are lower than for marine sediments; see Fig. 9.3) and palaeo-elevation some 100 m above sea level for deposition of the Winton Formation. The resultant tectonic subsidence during Winton deposition and erosion is

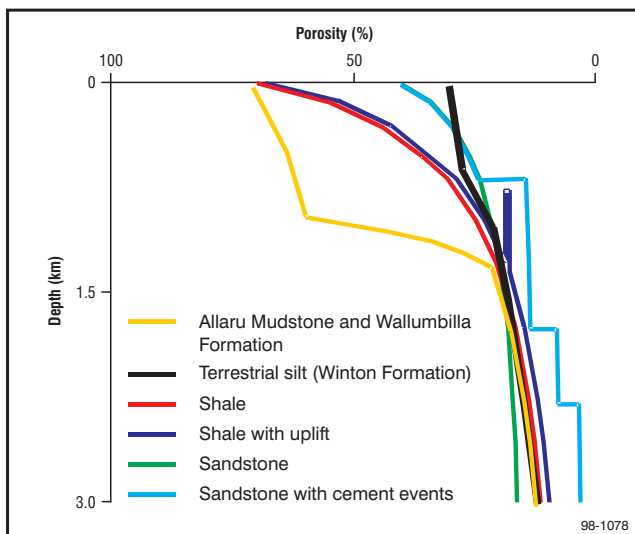


Fig. 9.3 Typical porosity versus depth profiles for various sediment types.

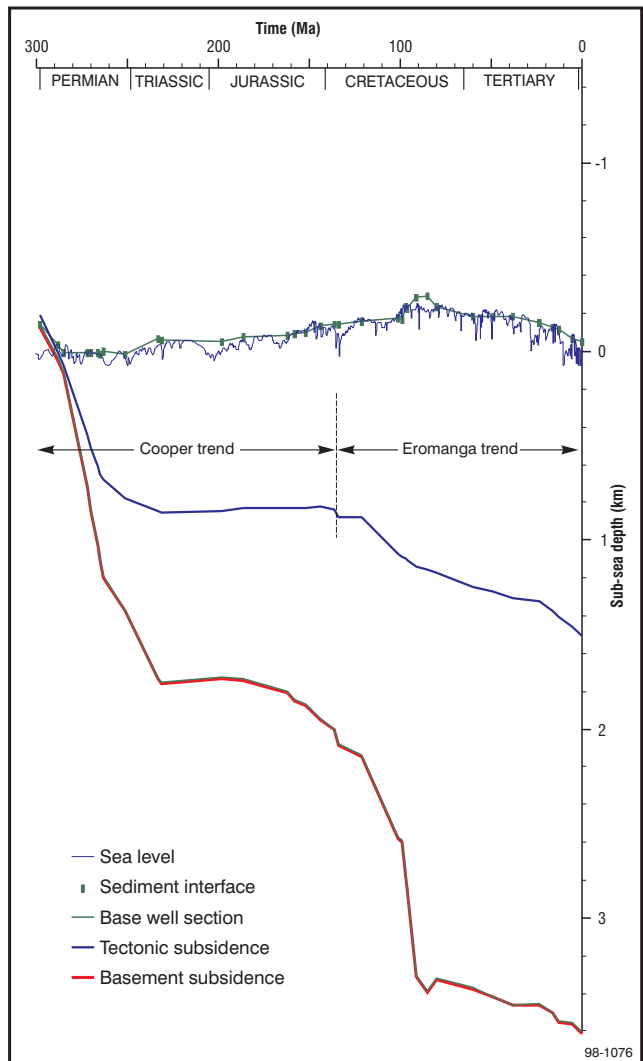


Fig. 9.4 Simplified burial and tectonic subsidence history of Burley 2. The lower curve shows subsidence of basement. The upper curves are sea-level (using the AGSO 95 sea-level curve) and the sediment interface (also showing age-control points). The middle curve is stripped-basement or tectonic subsidence. Deposition of the Winton Formation (mid-Cretaceous) was under subaerial conditions.

no different from the background Eromanga trend (Fig. 9.4). Cretaceous to Tertiary tectonic subsidence is small compared to Permian subsidence.

Figure 9.5 shows the tectonic subsidence of the wells in this study, normalised from the start of burial. Note the uniformity of mid-Cretaceous to present subsidence and the comparatively greater magnitude of Permian subsidence. Interpreted simply, in terms of the McKenzie (1978) crustal stretching model, Cooper subsidence at Burley 2 would correspond to a stretching factor of 1.2 (based on stretching subsidence of ~1 km), while Eromanga subsidence would correspond to a stretching factor of <1.1 (based on thermal subsidence of ~200 m).

## PALAEOTEMPERATURE DATA

The following thermal regime for the Cooper Basin in South Australia is proposed, based on combined AFTA and measured vitrinite reflectance ( $R_o$ ) analysis (Tingate and Duddy, 1996; Geotrack, 1997):

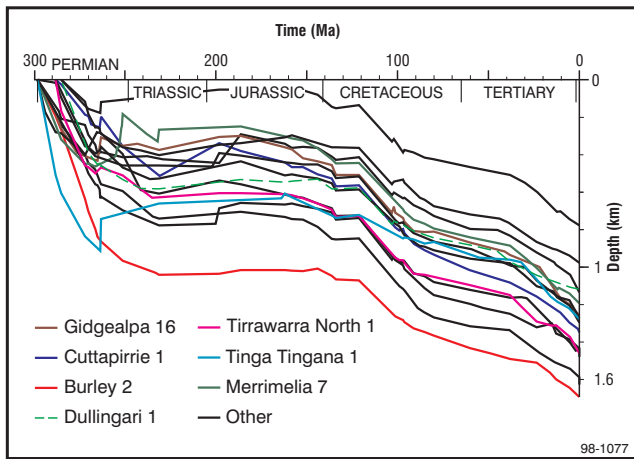


Fig. 9.5 Tectonic subsidence for selected Cooper Basin wells.

- Palaeotemperature profiles were highest at 90–100 Ma, with cooling prior to 70 Ma in the Cooper Basin. Cooling may have been caused by uplift and erosion, or heatflow decline.
- Palaeotemperature profiles were low prior to 2–5 Ma then increased to high at present. Argon dating (granite in Moomba 1; Gallagher, 1988), AFTA dating and reflectance modelling (not on all wells) indicate a recent rise in geothermal gradient of 10–20°C/km.

The results for four wells are shown in Figure 9.6, expressed in terms of geothermal gradient. The details for Burley 2 are shown in Figure 9.7.

This thermal scheme has been implemented in the current NGMA study, applying higher heatflows from 90 to 85 Ma, declining to below background till 2–5 Ma (see Figs 9.8, 9.9, 9.10). With the exception of ‘suppressed’ vitrinite, particularly just above the oil window (e.g. Figs 9.15, 9.21), this heatflow model successfully matches most vitrinite reflectance (VR) data.

## PRESENT HEATFLOW

Areas of present heatflow maxima are generally coincident with distribution of granites and/or high conductivity basement. Heatflow ranges from 70 to 120 milliwatts per square metre ( $\text{mW}/\text{m}^2$ ), with the higher values occurring over granite bodies and Warburton Basin ridges. The higher heatflows can be explained by 5 km thick, 50 km wide granite bodies which provide an additional 35–40  $\text{mW}/\text{m}^2$  above a background of 60–70  $\text{mW}/\text{m}^2$  (Gallagher, 1988, fig. 8.3.5). An additional 15  $\text{mW}/\text{m}^2$  can be produced by conductivity contrast in the basement (Gallagher, 1988, fig. 8.3.3). Minor heatflow maxima may be associated with aquifer discharge near basin depocentres.

## PALAEOHEATFLOW MODEL

The palaeoheatflow curves shown in Figure 9.8, and which result in a valid palaeotemperature model, are commented on below.

### Cooper event

Granite cooling may provide a method for overall declining heatflow in the Cooper Basin. Vitorello and

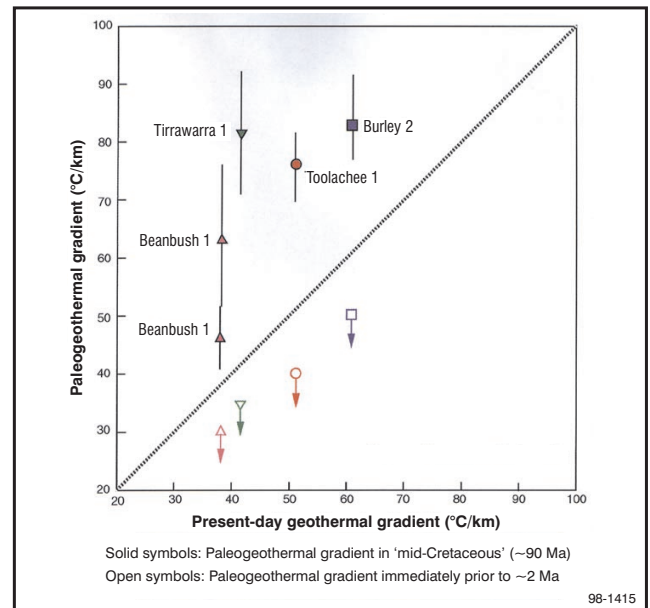


Fig. 9.6 Palaeogeothermal gradients determined from AFTA and VR palaeotemperature results versus present-day gradient for four Cooper–Eromanga wells (after Geotrack, 1997).

Pollack (1980) proposed a three-component model of decreasing heatflow with tectonic age as observed in continental granitic areas (Fig. 9.11). This model proposes that the main heatflow decline results from the decay of a sub-lithosphere transient thermal perturbation associated with tectogenesis of granite. In the case of the Cooper Basin, the age of the granite is ~300 Ma (i.e. only 5–10 million years prior to onset of Cooper Basin sedimentation). Thus, the majority of cooling proposed in the Vitorello and Pollack model took place during sedimentation of the Cooper and Eromanga Basins (Fig. 9.12). Most subsidence resulting from this cooling took place early, which explains the rapid subsidence of the Nappamerri Trough, over granite (represented by Burley 2) compared to the Patchawarra Trough (represented by Cuttapirrie 1 and Tirrawarra North 1). The deep-seated nature of the event means that lateral heat transfer will result in higher heatflow away from the granite basement areas and that similar (though lower) palaeoheatflow patterns should apply to areas without granite basement.

### Eromanga event

A high heatflow peak has been modelled from 90 to 85 Ma to provide the high temperatures evidenced by AFTA and  $R_o$  data in the mid-Cretaceous, although the origin of this high temperature event is unknown. At least part of the rise may be due to thermal blanketing by very low conductivity smectitic Allaru Mudstone and Wallumbilla Formation sediments, combined with a smaller crustal heatflow increase. The decline in this temperature event may be as late as 60 to 70 Ma (Fig. 9.7).

### Post-Eromanga event

The low temperature phase from 85 to ~5 Ma is also evidenced by AFTA and  $R_o$  analysis. Previous studies have proposed that the present heatflow is anomalous and the low temperature phase is ‘normal heatflow’. However, there is no easy mechanism to create a rise in heatflow over the last

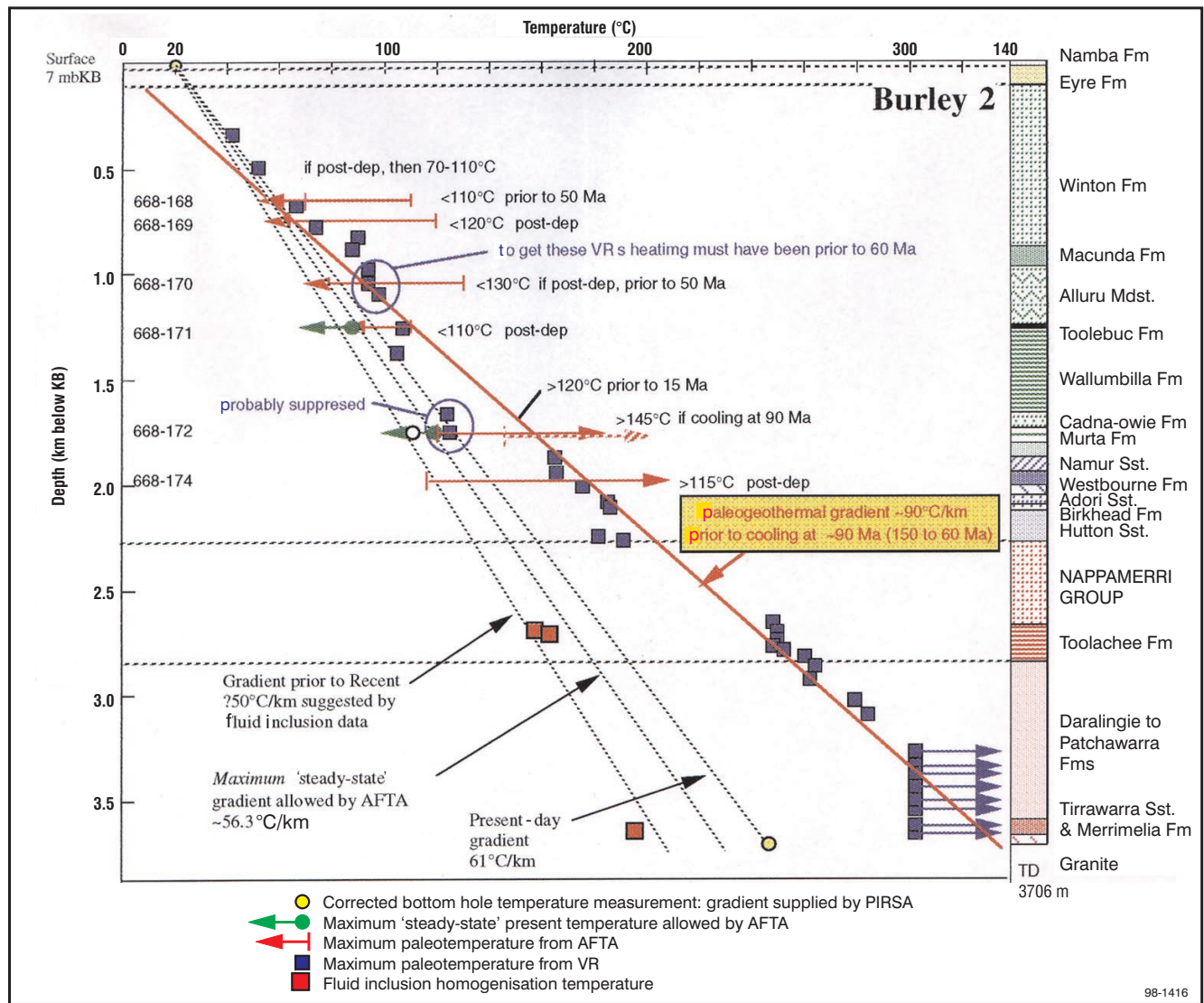


Fig. 9.7 Plot of palaeotemperatures derived from AFTA and VR data in Burley 2, against sample depth and the estimated present temperature profile for this well (after Geotrack, 1997).

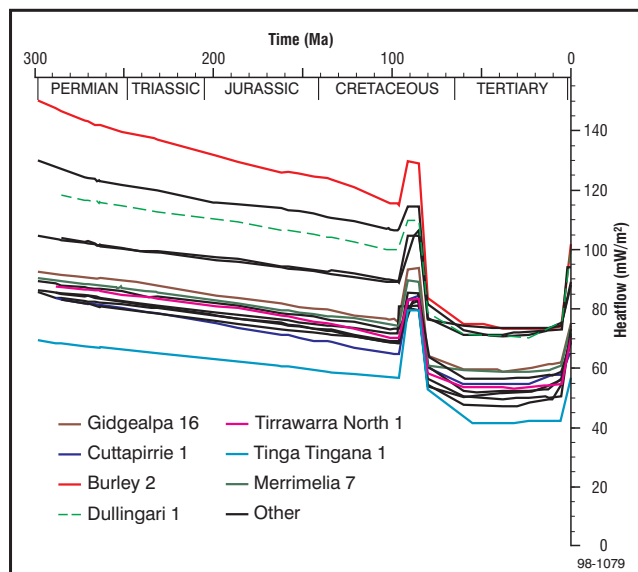


Fig. 9.8 Modelled heatflow versus time for selected Cooper Basin wells.

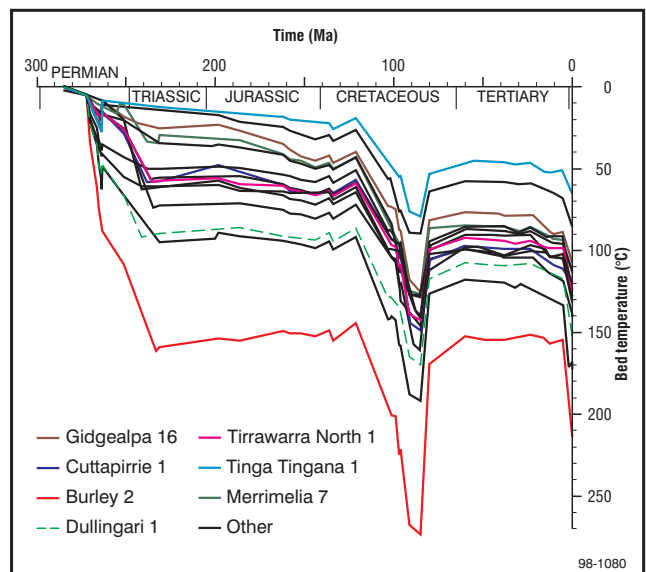


Fig. 9.9 Modelled temperature versus time, top Patchawarra Formation.

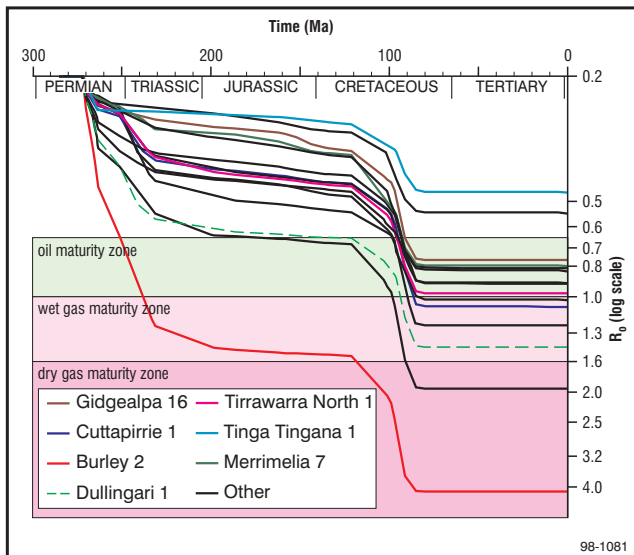


Fig. 9.10 Modelled maturity versus time, top Patchawarra Formation.

2–5 million years without some other geophysical evidence. For example, mantle hot spots or any other lower lithosphere heating event should cause some few hundred metres bulge, which is not observed.

Other studies have proposed that the present heatflow is ‘normal’ and that the low temperature phase is anomalous. This would suggest major changes in the aquifer flow regime of the Great Artesian Basin as the mechanism. These models propose that the low temperature phase results from increased artesian flow in the past, which removed large amounts of heat laterally, and that a slower rate in the last

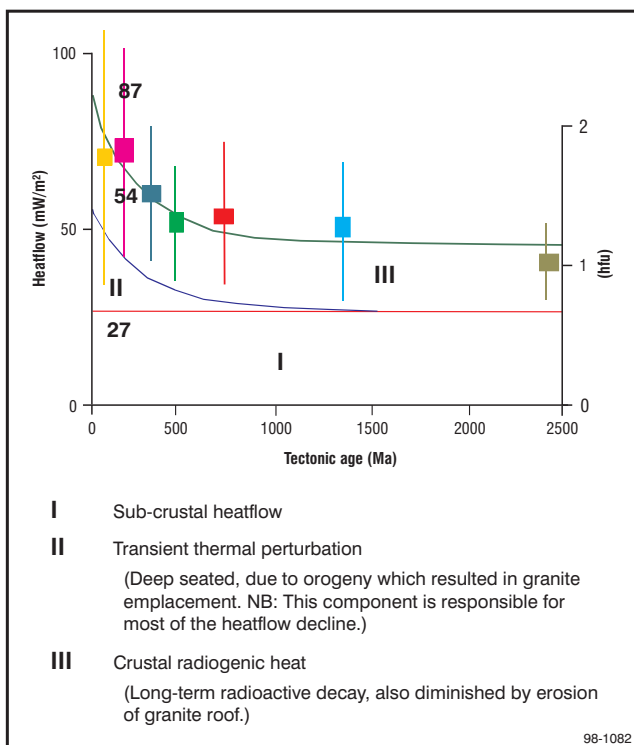


Fig. 9.11 Theoretical (and observed) heatflow decline in granite terranes (after Vitorello and Pollack, 1980). Total heatflow (green curve) is the sum of components I to III.

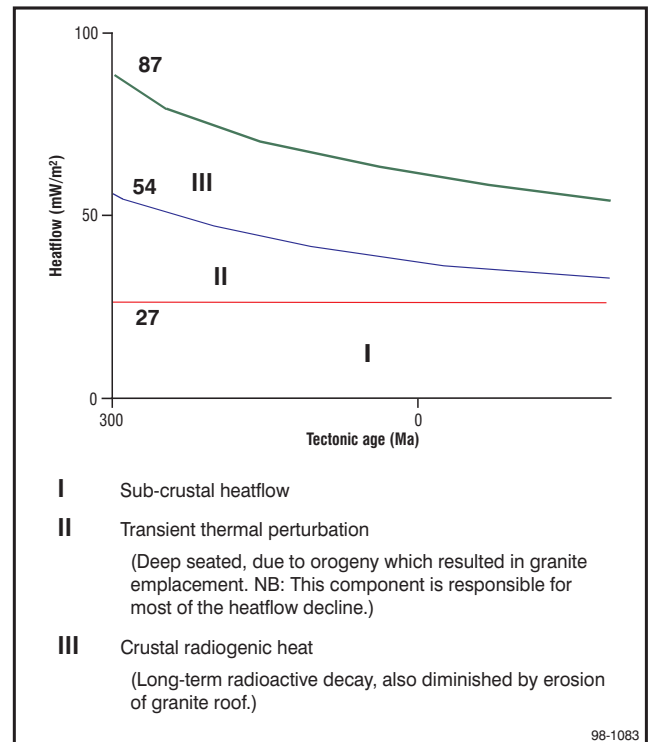


Fig. 9.12 Theoretical heatflow decline in young granite terranes (extracted from Fig. 9.11, with ages reversed. Cooper Basin granites are 290–300 million years old).

2–5 million years allowed the thermal regime to equilibrate to normal. Habermehl (1986), however, suggested that the hydrologic flow rate is at its peak now. Gallagher (1988) has shown that constant background heatflow is unlikely to be perturbed significantly by fluid flow except at the margins (or up faults) where vertical movement may be significant (Gallagher, 1988, p.94). Over the centre of the ‘granite’ the interval heatflow is lower above a 500 m thick aquifer (i.e. temperature gradient is lower). Gradients below are constant, but temperatures are lower for higher flow rates. For low flow rates, the gradient above the aquifer is the same as the gradient below. The main effects of high aquifer flow rates are to reduce temperatures over the granite and shift the temperature peak laterally downflow by about the half width of the granite. Toupin *et al.* (1997) proposed major uplift in the centre of the basin at the end of the Cretaceous as the origin of the cooling event, causing a depression of isotherms because of local influx of meteoric water. Although there was certainly uplift (though probably in the Late Cretaceous), it is difficult to see how this could provide the regional effect evidenced by AFTA and VR data. Not all areas were uplifted by the same amount (Moussavi-Harami, 1996b), with some experiencing no uplift at all.

## RESULTS

Using the above heatflow model to produce the palaeotemperature paths evidenced by AFTA and  $R_0$  data, kerogen generation and expulsion of the Cooper Basin sequence was modelled in version 2.4 of Winbury® using the standard industry model of Tissot and Welte (1984) and others. A summary of geohistories for major structural areas within the Cooper Basin using representative wells follows.

### NAPPAMERRI TROUGH

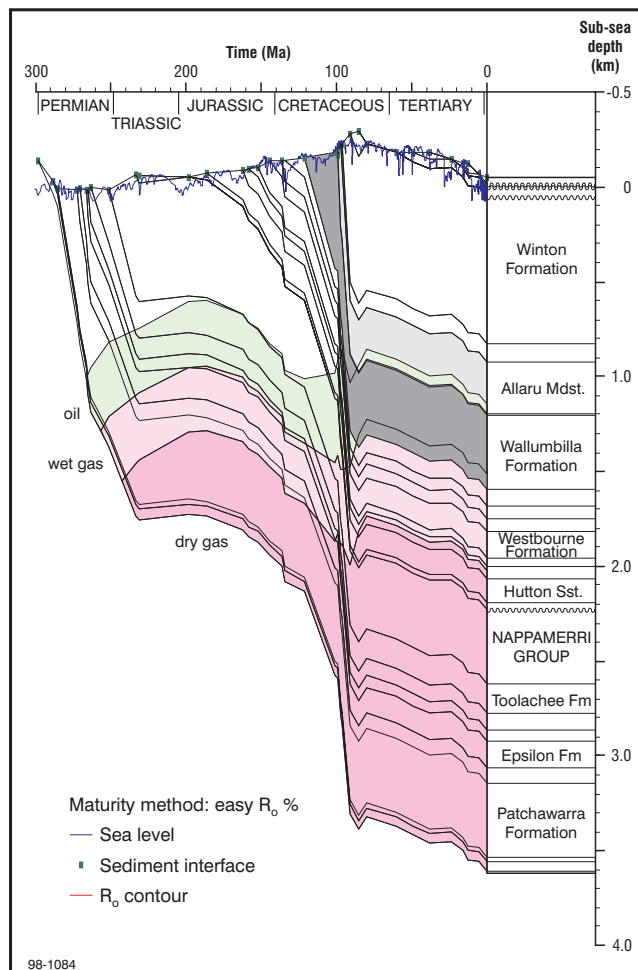
Figure 9.13 shows the burial geohistory for Burley 2, indicating that Cooper Basin sediments passed through the oil and gas maturity windows very early, due to high heatflow in the Permian. The palaeotemperature paths for each layer are shown in Figure 9.14 whilst depths to maturity windows are summarised in Table 9.1.

**Table 9.1** Hydrocarbon maturity, Burley 2.

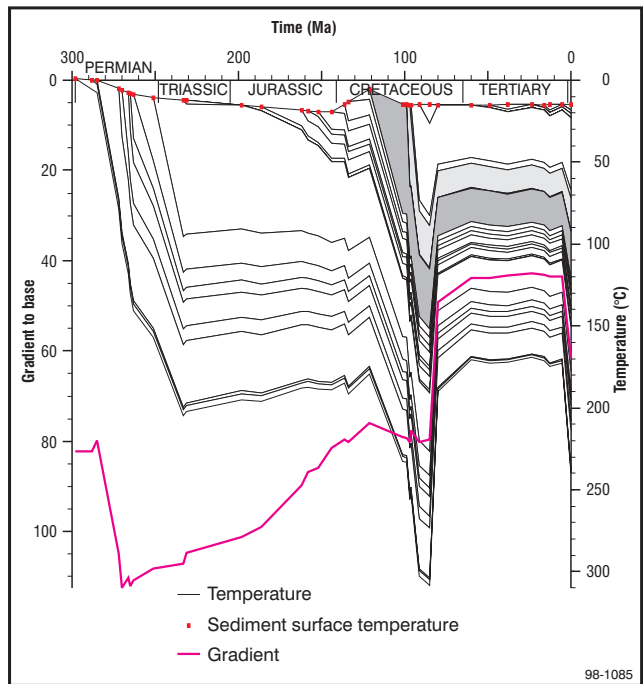
Unit	R <sub>o</sub> (%)	Maturity window	Depth (m subsea)
Allaru, upper Wallumbilla	0.65	oil	~1144
Lower Wallumbilla, Murta, Namur, Westbourne, Adori, upper Birkhead	1.0	~1513	
Lower Birkhead, Hutton, Poolowanna, Nappamerri, Toolachee, Epsilon, Murteree, upper Patchawarra, lower Patchawarra	1.6	dry gas	~2021

Figure 9.15 shows the cross-plot of observed and computed reflectance, which indicates a good fit except for some shallower data here presumed to be ‘suppressed’.

Figure 9.16 shows oil and gas generation through time for source rocks in Burley 2, calculated using standard techniques and compositional kerogen kinetics discussed in

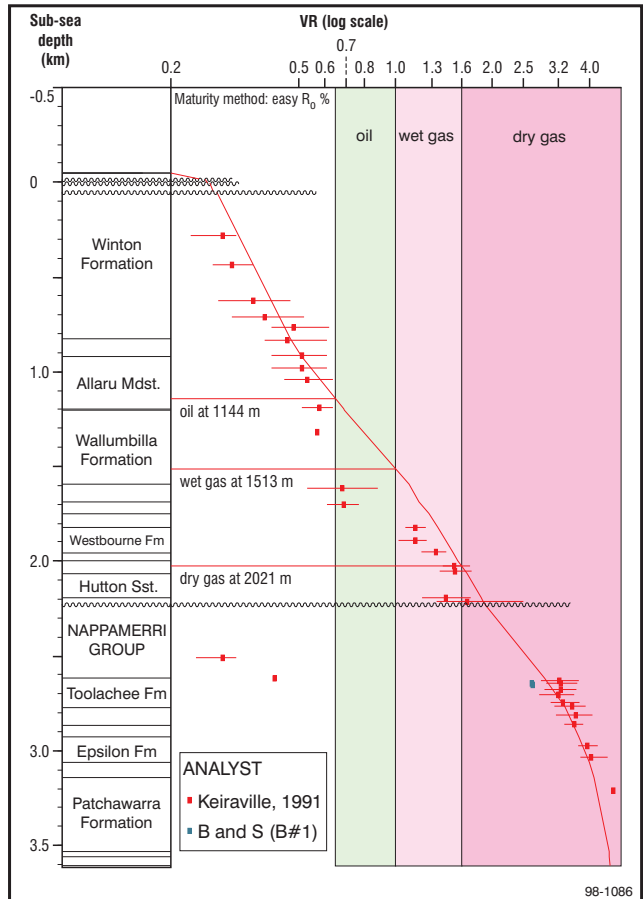


**Fig. 9.13** Burial and maturity geohistory plot, Burley 2.



**Fig. 9.14** Bed temperature versus time, Burley 2.

Chapter 8. These traces indicate that while some gas was generated in the Late Permian and Early Triassic from Patchawarra Formation coal and shale, most was generated from the Patchawarra and Toolachee Formations in the mid-Cretaceous. Patchawarra Formation shale expelled a total of 29 bbl equivalent/m<sup>2</sup> of gas compared to only 7 bbl



**Fig. 9.15** Maturity versus depth plot, Burley 2.

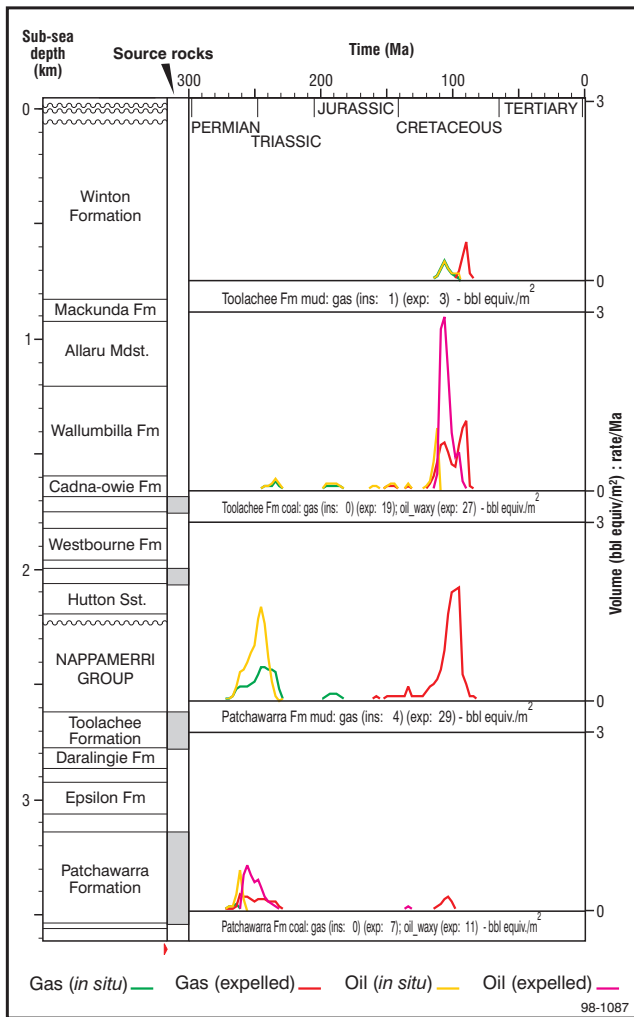


Fig. 9.16 Hydrocarbon generation and expulsion, Burley 2.

equivalent/m<sup>2</sup> of gas from coal\*. Significantly, any oil expulsion from the Patchawarra Formation in Burley 2 took place in the Late Permian. Conversely, a total of 27 bbl equivalent/m<sup>2</sup> of waxy oil was expelled from Toolachee Formation coal in the mid-Cretaceous. There appears to be considerable scope for Toolachee Formation sourced oil to migrate up into Early Cretaceous reservoirs depending upon seal integrity of the intervening units.

### PATCHAWARRA TROUGH

Burial and thermal histories of the western and central Patchawarra Trough are represented by Tirrawarra North 1 and Cuttapiirrie 1.

### Cuttapiirrie 1

The geohistory plot of Cuttapiirrie 1 indicates that the Early Permian to Late Jurassic succession entered the oil window at ~95 Ma, with Early to Late Permian rocks entering the wet gas window at ~87 Ma until present day (Fig. 9.17; Table 9.2).

Figure 9.18 plots maturity with depth and clearly shows significant suppression of vitrinite up to 0.1% at the onset of oil generation over the Westbourne and Birkhead Formations.

\* bbl equivalent/m<sup>2</sup> refers to yield/m<sup>2</sup> of kitchen area.

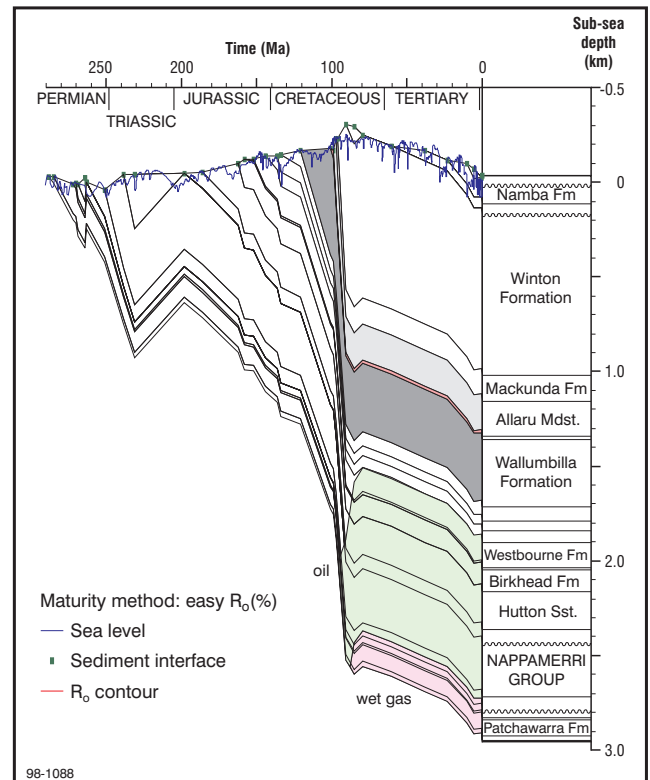


Fig. 9.17 Burial and maturity geohistory plot, Cuttapiirrie 1.

Table 9.2 Hydrocarbon maturity, Cuttapiirrie 1.

Unit	R <sub>0</sub> (%)	Maturity window	Depth (m subsea)
Westbourne, Adori, Birkhead, Hutton, Poolowanna, Nappamerri, upper Toolachee	0.65	oil	~1896
Lower Toolachee, Epsilon, Patchawarra, Tirrawarra	1.0	wet gas	~2760

Figure 9.19 shows oil and gas generation through time for source rocks in Cuttapiirrie 1, calculated using standard techniques and compositional kerogen kinetics discussed in Chapter 8. These traces indicate that some oil and minor gas were expelled during the Late Cretaceous at ~90 Ma, principally from Patchawarra Formation (coal, 4 bbl equivalent/m<sup>2</sup> of oil; shale, 0 bbl equivalent/m<sup>2</sup> of oil) and Toolachee Formation (coal, 4 bbl equivalent/m<sup>2</sup> of oil) source horizons. Significantly, little or no oil appears to have been expelled from the Poolowanna Formation, which hosts commercial oil reserves. This is consistent with whole-oil gas chromatography data (Appendix 2) that support a Permian source.

### Tirrawarra North 1

The geohistory plot of Tirrawarra North 1 indicates that the Early Permian to Late Jurassic succession entered the oil window at ~100 Ma. The Early Permian rocks entered the wet gas window at ~90 Ma and have remained there until the present day (Fig. 9.20; Table 9.3). It is worth noting that depths to the relative oil and wet gas windows for Tirrawarra North 1 are very close to those for Cuttapiirrie 1 (Tables 9.2, 9.3).

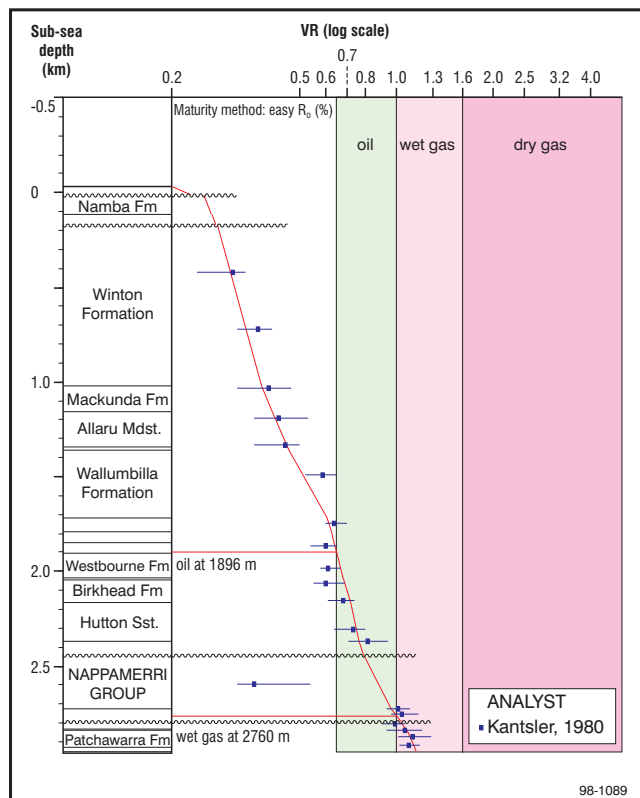


Fig. 9.18 Maturity versus depth, Cuttipirrie 1.

Figure 9.21 plots maturity with depth and also shows significant suppression of vitrinite up to 0.15%  $R_0$  at the onset of oil generation over the Westbourne to Poolowanna Formations.

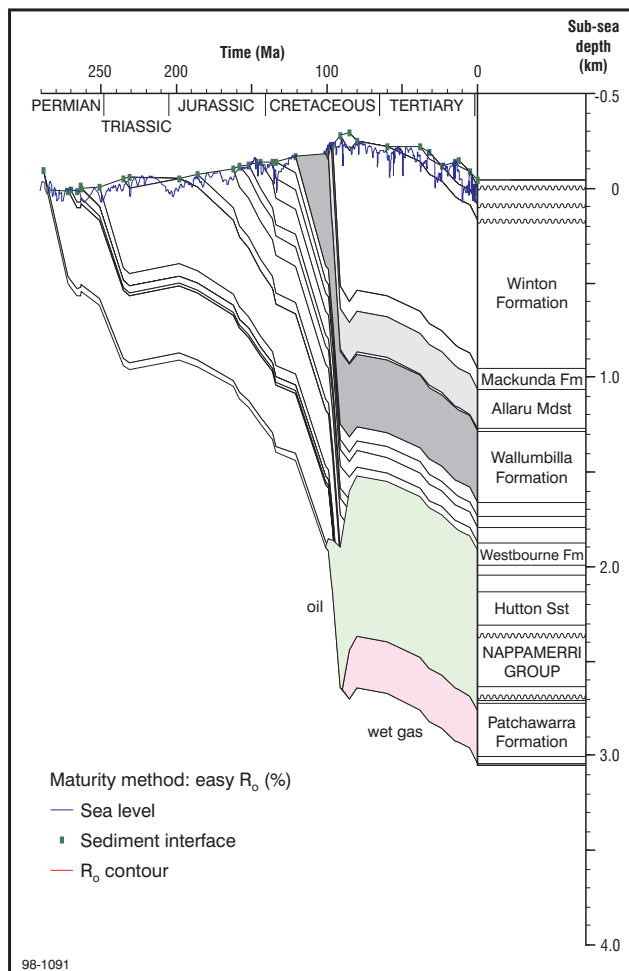


Fig. 9.20 Burial and maturity geohistory plot, Tirrawarra North 1.

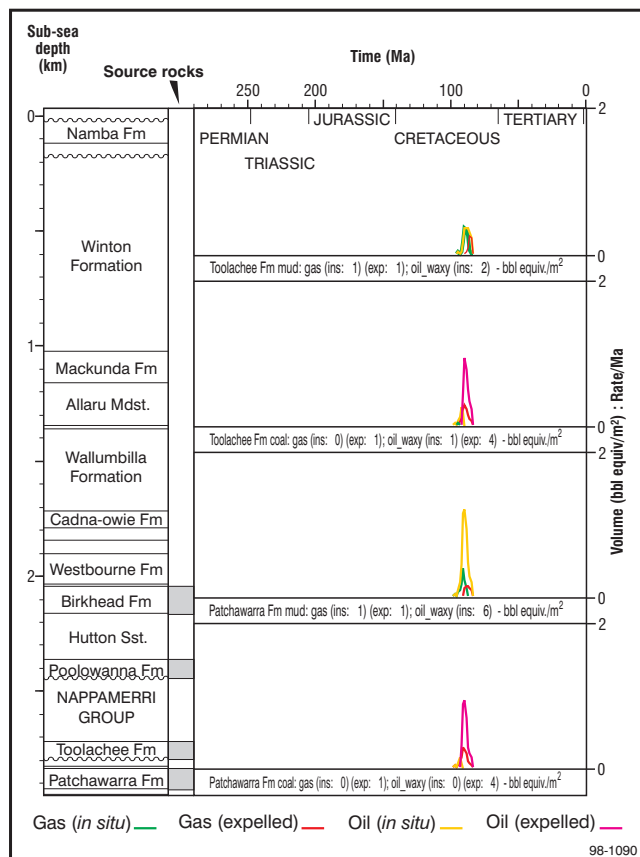


Fig. 9.19 Hydrocarbon generation and expulsion, Cuttipirrie 1.

Table 9.3 Hydrocarbon maturity, Tirrawarra North 1.

Unit	$R_0$ (%)	Maturity window	Depth (m subsea)
Westbourne, Adori, Birkhead, Hutton, Poolowanna, Nappamerri, Toolachee, Epsilon, Murteree, upper Patchawarra	0.65	oil	~1911
Lower Patchawarra, Tirrawarra	1.0	wet gas	~2761

A significant volume of oil was expelled during the Late Cretaceous at ~90 Ma principally from Patchawarra Formation coal (99 bbl equivalent/m<sup>2</sup>) with a further 7 bbl equivalent/m<sup>2</sup> of oil remaining *in situ*. Shale of the Patchawarra Formation contributes only minor amounts of expelled oil (1 bbl equivalent/m<sup>2</sup>).

It appears that Toolachee Formation source rocks have expelled wet gas in the order of 1 bbl equivalent/m<sup>2</sup> which is consistent with a minor gas accumulation in basal Toolachee Formation sand in crestal wells of the Tirrawarra Field (Fig. 9.22).

Tirrawarra Sandstone of the Tirrawarra Field hosts the largest Permian oil accumulation of the Cooper Basin; the oil is overlain by large gas reserves within Patchawarra Formation reservoirs. The kinetic model adopted in the NGMA study assumes that both oil and gas are generated simultaneously but with gas expulsion preceding oil

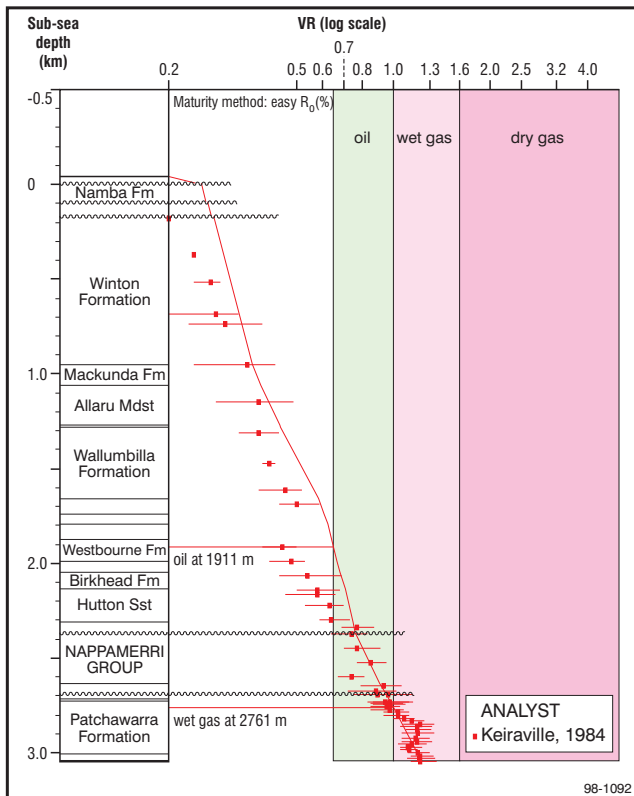


Fig. 9.21 Maturity versus depth plot, Tirrawarra North 1.

expulsion. This would account for gas occurring stratigraphically above the oil in the Tirrawarra Field.

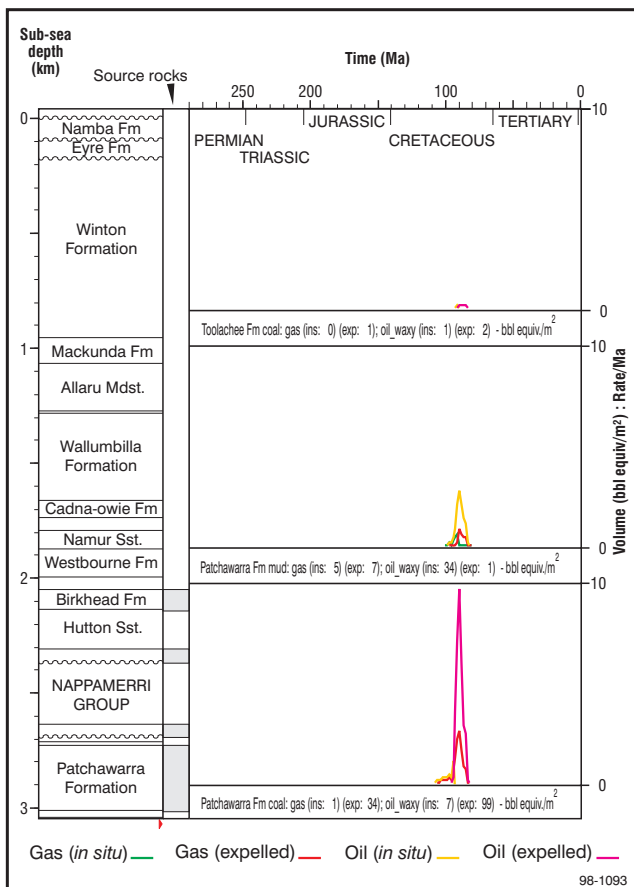


Fig. 9.22 Hydrocarbon generation and expulsion, Tirrawarra North 1.

## METTIKA EMBAYMENT

### Dullingari 1

Burial and thermal history of the Mettika Embayment of the Tenappera Trough is represented by Dullingari 1 (Fig. 9.23). Source rocks in Dullingari 1 entered the oil window close to the Late Permian – Early Triassic boundary, reflecting a higher geothermal gradient than the thermally cooler Patchawarra Trough wells discussed previously. With the exception of the lower Patchawarra Formation, which entered the dry gas window in the mid-Cretaceous (~90 Ma), the remainder of the Early and Late Permian succession has been in the wet gas window since ~108 Ma, whilst the Triassic to Early Cretaceous succession is currently within the oil window (Fig. 9.23). This is in agreement with hydrocarbon discoveries in the Dullingari Field with proven oil reserves in the Murta Formation, wet gas in the Toolachee and Daralingie Formations, and dry gas in Patchawarra Formation reservoirs. Depth to present day maturity windows are summarised in Figure 9.24 and Table 9.4.

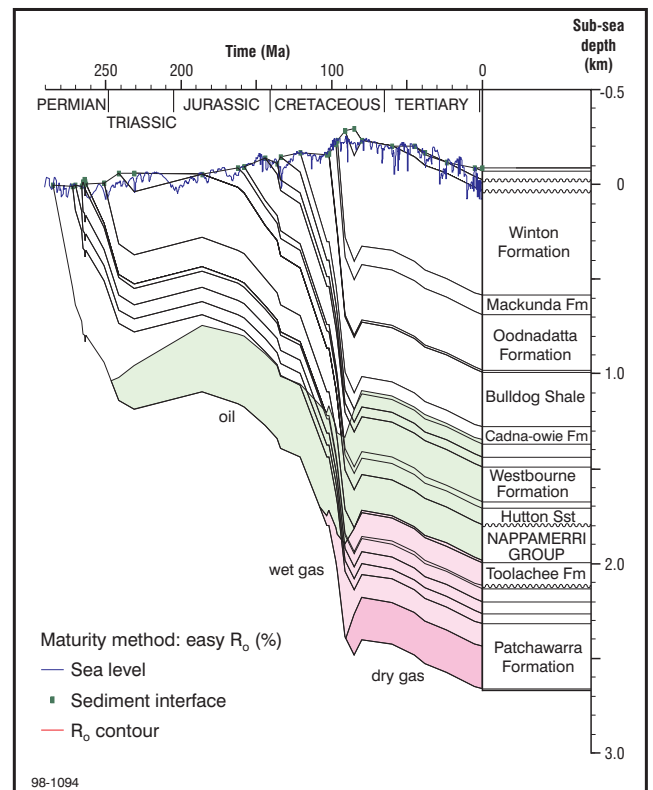


Fig. 9.23 Burial and maturity geohistory plot, Dullingari 1.

Table 9.4 Hydrocarbon maturity, Dullingari 1.

Unit	R <sub>0</sub> (%)	Maturity window	Depth (m subsea)
Murta, Namur, Westbourne, Adori, Birkhead, Hutton, Poolowanna, Nappamerri	0.65	oil	~1345
Toolachee, Epsilon, Murteree, upper Patchawarra	1.0	wet gas	~1982
Lower Patchawarra	1.6	dry gas	~2439

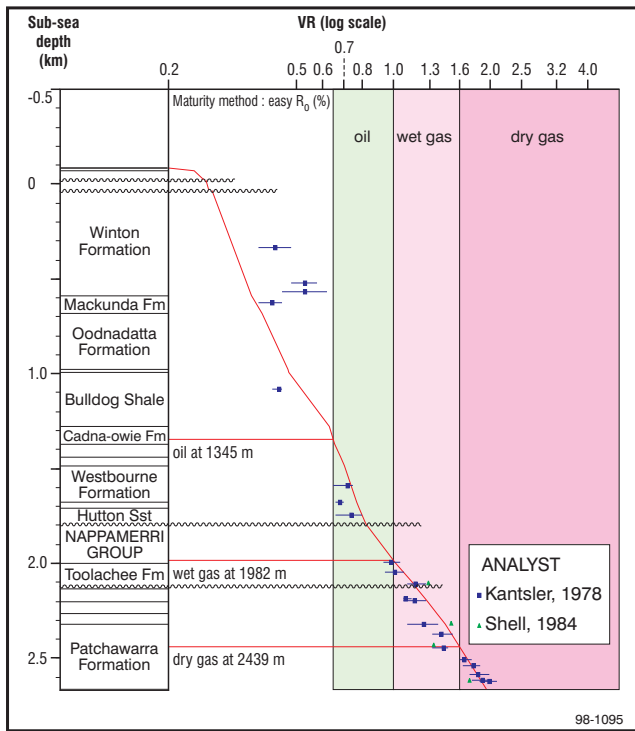


Fig. 9.24 Maturity versus depth, Dullingari 1.

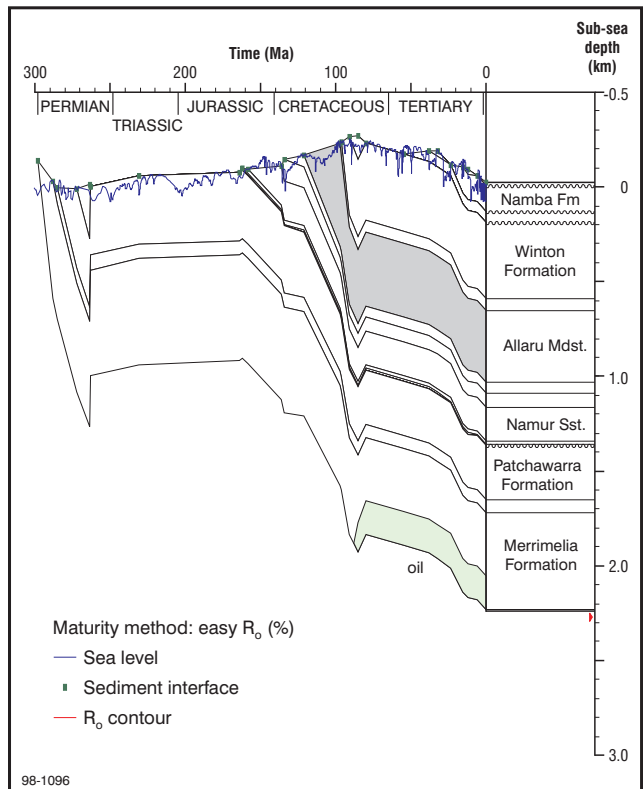


Fig. 9.25 Burial and maturity geohistory plot, Tinga Tingana 1.

## TINGA TINGANA RIDGE

(adjacent to the Weena Trough)

### Tinga Tingana 1

Tinga Tingana 1 is located on the Tinga Tingana Ridge (Fig. 5.5) and has been included in this review as a guide to the prospectivity of the Weena Trough which lies to the west. In the final report for the NGMA project, a synthetic well extrapolating thermal and burial history results from Tinga Tingana 1 to the central Weena Trough will provide a more accurate assessment of the region's prospectivity.

When considering the geohistory plot of Tinga Tingana 1 (Fig. 9.25) it is important to note that the well has limited maturity data (Fig. 9.26), resulting in a poorly constrained heatflow model. The majority of the sediments in the well are immature whilst the basal Merrimelia Formation has remained within the oil window since the mid-Cretaceous (Fig. 9.26; Table 9.5). Increased depth of burial and total coal thickness in the Patchawarra Formation, possibly in excess of 40 m (Fig. 6.6), suggests that the prospectivity of the Weena Trough has been underestimated.

## GIDGEALPA AND MERRIMELIA RIDGES

The thermal and burial history of the Gidgealpa and Merrimelia Ridges is represented by Merrimelia 7 and Gidgealpa 16 (Fig. 9.1).

### Merrimelia 7

Figure 9.27 shows that the Early Triassic to Late Jurassic succession in Merrimelia 7 entered the oil window between 80 and 90 Ma, and has remained there to the present day. This is consistent with oil production from the Nappamerri Group in Merrimelia 7. Depth to present day maturity windows are summarised in Figure 9.28 and Table 9.6.

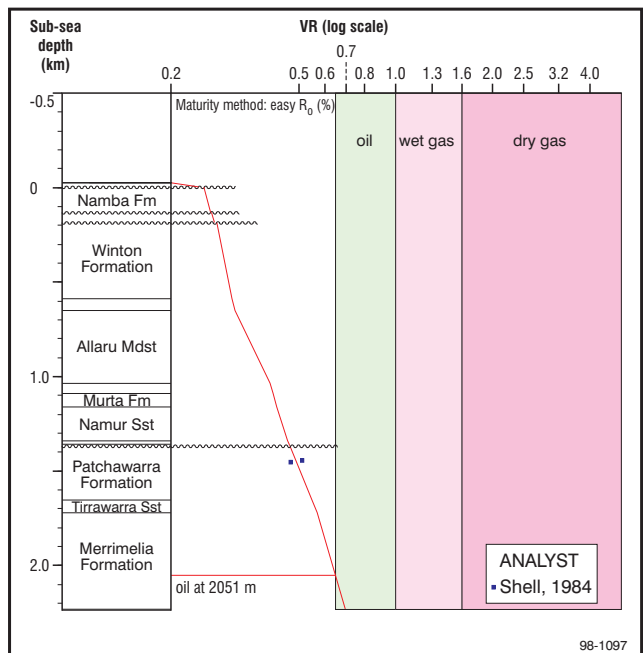


Fig. 9.26 Maturity versus depth, Tinga Tingana 1.

Table 9.5 Hydrocarbon maturity, Tinga Tingana 1.

Unit	R <sub>0</sub> (%)	Maturity window	Depth (m subsea)
Murda, Namur, Birkhead, Hutton	<0.65	immature	-
Patchawarra, Tirrawarra, Merrimelia	0.65	oil	~2051

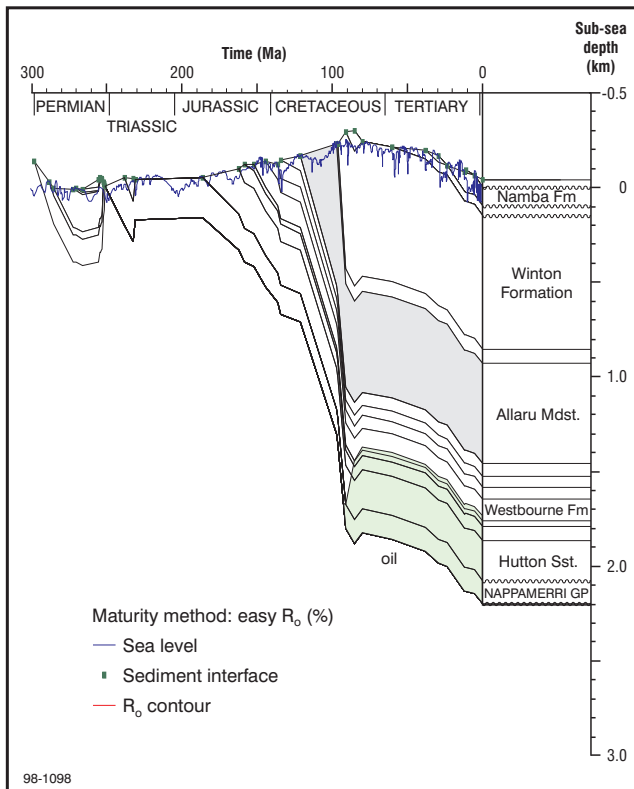


Fig. 9.27 Burial and maturity geohistory plot, Merrimelia 7.

Table 9.6 Hydrocarbon maturity, Merrimelia 7.

Unit	R <sub>0</sub> (%)	Maturity window	Depth (m subsea)
Westbourne, Adori, Birkhead, Hutton, Nappamerri	0.65	oil	~1731

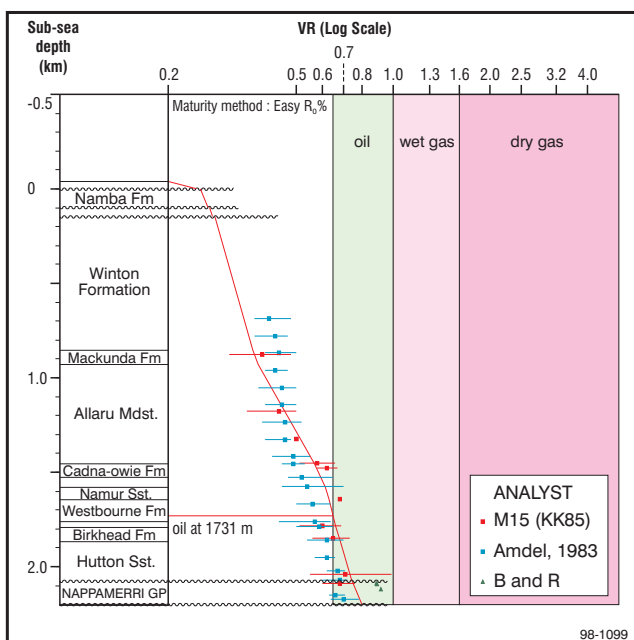


Fig. 9.28 Maturity versus depth, Merrimelia 7.

## Gidgealpa 16

Figures 9.29 and 9.30 show that Early Permian to Middle Jurassic source rocks are capable of generating oil and entered the oil window in the mid-Cretaceous (~90 Ma) in Gidgealpa 16. Computed maturity values are less than observed values towards the base of the well (Fig. 9.30), although the latter still lie within the oil window, albeit close to the wet gas threshold. This may help to explain drillstem test (DST) results over the Toolachee and Patchawarra Formations and Tirrawarra Sandstone, where commercial rates of wet gas were tested. Significantly, DST 2 tested gas at a rate of  $0.048 \times 10^6 \text{ m}^3$  (1.7 mmcf) per day and recovered 1.65 kL (10.4 bbl) of oil over the interval 2115.9–2123.5 m in the Toolachee Formation, whilst the deeper formations were only gas bearing. Gidgealpa 16 is structurally positioned to receive gas from gas-bearing source rocks on the flanks of the Gidgealpa Field. Depth to present day maturity windows is summarised in Table 9.7. The depth to the top of the oil window for Gidgealpa 16 closely matches that for Merrimelia 7.

Table 9.7 Hydrocarbon maturity, Gidgealpa 16.

Unit	R <sub>0</sub> (%)	Maturity window	Depth (m subsea)
Adori, Birkhead, Hutton, Poolowanna, Nappamerri, Toolachee, Patchawarra, Tirrawarra, Merrimelia	0.65	oil	~1713

## SUMMARY

Combining the results of the 15 wells studied provides a comparison across the Cooper Basin of the generation potential, and oil and gas expulsion with time. These are summarised below.

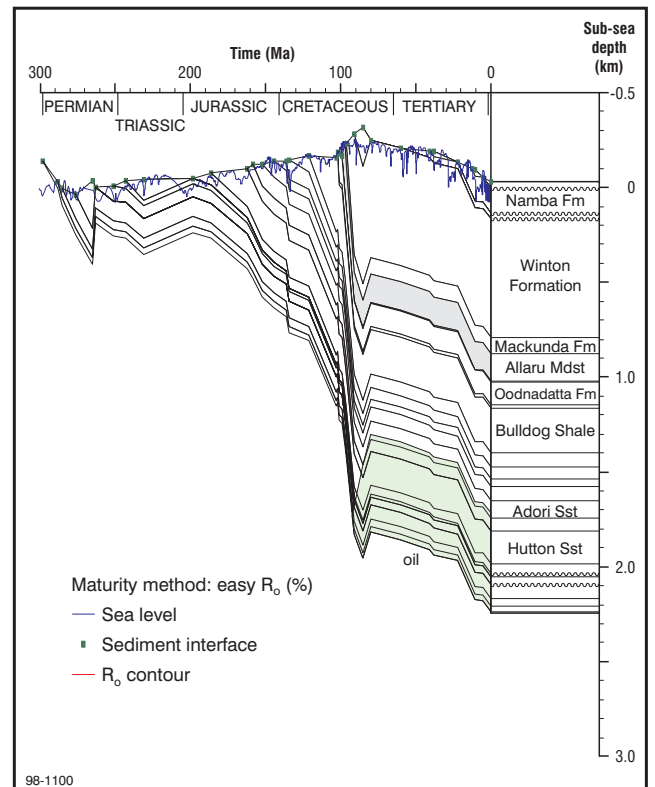


Fig. 9.29 Burial and maturity geohistory plot, Gidgealpa 16.

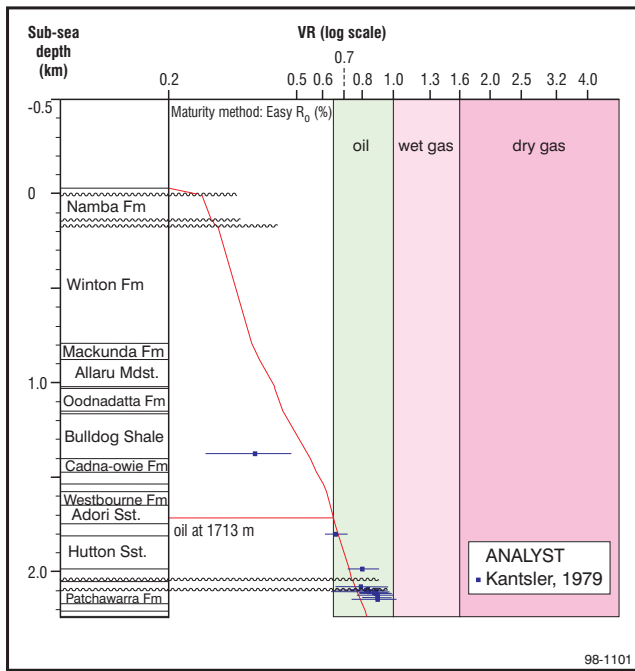


Fig. 9.30 Maturity versus depth, Gidgealpa 16.

Total (residual) generation potential through time for all wells in the study is shown in Figure 9.31, which indicates that most hydrocarbons were generated in the mid-Cretaceous. Minor amounts were generated during the Permian in the Nappamerri Trough.

Figure 9.32 shows total oil expulsion through time for all wells indicating major expulsion in the mid-Cretaceous, with minor amounts in the late Tertiary. Minor oil was expelled at Burley 2 in the Late Permian. The late Tertiary

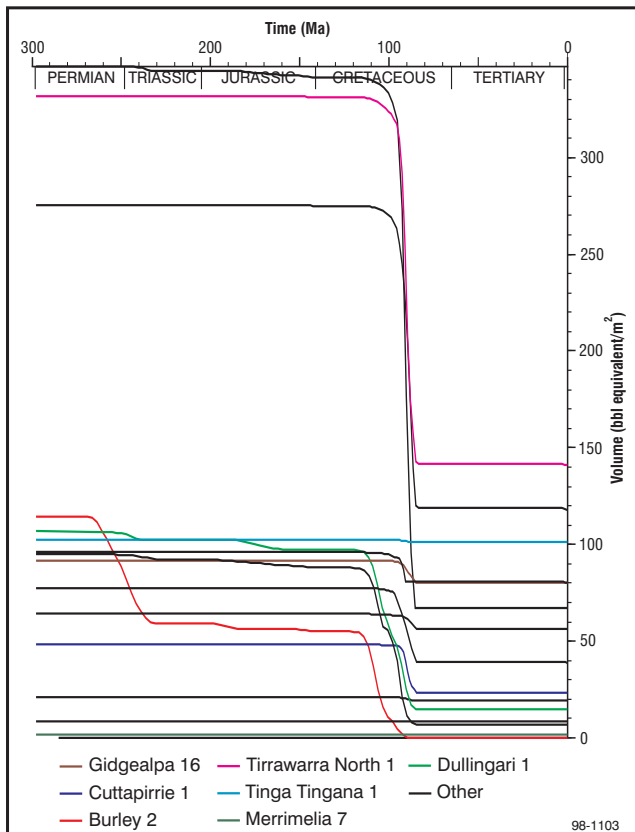


Fig. 9.31 Generation potential versus time, Cooper Basin.

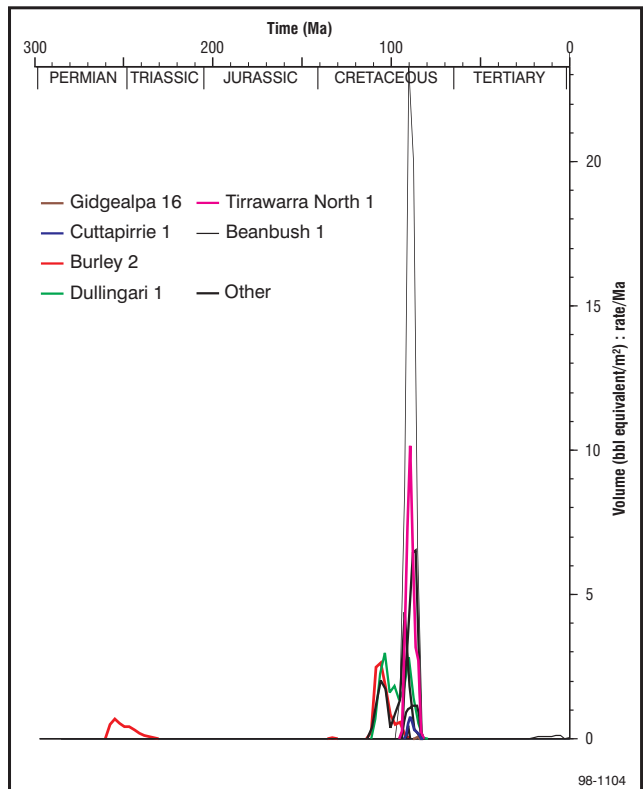


Fig. 9.32 Oil expulsion versus time, Cooper Basin.

event suggests that if sufficient residual kerogen remains, increased temperature as a result of the combined effect of Tertiary deposition and elevated temperatures in the late Tertiary may lead to late-stage oil expulsion in favourable parts of the basin.

Figure 9.33 demonstrates that gas expulsion is ubiquitous and mainly occurred in the mid-Cretaceous.

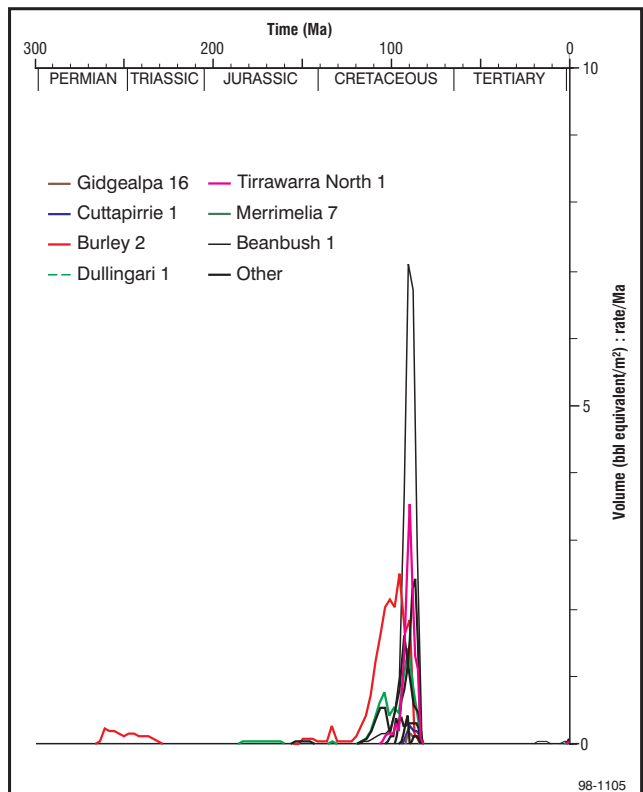


Fig. 9.33 Gas expulsion versus time, Cooper Basin.

The foregoing conclusions are based on the 15 wells used for this preliminary study. A more rigorous computed regional model (90 wells in South Australia and Queensland) will be used in the final NGMA report.

Previous studies based on consideration of the oil maturity window have implied significant hydrocarbon generation in the Late Cretaceous and early Tertiary (Kantsler *et al.*, 1986; Pitt, 1986). However, results of the present study indicate that the major generation occurred in the mid-Cretaceous, which provides explorers with a new perspective for understanding the timing of expulsion of hydrocarbons in the Cooper and Eromanga Basins. Accordingly, a reassessment of the changing migration pathways during Late Cretaceous or Tertiary structuring is warranted.



# RESERVOIRS and SEALS

## Chapter 10

### INTRODUCTION

At only one stage early in the evolution of the Cooper Basin did clastic depositional environments dominate the landscape and that was when sand-laden meltwater from retreating glaciers deposited its load on fluvial braidplains and braid deltas in broad valleys freed from the grip of continental ice. As the Cooper Basin continued to subside and as topographic relief diminished, the region was blanketed by extensive peat swamps that forced the confinement of fluvial channels, which though relatively narrow (~70–130 m), were stacked vertically to produce multistory reservoirs. The advance and retreat of two major lakes gave rise to accumulating deltaic, shallow lake and shoreface sand before peat swamps again claimed the land. With the extinction of peat-forming plants in the earliest Triassic, fluvial channels drained floodplains characterised by palaeosols and emptied into perennial lakes and these channels formed the last reservoirs in the Cooper Basin.

Porosity and permeability of Cooper Basin reservoirs are summarised in Table 10.1. The table is based on the results of routine core analysis (measured at ambient conditions) held in the PIRSA PEPS database and includes company and PIRSA generated analyses. These values are overestimates since porosity and permeability decrease under overburden pressures, and a correction factor of 0.95 needs to be applied (Morton, 1989).

### LITHOLOGY AND DIAGENESIS

Reservoirs within the Patchawarra, Epsilon, Daralingie and Toolachee Formations (excluding porosity) consist of quartz (65%), rock fragments including composite quartz (9.1%), minor to trace amounts of altered feldspar and the following authigenic components — kaolin (7.1%), illite (7.4%), carbonate (7.7%), carbonaceous material (7.7%) and mica (5.1%) (Stuart *et al.*, 1990). Tirrawarra Sandstone

and Merrimelia Formation reservoirs contain higher proportions of lithics, and range from quartzarenite to litharenite (Rezaee and Lemon, 1996; Chaney *et al.*, 1997).

The primary lithology (which varies within individual reservoirs due to changing facies) and the depth of burial of Cooper Basin reservoirs, largely account for variations in the relationship between porosity and permeability. Schulz-Rojahn and Phillips (1989) and Tingate and Luo (1992) have reviewed diagenetic controls on porosity and reservoir quality in Cooper reservoirs. In some reservoirs, particularly in the Toolachee Formation, early quartz overgrowths in relatively clean sand has preserved some primary porosity from compaction but, in general little of the porosity observed in Cooper reservoirs is primary. Detrital illite is the main cause of lower porosity and permeability in the finer grained floodplain sand. Porosity may also be reduced diagenetically due to the precipitation of authigenic materials (late quartz overgrowths, siderite and kaolin in the shallower reservoirs; illite, clinocllore and pyrophyllite in the more deeply buried sandstone). Secondary porosity, formed by the dissolution of lithic grains and feldspars, is predominant in many reservoirs, while microporosity may be significant where kaolin is present. Other studies of the diagenetic history of Cooper Basin reservoirs include the work of Steveson and Spry (1973), Martin and Hamilton (1981), Stuart *et al.* (1990), Rezaee and Lemon (1996) and Chaney *et al.* (1997). There is little published material on the composition and diagenetic history of Triassic reservoirs in the Cooper Basin.

### RESERVOIRS

#### Merrimelia Formation

Depositional processes within the glacial regime have controlled the distribution of all Merrimelia Formation facies including reservoir sandstone (Williams and Wild,

**Table 10.1** Summary of porosity and permeability data for the Cooper Basin.

Formation	Number	Sample depth (m)			Porosity (%)			Permeability (mD)		
		Minimum	Maximum	Average	Minimum	Maximum	Average	Minimum	Maximum	Average
Cuddapan Formation	22	2658	2667	2663	0.0	17.6	9.20	0.0	3674	1.58
Tinchoo Formation	56	2489	2506	2497	0.2	19.3	11.9	0.008	1985	26.1
Wimma Sandstone Mbr	32	2130	2164	2157	2.5	22.9	10.0	0.05	865	0.926
Paning Member	202	2125	2505	2173	1.2	22.9	11.6	0.01	865	1.98
Callamurra Member	96	2086	2859	2465	1.4	21.1	9.7	0.1	296	0.620
Toolachee Formation	996	1867	3234	2180	0.1	25.3	12.4	0.001	1995	3.363
Daralingie Formation	173	2331	2509	2424	0.4	20.4	9.7	0.004	414	0.397
Epsilon Formation	238	1952	3114	2409	0.9	21.0	9.1	0.007	407	0.680
Patchawarra Formation	846	1764	3547	2463	0.2	23.8	10.5	0.005	2503	0.933
Tirrawarra Sandstone	718	2208	3114	2643	1.7	18.8	11.1	0.007	329	1.59
Merrimelia Formation	59	1952	3148	2990	0.4	16.5	7.7	0.002	30	0.109

1984; Chaney *et al.*, 1997). In 1970 porous sandstone was recovered in a core from Merrimelia 5 and recognised as a potential reservoir (Mulready, 1970), but its distinctive paraglacial aeolianite origin was only recognised 15 years later (Williams *et al.*, 1985). These authors documented the aeolianite facies in core from the Merrimelia Field and mapped the unit seismically. Measured core porosity of 12–18% and permeability to 75 mD place the aeolian facies at the high end of the Merrimelia Formation reservoir spectrum as determined from porosity and permeability distributions (Fig. 10.1).

For almost 40 years the Merrimelia Formation was regarded as economic basement because the chief facies intersected while drilling are impermeable glaciolacustrine rhythmites and polygenetic diamictite. An altered zone at the top of the Warburton Basin has also been mistaken for Merrimelia Formation (see ‘Seals’ below) which has added to its perceived low reservoir status. However, the drilling of Pondrinie 5 in 1989 and Malgoona 1A in 1990 led to the discovery of commercial hydrocarbons in the Merrimelia Formation.

The Pondrinie discovery is significant because the gas is trapped in the same aeolian dune system described above and has the best reservoir quality in terms of thickness and average porosity in the entire Cooper Basin. As shown in Table 10.2 which lists a selection of drillstem test and sand thickness data for all reservoir units, the Pondrinie aeolianite is by far the thickest of the Permian reservoirs. Pondrinie 8 for instance (Table 10.2), has an average log porosity of

17.8% and flowed gas at a rate of 245 395 m<sup>3</sup> (8.71 mmcf) per day from a net pay column 55.8 m thick.

A further discovery was made in a more common reservoir facies, namely a meltwater stream channel deposit in Malgoona 1A near the southern margin of the Patchawarra Trough. This sidetrack of Malgoona 1 was programmed to cross a fault before intersecting a substantial thickness of Merrimelia Formation sealed laterally by the fault (Ostler, 1991; Oldham and Gibbins, 1995). The well was successful and tested 101.8 kL (640 bbl) of oil per day and a small quantity of gas from a net pay thickness of 2.4 m. The channel sandstone is quartzose, fine grained and well sorted, and differs markedly from the poorly sorted lithic, volcanoclastic sandstone and conglomerate which mantled the outwash plain over which the meltwater stream flowed. The Malgoona reservoir can be considered to represent a transition to the Tirrawarra Sandstone but is too thin to be resolved seismically (Oldham and Gibbins, figs 7c, 8).

### Tirrawarra Sandstone

The Tirrawarra Sandstone is the major oil reservoir in the Cooper Basin and, in addition produces free-flow and tight gas. Oil is produced in Tirrawarra, Fly Lake, Brolga and Moorari–Woolkina Fields; Gidgealpa Field south dome has oil with a gas cap and wet gas and condensate occur in Narie 1 situated near the gas-producing Merrimelia Field. Other Tirrawarra Sandstone gas fields are Pondrinie, Bookabourdie, Kurunda and Big Lake, the last including free-flow and tight dry gas which has responded well to fracture stimulation (Stanley and Halliday, 1984). Enhanced oil recovery programs by miscible gas drive have been successful in Tirrawarra and Moorari Fields (Pecanek and Paton, 1984; Rodda and Paspaliaris, 1989).

The Tirrawarra is a widespread single sandstone package which has uniform reservoir character at regional scale, a result of its braidplain to braid delta origin. Reservoir porosity is 10–15% and permeability 1–100 mD based on data from >700 core samples (Fig. 10.2). At reservoir scale the sand is moderately heterogeneous and distinct flow units can be related to shoreface, alluvial fan, braid delta and braidplain facies (Seggie *et al.*, 1994; Seggie, 1997; Rezaee and Lemon, 1996). An approximately twofold variation in directional permeability has also been detected using probe permeametry (Boult *et al.*, 1995).

Regionally, Tirrawarra Sandstone thickness is variable, a result of deposition in a topographically diverse setting. Excluding interface sequences and ‘Tirrawarra Sandstone-like’ facies (see Ch. 6), the Tirrawarra Sandstone (*sensu stricto*) ranges in thickness from 20 to 50 m in Tirrawarra Field and 35 to 100+ m in Big Lake Field. The thickest well intersection is Kumbarie 1 (128 m) located on a depositional fairway out of the Weena Trough.

Because of its thickness the Tirrawarra Sandstone is a good candidate for fracture stimulation which has been carried out in Tirrawarra Field in conjunction with enhanced oil recovery (Salter, 1989) and in Big Lake Field to improve gas production. Several deviated wells have also been drilled in Big Lake Field to increase gas flow. A conglomerate at the top of the Tirrawarra Sandstone in several Big Lake wells has increased the complexity of design and treatment methods (Stanley and Halliday, 1984).

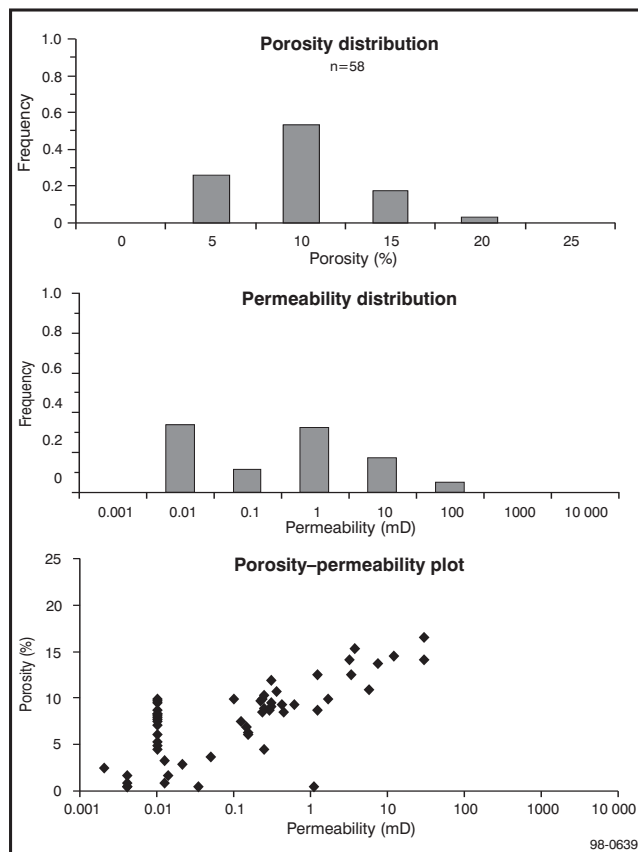


Fig. 10.1 Porosity and permeability distributions, Merrimelia Formation.

**Table 10.2.** Selected drillstem test results and sand statistics in Cooper Basin reservoirs.

Well	Flow rate	Test interval (m)		Number of sands tested
		Gross sand	Net pay	
<b>Tinchoo Formation</b>				
James 1	287.8 kL (1810 bbl) oil per day	2.1	2.1	1
<b>Wimma Sandstone Member</b>				
Pondrinie 9	50.6 kL (318 bbl) of oil and 104 244 m <sup>3</sup> (3.7 mmcf) of gas per day	2.4	2.4	2
<b>Paning Member</b>				
Merrimelia 17	264 836 m <sup>3</sup> (9.4 mmcf) of gas per day	4.5	4.5	1
Merrimelia 29	171 861 m <sup>3</sup> (6.1 mmcf) of gas, 23.2 kL (146 bbl) of oil and 1.0 kL (6 bbl) of water per day	6.4	6.4	1
<b>Callamurra Member</b>				
Moorari 3	67 618 m <sup>3</sup> (2.4 mmcf) of gas per day	5.8	5.8	2
Pondrinie 9	222 575 m <sup>3</sup> (7.9 mmcf) of gas per day	4.2	3.6	2
Burke 3	239 479 m <sup>3</sup> (8.5 mmcf) of gas per day	5.5	5.5	1
Merrimelia 17	109 879 m <sup>3</sup> (3.9 mmcf) of gas per day	3.0	3.0	2
<b>Toolachee Formation</b>				
Toolachee 41	103 962 m <sup>3</sup> (3.69 mmcf) of gas, 3.8 kL (24 bbl) of condensate and 3.0 kL (19 bbl) of water per day	6.1	6.1	1
Moomba South 1	256 383 m <sup>3</sup> (9.1 mmcf) of gas per day	11.9	6.4	4
Strzelecki 15	258 074 m <sup>3</sup> (9.16 mmcf) of gas per day	10.6	8.2	6
Meranji 7	225 392 m <sup>3</sup> (8 mmcf) of gas and 17.5 kL (110) of water per day	11.6	9.1	1
<b>Daralingie Formation</b>				
Moomba 12	267 653 m <sup>3</sup> (9.5 mmcf) of gas per day	3.9	2.1	3
Moomba South 1	177 496 m <sup>3</sup> (6.3 mmcf) of gas per day	5.2	1.2	2
Burke 4	264 836 m <sup>3</sup> (9.4 mmcf) of gas per day	11.6	7.6	2
<b>Epsilon Formation</b>				
Cuttapirrie 3	358 937 m <sup>3</sup> (12.74 mmcf) of gas and 14.0 kL (88 bbl) of condensate per day	3.3	1.4	1
Moomba 76	352 175 m <sup>3</sup> (12.5 mmcf) of gas per day	11.0	–	4
Yapeni 1	273 288 m <sup>3</sup> (9.7 mmcf) of gas per day	8.2	4.4	1
Kerna 4	233 844 m <sup>3</sup> (8.3 mmcf) of gas and 4.0 kL (25 bbl) of condensate per day	15.2	8.2	1
<b>Patchawarra Formation</b>				
Garanjanie	2440268 m <sup>3</sup> (8.67 mmcf) of gas and 27.3 kL (172 bbl) of condensate per day	10.4	7.0	2
Gahnia 1	174 679 m <sup>3</sup> (6.2 mmcf) of gas, 2.9 kL (18 bbl) of condensate and 10.3 kL (65 bbl) of water per day	23.8	20.1	3
Coopers Creek 2	146 505 m <sup>3</sup> (5.2 mmcf) of gas and 0.3 kL (2 bbl) of condensate per day	10.7	7.3	2
Beanbush 1	42 261 m <sup>3</sup> (1.5 mmcf) of gas per day	4.9	0.9	2
<b>Tirrawarra Sandstone</b>				
Merrimelia 14	259 201 m <sup>3</sup> (9.2 mmcf) of gas per day	21.3	17.4	1
Tirrawarra 70 (pre-frac)	11 551 m <sup>3</sup> (0.41 mmcf) of gas and 17.8 kL (112 bbl) of oil per day	30.5	15.5	1
Big Lake 27 (pre-frac)	4508 m <sup>3</sup> (0.16 mmcf) of gas per day	43.0	15.8	1
<b>Merrimelia Formation (meltwater/stream)</b>				
Malgoona 1A	16 904 m <sup>3</sup> (0.6 mmcf) of gas and 101.8 kL (640 bbl) of oil per day	4.3	2.4	1
<b>Merrimelia Formation (aeolianite)</b>				
Pondrinie 8	245 395 m <sup>3</sup> (8.71 mmcf) of gas per day	120.1	55.8	1

## Patchawarra Formation

The Patchawarra Formation contains the most significant gas–condensate reservoirs in the Cooper Basin and has produced almost 45.1 x 10<sup>9</sup> m<sup>3</sup> (1.6 tcf) of raw gas to date. The Patchawarra is the thickest formation of the Gidgealpa Group and one of the most variable in thickness (Battersby, 1976), having been initially deposited in valleys before thinning by onlap of bounding ridges. Uplift at the end of the Early Permian led to truncation of the Patchawarra on structural crests and at the basin margins, thus also creating structurally thinned areas. The reservoirs are multistory fluvial channel, point bar and crevasse splay sandstone ranging from 1800 to 3500 m below the present

surface. As shown in Figure 10.3, porosity and permeability range widely but rarely exceed 15% and 100 mD. A plot of porosity versus depth shows that even at shallow depth, minimum porosity may be below net sand cutoff values (<7%). However, maximum porosity values indicate that ‘sweet spots’ may persist to depths approaching 3200 m or more.

Drillstem tests of Patchawarra Formation in widely spaced wells illustrate reservoir permeability (Table 10.2). Rates range from 42 261 to >244 268 m<sup>3</sup> (1.5–>8.7 mmcf) per day of gas (excluding rates too small to measure). Such variation is typical of mixed-load fluvial systems which have markedly anisotropic channel fill sandstone with lateral and vertical compartmentalisation provided by shaly

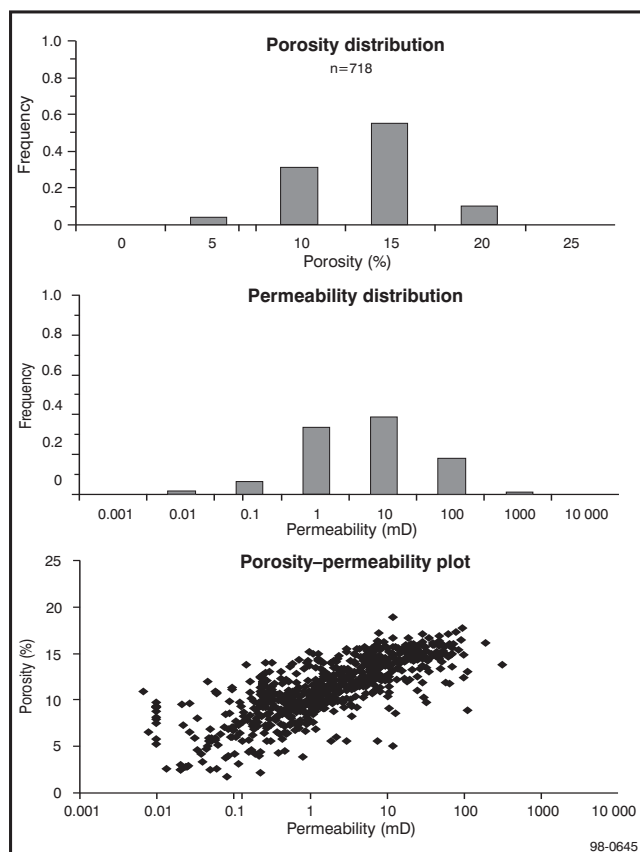


Fig. 10.2 Porosity and permeability distributions, Tirrawarra Sandstone.

facies (Williams, 1995). Thin but sometimes numerous sandstone beds are interspersed with thicker beds seemingly at random. Histograms of bed thickness are illustrated for four wells in Figure 10.4m–p. The number of beds ranges from 11 in Garanjanie 1 where the Patchawarra Formation is 175.3 m thick, to 40 in Coopers Creek 2, where the Patchawarra Formation is 373.4 m thick. The latter well is located in an area of the Patchawarra Trough where sandstone thickness is less than the summed thickness of siltstone and coal. More than half the sands in Coopers Creek 2 (28 of a total of 40) are <2 m thick. Half the sands in Beanbush 1 are also <2 m thick and, like Coopers Creek 2 this well is in a swamp-dominated environment. Thin sand beds contribute to net pay in both wells but the net:gross ratio is low (Fig. 10.4o, p).

Gahnia 1 contains reservoirs at a sand-prone location northeast of the Toolachee gas field. In contrast to wells in the Patchawarra Trough, only one quarter of the beds (5 of 20) are <2 m thick and the Patchawarra in Gahnia 1 contains ten or more upward-fining channel and point-bar to overbank sequences. Sands  $\geq 3$  m thick have contributed to net pay and the net:gross ratio is almost 50% (Fig. 10.4n).

In contrast to Coopers Creek 2 and Beanbush 1, the contribution of thick sand beds to gross sand in Gahnia 1 has increased over that of thin beds. This trend is continued in Garanjanie 1 in which beds <3 m thick contribute only 20% to gross sand but beds >6 m thick contribute 58%. Garanjanie 1 is in an area of the southwestern Cooper Basin where sandstone bed thickness is greater than the summed thickness of siltstone and coal and the Patchawarra Formation is relatively thin. Beds >2 m thick contribute to

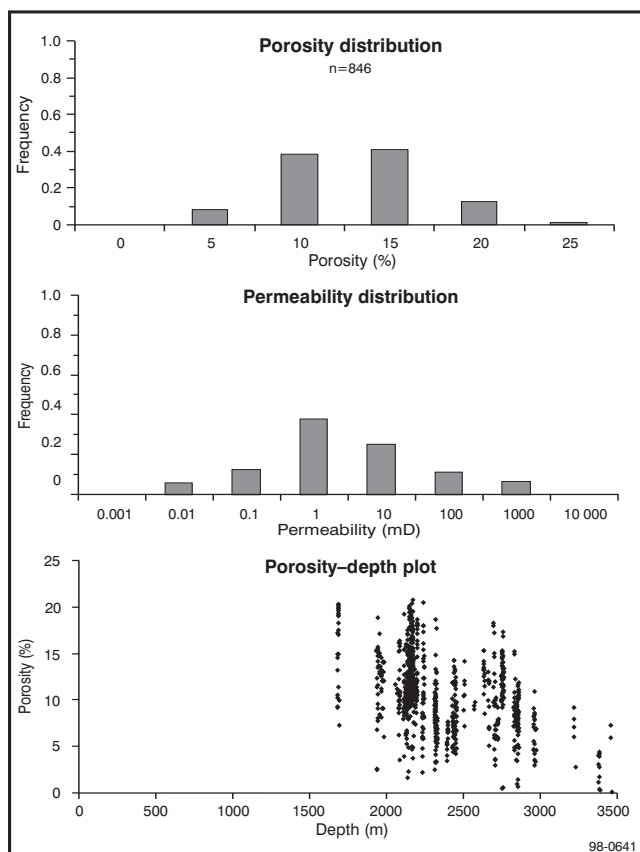


Fig. 10.3 Porosity and permeability distributions, Patchawarra Formation.

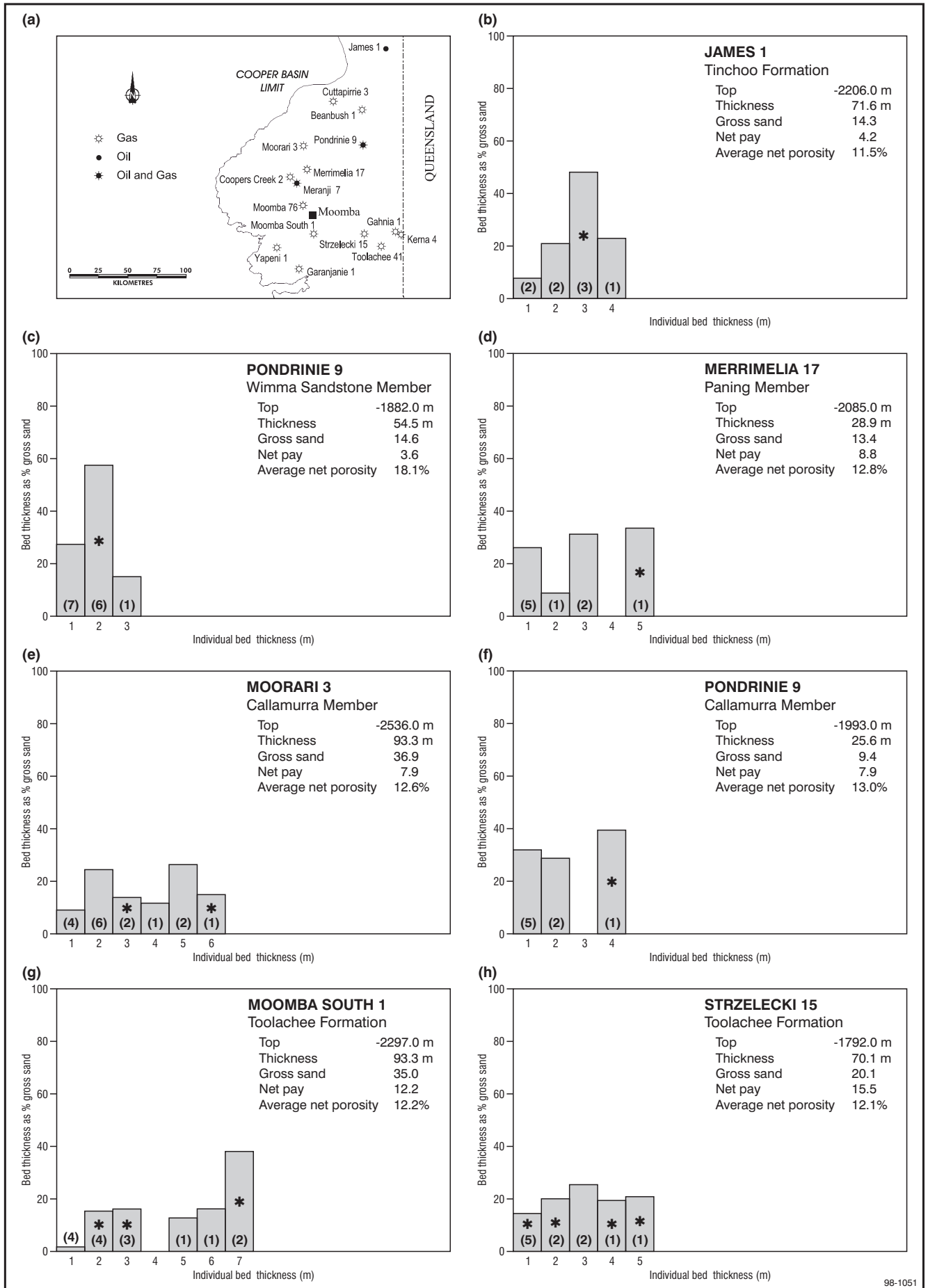
net pay and it is worth noting that at the shallow depth of 1910–2100 m, the Patchawarra reservoirs have a relatively high-average net porosity of 14.1% in this well.

The Patchawarra sandstone reservoirs in summary are of variable thickness but rarely >14 m. Thin but numerous sands in swamp-prone facies are not interpreted to contribute significantly to net pay; stacked channel and point bar facies are the main reservoirs and have higher porosity in shallow parts of the basin, although ‘sweet spots’ may be found at depths >3200 m.

Sand thickness in the Patchawarra and in all of the remaining formations described below was measured on wireline logs using a 100 API cutoff. As Khaksar and Mitchell (1995) have shown, this ‘quick look’ method underestimates the contribution of thin sand beds to the total sand and to net pay. As a result, the ‘thin bed’ portions of histograms shown in Figure 10.4 should be regarded as approximations. Khaksar and Mitchell (1995) have successfully applied a binary lithology method to the resolution of thin sand beds in the Patchawarra Formation of Toolachee Field.

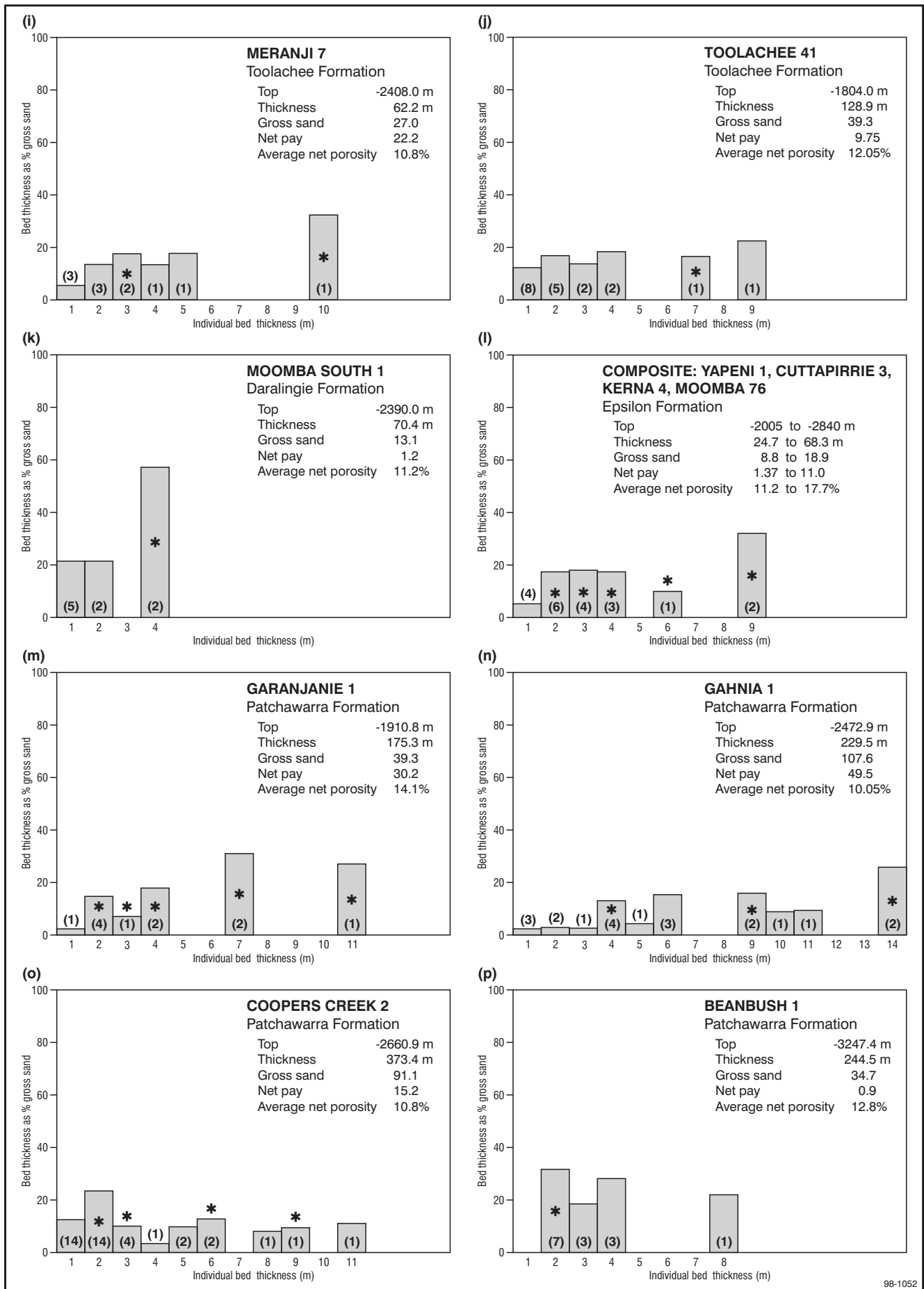
### Epsilon Formation

Fluvio-deltaic and shoreline sandstone of the Epsilon Formation was deposited over much of the southern Cooper Basin. In low-lying areas, with the exception of the Patchawarra Trough, this sand developed between two major phases of lake expansion marked by the Murteree and Roseneath Shales. In the Patchawarra Trough the Epsilon Formation, where not eroded totally, is disconformably overlain by the Toolachee Formation because the trough was



98-1051

Fig. 10.4 Cooper Basin reservoirs. (a) Well locations. (b–p) Histograms of bed thicknesses as per cent gross sand. The number of beds in a given thickness range is given in brackets; \* indicates beds which have contributed to net pay.



98-1052

relatively elevated while the Epsilon Formation was being deposited (Fig. 6.24).

Distributary and shoreface sandstones rarely exceed 4 m gross thickness but locally reach 10–15 m in the Big Lake, Kerna, Munkarie and Yapeni Fields. The broad spread of porosity and permeability values (Fig. 10.5) appears unrelated to gross sand thickness and also unrelated to the two major facies associations. A histogram of sandstone bed thickness plotted against per cent gross sand is shown in Figure 10.4l. This is a composite plot which sums the number of beds in four wells since each well only has 4–6 Epsilon sands. The histogram shows that the majority of beds are 2–4 m thick and all but the thinnest are interpreted to contribute to net pay. A feature of Epsilon Formation reservoirs is the variation in net pay thickness and fair to excellent net porosity. As shown in Table 10.2, thin shoreface sand flows at the same rate as stacked deltaic sand. The test results in Table 10.2 also demonstrate the wide distribution of good Epsilon Formation reservoirs in both shoreface and fluvio-deltaic settings.

A semi-regional sand-by-sand description of Epsilon reservoir facies is provided by Fairburn (1992) who points out that individual distributary channel sand or ribbon shoreface sand is not only thin but is also narrow and thus difficult to map. From seismic amplitude versus offset studies Pinchin and Mitchell (1991) correlated ‘dim spots’ with a lithological change from coal to sand and mapped Epsilon channels ~1 km wide in the Kerna–Alisma area. Taylor *et al.* (1991), in their detailed description of the Epsilon Formation in the Moomba and Big Lake Fields, noted a ‘performance anomaly’ (material balance greater than volumetric calculations) which led to discovery of a field extension on the southwestern flank of the structure. These authors concluded that even in areas with moderate well density a linear sand fairway 1–2 km wide could be overlooked.

A quality shoreface reservoir is the 93-8 sand in Cuttappirrie 3 which provides an insight into post-depositional reservoir enhancement linked to a specific environment.

In Cuttappirrie 3, a core was cut in the lower Epsilon Formation through the top seal, the reservoir sand, the non-reservoir sand and through the underlying Murteree Shale. An interpretation of the depositional setting is given in the section below (‘Seals’, and illustrated in Figures 10.17 and 10.18). The reservoir is a 1.5 m thick medium-grained, well sorted sandstone overlain directly by coal and with measured maximum porosity and permeability of 21.2% and 2391 mD respectively. Accessory glaucony is oxidised and quartz grains are rimmed with iron oxide (Phillips, 1996). High porosity and permeability are attributed here (and independently by Dr. S.E. Phillips, Phillips-Gerrard Petrology Consultants, pers. comm., 1998) to leaching by rain which percolated through an elevated peat swamp and became strongly acidic in the process. This early diagenetic change may have occurred over a period of ~10 000 years, transforming the shoreface sand into a siliceous palaeosol or ‘ganister’. The compacting peat subsequently altered to coal which became the top seal of the reservoir. Primary porosity of the original shoreface sand was enhanced by leaching which prevented formation of quartz overgrowths.

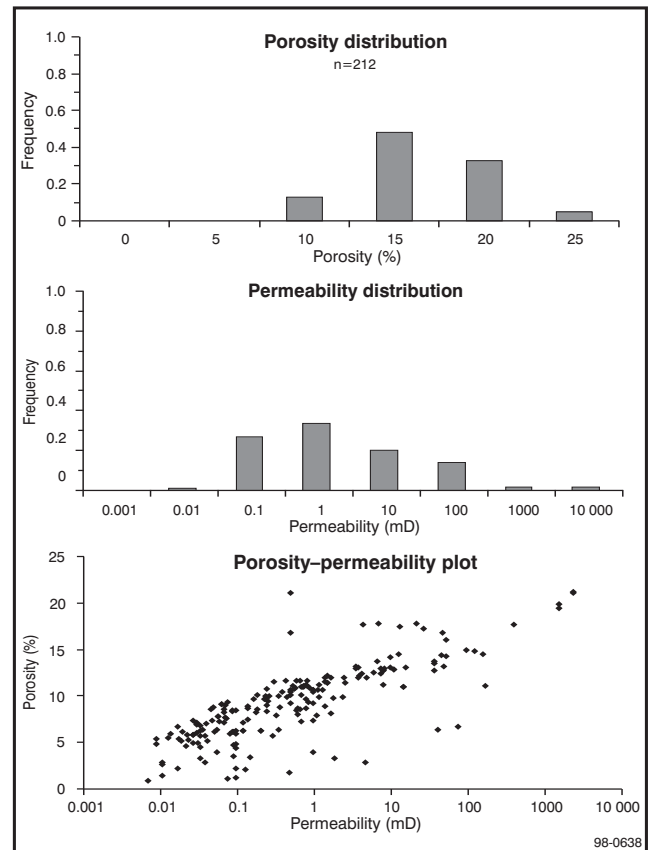


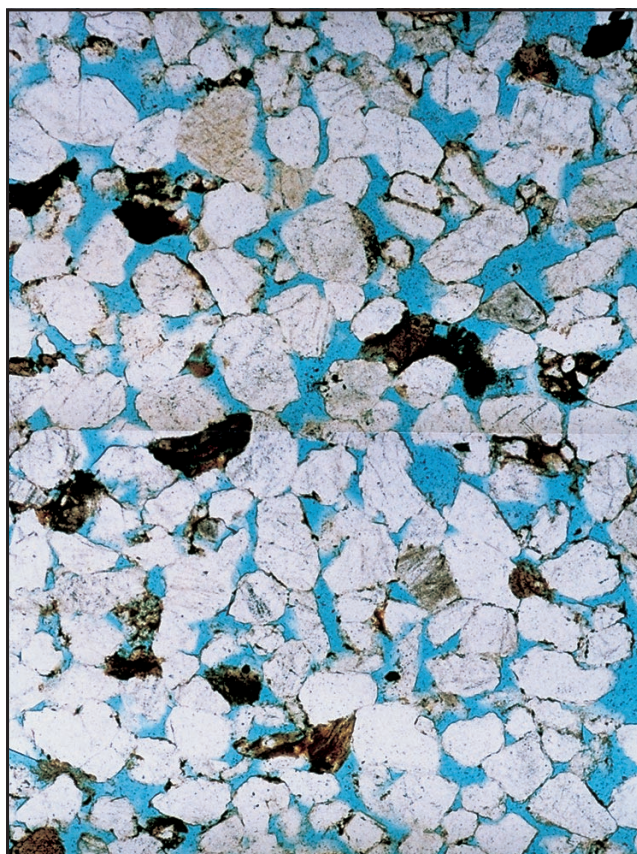
Fig. 10.5 Porosity and permeability distributions, Epsilon Formation.

The reservoir is underlain by fine to very fine-grained, planar cross-laminated silty sandstone, 3.4 m thick, tightly cemented by silica and locally with kaolinitic matrix, with average porosity and permeability of 6.1% and 0.035 mD. These subaqueous lake margin beds pass via thin hummocky cross-stratified, silica and siderite cemented sandstone into the Murteree Shale. At only 4.9 m thick, the Murteree is close to its onlap limit. The transect shown in Figure 10.18 suggests the reservoir sand may have extended downdip for 30 km or more. However, it is more likely that a series of shore-parallel sand sheets developed progressively as ‘Murteree Lake’ retreated. This sand was covered in turn by the advancing peat swamp.

## Daralingie Formation

Daralingie Formation is restricted to an area south of the GMI Ridge and has been eroded from the crests and flanks of structural highs. Cored reservoirs occur at depths ranging from 2300 to 2500 m below the present surface. Stacked reservoir sandstone in the lower Daralingie Formation is interpreted as lacustrine delta front bar, beach and shoreface deposits in the Moomba Field (Williams, 1995). High-sinuosity fluvial channel sandstone with crevasse splay is interpreted in the middle and upper parts of the formation.

Daralingie Formation sand has recorded gas flows of over 169 044 m<sup>3</sup> (6 mmcf) per day from net pay thicknesses ranging from 1.2 to 7.6 m in the three examples in Table 10.2. Figure 10.4k shows sand thickness distribution in Moomba South 1, where Daralingie Formation is relatively thick (70 m). There are nine sand beds, most of which are



Medium-grained, well sorted sandstone with partly oxidised lithics and grains of brown glaucony in the Epsilon Formation, Cuttahirrie 3, core plug 7, 2902.3 m (driller). Plane light, porosity stained blue, field of view 3.37 mm. (Courtesy of Dr S.E. Phillips and the PELs 5 and 6 Cooper Basin Joint Venture; photo 46058)

<2 m thick. A 1.2 m thick net pay zone flowed gas at 177 496 m<sup>3</sup> (6.3 mmcf) per day in this well.

Measured porosity ranges from 0.4 to 20.4% and permeability from 0.40 to 414 mD, with averages of 9.7% and 0.4 mD respectively, from 173 core plugs. Porosity and permeability distributions are shown in Figure 10.6. The most common porosity range is 5–10% and permeability is 0.01–0.1 mD, with an abrupt reduction of measurements at lower values. Most samples lie at the high end indicating good reservoir quality.

In Moomba Field, depleted gas reservoirs within the lower Daralingie Formation have been used for sales gas storage since 1981 and ethane storage since 1984 (Kelemen, 1986). Two laterally extensive sands were selected on the basis of high productivity and proximity to the Moomba plant — the 80-8 and 81-0 reservoirs (2438–2530 m deep). These upward-coarsening sands were deposited in a delta mouth bar environment, where extensive reworking occurred. The 80-8 sand was more productive and 2.1 m of net pay were assigned (permeability 100–1000 mD); the 81-0 sand had 0.6 m net pay (permeability <1 mD). The reservoirs have an areal extent of 18 x 4 km in Moomba Field and 17 x 2.4 km in Big Lake Field (Kelemen, 1986).

During the course of gas storage, it became evident that cross-flow between the two sands was occurring, indicating interconnection away from the well bore. Sales gas production rates of 2.8 x 10<sup>6</sup> m<sup>3</sup> (100 mmcf) per day from

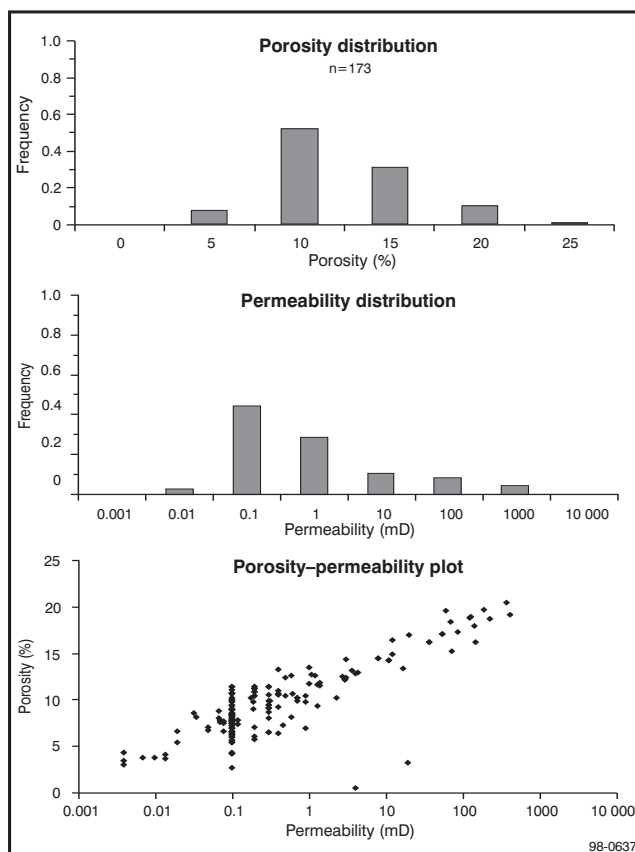


Fig. 10.6 Porosity and permeability distributions, Daralingie Formation.

three wells were predicted, however formation damage was high in two of the wells where siderite cement and authigenic clays were present (Kelemen, 1986). A peak deliverability of 14 x 10<sup>6</sup> m<sup>3</sup> (500 mmcf) per day was achieved from one of the storage wells.

### Toolachee Formation

The Toolachee Formation in Moomba Field contains ~25% of all Cooper Basin gas discovered to 1994 (Mackie *et al.*, 1995). The formation is widespread across the Cooper Basin, but has been eroded from crests of the Merrimelia, Murteree and Dunoon Ridges. Toolachee Formation reservoirs occur at depths ranging from 1870 to 3250 m below the present surface. The main reservoirs occur in the lower Toolachee Formation (Association 1 of Williams, 1984; Unit C of Stuart, 1976) and consist of stacked moderately thick (up to 6 m) point bars (Williams, 1984). The Moomba Field reservoir sands are named 75-8, 76-2, 76-4, 76-5, 76-8, 77-0 and 77-1 (Fairburn, 1989). Other sandstones are interpreted as abandoned channel and proximal and distal crevasse splay deposits (Mackie *et al.*, 1995). Fairburn (1989) noted that high-porosity sand was deposited in-channel (point bar) and low-porosity sand was deposited in overbank settings (e.g. crevasse splay).

Dimensions of fluvial channels in the lower Toolachee Formation in Moomba Field were determined by Williams (1995) and by Mackie *et al.* (1995). Both measured average channel thicknesses of 5 m from core logs, the average bankfull width was calculated as 105 m by Williams (1984) while the average channel width was calculated as 166 m by

Mackie *et al.* (1995). In the Moomba and Big Lake Fields, Mackie *et al.* (1995) found a qualitative relationship between seismic amplitude character and reservoir quality. Both reservoir compartmentalisation and by-passed reservoirs were indicated by the three dimensional geometry of the high-sinuosity fluvial channels.

The middle and upper Toolachee Formation is dominated by mudstone and coal, with only thin interbedded crevasse splay sandstone which does not generally constitute economic reservoir. A locally developed (e.g. Gidgealpa Field) coarse-grained, high-sinuosity channel facies occurs in the upper Toolachee Formation (Association 3 of Williams, 1984).

Histograms of sand bed thickness in four wells where the Toolachee Formation has flowed gas at rates ranging from 103 962 to 326 818 (3.69–11.6 mmcf) per day are shown in Figure 10.4g–j. Over half the sand in these wells is <2 m thick. Sand over 5 m thick is less common, however each example well has penetrated at least one, and as many as four thick sands, which represent stacked point bars deposited in the main channels. It is this thick channel sand which is generally the most productive (Table 10.2, Fig. 10.4g–j).

The thickest Toolachee Formation shown in Figure 10.4j (129 m in Toolachee 41) has the most sand beds (19) and the thickest sand (6.1 m of net pay) which flowed gas at 103 962 m<sup>3</sup> (3.69 mmcf) per day (Table 10.2). The Toolachee Formation in the other examples ranges from 62 to 93 m thick and the number of sand beds ranges from 11 to 15 (Fig. 10.4g–i).

Toolachee Formation porosity ranges widely from 0.1 to 25.3% and permeability from 0.001 to 1995 mD with averages of 12.4% and 3.4 mD respectively. Porosity and permeability distributions of 996 samples are shown in Figure 10.7. The most common porosity range is 10–15%, while permeability is more evenly distributed from 0.1 to 10 mD with a relatively high frequency in the range 100–1000 mD. A porosity–depth plot shows the expected reduction of maximum porosity with depth (Fig. 10.7) however, like the Patchawarra Formation many shallow samples have porosities below net sand cutoff values (7%) and some of the deepest samples show values above the cutoff, indicating potential ‘sweet spots’ at depth.

### Callamurra Member

The Callamurra Member of the Arrabury Formation is conventionally regarded as a regional seal and has been described as the ‘major fluid migration barrier between the Cooper and Eromanga Basins’ (Channon and Wood, 1989, p. 19). The unit nevertheless contains economic oil and gas reservoirs in some areas and is a leaky seal in others (see ‘Seals’ below).

Callamurra Member is widespread, but it has been eroded in the northern and southern Cooper Basin and from the Murteree and Dunoon Ridges. Callamurra Member reservoirs occur at depths ranging from 2086 to 2860 m below the present surface. Sandstone was deposited in channels carved by high-sinuosity rivers which flowed across a floodplain into perennial lakes. Pedogenic profiles developed away from areas of active sediment accumulation. The environment of deposition was similar to that of the upper Toolachee Formation, with the exception of

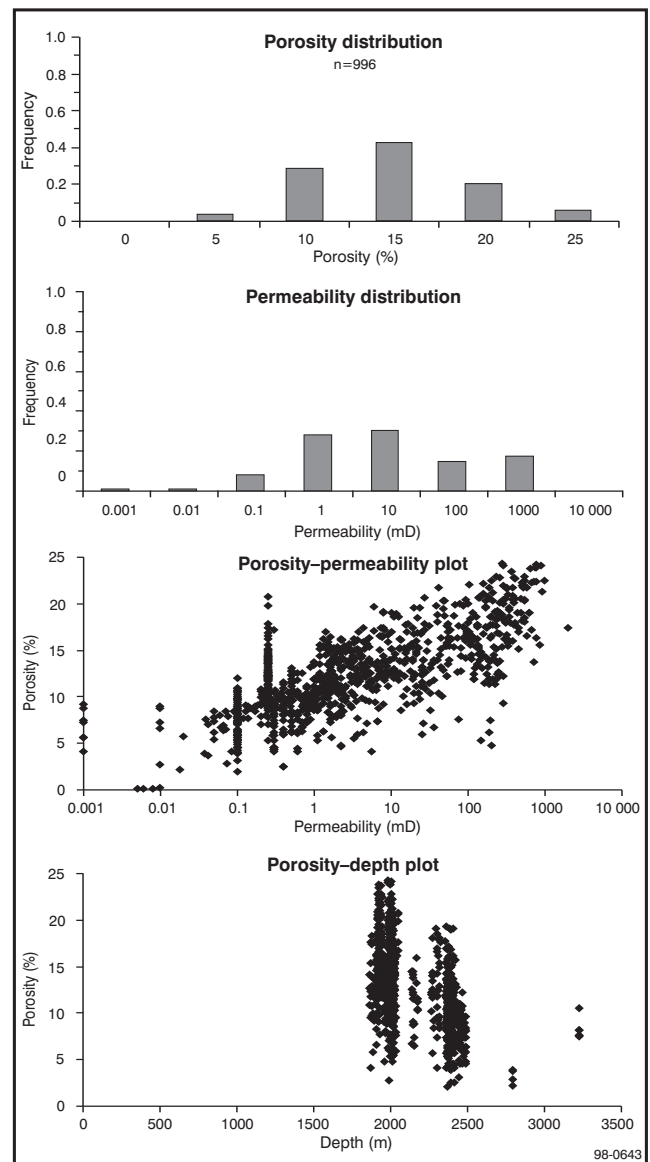


Fig. 10.7 Porosity and permeability distributions, Toolachee Formation.

coal swamp environments which are absent in the Callamurra Member.

The Callamurra Member has recorded gas flows of 67 618 – 239 479 m<sup>3</sup> (2.4–8.5 mmcf) per day from net pay thicknesses of 3.0–5.8 m in the four examples listed in Table 10.2. Although the thickness of the Callamurra Member is variable in the two examples shown in Figure 10.4e, f) the ratio of gross sand to total thickness is similar (Moorari 3, 0.39; Pondrinie 9; 0.36). Sands <2 m thick dominate (17 of a total of 24 sands in the wells), however like the Toolachee Formation it is the thicker, stacked point bar sand which is the most productive.

Core depths range from 2000 to 2850 m for the Callamurra Member. Porosity ranges from 1.4 to 21.0%, permeability from 0.1 to 296 mD, with averages of 9.7% and 0.62 mD respectively from 96 core plugs. The porosity histogram shows a near normal distribution, with a broad peak between 5 and 15% (Fig. 10.8). Permeability has the largest number of samples in the range 0.1–1 mD and tails off at lower values.

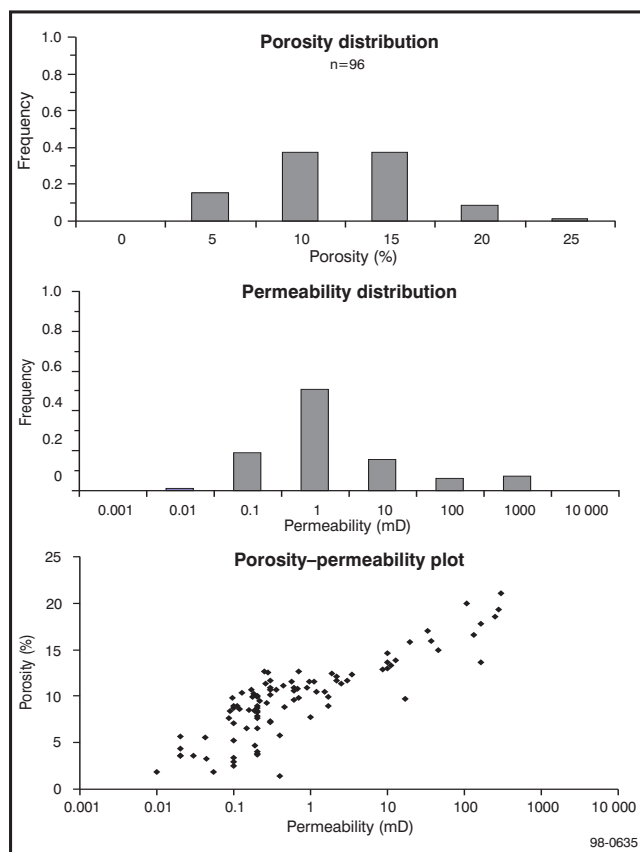


Fig. 10.8 Porosity and permeability distributions, Callamurra Member.

## Paning Member

The Paning Member is the most widely distributed member of the Arrabury Formation in the Cooper Basin. It is absent in the southern Cooper Basin but extends northwards beyond the Permian zero edge into Queensland. Paning Member reservoirs occur at depths ranging from 2120 to 2500 m below the present surface and contain economic accumulations of both oil and gas. The Paning Member was deposited in a floodplain environment, with soil profiles, localised lakes and high-sinuosity fluvial channels. Channon and Wood (1989, fig. 17) delineated channel belts with good sand development in the Patchawarra Trough, which pass laterally into low-energy floodplain environments.

Two examples of Paning Member reservoirs are shown in Table 10.2 from Merrimelia 17 and 29. The Paning Member flowed gas at rates over 169 044 m<sup>3</sup> (6 mmcf) per day from net pay ranging from 4.5 to 6.4 m thick in the examples. A histogram of Paning Member sand bed thickness in Merrimelia 17 is shown in Figure 10.4d. Two thirds of the beds are <2 m thick, and the thickest bed flowed gas at 264 836 m<sup>3</sup> (9.4 mmcf) per day. Merrimelia Field is located near the edge of the channel belt mapped by Channon and Wood (1989).

Porosity ranges from 1.2 to 22.9%, permeability from 0.01 to 865 mD, with averages of 11.6% and 1.98 mD respectively. Porosity and permeability distributions are shown for 202 core plugs in Figure 10.9. Porosity distribution peaks at 5–10% with a gradual tail off at the high

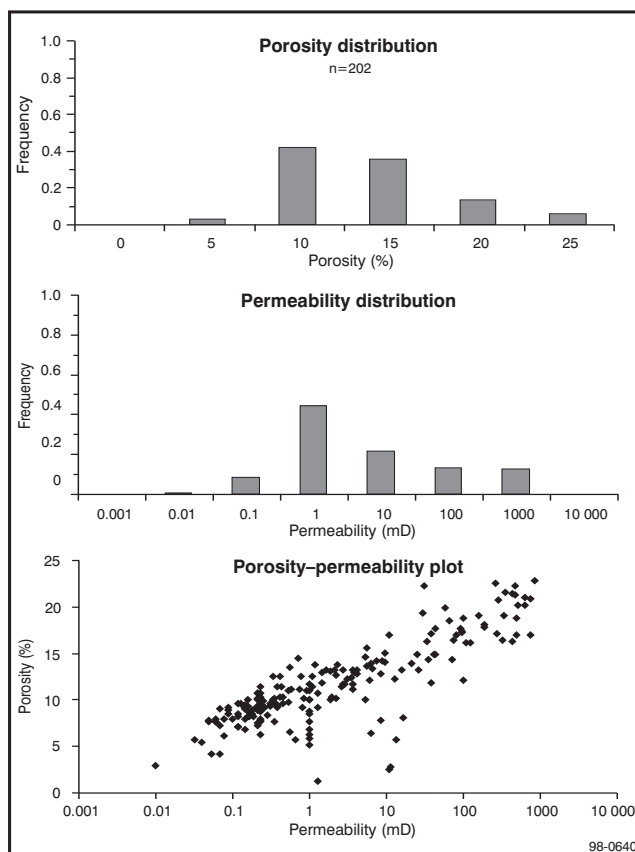


Fig. 10.9 Porosity and permeability distributions, Paning Member.

end. Permeability values are mostly in the range 0.1–1 mD and the distribution is skewed towards the high end.

## Wimma Sandstone Member

Wimma Sandstone Member reservoirs were deposited by low-sinuosity rivers which form a 70 km long southwest–northeast belt along the Patchawarra Trough in South Australia and Queensland (Channon and Wood, 1989, fig. 10; Powis, 1989, fig. 11). Economic oil and gas reservoirs occur at depths ranging from 2130 to 2160 m below the present surface.

Porosity ranges from 2.5 to 22.9% and permeability from 0.05 to 865 mD in the relatively small number (32) of available core plugs. Average porosity is 10.0% and permeability 0.93 mD. Figure 10.10 shows porosity and permeability distributions; porosity shows a strong bias at 5–10%, permeability is more evenly distributed in the range 0.01–1 mD.

The distribution of sand bed thickness in the Pondrinie 9 well is shown in Figure 10.4c. Most beds are <2 m thick. The zone which produced the gas flow of 104 244 m<sup>3</sup> (3.7 mmcf) per day and oil flow of 50.6 kL (318 bbl) per day (Table 10.2) has a total of 3.6 m of net pay from two sand beds. The Wimma Sandstone Member is 54.5 m thick in Pondrinie 9 and contains a total of 14.6 m of gross sand (only ~25% of the formation). Pondrinie 9 is located on the edge of the main channel belt (Powis, 1989, fig. 11) where the unit passes laterally into the Paning Member, hence the relatively thin sand beds, the low proportion of sand and the low net:gross ratio in the well.

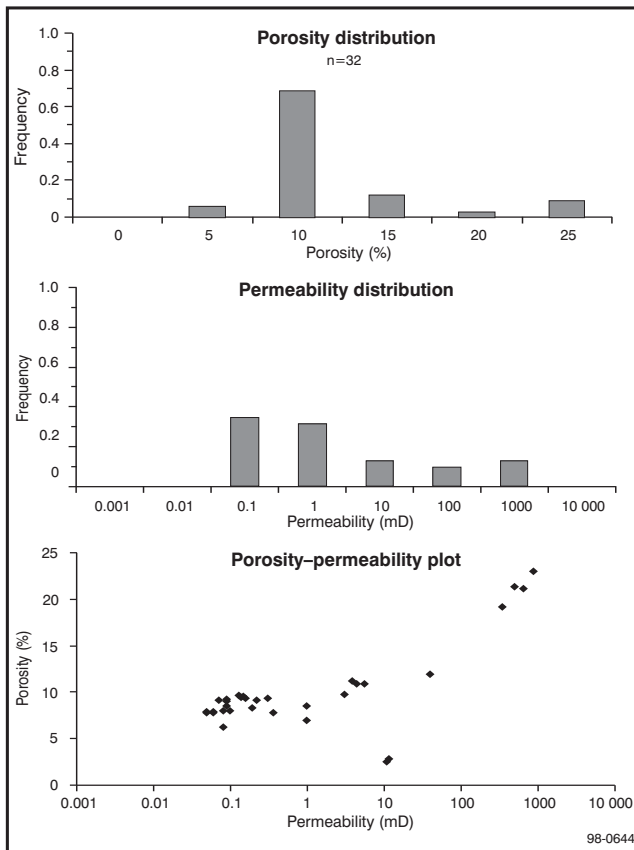


Fig. 10.10 Porosity and permeability distributions, Wimma Sandstone Member.

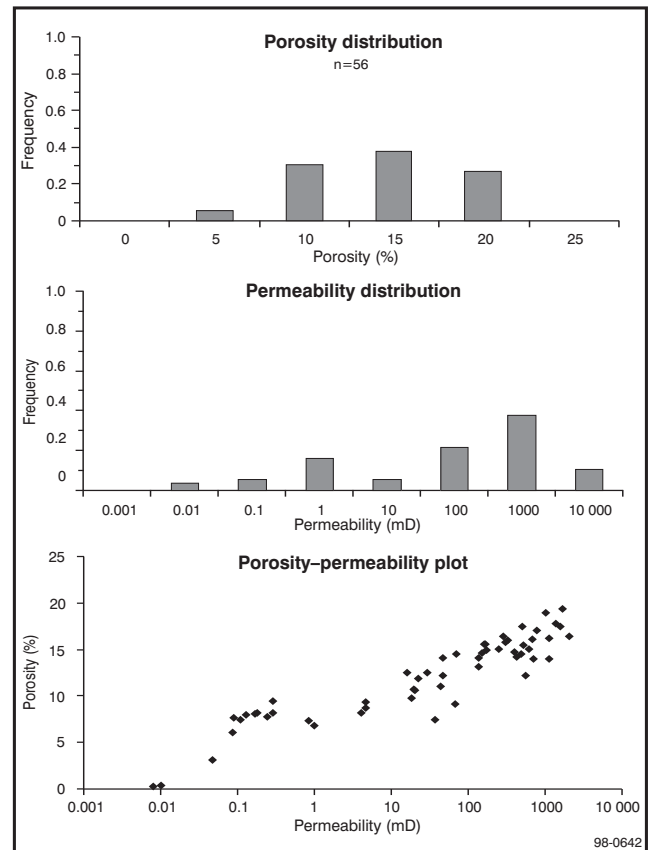


Fig. 10.11 Porosity and permeability distributions, Tinchoo Formation.

## Tinchoo Formation

Tinchoo Formation is restricted to the northeastern Patchawarra Trough and northern Cooper Basin in South Australia, where it extends beyond the Permian zero edge. Tinchoo Formation reservoirs occur at a depth of ~2500 m below the present surface and produce oil.

Tinchoo Formation reservoirs were interpreted as high-sinuosity fluvial channels by Youngs and Boothby (1985) based on upward-fining log signatures. However, in the one Tinchoo Formation core in South Australia (Telopea 1), upward-fining packages are not common and sedimentary structures typical of point bar and abandonment facies have not been observed. Hence a low-sinuosity fluvial environment is interpreted.

An example from James 1 of a Tinchoo Formation sand with 2.1 m of net pay which flowed 287.8 kL (1810 bbl) of oil per day is shown in Figure 10.4b. Unlike most other Cooper Basin formations, sand bed thicknesses are evenly distributed, with no dominance of either thick or thin beds.

From a total of 56 Tinchoo Formation core plugs, porosity ranges from 0.2 to 19.3%, permeability from 0.008 to 1985 mD, with averages of 11.9% and 26.1 mD respectively. The distribution of porosity and permeability is shown in Figure 10.11. Porosity is most commonly distributed in the range 10–15%, and tails off over 20%, however permeability is more widely distributed, mostly ranging from 100–1000 mD and declining in frequency at low values.

## Cuddapan Formation

Cuddapan Formation is restricted to the Patchawarra Trough in South Australia, where reservoirs occur at a depth of ~2670 m below the present surface. Cuddapan Formation has only been cored in Beanbush 1 and was previously thought to correlate with the Jurassic Poolowanna Formation (Gravestock and Alexander, 1988). The sand is interpreted as a high-sinuosity fluvial channel deposit. As yet, there have been no economic oil or gas fields discovered in the Cuddapan Formation in South Australia.

The Cuddapan Formation is represented by only 22 core plugs from Beanbush 1 (Fig. 10.12). Porosity ranges from 0 to 17.6%, permeability from 0 to 3674 mD, with averages of 9.2% and 1.58 mD respectively. Porosity is evenly distributed from 0 to 20%, with a large number of values at 10%. Permeability shows a more bimodal distribution, with a low end peak at 0.01–0.1 mD and a high-end peak of 100–1000 mD (Gravestock and Alexander, 1988).

## RESERVOIR PETROPHYSICS

Study of reservoir petrophysics including calculation of porosity, shale content and water saturation from wireline logs in the Cooper Basin is problematic due to the combination of high downhole temperatures, low formation-water salinities and poor (over-gauge) hole conditions. Traditionally only sonic, gamma ray and resistivity logs have been run in Cooper Basin wells, as hole conditions are often too poor for meaningful density or neutron data to be acquired. In addition there is a significant

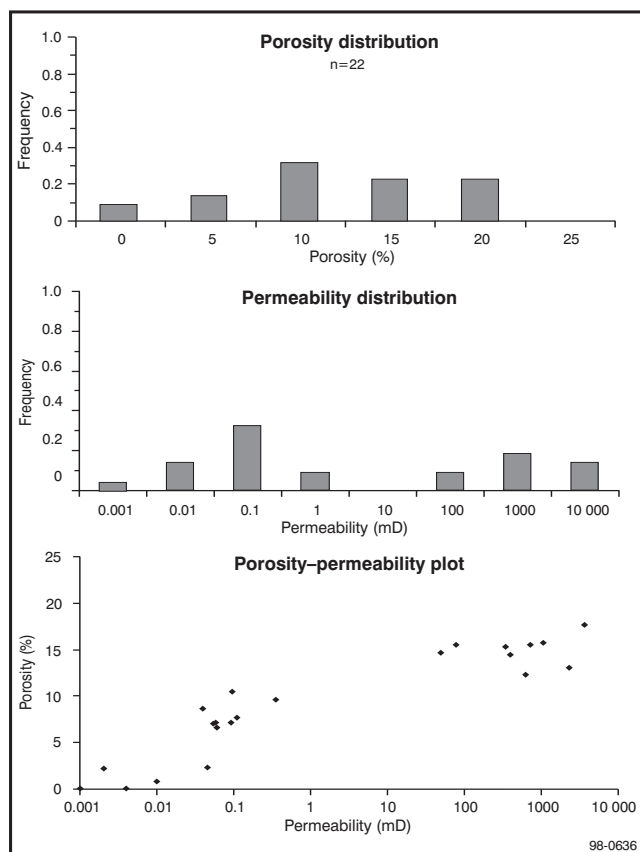


Fig. 10.12 Porosity and permeability distributions, Cuddapan Formation.

gas effect on density logs. As a result, most log-derived porosity is based on the sonic log, and clay volume is based on the gamma ray log.

### Determining porosity from logs

Several empirical log porosity equations based on core data have been developed for Cooper Basin reservoirs. These are derived from the Wyllie time average equation (Wyllie *et al.*, 1956, 1958), the oldest being the Porter equation (Porter, 1976) which was used as the basis for reserve estimation, until the growth in available core data allowed more refined and region-specific equations to be developed (Morton, 1989, 1990).

Important work by Khaksar and Griffiths (1996) has shown that all of the above equations may significantly underestimate porosity in cases where reservoir pressure is depleted, such as development wells with a significant production history. Erroneous reductions of the order of six porosity units or 44% in pore volume have been recorded and in such cases local calibration is required. The anomaly is caused by the effect of reduced pore pressure on compressional wave velocity, resulting in pessimistic sonic log values (Khaksar, 1994).

### Determining water saturation

Approaches to estimating water saturation have usually been the conventional shale volume type equations that rely on the gamma ray as an estimate of 'shale' (clay) content. The 'Simandoux' equation (Simandoux, 1963) has been used, but is inaccurate in relatively freshwater reservoirs (Worthington, 1985), typical of many in the Cooper Basin.

A modified version for freshwater reservoirs was developed (the 'Indonesia' equation; Poupon and Leveaux, 1971; Fertl, 1987), but has not been used extensively in the Cooper Basin.

Morton (1990) proposed the use of Waxman-Smits type equations (Waxman and Smits, 1968), which do not rely on shale volume from the gamma ray log, but incorporate laboratory measurements of the clay conductive component of total resistivity (cation exchange capacity). Regional and formation-specific values have been developed for use in the Cooper Basin and shaly sand equations better account for the effect of dickite in the coarser grained reservoirs, because dickite is not accurately detected by the gamma ray log.

There have been several alternative ionic double layer models proposed since the publication of the original Waxman and Smits (1968) model, in particular the Dual-Water Model (Clavier *et al.*, 1977, 1984), and the Grain Consolidation Model (Schwartz and Sen, 1988, Sen *et al.*, 1988, Sen and Goode, 1988, 1992; Sen, 1989). The latter authors also concluded that all of these models result in less accurate water saturation determination under the reservoir conditions which occur in the Cooper Basin, namely low formation-water salinity, high shaliness and/or high hydrocarbon saturation and elevated temperatures.

In typical Cooper Basin reservoirs, there are relatively minor differences in calculated water saturations between the various ionic double layer models and the shale volume models. However, the most significant factor that can affect water saturation determination is the formation-water resistivity. Formation-water salinity in Cooper Basin reservoirs ranges from saline to moderately fresh (0.4–4.0 ohm.m @ 23.9°C). The major control on formation-water resistivity is proximity to formation zero edges, where fresh Eromanga Basin artesian water is mixed with the more saline Permian water. Dunlop *et al.* (1992) have suggested that gas could have escaped by diffusion in such water, and whether true or not, combinations of low salinity and high shaliness are likely to lead to inaccurate calculated water saturations in some reservoirs.

Determination of water saturation is particularly difficult in the low-permeability Patchawarra Formation reservoirs of the Nappamerri Trough and Moomba Field. The observed log resistivities are significantly higher than those in the Toolachee Formation — Patchawarra gas zones have resistivities of 400–500 ohm.m, whereas the Toolachee gas zones have resistivities of 40–80 ohm.m. As no confirmed water zones have been observed in the lower Patchawarra Formation in this area, it is possible that these reservoirs are at very low irreducible water saturation, possibly caused by very large gas columns (the lower Patchawarra reservoirs appear to be filled beyond spill in the Moomba Field). Alternatively (although less likely) the formation-water may be much fresher than in the shallower Toolachee Formation, or high formation temperatures may alter rock wettability. Transition zones may vary according to reservoir permeability from ~1 m in highly permeable sand to 10 m in moderately permeable reservoirs.

### Low permeability pay

Some low-permeability zones which have flowed gas at uneconomic rates on drillstem test have nevertheless been depleted on Repeat Formation Tester pressure



Arrabury Formation (the lowest unit of the Nappamerri Group) which is shown to be thickest over gas-prone trough no. 3 which represents the Nappamerri Trough. This is a consequence of the sketch since there is a comparable thickness of Arrabury Formation over the oil and gas-generating Patchawarra Trough. Nevertheless, the point to note is that where the regional seal is thick, it too may contain reservoirs and, above it, Eromanga Basin reservoirs exist only at one or two levels (Poolowanna Formation and Murta Formation). These reservoirs may be charged from Eromanga Basin source rocks (Michaelsen and McKirdy, 1989).

Where the regional seal is thin or absent multiple oil and gas pools may be stacked in coaxial Permian–Mesozoic structures (Heath *et al.*, 1989; Boulton *et al.*, 1997). The Arrabury seal separates Jurassic artesian freshwater aquifers from more saline Permian brines but mixing occurs towards the seal edge (Dunlop *et al.*, 1992). Stacked pools near the regional seal zero edge (or near the basin margin) may occur from as low as the Patchawarra Formation (Permian) to as high as the Murta Formation (Cretaceous). Rarely, dry gas has accumulated in thin (5–12 m) shoreface sand (Coorikiana Sandstone) in the marine Cretaceous Bulldog Shale regional seal. Locally, Permian oil has migrated into Warburton Basin reservoirs on the basin margin and gas has migrated into fractured Ordovician reservoirs fringing the Allunga Trough. Beneath the Darlingie unconformity are two important Early Permian regional seals — the Roseneath and Murteree Shales. The Roseneath Shale is the top seal of the Epsilon Formation and the Murteree Shale seals the Patchawarra Formation. For clarity only the Murteree Shale is shown in Figure 10.13.

Permian source and Triassic seal isopachs are brought together in Figure 10.14 which shows the thickest Permian coal intersections (coal is presumed here to be a source of oil as well as gas), the Triassic Nappamerri Group isopach and Cooper–Eromanga oil wells. Five features stand out:

- oil occurs in or above coal-rich deposits
- fields with stacked Permian and Mesozoic oil reservoirs (e.g. Mawson, Sturt, Tantanna, Spencer and Wancoocha) occur within 10 km of the Nappamerri Group zero edge (and within 1 km of the Murteree Shale zero edge (Oldham and Gibbins, 1995))
- Murteree Ridge is a focus of oil in Cretaceous reservoirs (e.g. Limestone Creek, Biala and McKinlay Fields)
- Dullingari–Murta oil field is above relatively thick Nappamerri Group and its oil is of Cretaceous origin (Michaelsen and McKirdy, 1989)
- the largest Permian oil field — Tirrawarra, and its neighbours (Fly Lake, Brolga, Moorari and Woolkina) — are sealed well below the Nappamerri Group by Early Permian shale

Also obvious are the sparsely explored southern and northwestern margins of the Nappamerri limit where successful wildcats (Kobari 1, Callabonna 1, Charo 1 and Tarragon 1) represent a success rate of one for every nine wells drilled. This low statistic does not mean hydrocarbons do not occur, but it does point out a need to learn more about the properties of seals.

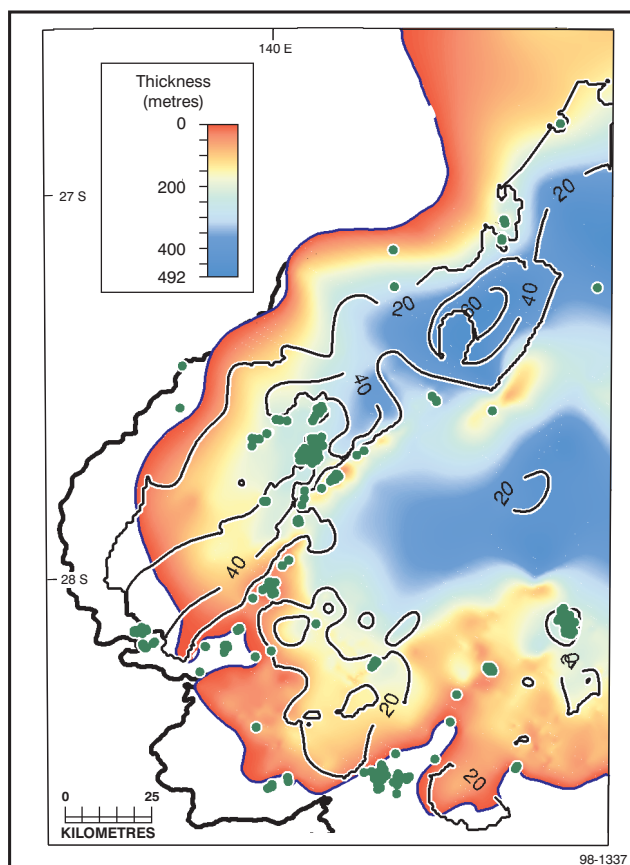


Fig. 10.14 Isopachs of Nappamerri Group (seal: colour-fill) and total mature coal thickness (source: contours). Oil wells also shown.

### Arrabury Formation regional seal

The Arrabury and Tinchoo Formations constitute the Late Permian – Middle Triassic Nappamerri Group. The organically lean Arrabury Formation conformably overlies coal measures of the Toolachee Formation, thus directly sealing the latter and indirectly forming the regional seal above all of the Permian formations.

In order to test the quality of the Arrabury seal, five wells 15 km basinward of the Arrabury Formation zero edge were examined. Well locations are shown in Figure 10.15 and various attributes are listed in Table 10.3. The wells were chosen for a number of reasons: first, the line of section is basinward of the ‘zone of gas depletion’ of Dunlop *et al.*, (1992), thus relegating gas diffusion to ‘non-player’ status; second, thickness of the Arrabury Formation varies from 43 to 165 m; third, Permian regional seals (Roseneath and/or Murteree Shale) are present in three wells; and fourth, the wells display a wide range of oil and gas shows, including fluorescence in the Arrabury seal (Table 10.3).

The wells lie in a part of the southern Cooper Basin where the aggregate thickness of Permian coal is only 10 to 15 m. Though thin, this coal may be sufficient to generate economic petroleum but it is assumed that hydrocarbons may also have migrated south from the Nappamerri Trough or east from the Allunga Trough into the sub-Arrabury reservoirs. One important question and a source of debate and active research centres on whether the Eromanga oil occurrences stem from migrated Permian hydrocarbons or from *in situ* Jurassic and Cretaceous source rocks, or from

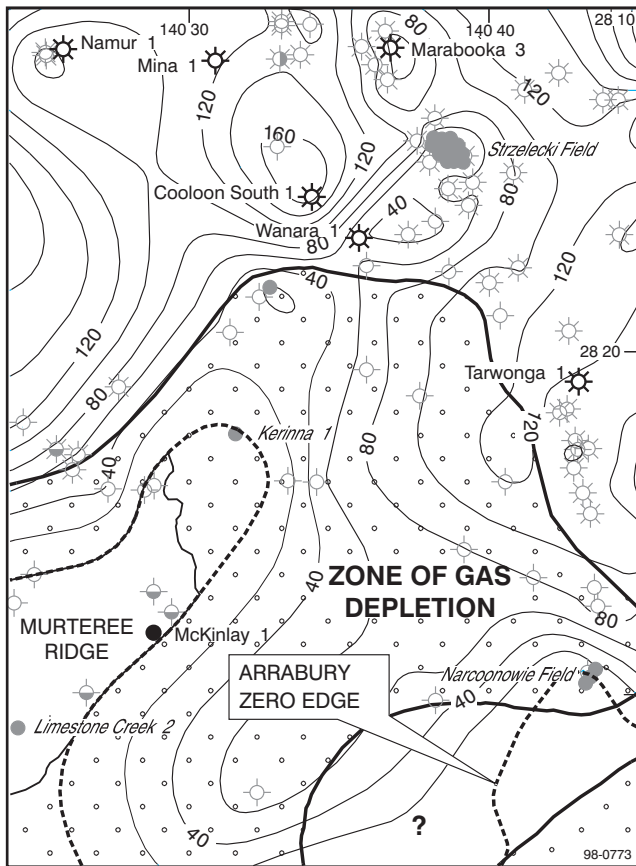


Fig. 10.15 Portion of southern Cooper Basin north and east of the Murteree Ridge showing selected wells, Arrabury Formation isopach and 'zone of gas depletion' (after Dunlop et al., 1992).

both sources (Heath et al., 1989; Michaelsen and McKirdy, 1989). Dry gas in the Coorikiana Sandstone, encased in the Bulldog Shale Cretaceous marine seal, is taken to be Permian-sourced and interpreted to have accumulated via diffusion (Dunlop et al., 1992). Namur gas is suggested to have accumulated via fault conduits (Heath et al., 1989). Curiously, there has been no opinion offered on how live oil came to be in the Arrabury seal.

Examination of Table 10.3 reveals several interesting associations. Those wells with the thickest Arrabury seal (Mina 1, Tarwonga 1 and Cooloon South 1) have Murteree and/or Roseneath Shale which form top seals for Patchawarra and Epsilon gas reservoirs respectively. These wells also have Arrabury oil fluorescence ranging from trace to 60% and, in addition Tarwonga 1 has 10–90% oil fluorescence in the Toolachee Formation. It seems reasonable to infer the Toolachee is a source of the overlying Arrabury fluorescence and also to suggest that the Arrabury Formation may not be a particularly efficient seal compared with the Roseneath and Murteree Shales. It is worth noting that in Mina 1, where Murteree Shale is present but Roseneath Shale is absent, there is oil fluorescence in three Jurassic to Early Cretaceous units and oil fluorescence as well as a dry gas flow in the Coorikiana Sandstone (6198 m<sup>3</sup> (0.22 mmcf) per day). Can we surmise that the Epsilon may be added to the Toolachee Formation as a potential source of oil which migrates upward where the Roseneath Shale is absent? Mina 1 was completed as a Patchawarra gas producer, suggesting the Murteree is an effective top seal to the gas reservoir.

In the two wells where the Arrabury seal is thin (Wanara 1 and Marabooka 3), the Toolachee is in contact with the Patchawarra Formation and the intervening Permian seal and source units have been eroded. As a result, the Patchawarra Formation is water saturated and although fluorescence was noted in Marabooka 3, no hydrocarbons flowed to surface on test. Oil fluorescence was also recorded in the Arrabury Formation, Hutton and Namur Sandstones and Murta Formation and gas was tested in the Coorikiana Sandstone in Marabooka 3 (18 313 m<sup>3</sup> (0.65 mmcf) per day). The wells were completed as Toolachee producers and Marabooka 3 was also completed in the Namur which initially produced gas at ~281 740 m<sup>3</sup> (10 mmcf) per day (Hanwell, 1986).

The extent to which these shows may be attributed to loss through the Arrabury seal by migration through beds of low-capillary seal efficiency or loss through faults and fractures is conjectural at present. However, we can examine the lithology of the Arrabury from cuttings and

Table 10.3 Oil shows and seal statistics from selected wells in the southern Cooper Basin.

Well	Arrabury Thickness (m)	Arrabury Seal efficiency (%)	Toolachee Thickness (m)	Formation below Toolachee	Roseneath Thickness (m)	Roseneath Seal efficiency (%)	Murteree Thickness (m)	Murteree Seal efficiency (%)	Formations with petroleum shows (Producing zones are shown in bold)
Wanara 1	43	18	63	Patchawarra	Absent		Absent		Namur (oil, gas), Hutton (oil), <b>Toolachee</b> (gas)
Marabooka 3	58	13	63	Patchawarra	Absent		Absent		Coorikiana (gas), Murta (oil), <b>Namur</b> (oil, gas), Arrabury (oil), <b>Toolachee</b> (gas), Patchawarra (oil)
Mina 1	116	8	60	Murteree	Absent		43	67	Coorikiana (oil, gas), Murta (oil), Namur (oil), Hutton (oil), Arrabury (oil), <b>Patchawarra</b> (gas)
Tarwonga 1	117	9	119	Daralingie	64	41	55	74	Cadna-owie (oil), Arrabury (oil), Toolachee (oil), <b>Epsilon</b> (gas), Patchawarra (tight gas)
Cooloon South 1	165	10	86	Roseneath	28	71	59	85	Arrabury (oil), <b>Patchawarra</b> (gas, condensate)



Disconformable contact between Jurassic Hutton Sandstone and Triassic Arrabury Formation, Marabooka 3, core 1, 1865.3 m (driller). Fine-grained Arrabury Sandstone has porosity 8.5% and permeability 0.17 mD. Core diameter 100 mm. (Photo 46051)

wireline logs. In addition, the basal Hutton Sandstone and upper 9 m of Arrabury Formation were cored in Marabooka 3. The lithology of the latter consists of pedogenic zones of mottled siltstone interbedded with cross-laminated fine-grained sandstone. The disconformable contact is a scoured surface overlain by thin conglomerate with pebbles of quartz, grey shale and sideritic mudrock up to 30 mm in diameter. Ten per cent bright yellow fluorescence was observed in the Arrabury sandstone beneath the disconformity.

Porosity (helium injection) measured on four sandstone core plugs is in the range 8.1–10.2% and permeability is 0.16–0.27 mD. If these values represent the Arrabury Formation in the vicinity of the wells listed in Table 10.3 then this unit contains some very poor seal facies (and in fact, some moderately good reservoir sands).

There are systematic variations on wireline logs between the Arrabury Formation seal on one hand and the Roseneath and Murteree Shale seals on the other. These variations are exemplified by the gamma ray and resistivity logs of the three formations in Tarwonga 1, shown in Figure 10.16. Similar log character is seen in other wells although the upper part of the Arrabury in Cooloon South 1 is distinctly sandier (the sandy section may correlate with the Paning Member of the Arrabury Formation). The gamma ray and resistivity values are greater in the Permian shale and, *as a rough guide*, a gamma ray of 160 API has been selected as a ‘seal efficiency’ value. The thickness of seal >160 API, divided by total seal thickness, is the ‘seal efficiency’ expressed as a percentage.

The ‘seal efficiency’ has been calculated in this manner for the Arrabury, Roseneath and Murteree (where present) for each of the five wells and is given in Table 10.3. As shown, between 67% and 85% of the Murteree Shale has gamma ray values >160 API. Similarly, between 41% and 71% of the Roseneath Shale lies above 160 API. In contrast, only 8–18% of the Arrabury Formation lies >160 API *regardless of the thickness* of the unit. As Downey (1984) has pointed out, average petrophysical properties do not reflect seal efficiency since a seal is only as strong as its weakest link (which may not be intersected in a well). Nevertheless, the striking contrast in gamma ray and other log values, as well as the available core analysis, does indicate that the Triassic Arrabury Formation seal has many more ‘weak links’ than the Permian Roseneath and Murteree Shales by virtue of its sandier character.

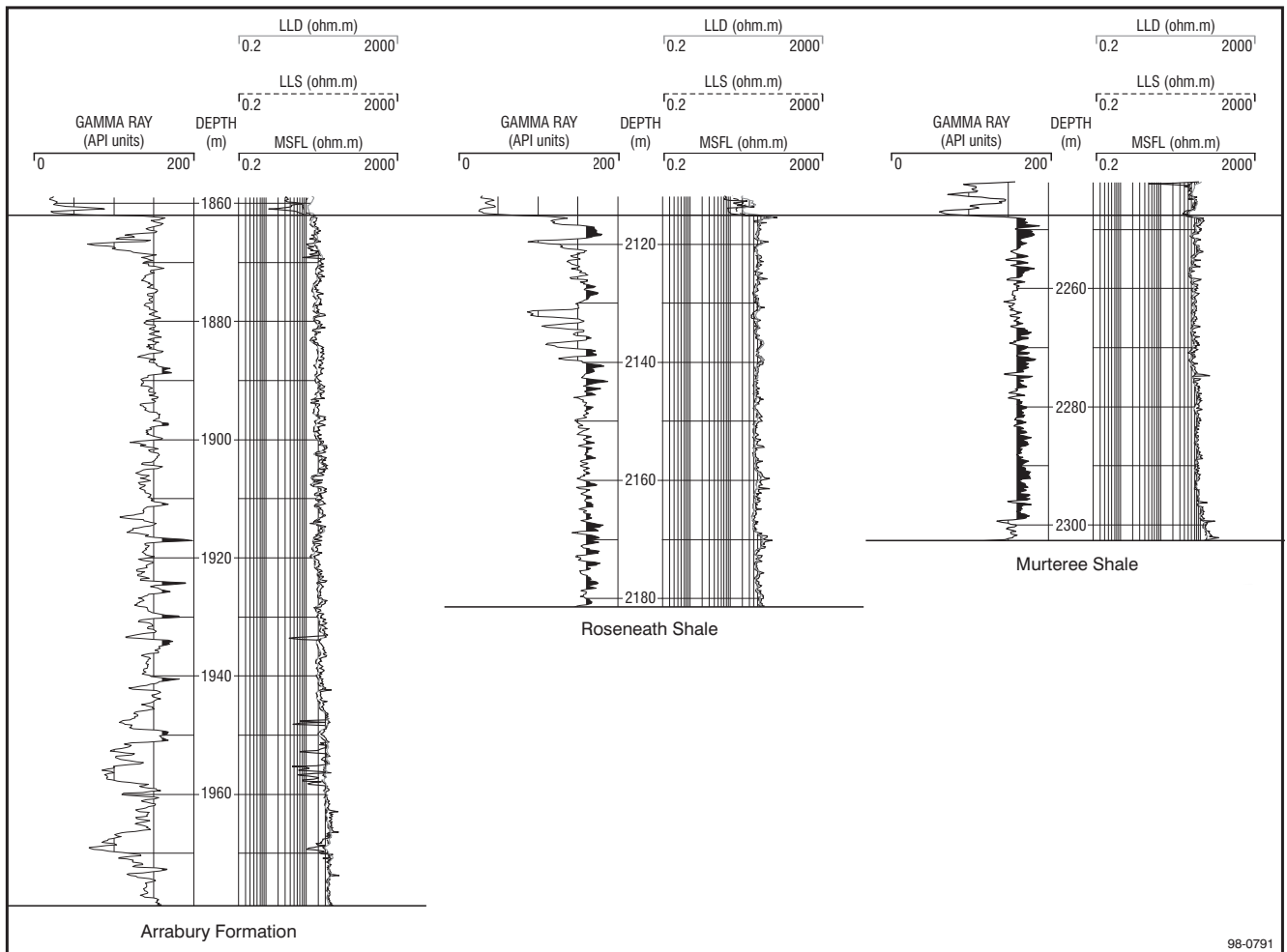
A search of Cooper Basin shows revealed only six occurrences of oil fluorescence in Roseneath and Murteree Shale seals: Dune 1 and Yapeni 2 in the basal 3 m of Roseneath and continuous with Epsilon shows beneath; Deina 1, Cowan 3 and Wilpinnie 3 in the basal 5 m of Murteree and continuous with Patchawarra Formation shows beneath; and in the mid-Murteree in Yalcumma 1. The conclusion is that little oil seems to have migrated through these seals which have no indigenous oil source potential. The Arrabury Formation is also organically lean but is heterolithic, with sandy units particularly in the Patchawarra Trough and on the Merrimelia Ridge where they form oil and gas reservoirs. It appears that parts of the Arrabury Formation contain more porous and permeable ‘weak links’ independently of thickness, than commonly assumed. There is a positive relationship between pore throat size and matrix quartz content in non-organic shale (Krushin, 1998). Thus the gamma ray log (which is an approximate quantitative measure of non-quartz minus quartz) may turn out with more work to be a useful seal indicator.

Out of curiosity, Moomba 56, drilled ten years ago and 35 km from the Arrabury zero edge was analysed in a similar way (Table 10.4).

The low number of oil shows beneath the Roseneath and Murteree Shales can be attributed to the formations being gas mature at these depths (>2500 m subsea). The shales are thin but form effective seals. However, despite its thickness the Arrabury seal in contrast is decidedly inefficient and appears to be a hydrocarbon chimney to the Eromanga reservoirs above. If this rough analysis is correct, it comes as no surprise that a 954 000 kL (6 mmbbl) oil field should be

**Table 10.4** Oil show and seal statistics, Moomba 56.

Arrabury Formation thickness (m)	210.9
Proportional thickness >160 API gamma ray units (%)	18
Roseneath Shale thickness (m)	54.6
Proportional thickness >160 API gamma ray units (%)	93
Murteree Shale thickness (m)	58.2
Proportional thickness >160 API gamma ray units (%)	88
Number of levels with oil shows above the Arrabury seal	8
Number of levels with oil shows within the Arrabury seal	7
Number of levels with oil shows between the Arrabury Formation and Roseneath Shale	3
Number of levels with oil shows between the Roseneath and Murteree Shales	0
Number of levels with oil shows beneath the Murteree Shale	1



**Fig. 10.16** Gamma ray and resistivity logs of Arrabury, Roseneath and Murteree regional seals, Tarwonga 1. Gamma ray values exceeding 160 API units are shaded.

discovered in the Namur Sandstone on the Moomba structure. It is a surprise that its discovery should take so long. It is predicted that other similar discoveries will be made, perhaps within the Arrabury Formation itself in the region southwest of the Nappamerri Trough.

In their incisive study of Eromanga Basin reservoirs and hydrocarbon migration, Heath *et al.* (1989) noted a strong relationship between oil discoveries and relatively thin combined Permo-Triassic seals. Many of their observations of the geographic and stratigraphic distribution of oil and gas are captured in Figure 10.13. However, these authors assumed that the lack of charge in traps close to the Cooper Basin margin resulted from lower volumes of hydrocarbon generated by marginally mature source rocks (vitrinite reflectance 0.7–0.9%), and they also lumped the Triassic with the Permian seals. Here, it is maintained that coal-rich Permian units have generated large volumes of hydrocarbon (where mature) close to the basin margin but because the Arrabury is a poor seal, much of the oil generated in the Toolachee, Epsilon and Daralingie Formations has migrated vertically to higher traps. Despite this slightly different interpretation, the observation of Heath *et al.* (1989 p. 406) still applies: ‘as a broad generalisation, the largest oil-in-place in any field occurs below the deepest, inferred, most competent top seal, estimated from shale thickness’. However, shale thickness is not a measure of seal efficiency unless it is sand free.

Although the interpretation in this chapter casts doubt on the efficiency of the Arrabury Formation seal northeast of the Murteree Ridge and in parts of the Moomba Field it does not relegate the unit to poor seal status throughout the basin. As pointed out by Boulton *et al.* (1997) the Arrabury regional seal exerts an influence in Gidgealpa Field by controlling secondary migration of Permian oil and gas into Jurassic–Cretaceous traps. Further work on the Arrabury Formation is planned to assess the influence of facies control on seal competence (E.M. Alexander, PIRSA, unpublished data, 1998).

### Intraformational seals

The Roseneath and Murteree Shales are competent, basin-wide lacustrine seals, but at prospect-scale most of the effective Permian seals are intraformational. All of the reservoir units except the Tirrawarra Sandstone and Merrimelia Formation are characterised by stacked upward-fining fluvial deposits or upward-coarsening crevasse splay, delta top, shoreline and bar deposits. The impermeable seal is typically a succession ranging from 3 to 20 m thick of carbonaceous siltstone and shale beds with thin coal seams or alternatively, it may consist of thick, 10–20 m coal seams with thin interbedded shale. These fine-grained carbonaceous lithologies, which also comprise the Cooper Basin source rocks, effectively cap the sandstone reservoirs.

An example from Della 12 (Fig. 10.17) has been chosen to illustrate intraformational seals because the Roseneath and Murteree Shales have been eroded and the Toolachee disconformably overlies the Patchawarra Formation. Thus there is no regional Permian seal in this formerly prolific dry gas field. In addition, the Arrabury Formation regional seal is 15 m above the highest gas pool and hence the seals are all intraformational. Six upward-fining successions are shown on the figure and gas is produced from each of the basal sandstone reservoirs. In Della Field the Toolachee and Patchawarra Formations are gas saturated with a common field-wide gas–water contact. In other fields the stacked

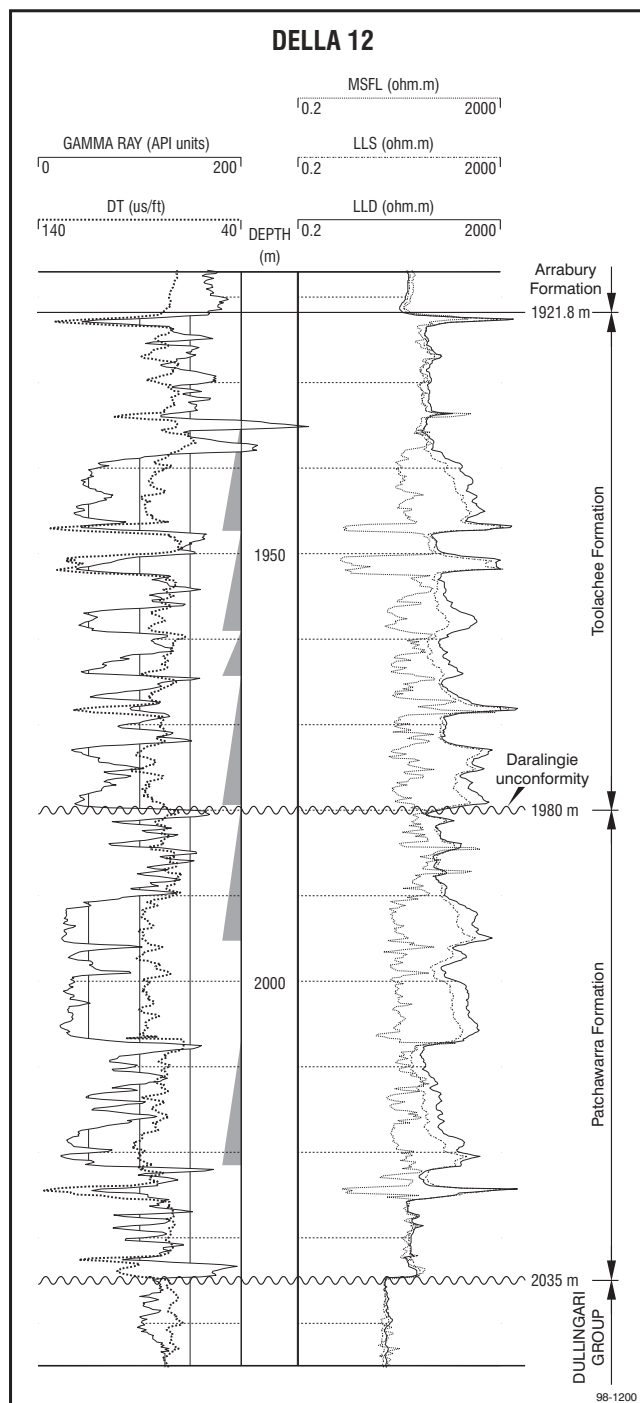


Fig. 10.17 Wireline logs recorded across the Toolachee and Patchawarra Formations, Della 12. Six upward-fining fluvial facies transitions are indicated.

reservoirs can have separate gas–water contacts. The majority of Cooper Basin gas and oil fields are sealed by intraformational shale and siltstone in a similar manner.

There is a rarer type of seal that is not the shale cap of an upward-fining succession but is composed of coal seams which rest directly on the sandstone reservoir (see photo overleaf). This reservoir–seal combination occurs for example in parts of the Patchawarra Formation in the Tirrawarra and Fly Lake Fields, and in the Toolachee Formation in Wanara 1. A coal seal appears to be more common in the Epsilon Formation and in the example described below it extends for 20 km or more.

One of the superior Cooper Basin reservoirs is the 93-8 sand which characterises the lower Epsilon Formation in Cuttampirrie 3 (see Reservoirs above). This 3.6 m sandstone flowed at a rate of 358 937 m<sup>3</sup> (12.74 mmcf) of gas and 14 kL (88 bbl) of condensate per day (19 mm choke) in Cuttampirrie 3, 222 856 m<sup>3</sup> (7.91 mmcf) of gas and 23.8 kL (150 bbl) of condensate per day (12.7 mm choke) in Gudi 1, and 532 488 m<sup>3</sup> (18.90 mmcf) of gas per day (19 mm choke) in Pennie 1, an Epsilon record flow. In each of these cases the sandstone is overlain directly by coal.

Five wells on a northwest–southeast transect through the northern Patchawarra Trough were selected to assess the extent and effectiveness of the coal seal. The well locations



Fine-grained sandstone with wispy shale and carbonaceous laminae overlain by laminated carbonaceous siltstone, shale and thin coal in the Patchawarra Formation, Cuttampirrie 3, core 1, 2916 m (driller). Core diameter 100 mm. (Photo 46057)



Porous, permeable sandstone overlain by coal with no intervening shale in the Epsilon Formation, Cuttahirrie 3, core 1, 2902.3 m (driller). Fractures in coal induced by unloading. Core diameter 100 mm. (Photo 46326)

are shown in Figure 10.18 which also illustrates Epsilon Formation total coal thickness. Gamma ray, sonic and resistivity logs are illustrated in Figure 10.19 in which the selected datum is the top of the Murteree Shale. In each well the Toolachee Formation unconformably overlies the Epsilon Formation with the Roseneath Shale and Daralingie Formations missing at the unconformity. The Epsilon Formation conformably overlies the Murteree Shale which thins from 33 to 7 m by onlap in a northwesterly direction. The Murteree Shale is a bottom seal to the Epsilon reservoir, although towards its northwestern onlap margin, the shale's seal efficiency may be reduced. In every well except Napowie 1, the basal Epsilon reservoir is overlain by coal which was cored in Cuttahirrie 3 where it is only 2.13 m thick. An absence of shows above the coal indicates that it seals the Epsilon reservoir in both Gudi 1 and Cuttahirrie 3 which are 10 km apart. The lack of gas to surface on test in Woma 1, and low pressure on test in Wimma 1 (3 psi) suggest that at the greater depths in these wells (>3100 m), the Epsilon reservoir is tight. Somewhere along the transect between Wimma 1 and Napowie 1, the coal seal is replaced by stacked sandstone separated by thin siliceous siltstone beds. Drillstem test and Modular Dynamics Tester data indicate that gas in Napowie 1 is reservoired in the upper Epsilon Formation, the basal Epsilon sandstone (sealed

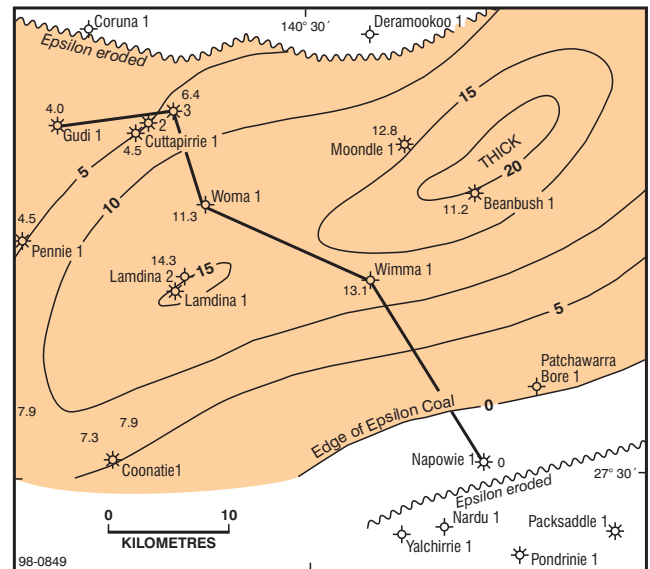


Fig. 10.18 Portion of Patchawarra Trough showing Epsilon Formation coal thickness. Location of section shown in Figure 10.19 is marked.

elsewhere by coal) is wet, and the intervening sandstone is tight (Allen, 1994).

The geology and test results are interpreted as follows. Wet gas migrated from Patchawarra Formation coaly source rocks into the basal Epsilon sand through the thin Murteree Shale 'seal' somewhere between Woma 1 and Cuttahirrie 3, and was trapped beneath the basal Epsilon coal. In the vicinity of Wimma 1 and Napowie 1, and thence down the palaeoslope, the Murteree Shale seal is too thick and competent to admit Patchawarra-sourced hydrocarbons and Epsilon Formation coals are interpreted as the gas source in Napowie 1. The Epsilon succession in Napowie 1 is interpreted here as a suite of stacked strandline sands, separated by thin, very fine-grained, silica (and siderite?) cemented, lacustrine lower shoreface sands, possibly tempestites, as cored at the Epsilon–Murteree transition in Cuttahirrie 3. These form a bottom seal to the upper Epsilon reservoir and a top seal to the basal sand which is wet. It is worth noting that the maximum coal seam thickness in the Epsilon Formation is in Woma 1 and Wimma 1 on this line of section. The primordial peat swamps which gave rise to these coal deposits were located upslope from lake marginal facies (represented by Napowie 1) and downslope from the relatively more clastic-rich deposits near the basin margin (represented by Gudi 1). This is an optimum location for raised swamps as discussed in Chapter 6.

### Basement seals and reservoirs

Yew and Mills (1989) have observed that downdip appraisal drilling for oil was not pursued systematically before the Accelerated Gas Program (AGP) of 1983–85. Exploration of fault-dependent lowside prospects was similarly delayed but they are being drilled with increasing frequency on both sides of the major basement ridges. The Dunoon and Murteree Ridges have been notably avoided, possibly due to perceived lack of seal or lack of access to mature source rocks. Drilled prospects include, e.g.:

- Snake Hole 1 (AGP, 1984), northwest of Gidgealpa Ridge, plugged and abandoned

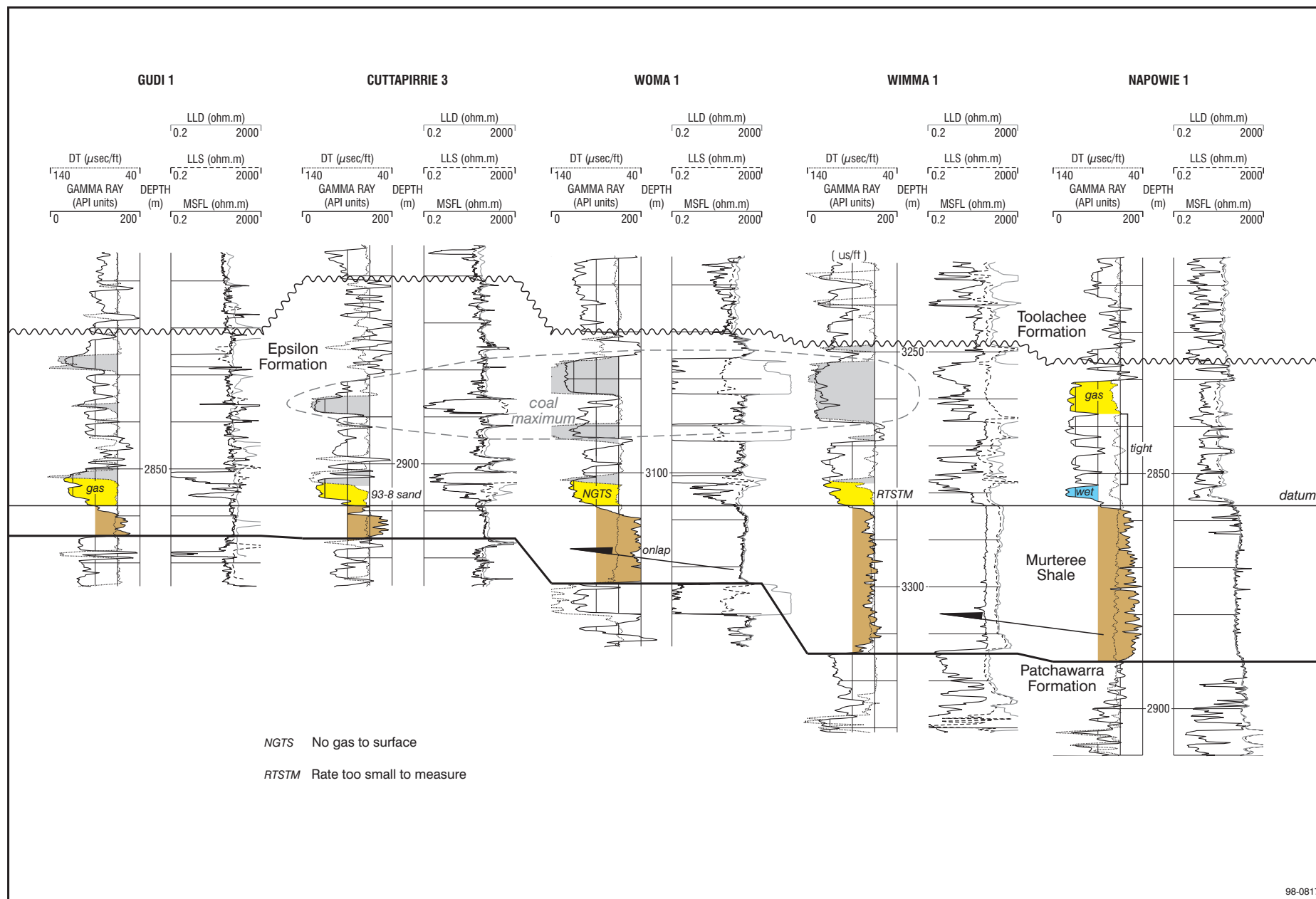


Fig. 10.19 Wireline log correlation over the interval lower Toolachee Formation to upper Patchawarra Formation, Gudi 1 to Napowie 1. Datum is top of Murteree Shale. Line of section is located in Figure 10.18.

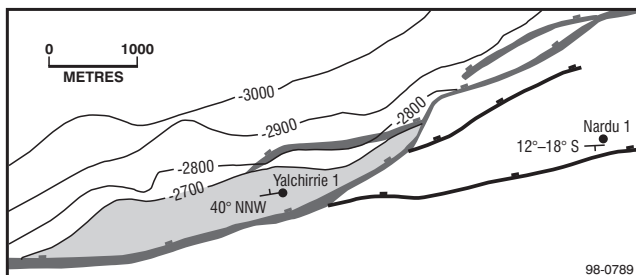
- Three Queens 1 (AGP, 1984), north of Della–Nappacoongee Ridge, suspended gas well
- Malgoona 1, 1A (1990), north of Sturt oil field, Merrimelia oil producer (see above)
- Yalchirrie 1 (1991), north of Packsaddle Ridge, plugged and abandoned with shows
- Katingawa 1 (1992), north of Kidman Field, plugged and abandoned
- Napowie 1 (1993), north of Packsaddle Ridge, Epsilon gas producer (see above)
- Darmody 1 (1996), south of Packsaddle Ridge, suspended tight gas well

These represent about one-third of lowside traps drilled to date in the Cooper Basin.

Malgoona 1A and Napowie 1 are models of success and in each case integrity of the basement lateral seal is demonstrated (Ostler, 1991; Allen, 1994). Reasons for failure, in contrast, have not been attributed to poor seal but to a number of other factors, e.g. failure to intersect the target or tight or wet reservoirs.

Consideration was given to basement lateral seal integrity in Yalchirrie 1, as discussed by Baily (1992, p. 6): ‘Prior to the drilling of Yalchirrie 1, the nature of the basement on the upthrown side of the Packsaddle Fault was not known. It was postulated that if the lithologies juxtaposed against the Tirrawarra Sandstone were not competent seals, then a complex four-way dip structure could be considered. .... hydrocarbons could have leaked across the fault from the Tirrawarra Sandstone and migrated updip to the pre-Permian culmination’. In a later paragraph Baily (1992) also discussed the basement lithology and dip of bedding in Nardu 1, on an adjacent fault terrace <4 km east, in order to provide a basis for comparison with Yalchirrie. It is worth noting with hindsight that basement in Nardu 1 (Ordovician fine-grained sandstone with thinly interbedded claystone) dips 12–18° south, whereas in Yalchirrie 1, basement (Ordovician very fine-grained sandstone) dips 40° north-northwest. As shown in Figure 10.20, structural interpretation prior to drilling placed Nardu 1 on a higher fault terrace than Yalchirrie. However, due to complex faulting, the dip of the lateral basement seal south of Yalchirrie 1 remains unknown.

Downey (1984) has pointed out that faults do not trap; they place reservoirs against seals. Cooper Basin reservoirs (and source rocks and seals) have been placed against elevated ridges of Warburton Basin rock by faulting or by original deposition. These ridges are potential lateral seals



**Fig. 10.20** Depth structure map (m subsea) of near top Tirrawarra Sandstone and faulted basement in the Yalchirrie 1 – Nardu 1 area (after Smit in Baily, 1992).

and their lithologic composition covers the full spectrum from sandstone to shale, carbonates, volcanics and tuffs. These rocks range from fresh to severely altered by weathering and diagenesis (but only slight metamorphism), they are bedded to massive and slightly to pervasively fractured. In addition, their bedding attitude varies from horizontal to vertical and they may be weakly to strongly folded and faulted. Their competence as lateral seals is dependent upon a combination of lithologic and structural factors.

Three sketches in Figure 10.21 illustrate combinations of basement ridge lithology and dip of bedding which may determine lateral seal efficiency. In each sketch, a Permian top seal is considered to have been deposited on the crest of the ridge and a normal fault is interpreted between the downthrown basement block and the upthrown block. Basement lithology consists of alternating beds of sandstone and shale with steeply dipping fractures.

In the first sketch (Fig. 10.21a), sandstone and shale in the ridge dip towards the prospect and shale is in contact with both the Permian top seal and the sandstone reservoir. Basement in contact with the Permian sediments is altered, the thickness of the zone of alteration ranging from zero where eroded to 100 m or more. Shales which are normally brittle are particularly susceptible to alteration to impermeable claystone (Boucher, 1997a). This impermeable claystone seals open fractures at the top of the fresh shale from access by migrating hydrocarbons and hence a trap is formed.

In the second sketch (Fig. 10.21b), sandstone and shale in the ridge dip away from the prospect and altered shale near the Permian contact again forms a lateral seal. As Boucher (1997a) has observed, an altered zone is not readily apparent in sandstone due to a lack of clay-forming minerals. In a number of instances, sandstone in the altered zone has a higher matrix porosity than in fresh sandstone due to dissolution of carbonate cement and feldspar grains. Thus altered sandstone beds may provide an avenue for the escape of hydrocarbons. In figure 10.21b, the dip of beds in the basement ridge is such that the porous zone of altered sandstone does not form part of the lateral seal although a potential ‘weak link’ is clearly evident.

In the third sketch (Fig. 10.21c), sandstone and shale in the ridge dip towards the prospect, potentially a poor sealing attitude, (see Downey, 1984, fig. 9). In this example altered sandstone is juxtaposed with the reservoir hence migrating hydrocarbons have access to basement sandstone with matrix and fracture porosity and no trap is formed. Although not shown, a basement trap may form on the crest of the ridge beneath the top seal. However, the thinner top seal may be sandier due to onlap, or fractured during compaction against rigid basement. In Figure 10.21c, hydrocarbons are depicted as leaking through the top seal. By varying the lithology and dip of the ridge-forming rocks it is thus possible to fill or empty potential traps on the downthrown side of basement ridges.

Altered sandstone is often gas saturated (indicating matrix porosity) with characteristic broad peaks on gas detector curves. Gas shows are common in the Toolachee area where Ordovician sandstone is interbedded with shale. In an example from Toolachee 36 (Fig. 10.22), the 49 m

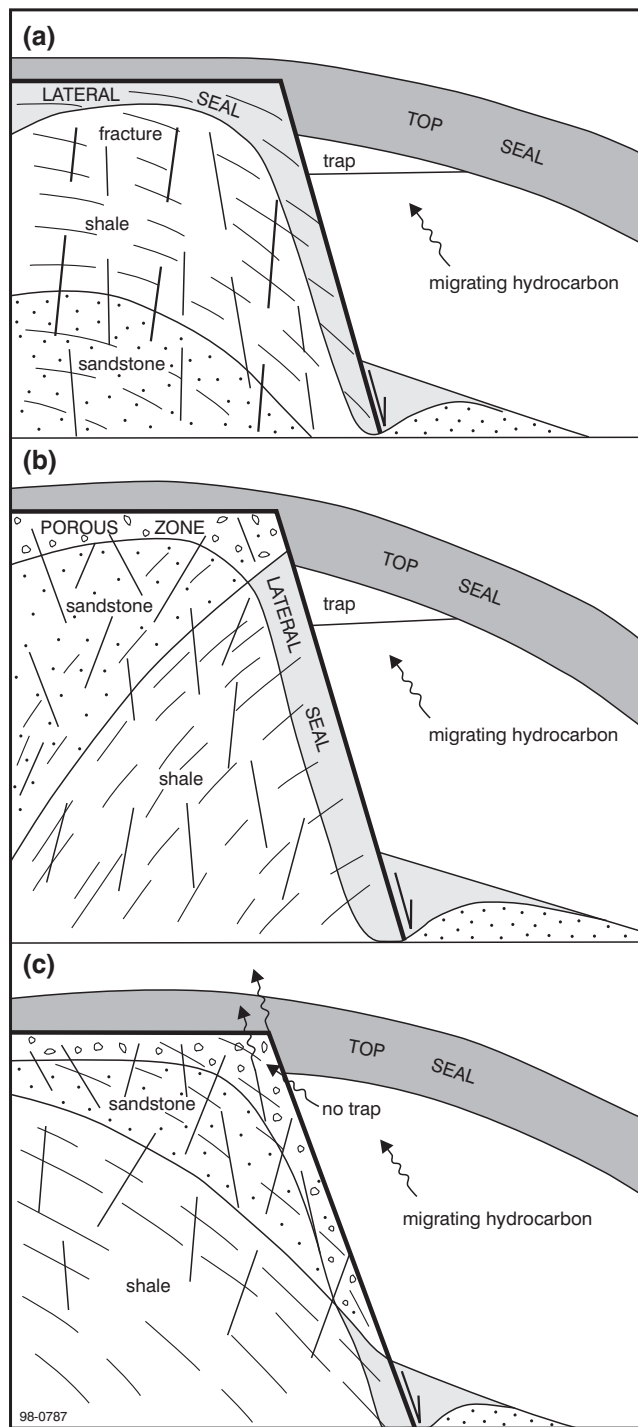


Fig. 10.21 Sketches of basement seal configurations. (a) Shale with sealing altered zone at contact with Cooper Basin. (b) Shale and sandstone dipping away from prospect. (c) Sandstone and shale dipping towards prospect (after Downey, 1984).

thick altered zone is distinguished by low-resistivity values relative to fresh rock, a characteristic feature of the upper basement levels (Boucher, 1997a). Within the altered zone is a 23 m thick interbed of lithic sandstone with gas readings up to 520 units (1 unit = 200 ppm methane equivalent). Gas readings are low in weathered shale above the sandstone and taper to negligible values in the fresher shale beneath the altered zone.

Figure 10.22 also depicts wireline logs and gas readings in an Ordovician basement siltstone in Lycosa 1. The altered

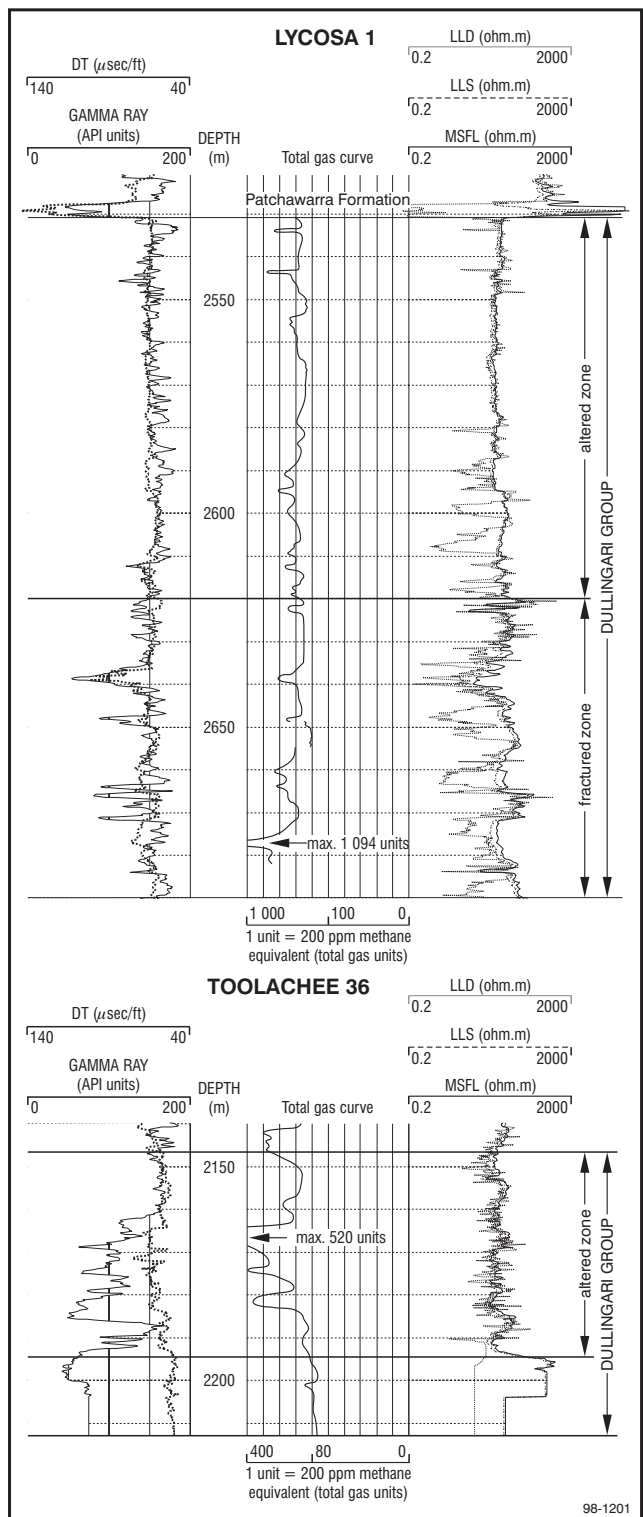


Fig. 10.22 Wireline log and gas detector readings in altered and fresh Ordovician rocks, Toolachee 36 and Lycosa 1.

zone is 89 m thick and is also distinguished by depressed, uniform resistivity values compared with fresh rock beneath. In the altered zone (mistaken originally for Merrimelia Formation), gas readings hover around background but fractures in fresh rock are the source of gas readings to 1094 units (90% C<sub>1</sub>). Thus the fractures are effectively sealed by impermeable clay in the altered zone.

Lycosa 1 was drilled on a complexly faulted basement structure overlapped by Cooper Basin sediments. A

comprehensive account of the discovery is provided by Taylor *et al.*, (1991) who describe four fracture sets identified from core and Formation Micro Scanner data. Bedding in the siltstone dips predominantly 40–60° north, and fractures dipping steeply southwest may be responsible for the gas flows of up to  $0.14 \times 10^6 \text{ m}^3$  (5.0 mmcf) per day.

Two other basement-related discoveries are Moolalla 1 which tested gas at a rate of up to  $270\,470 \text{ m}^3$  (9.6 mmcf) per day from porous and probably fractured Ordovician sandstone on the downthrown side of a major fault (Taylor *et al.*, 1991), and Sturt 6 which tested oil at a rate of 198.7 kL (1250 bbl) per day from fractured Cambrian tuff on the southern margin of the Patchawarra Trough (Baily, 1991b; Oldham and Gibbins, 1995). Although the flow rates have declined these three discoveries have extended the stratigraphic range of effective traps to include conventional basement.

### Loss of seal integrity

Structural interpretation of the Cooper Basin presented in Chapter 5 emphasises the role of palaeotopography and considers fault displacement to be minor in the Early Permian. Relatively few faults are suggested to propagate

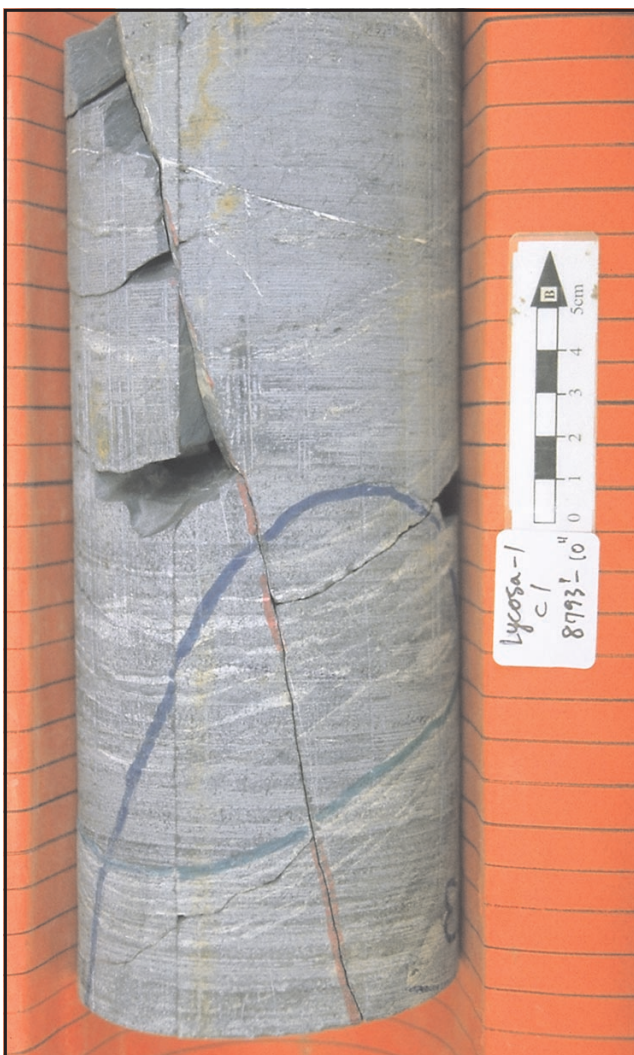
upward into the Mesozoic, at least few at the limit of vertical seismic resolution (~10 m). However, it is recognised that faults with small displacements and fractures are likely to be common given the degree of relief in the Cooper Basin floor. Conventional seismic surveys record P-waves which do not convey information about fractures (three component seismic which records S-wave data has not been recorded in the Cooper Basin). Fractures clearly carry a seal risk and may occur in two main modes:

- by differential compaction on the margins of structural and topographic ridges, where maximum curvature occurs at the boundary between thin on-ridge and thicker off-ridge locations (e.g. top seal in Fig. 10.21c)
- by structural reactivation, especially reactivation which post-dates the main phase of hydrocarbon migration

The timing of structural reactivation has been found to contribute significantly to seal risk in parts of the northern Cooper Basin (Queensland) where Permian strata are relatively thin (<150 m). Wecker *et al.* (1996, p. 107) recognised a useful distinction between first-order and second-order structures: ‘first-order structures exhibit multi-stage evolution with a subordinate development in the Mid to Late Triassic and a dominant Late Cretaceous – early Tertiary component’; in contrast: ‘second-order (structures) have a dominant Mid–Late Triassic component and a subordinate Late Cretaceous – early Tertiary component’.

The chief distinction between the two is the timing of trap formation relative to the main Early Cretaceous phase of hydrocarbon generation and migration. Simply put, the Triassic traps associated with second-order structures were formed before hydrocarbon migration and relatively undeformed after, and the Triassic traps associated with first-order structures were partially formed before hydrocarbon migration and relatively strongly deformed after. Deformation was chiefly by near-crestal faulting which led to breach of the top seal (Arrabury Formation). In some first-order structures these faults propagated to the present surface. From the results of drilling, Wecker *et al.* (1996) concluded that first-order structures most commonly failed due to fault leakage, leading to one successful well from three drilled in this structural category whereas second-order structures less commonly failed from fault leakage, leading to three successful wells from four that were drilled in this structural category.

In South Australia where the Permian is considerably thicker, fractures may substitute for faults as a major consideration when assessing seal risk, and an approach such as that proposed by Wecker *et al.* (1996) could be extended usefully into the South Australian portion of the Cooper Basin.



Moderately dipping fractured siltstone in the Dullingari Group, Lycosa 1, core 1, 2680 m. Bedding dip traced by green colour, conjugate fractures traced by red and blue colours. (Photo 46324)



### INTRODUCTION

The technology of recovering hydrocarbons in the Cooper region has become more sophisticated in the last decade. Drilling, fracture stimulation, acidisation and pumping techniques have been applied to optimise recovery in challenging and variable subsurface conditions and some of the more important techniques are reviewed below.

### HORIZONTAL DRILLING

The first horizontal drilling in the Cooper region was Meranji 14H (horizontal) development well in 1993 which had a horizontal section of 400 m in a total drilled depth of 2310 m. Located ~30 km northwest of Moomba, the well had the relatively thin Eromanga Basin Namur Sandstone oil reservoir as its target. The vertical wells in the field were all producing oil with a large water content and it was anticipated that a horizontal well would reduce the percentage of water and in doing so allow an increased oil recovery by reducing water handling costs and increasing the volume of oil accessed by a single well. The best flow rate achieved from Meranji 14H was 254 kL/day (1600 bopd). The total recovery flow rate and producing water cut are approximately the same as the adjacent vertical wells; this initial attempt at improving recovery using horizontal drilling was unsuccessful.

In 1996 the Big Lake 56H gas development well was drilled to target Tirrawarra Sandstone as an experiment to improve deliverability and recovery in a thick reservoir unit. The Tirrawarra Sandstone has a zone of good to moderate permeability in the centre of the field surrounded by an area of low permeability; Big Lake 56H was designed to increase drainage from the large lower permeability area of the reservoir. The well had a near horizontal section of 646 m in a total drilled length of 3709 m (Fig. 11.1). High temperatures were expected and precautions were taken to cool the mud and to use a minimum of temperature sensitive equipment while drilling. The highly abrasive nature of the sandstone reservoir caused delays with frequent removal of worn drilling bits. On initial clean-up Big Lake 56H flowed at 198 000 m<sup>3</sup>/day (7.0 mmcf/d) then reduced to 99 000 m<sup>3</sup>/day (3.5 mmcf/d) over a period of extended production against line pressure from an uncased open hole section of the well. A portion of the Tirrawarra that was cased was perforated and the flow rate increased to 127 000 m<sup>3</sup>/day (4.5 mmcf/d). The well continues to flow steadily at this rate into the gathering system. In comparison, drillstem tests of vertical wells which penetrate the Tirrawarra Sandstone in Big Lake Field have flow rates which range from a rate too small to measure (RTSTM) to 127 000 m<sup>3</sup>/day (4.5 mmcf/d).

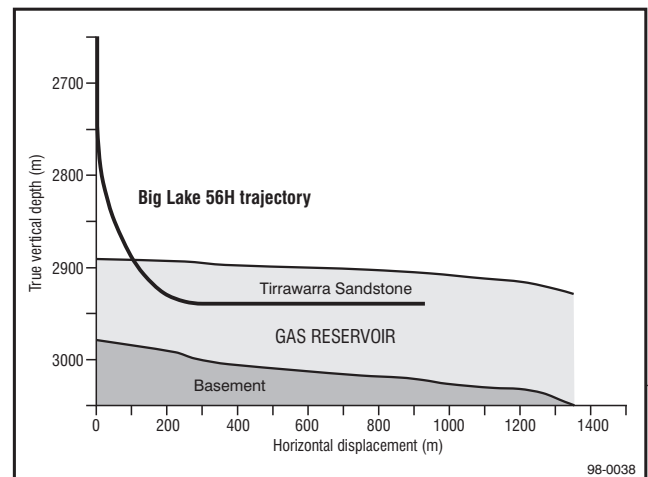


Fig. 11.1 Horizontal well trajectory, Big Lake 56H.

Big Lake 56H penetrated a thicker than expected Eromanga Basin Namur oil section. In 1997 two near-horizontal oil development wells were drilled to the Namur reservoir from close-spaced surface locations (58 m apart). Big Lake 58 was drilled to the southwest and penetrated the oil reservoir at a maximum angle of 76° from the vertical. Big Lake 59 was drilled in a north–northeast direction and had a maximum angle of 84° from the vertical in the oil reservoir (Fig. 11.2). Production rates have been 239 kL/day (1500 bopd) each compared to 80 kL/day (500 bopd) from adjacent vertical wells.

The Daralingie Formation in the Moomba Field was first used for sales gas storage in 1981 and for ethane storage in 1984 (Keleman, 1986). The Moomba 18H gas storage–

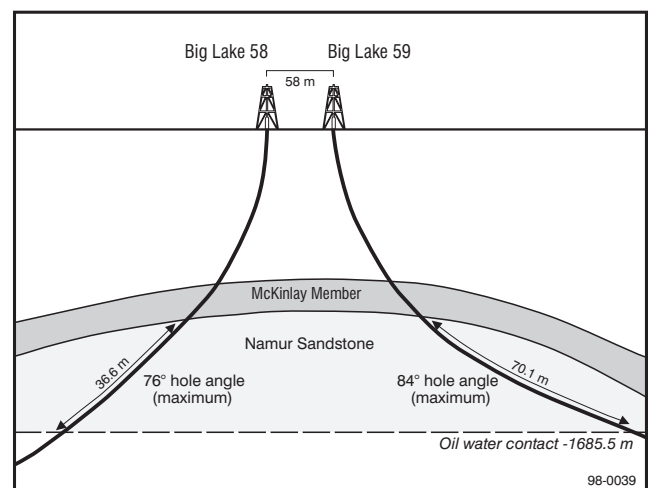


Fig. 11.2 Schematic section of high angle-wells, Big Lake 58 and 59 (data courtesy of Santos).

development well was drilled in 1996 when the abandoned Moomba 18 gas well was re-entered and a lateral section was drilled out through the casing into the Daralingie Formation; a near horizontal section of 142 m was drilled in the 2 m thick reservoir (Fig. 11.3). The well was designed to increase gas withdrawal rates from the storage reservoir. A flow rate of 850 000 m<sup>3</sup>/day (30 mmcf) was achieved compared to 283 000–425 000 m<sup>3</sup>/day (10–15 mmcf) from nearby vertical wells.

## AIR DRILLING TIGHT GAS RESERVOIRS

Swan Lake 1 was drilled with mud in 1986. In 1996 it was re-entered, a hole drilled through the casing above the Permian gas target reservoirs and Swan Lake 1 DW1 (deviated well) drilled with air roughly parallel to the original well-bore. The top Toolachee Formation intersections were within 0.3 m of each other in the two wells. In Swan Lake 1, the top 7.3 m of the Toolachee was tested and flowed at RTSTM; in comparison Swan Lake 1 DW1 recorded a flow of 5097 m<sup>3</sup>/day (0.18 mmcf) over the top 13.7 m of the formation (Table 11.1). Log pay in the original well is below the tested intervals. Flow test 2 in the deviated well tested the Toolachee to a depth which included all of the log pay in the original well and flowed at 133 088 m<sup>3</sup>/day (4.7 mmcf). Flow test 3 included all of the Toolachee section which flowed at 232 196 m<sup>3</sup>/day (8.2 mmcf); lower Toolachee Formation sands previously interpreted as wet on logs contained gas pay.

In summary, the non pay zone at the top of the Toolachee Formation flowed at uneconomic rates in both wells with the air drilled well giving the best flow rate; air drilling did not enable the top tight reservoirs to flow at economic rates. The pay zone untested in the original well flowed at economic rates in the air drilled well.

In Swan Lake 1, the lower targets, the basal Patchawarra Formation and the Tirrawarra Sandstone were drillstem tested and flowed at 10 900 m<sup>3</sup>/day (0.39 mmcf). The adjacent air drilled Swan Lake 2, tested the same interval on a flow test with a resulting flow rate of 10 477 m<sup>3</sup>/day (0.37 mmcf). Air drilling in this example gave essentially the same result as mud drilling in a tight gas sand.

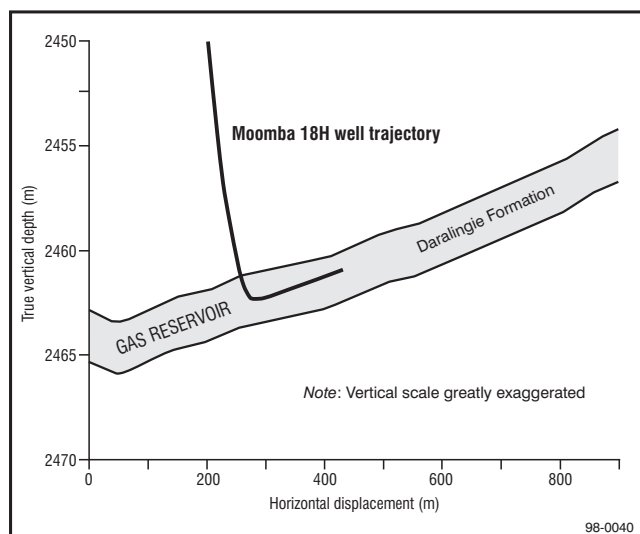


Fig. 11.3 Horizontal well trajectory, Moomba 18H.

Air drilling was then tested in the Tindilpie Field. The main target was the Patchawarra Formation. In Tindilpie 1, drilled with mud in 1970, the best test from a number of intervals in the Patchawarra Formation above the Patchawarra coal (Vc) was 58 900 m<sup>3</sup>/day (2.08 mmcf). Tindilpie 2 appraisal well was also drilled with mud and flowed at RTSTM above Vc and at 14 158 m<sup>3</sup>/day (0.5 mmcf); best test) below Vc. Tindilpie 2 DW1 was drilled out from Tindilpie 2 through the casing above the target and used air as the drilling fluid. The best flow test result in the deviated well was 39 600 m<sup>3</sup>/day (1.4 mmcf) with approximately 183 m of the Patchawarra Formation (above Vc) open. In this case the air drilled test result was better than in the adjacent well but not as good as the original Tindilpie 1 result.

Air drilling was also tested in the deep tight gas reservoirs of the Nappamerri Trough. Burley 1, drilled with mud in 1971, tested a thick Permian section; most tests flowed at RTSTM. However, the lower Epsilon Formation flowed gas at 25 202 m<sup>3</sup>/day (0.89 mmcf). Burley 3 was drilled 150 m from Burley 1 and the Permian section from the top Toolachee Formation was drilled with air. In Burley 1, two individual Toolachee intervals flowed gas on test at 5097 and 4531 m<sup>3</sup>/day (0.18 and 0.16 mmcf). In Burley 3 with all of the formation open a flow test recorded 425 m<sup>3</sup>/day (0.015 mmcf). The air drilled well had a ten times poorer result than the mud-drilled well. Burley 3 never reached the basal Epsilon target as down-hole fires on two occasions damaged the drill collars and the well was abandoned.

Air drilling was tried in the Moomba North Field where a large number of tight Permian gas reservoirs exist. Moomba 86, the northeasternmost well on the field, was drilled conventionally with mud through the Toolachee and Epsilon reservoirs, but was converted to air to drill the Patchawarra Formation above Vc. The Patchawarra Formation was flow tested and produced gas at RTSTM. The two nearest wells to Moomba 86, previously drilled with mud, Moomba 73 and Moomba 26 had Patchawarra tests of 22 653 and 14 158 m<sup>3</sup>/day (0.8 and 0.5 mmcf) respectively. Although not immediately adjacent to a mud-drilled well, air drilling in Moomba 86 failed to improve gas deliverability in the Patchawarra Formation.

The basal Patchawarra Formation and the Tirrawarra Sandstone were drilled with air in Coonatie 4 appraisal well during 1997. An open hole flow test of the basal Patchawarra flowed at 8495 m<sup>3</sup>/day (0.3 mmcf) in Coonatie 4 compared to a drillstem test of the same interval in Coonatie 2 that flowed at 14 158 m<sup>3</sup>/day (0.5 mmcf). When Coonatie 4 was deepened into the upper Tirrawarra Sandstone, the open hole flow rate increased to 14 158 m<sup>3</sup>/day (0.5 mmcf). It is hard to determine the contribution of the Tirrawarra Sandstone to the flow rate, but if the extra 5663 m<sup>3</sup>/day (0.2 mmcf) is taken as an approximate addition, then it is the same as the Tirrawarra test in Coonatie 2.

Air drilling in tight gas reservoirs in the South Australian Cooper Basin area has had limited success as shown in Table 11.1. The Tindilpie 2 DW1 probably represents the best increase in flow rate. The remainder of the accurate comparisons between air and mud drilling resulted in the air drilling result being the same or worse. In addition a number

**Table 11.1** A comparison of gas flow rates between wells drilled with air versus mud.

Well	Formation	Drilling type		Flow rate		Comments
		M (mud)	A (air)	m <sup>3</sup> /day	mmcf/d	
Swan Lake 1	Toolachee Formation	M		RTSTM	RTSTM	Tested top 7.3 m of formation above log pay (13.1 m pay untested).
Swan Lake 1 DW1	Toolachee Formation	A		5 097 232 200	0.18 8.2	
Swan Lake 1	basal Patchawarra Formation – Tirrawarra Sandstone	M		10 900	0.39	Flow rates comparable for both drilling types.
Swan Lake 2	basal Patchawarra Formation – Tirrawarra Sandstone	A		10 477	0.37	
Tindilpie 1	Patchawarra Formation above Vc	M		58 900	2.08	Flow rates were better above Vc with air drilling.
Tindilpie 2	Patchawarra Formation above Vc Patchawarra Formation below Vc	M M		RTSTM 14 158	RTSTM 0.5	
Tindilpie 2 DW1	Patchawarra Formation above Vc	A		39 600	1.4	Both drilling types gave low flow rates; mud drilling produced a better result.
Burley 1	Toolachee Formation	M		5 100 4 531	0.18 0.16	
Burley 3	Toolachee Formation	A		425	0.015	
Moomba 86	Patchawarra Formation above Vc	A		RTSTM	RTSTM	Nearest well to Moomba 86. Next nearest well to Moomba 86.
Moomba 73	Patchawarra Formation	M		22 653	0.8	
Moomba 26	Patchawarra Formation	M		14 158	0.5	
Coonatie 2	basal Patchawarra Formation Tirrawarra Sandstone	M M		14 158 5 663	0.5 0.2	Nearest well to Coonatie 4.
Coonatie 4	basal Patchawarra Formation basal Patchawarra Formation – Tirrawarra Sandstone	A A		8 495 14 158	0.3 0.5	

RTSTM rate too small to measure  
Vc Patchawarra coal

of mechanical problems were identified while air drilling. When penetrating coal seams, the holes caved badly and the coal fragments settled around and jammed the drill pipe; several bottom-hole assemblies were lost. In Burley 3 the combination of high temperature, high air pressure, gas and possibly coal dust caused down-hole fires which partially melted the drill collars causing a break in the drill string on two occasions and led to the abandonment of the well.

## NITRIFIED ACIDISATION

Acid has traditionally been used to reduce formation damage in relatively tight sandstone reservoirs and improve deliverability and increase recoverable reserves. The wells are 'killed' by a heavy weight fluid then injected with acid using a completion fluid. The reservoir is then allowed to soak in the acid before back-flowing the well to remove the acid and completion fluid and to measure the post acidising flow rate.

Nitrified acidisation was introduced to the Cooper Basin in 1996. This method uses a coiled tubing unit and is applied to highly depleted gas reservoirs which could be susceptible to formation damage if killed with overbalanced completion fluid. Nitrogen is initially pumped into the formation as an injectivity test. Acid is then squeezed with nitrogen into the formation and is finally displaced out of the well with nitrogen. The technique is designed to remove well-bore formation damage which has occurred during the productive life of the well without causing additional damage with kill fluids.

To July 1996 three wells in the Della and Moomba Fields were subjected to nitrified acidisation treatments and each had a post acid wash gas flow increase. During 1997 a further seven gas wells in the Big Lake, Moomba, Daralingie and Tirrawarra Fields had nitrified acidisation programs. Most of the initial ten wells showed flow rate increases. The overall deliverability increase achieved with the first ten wells was 362 452 m<sup>3</sup>/day (12.8 mmcf/d). The encouraging results will lead to further gas wells receiving nitrified acid treatments during 1998.

## WATER-FLOOD SECONDARY OIL RECOVERY

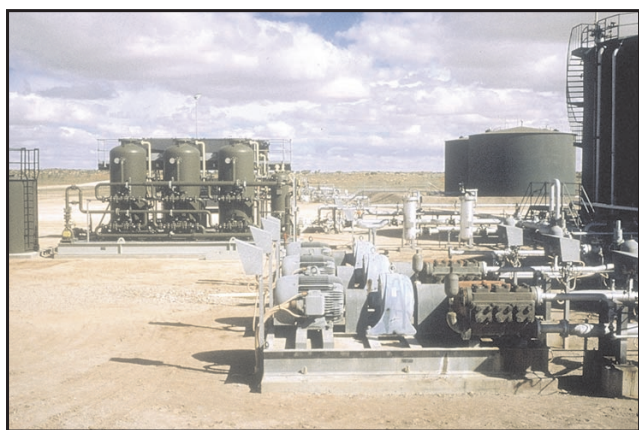
In 1979 oil reservoirs were discovered in the Murta Formation (Eromanga Basin) of the Dullingari Field, located ~60 km east of Moomba; production commenced in 1982. The reservoirs of Cretaceous age were deposited in a lacustrine environment and consist of three sandstone units. The oldest, the 49-0 sand, was deposited on a proximal delta slope. It is 1.5–3 m thick but has low permeability and its contribution to the oil production is limited as it is only completed in one well. The 48-6 sand is approximately 0.3 m thick and is interpreted as a lacustrine fan. This reservoir is separated by 1.2 m of siltstone from the 48-5 reservoir, a 0.3 m thick shoreline-bar sandstone with good porosity and permeability. The 48-5 and 48-6 reservoirs have a volumetrically calculated original oil-in-place of 1.44 x 10<sup>6</sup> kL (9.1 mmstb; Robinson and Butler, 1989). However, material balance calculations assuming no water-drive give

an estimate in the range of  $2.2\text{--}7.5 \times 10^6$  kL (14–47 mmstb). This includes a large volume of oil in low permeability reservoirs in contact with the 48-5 and 48-6 sands. The edge of the Murta reservoir is defined by a zero pay contour as the reservoirs are present but tight down flank. Eight appraisal wells were drilled seeking down-dip reservoir extensions because the production decline indicated a large original oil-in-place as no water was produced with the oil. It was then realised that low permeability sands in contact with the 48-5 and 48-6 reservoirs were contributing to the oil production and the reservoir had a depletion drive.

An enhanced oil recovery (EOR) scheme using a low pressure water flood of the 48-5 and 48-6 sands was implemented in 1984 after 240 000 kL (1.5 mmstb) of primary production had been achieved. It aimed to improve the recovery in the good quality thin reservoirs and at the same time allowing cross flow from the adjacent tighter oil sands. The injection project started with two injectors and was later expanded to four, all relatively low on the structure, with eleven producing oil wells on pump while an average reservoir pressure was maintained at  $\sim 8621$  kPa. A fifth injector was added in 1990. The ultimate recoverable reserves are 920 000 kL (6.4 mmstb) of which 460 000 kL (3.5 mmstb) are attributable to the water-flood project.

Another water-flood EOR scheme was implemented in the Murta reservoir of the Limestone Creek–Biala oil field in 1993. The underlying Namur Sandstone was perforated to allow the Great Artesian Basin aquifer to dump into the Murta forcing oil from the dump flood well towards surrounding producers. There has been a measured increase in the Murta reservoir pressure, but no change in the oil production declining trend.

The Gidgealpa Field, Birkhead Formation (Eromanga Basin) oil reservoir was subjected to a water dump flood trial in October 1995. The Birkhead is a partial depletion drive reservoir. The underlying Hutton Sandstone was perforated in Gidgealpa 22 and allowed to flood into the oil reservoir. A minor increase in reservoir pressure has been recorded since the flood commenced. The Birkhead reservoir in Gidgealpa 22 was fracture stimulated to allow increased access of the Hutton water to the depleted reservoir. No significant change in oil production has been recorded to date.



Filters, injection pumps and tanks used during water-flood secondary oil recovery, Dullingari Field. (Photo 45947)

## GAS-FLOOD SECONDARY OIL RECOVERY

The Tirrawarra Field discovered in 1970 was the first Permian oil field found in the Cooper Basin. The field also has the largest in-place oil accumulation in the basin with estimates ranging from  $19.56 \times 10^6$  kL (123 mmbbl; Pecanek and Paton, 1984) to  $25.9 \times 10^6$  kL (163 mmbbl; Seggie *et al.*, 1994). The reservoir is the Tirrawarra Sandstone with minor volumes in the younger basal Patchawarra Formation and the older Merrimelia Formation. The nearby Moorari Field was discovered soon after Tirrawarra in 1971 and like Tirrawarra has oil in the Tirrawarra Sandstone. Moorari contains approximately  $2.07 \times 10^6$  kL (13 mmbbl) oil-in-place (Brown and Barley, 1986).

Production commenced in 1983 from the Tirrawarra and Moorari Fields. Individual wells showed substantial declines in productivity as the Tirrawarra oil is undersaturated at initial reservoir conditions. As reservoir pressures fall below the bubble-point the oil phase shrinks rapidly with a major loss of liquids production. To minimise this affect bottom-hole flowing pressures were maintained where possible above the bubble-point. The Tirrawarra reservoir has low permeability and no active aquifer. The maintenance of pressure support was thought necessary to slow the deliverability decline and increase oil recovery. Studies of the oil characteristics indicated that the oil was amenable to miscible gas flooding.

A pilot gas injection EOR scheme commenced in the Tirrawarra Field in 1984 when Tirrawarra 15 producing well was converted to an injector to supply energy to the surrounding six producing wells (Figs 11.4, 11.5). An observation well, Tirrawarra 35, was added to the pilot injection program to provide data for a study of the effectiveness of the pilot injector. Tirrawarra Field, Patchawarra Formation separator gas was used as the injector fluid. Prior to long-term injection commencing in Tirrawarra 15, a ‘huff and puff’ experiment was carried out on the well in early 1984, using Patchawarra gas. Injection rates varied from 99 000 to 170 000 m<sup>3</sup>/day (3.5–6.0 mmcf) over several months and the total volume injected was  $7.0 \times 10^6$  m<sup>3</sup> (247 mmcf). The well was shut in for approximately one week for a ‘soak’ period; well head pressures were measured and a production logging tool was used to monitor any cross flow between perforations. The puff section of the experiment involved back-flowing the well for approximately one week. About 660 000 m<sup>3</sup> (23.3 mmcf) of gas was produced with no significant quantities of oil recovered. Later in 1984 the Moorari Field pilot injector project commenced using Moorari 3 as the injector well with four adjacent producers (Figs 11.5, 11.6).

In 1985 radioactive tracer was added to the Tirrawarra Field injection gas to track the injector gas fronts. Production decline of the pilot producers was arrested by the gas injection. In Tirrawarra 15 pattern, response times seen in the production rate declines of the surrounding producers to the effects of gas injection varied from 5 to 13 months.

From 1984 to 1995 an additional eleven injector wells were added to the Tirrawarra EOR scheme. In 1986 a below bubble-point production trial commenced and in 1987 ethane from the Moomba plant became the secondary recovery injection fluid. Ethane injection into the Moorari

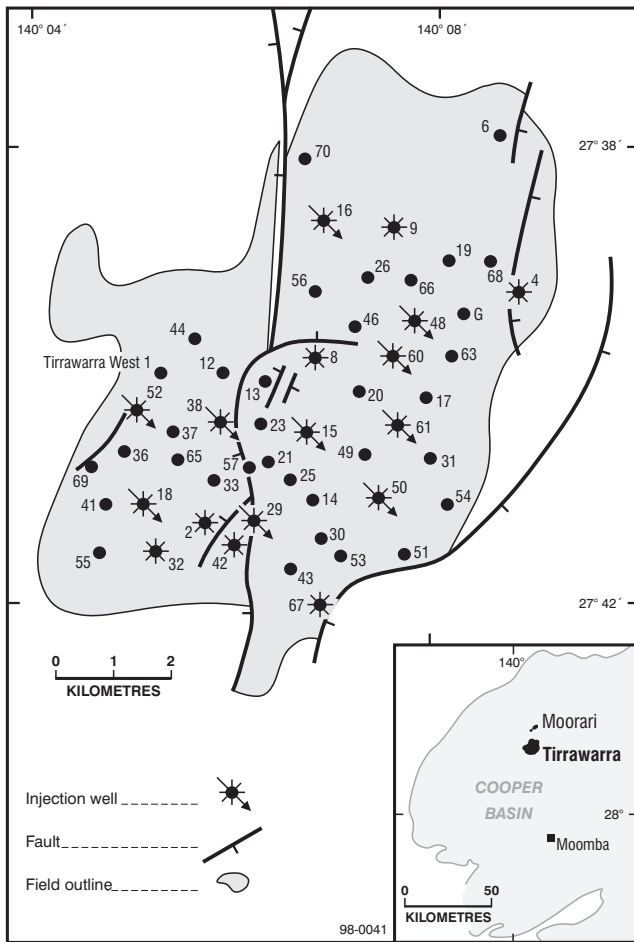


Fig. 11.4 Tirrawarra Field EOR scheme 1.1.95 (data courtesy of Santos).

Field also commenced in 1987. The later EOR patterns that were established in the Tirrawarra main field area were designed to include more of the northern area of the field in the EOR pattern.

With full EOR development and ethane injection until breakthrough volumes of ethane make oil production uneconomic, it is expected that total oil recovery from Tirrawarra will be  $5.5 \times 10^6$  kL (37.7 mmbbl) of which  $3.04 \times 10^6$  kL (19.1 mmbbl) would be primary and the remainder secondary oil. In Moorari, using the single injector, it is expected that  $0.67 \times 10^6$  kL (4.2 mmbbl) of oil will be



Well head of a Tirrawarra Field gas injector. (Photo 35486)

recovered of which  $0.4 \times 10^6$  kL (2.5 mmbbl) would be through primary recovery (Rodda and Paspaliaris, 1989). At January 1998 the Tirrawarra Field had produced  $3.8 \times 10^6$  kL (20.6 mmbbl) of oil and Moorari  $0.5 \times 10^6$  kL (2.7 mmbbl). Both fields are expected to produce until 2012.

In December 1996 ethane injection into Tirrawarra and Moorari Fields ceased as the operator required the ethane as a substitute for sales gas and pure ethane was required to supply ICI in Sydney as a petrochemical feedstock. It is expected that ethane injection will not occur for all of 1997 and 1998 as extra gas deliverability is required to meet South Australian and interstate markets. The effect on oil production rates and recovery has not yet been quantified.

## PLUNGER LIFT SYSTEMS

### Gas wells

In the period 1986 to 1996, 18 gas wells in the Cooper Basin had plunger lift systems installed (Toolachee, Tirrawarra, Daralingie, Deina, Bimbaya, Marana, Thurakinna, Cooba and Cooper's Creek Fields). The wells had experienced production difficulties because of reduced formation pressure, increasing liquids (condensate and water) and reduced gas flow rates. Liquid build-up in the production tubing had been gradually killing these wells and allowing only intermittent production after frequently being blown down to atmosphere to unload accumulated liquids.

Plunger lift uses a piston in the production tubing to lift liquids to the surface. The annulus has a connection to the tubing through perforations and a build-up of pressure in the annulus by the gas is required to lift the liquid load. The piston periodically clears the tubing of liquids which allows an intermittent flow of gas from the well. Having unloaded the fluid in the tubing, the piston falls back to the bottom of the well through accumulated fluids until sufficient gas pressure builds up to repeat the lifting cycle (Fig. 11.7).

Plunger lift is not successful in all gas wells as the gas-liquid ratio has to be great enough to provide the lifting energy and the lower the gathering system line pressure, the more effective the plunger lift operation. Total gas deliverability from the 18 wells with plunger lift installed has been increased by 198 000 – 227 000 m<sup>3</sup>/day (7–8.0 mmcf/d).

### Oil wells

The Moorari, Tirrawarra, Woolkina and Fly Lake-Brolga oil fields have relatively high gas-oil ratios in the Tirrawarra oil reservoir. This property makes the Tirrawarra Formation unsuitable for mechanical pumping operations as gas bubbling out of the oil in the well would severely reduce the efficiency of the pump. Moorari and the adjacent Tirrawarra Field have been subjected to EOR methods. Moorari 6 is separated from the remainder of the field by a series of faults and does not receive pressure support from the EOR project (Fig. 11.6). In 1987 a plunger lift was installed on the Moorari 6 oil well (Barry, 1988). Moorari 6 has a high gas-liquid ratio and the well had to be frequently blown down to atmosphere to prevent water loading in the production tubing, which stopped production. As the reservoir pressure in the oil reservoir drops below the bubble-point the gas-oil ratio of 362–711 m<sup>3</sup>/kL (2000–4000 scf/bbl) was forecast to increase to 1781 m<sup>3</sup>/kL (10 000

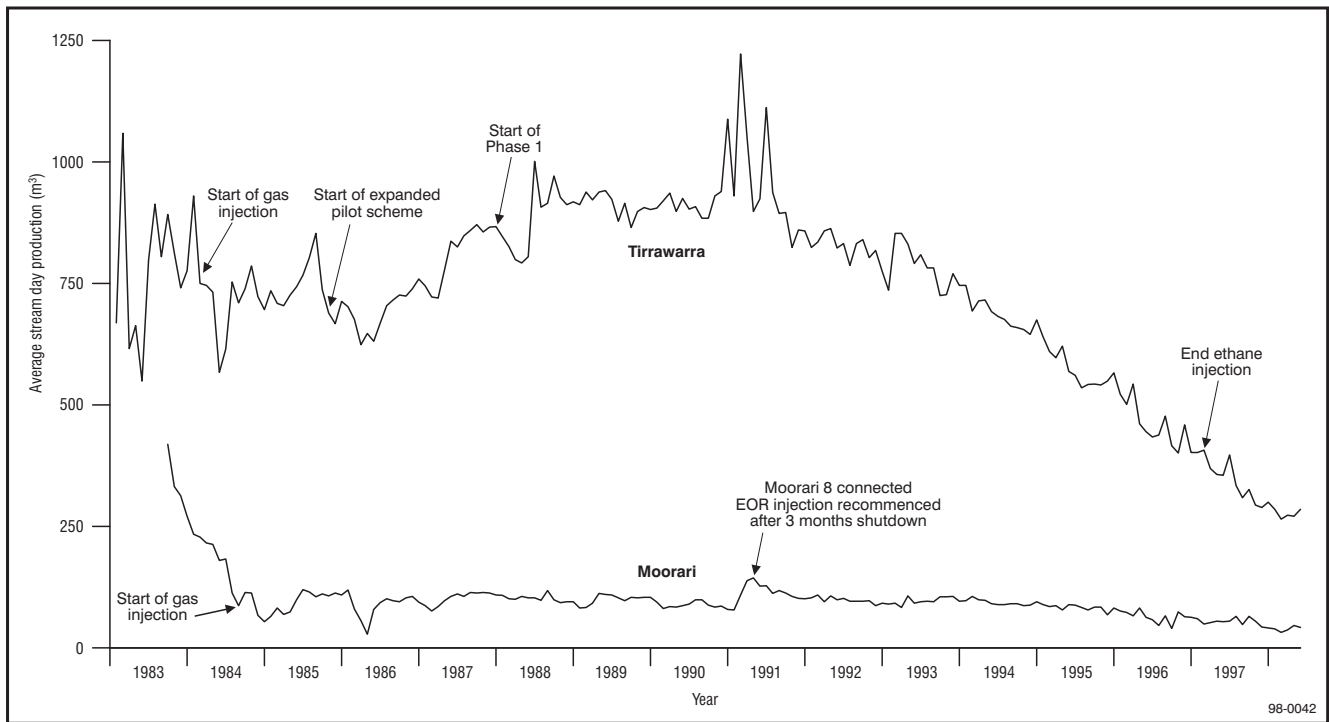


Fig. 11.5 Tirrawarra and Moorari Fields' production history (after Rodda and Paspaliaris, 1989).

scf/bbl). The installation of plunger lift in Moorari 6 produced an increase of 5.9 kL (37 bbl) of oil per day. To the end of 1997 Moorari 6 had produced 46 000 kL (0.289 mmbbl) of oil.

Tirrawarra 42, located at the southern edge of the Tirrawarra West Field, is a Tirrawarra oil producer which had production problems with fluid loading in the production string. A plunger lift was installed in 1987; production increased, but the rate was erratic. In 1990 a gas lift valve was added to the plunger lift to allow ethane to be injected into the annulus to add lifting energy for the plunger operation (artificially increasing the gas-oil ratio). At the end of 1997 the well had ceased production, having produced 20 000 kL (0.126 mmbbl) of oil to date. Tirrawarra 44 oil well, located on the northern margin of the field, had a gas-assisted plunger lift system installed in 1992. Production has been poor since the installation with the well unable to produce for the majority of the time; production from the well is 1000 kL (0.006 mmbbl) of oil.

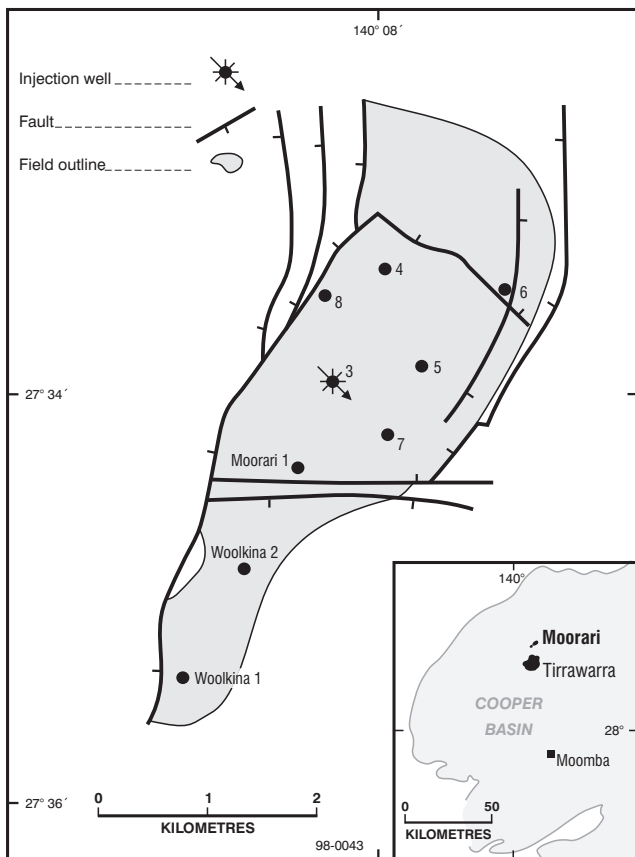


Fig. 11.6 Moorari-Woolkina Field EOR scheme 1.1.95 (data courtesy of Santos).

## HYDRAULIC FRACTURING

### Gas reservoirs

The Cooper Basin sandstone reservoirs are generally poor to medium quality in terms of porosity and permeability. A large volume of gas is contained in low permeability reservoirs which require stimulation to increase effective permeability to allow the well to flow at an economic rate and improve the gas recovery. The Moomba Field, discovered in 1966, is a good example of a large volume low permeability reservoir. Hydraulic fracturing of the tight reservoirs involves pumping a fluid containing hard spherical proppant material (sand, glass, sintered bauxite etc.) under high pressures into a cased and perforated well. The high pressure fluid induces fractures in the sandstone reservoir which propagate away from the well as vertical wings. The proppant keeps the fractures open after the pressure is released and the fracture fluid is produced out of the well in post-fracture clean-up. The fractures increase the surface area of the well allowing an increased flow of gas to

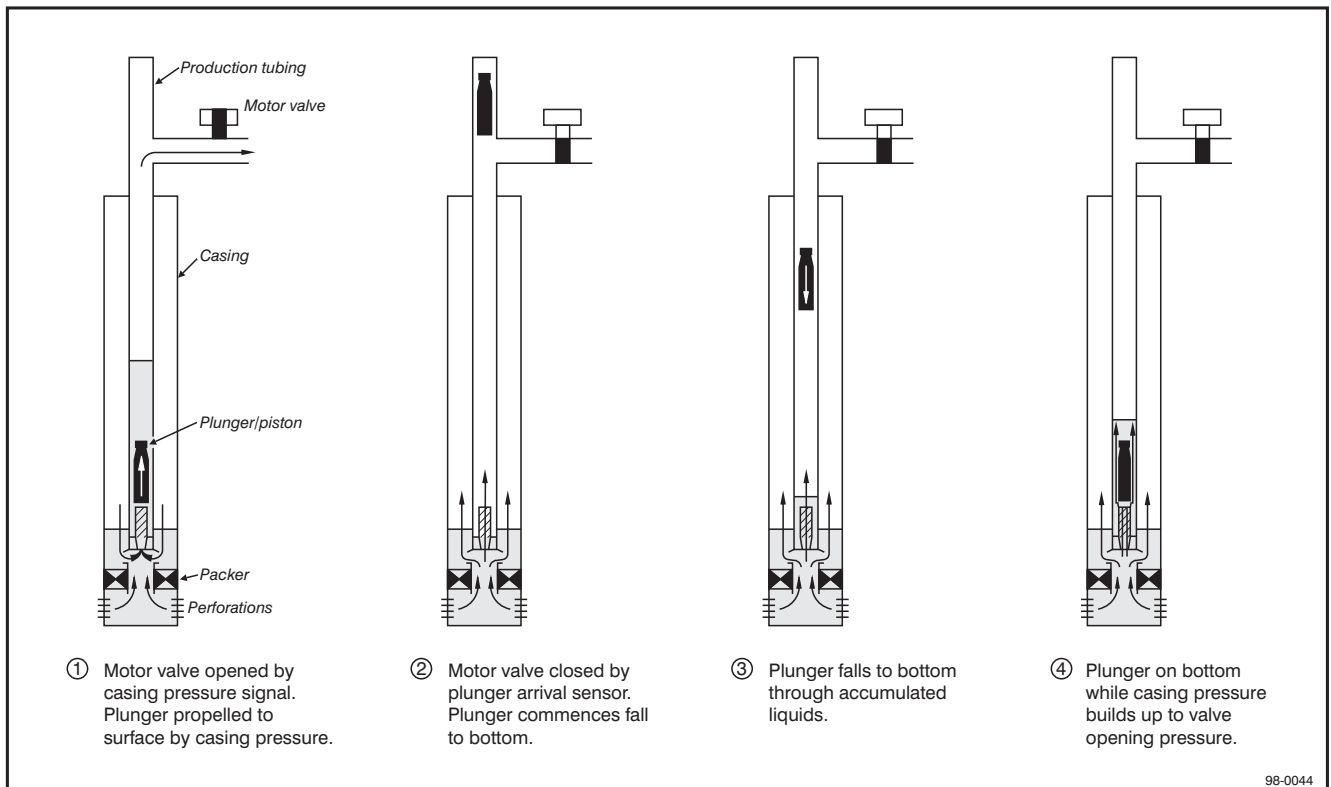


Fig. 11.7 A typical plunger lift cycle (after Barry, 1988).

occur and also drain a larger volume of reservoir than a standard well.

One of the earliest fracture operations in the Cooper Basin was on Moomba 6 in 1968. Fracture stimulation of Moomba wells has been successfully carried out on an irregular basis up to and including 1997. The Moomba North area has the highest number of fractured gas wells in the field as the Toolachee and Daralingie reservoirs are generally of a lower permeability than the southern remainder of the field. The materials used, the design and size of hydraulic fractures have changed with time. Many of the modern fracture treatments in the Cooper Basin are carried out on better quality reservoirs prior to production to increase permeability and to penetrate well-bore zones which may have been damaged by drilling fluids. The fracture increases the well's initial production rate and avoids a long flow period while the well 'cleans up'.

Hydraulic fracturing of gas reservoirs in 1997 resulted in five successful programs averaging 65 000 m<sup>3</sup>/day (2.3 mmcfd) pre-fracture increasing to 139 000 m<sup>3</sup>/day (4.9 mmcfd) post-fracture.

Fracture stimulation of gas wells has been an integral part of a number of tight gas evaluation programs. In 1982 the South Australian Oil and Gas Corporation Sole Risk Gas Program included the drilling and fracturing of Early Permian reservoirs in Big Lake 26 and 27 (Stanley and Halliday, 1984). This was followed in 1983–85 by the Accelerated Gas Program in which Big Lake 29, 30 and 31 were drilled and fractured (Crosby *et al.*, 1995).

In 1994 the Bulgeroo 1 well was drilled in the Nappamerri Trough, the deepest area of the Cooper Basin, in which tight reservoirs and a large tight gas resource had been identified by earlier drilling. The aim was to fracture

stimulate the best of the Permian reservoirs. The Early Permian reservoirs proved to be too tight to fracture stimulate and a fracture program was carried out on the Late Permian Toolachee Formation instead. Although mechanically successful, the fracture program did not provide an economic gas rate from the well.

Zones which flow at measurable but uneconomic gas rates (e.g. 14 100 m<sup>3</sup>/day (0.5 mmcfd)) can often be successfully stimulated by hydraulic fracturing, but tight reservoirs have not generally produced economic flow rates after fracturing.

Positive results from 1996 where fracture projects on seven wells added 617 300 m<sup>3</sup>/day (21.8 mmcfd) and from 1997 where fracturing six wells added 356 800 m<sup>3</sup>/day (12.6 mmcfd) deliverability means that fracturing of gas reservoirs will continue in the Cooper Basin as a method of



Surface equipment used during hydraulic fracturing, Tirrawarra 48. (Photo 45948)

adding deliverability and increasing the recovery of gas reserves.

## Oil reservoirs

Fracture stimulation of oil wells commenced in the Tirrawarra Field in 1971 (Rodda and Paspaliaris, 1989). The first fracture program of the Tirrawarra Sandstone in Tirrawarra 2 was unsuccessful. Tirrawarra 9, fractured in 1972, was moderately successful and by the time Tirrawarra 12 and 14 were fractured in 1981 the technique was proven. A typical Tirrawarra fracture program consists of 45 000–82 000 kg of proppant with 190–300 m<sup>3</sup> of water based gel. The Tirrawarra Sandstone contains a high gas–oil ratio oil and it was found that by fracturing the reservoir the oil production rate increased in most wells as did the productivity index which measures the amount of oil produced per day for each unit drop in the oil reservoir pressure. Fracturing has increased the average well productivity and injectivity by two to three times enabling economic development of low permeability reservoir areas. Analysis of the oil reservoir tests indicated that the wells were generally not damaged by drilling fluids and the effect of the fractures was to connect the well to higher permeability reservoir zones from which the higher flow rates resulted. All oil wells in the Tirrawarra Field were fractured early in their production history. Refracturing was also carried out after a number of years of production where it was felt that the original fractures had closed-up.

Oil well fracturing was previously concerned with Cooper Basin Patchawarra Central fields near Tirrawarra where the thick Tirrawarra Sandstone was the major target (Woolkina, Moorari, Fly Lake and Brolga Fields). As the Cooper Basin oil fields have been fully developed the number of fracture projects has declined in recent years.

More recent oil field fracture operations have involved the relatively shallow and very thin reservoirs of the Eromanga Basin Murta Formation. Production from the Murta relies on the presence of thin high permeability streaks in a much larger volume of oil saturated low permeability reservoir. Fracturing of the Murta allows a much larger area of low permeability reservoir to be in contact with high permeability streaks than in unfractured wells. This allows access to larger volumes of oil-in-place and increases oil recovery per well. Murta fracture projects have taken place in the Jena, Merrimelia and Wancoocha Fields with encouraging results.

# FIELD SUMMARIES

D.I. Gravestock,  
B. Jensen-Schmidt and A. Sansome,  
with contributions from  
R.A. Frears and J.G.G. Morton

## Chapter 12

### INTRODUCTION

The Cooper Basin has had 121 gas fields and 25 oil fields progressively on production since the first discovery of natural gas at Gidgealpa in 1963 (Fig. 1.2). Most of the gas reserves are held in the five major fields — Moomba, Big Lake, Della, Tirrawarra, Toolachee — but economic volumes continue to be discovered in the numerous small fields that occur throughout the basin. Gas wetness is greatest near the basin margins (Fig. 8.1), and elevated CO<sub>2</sub> content occurs in gas produced from the deeper parts of the Patchawarra and Nappamerri Troughs (Fig. 8.2).

More than 80% of the oil is in Early Permian braid delta and braided stream sandstone reservoirs in the Tirrawarra Sandstone at Tirrawarra alone. Fly Lake and Moorari–Woolkina contribute most of the remaining Permian oil. Significant oil reserves have also been found in fluvial sandstone in formations of the Triassic Nappamerri Group (Telopea, Keleary) and oil legs are also associated with Permian gas in some large fields e.g. Daralingie.

Brief summaries of the Tirrawarra oil field and three gas fields (Della, Toolachee, Munkarie) are provided below.

### TIRRAWARRA FIELD

Substantial volumes of oil and gas were discovered in Permian sandstone reservoirs at Tirrawarra in 1970, which was at that time in a remote location 50 km north of Moomba (Bridge Oil NL, 1970). Oil was also discovered at nearby Moorari and Fly Lake but the volume was not considered sufficient to warrant development. Production was delayed until gas liquids production, oil discoveries in Mesozoic traps and a rising oil price justified commencement of the Cooper Basin Liquids Project in 1983 (Hollingsworth, 1989).

Primary depletion of the low permeability reservoirs (which lack aquifer support) within one year of start-up called for rapid development of secondary recovery techniques. A pilot miscible flood scheme was implemented in 1984 (Brown and Barley, 1986) and encouraging results led to expansion of an ethane enhanced oil recovery (EOR) scheme in 1985. This has boosted production (Rodda and Paspaliaris, 1989) and productivity has been maintained by fracture stimulation (Salter, 1989). Tirrawarra and Moorari Field production data and the EOR scheme are shown in Figures 11.4 and 11.5, and additional information is listed in Table 12.1.

The oil is produced from the Early Permian Tirrawarra Sandstone and the field has been studied in detail by Battersby (1976), Pecanek and Paton (1984), Skilbeck *et al.* (1991) and Seggie *et al.* (1994). A structure contour map (Fig. 12.1) shows a fault extending north–south, down-

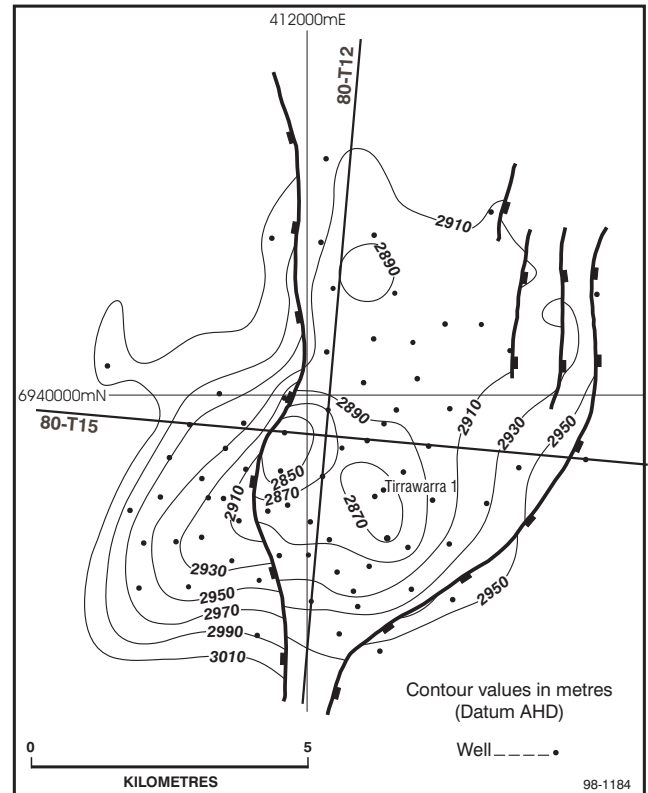
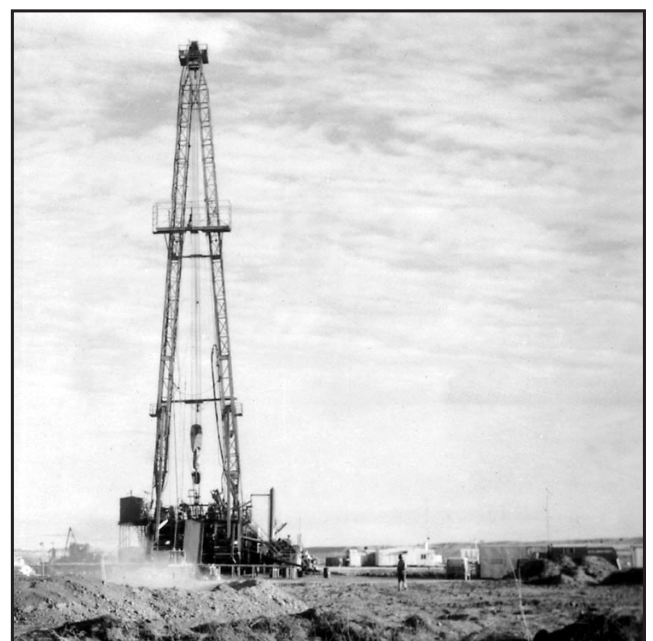


Fig. 12.1 Depth structure contour map on top Tirrawarra Sandstone, Tirrawarra Field (after Skilbeck *et al.*, 1991).

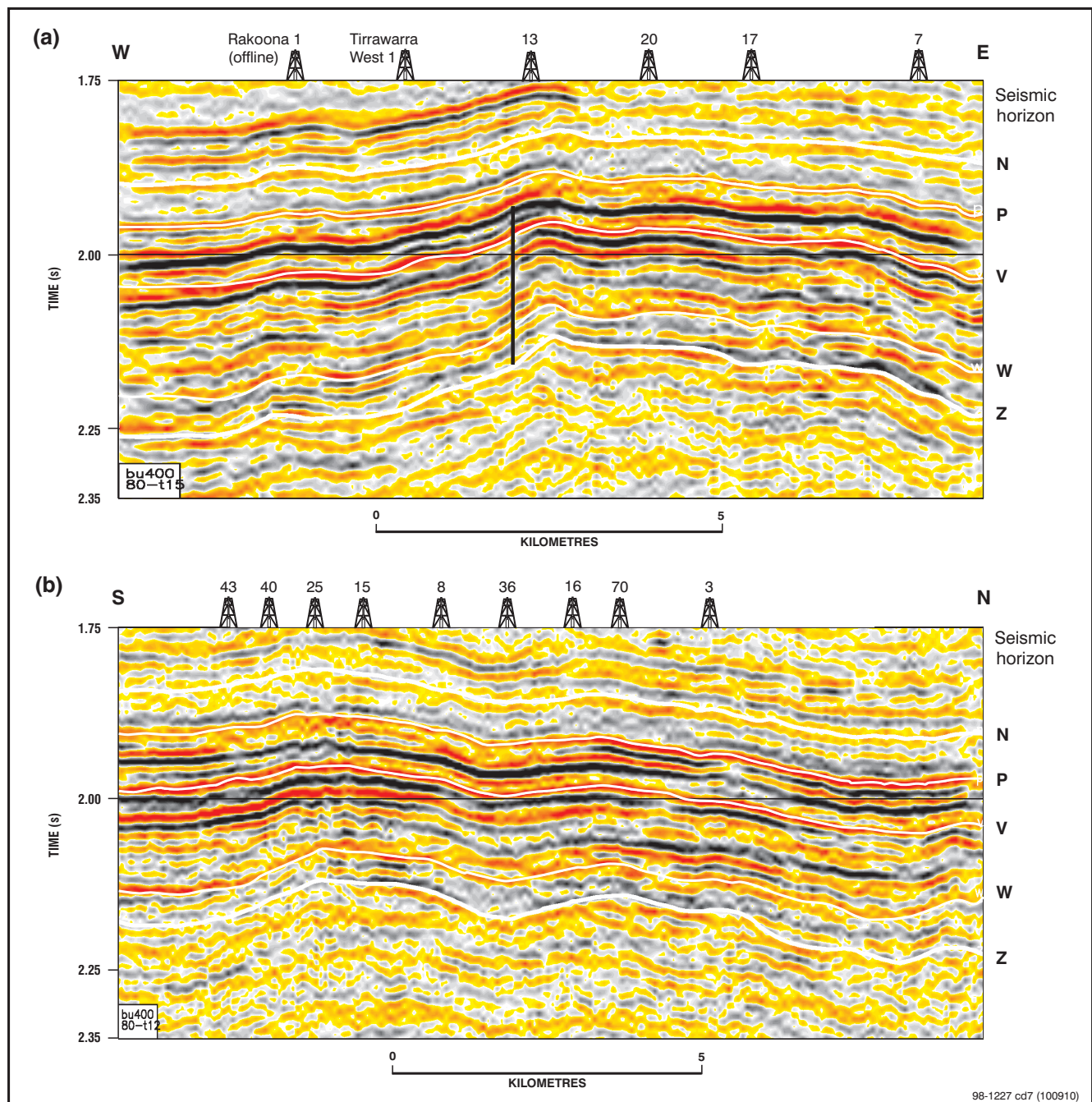


Drilling Tirrawarra 1, 1970. (Photo n021057)

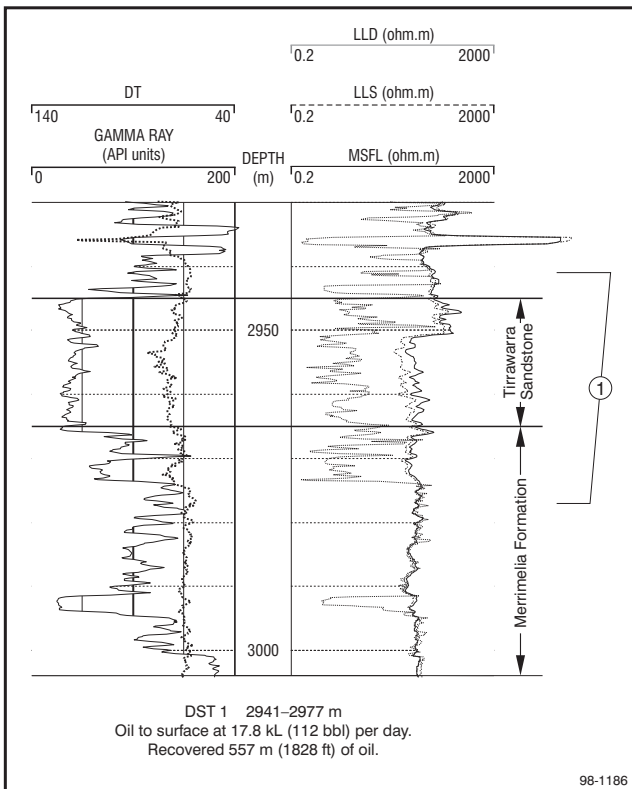
thrown to the west, which separates the field into a main part and a west part. Although the distribution of other faults is interpreted differently by various authors, all agree on the location of the main fault and its originally extensional nature. An east–west seismic section shows the fault extending into the lower Patchawarra Formation (Fig. 12.2a), and a north–south seismic section (Fig. 12.2b) illustrates the two culminations of the main field. Gamma ray, sonic and resistivity logs across the Merrimelia Formation, Tirrawarra Sandstone and lower Patchawarra Formation in Tirrawarra 70 are shown in Figure 12.3. Tirrawarra 70 oil appraisal well was completed in 1992 on the northern dome of the main field. The oil flow rate was good enough to encourage expansion of the EOR scheme into this area and the well was fracture stimulated before

**Table 12.1** Production, reservoir and fluid data, Tirrawarra oil field.

<b>Formation:</b>	Tirrawarra Sandstone
<b>Original oil-in-place:</b>	3.757 x 10 <sup>6</sup> kL (23.63 mmbbl)
<b>Cumulative production (31.1.98):</b>	3.765 x 10 <sup>6</sup> kL (23.68 mmbbl)
<b>Average net pay:</b>	18 m
<b>Area:</b>	4858 ha (12 004 acres)
<b>Average porosity:</b>	10%
<b>Average permeability:</b>	1 mD
<b>Initial oil saturation:</b>	70%
<b>Solution gas oil ratio:</b>	481 sm <sup>3</sup> /sm <sup>3</sup>
<b>Initial pressure:</b>	29 517 kPa
<b>Reservoir temperature:</b>	141°C
<b>Formation volume factor:</b>	2.9 m <sup>3</sup> /sm <sup>3</sup>
<b>Viscosity:</b>	0.09 cp



**Fig. 12.2** Seismic sections through the Tirrawarra Field. (a) East–west line 80-T15, (b) north–south line 80-T12. Top Tirrawarra Sandstone is the W horizon. Line of sections are located in Figure 12.1.



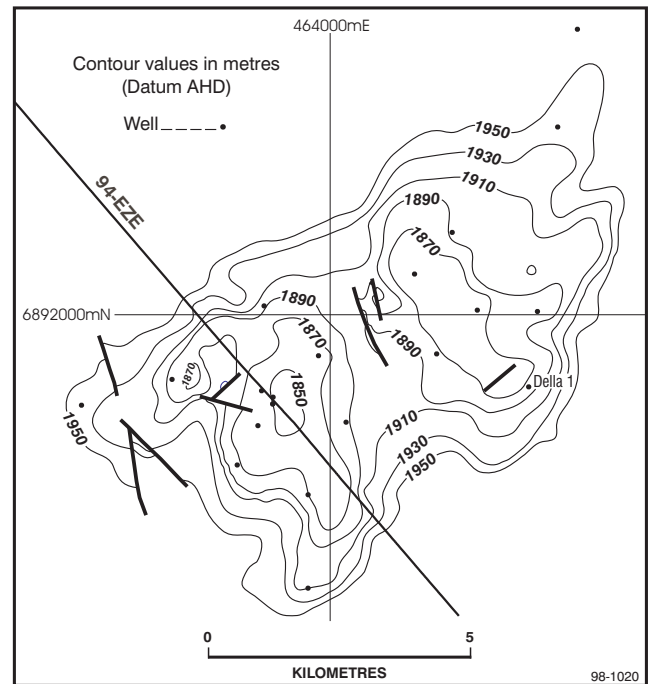
**Fig. 12.3** Wireline logs and drillstem test data in the Tirrawarra Sandstone and Merrimelia Formation, Tirrawarra 70.

being placed on production. Since the end of 1996, the EOR scheme has been discontinued with the cessation of ethane injection. There is insufficient ethane available to supply the ICI petrochemical plant in Sydney, for use as a peak period sales gas, as well as an EOR injection fluid. Carbon dioxide is considered too expensive to use as an alternative injection fluid.

## DELLA FIELD

Gas was discovered in the Late Permian Toolachee Formation at Della in 1970, three months after discovery of oil at Tirrawarra (Pyecroft, 1973; Battersby, 1976). Della Field is 40 km east of Moomba on the southern margin of the Nappamerri Trough on an ~8 km long northeast-trending structure consisting of two culminations separated by a saddle (Fig. 12.4). Della is a high-relief basement ridge that had been uplifted and eroded prior to deposition of the Toolachee Formation (Battersby, 1976). As a result, the Toolachee Formation disconformity overlies weathered Ordovician Shale (Dullingari Group) on the highest culmination, with Early Permian strata wedging in downflank to the southeast. As shown on seismic section 94-EZE (Fig. 12.5), Permian strata thicken dramatically into the Nappamerri Trough on the northern side of a major boundary fault. Evolution of the northern margin of the Della structure is described in Chapter 5 and illustrated in Figure 5.11.

Development drilling on Della Field commenced in 1979, with initial production from the Toolachee Formation. The underlying Patchawarra Formation was thought to be water filled even though minor oil had been recovered during drillstem testing in Della 1 (Battersby, 1976). However, Della 9 drilled in 1980 tested 81 705 m<sup>3</sup> (2.9



**Fig. 12.4** Depth structure contour map on top Toolachee Formation, Della Field.

mmcf) of gas per day from the Patchawarra and was completed as a Patchawarra gas producer. The Patchawarra and Toolachee reservoirs are in pressure communication and have a common gas–water contact. Della Field gas statistics are listed in Table 12.2.

**Table 12.2** Production, reservoir and fluid data, Della gas field.

<b>Formation:</b>	Co-mingled Toolachee and Patchawarra Formations
<b>Cumulative production (31.1.98):</b>	18 128 x 10 <sup>6</sup> m <sup>3</sup> (643 bcf)
<b>Production commenced:</b>	1.2.80
<b>Initial pressure:</b>	19 986 kPa
<b>Reservoir temperature:</b>	134°C
<b>Density:</b>	0.5055 kg/m <sup>3</sup>
<b>Ethane content:</b>	0.0217 m <sup>3</sup> /m <sup>3</sup>
<b>LPG content:</b>	36.668 kL/10 <sup>6</sup> m <sup>3</sup> (6.5 bbl/mmcf)
<b>Condensate content:</b>	18.036 kL/10 <sup>6</sup> m <sup>3</sup> (3.2 bbl/mmcf)

The gas in both the Toolachee and Patchawarra Formations is trapped in channel and point-bar sandstones characterised by upward-fining cycles capped with shale and coal. Lateral accretion (channel belt) and vertical accretion (floodplain) deposits were mapped by Gravestock and Morton (1984). Gamma ray, sonic and resistivity curves from Della 10 illustrate the cyclic nature of the Permian formations (Fig. 12.6). Della Field sandstone reservoirs have relatively high average porosity and permeability which is reflected in excellent flow rates on test. Della Field has produced 18 x 10<sup>9</sup> m<sup>3</sup> (643 bcf) of raw gas to date (Fig. 12.7).

## TOOLACHEE FIELD

Toolachee 1 was drilled in 1969 and flowed gas on drillstem test at rates to 197 218 m<sup>3</sup> (7 mmcf) per day (Battersby, 1976). Gas is produced from the Early Permian Patchawarra and Epsilon Formations. The Toolachee Field,

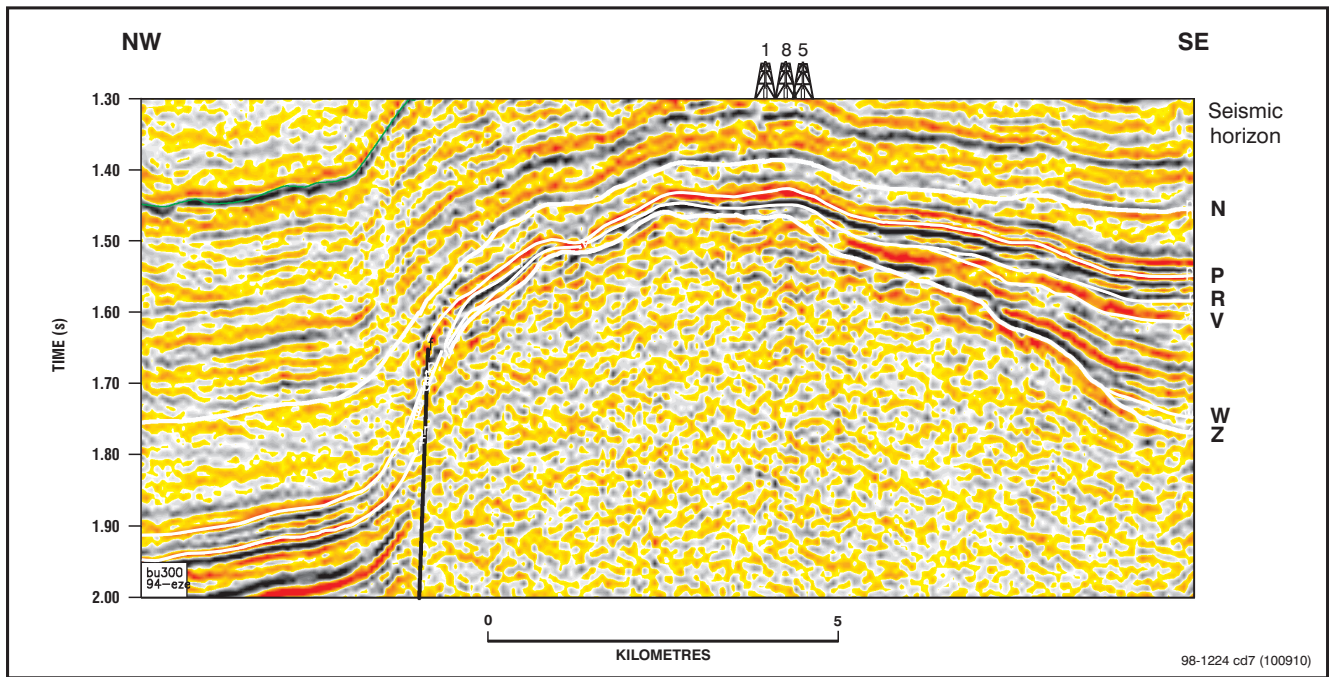


Fig. 12.5 Seismic section 94-EZE through Della Field. Top Toolachee Formation is the P horizon; top Patchawarra Formation is the V horizon. Line of section is located in Figure 12.4.

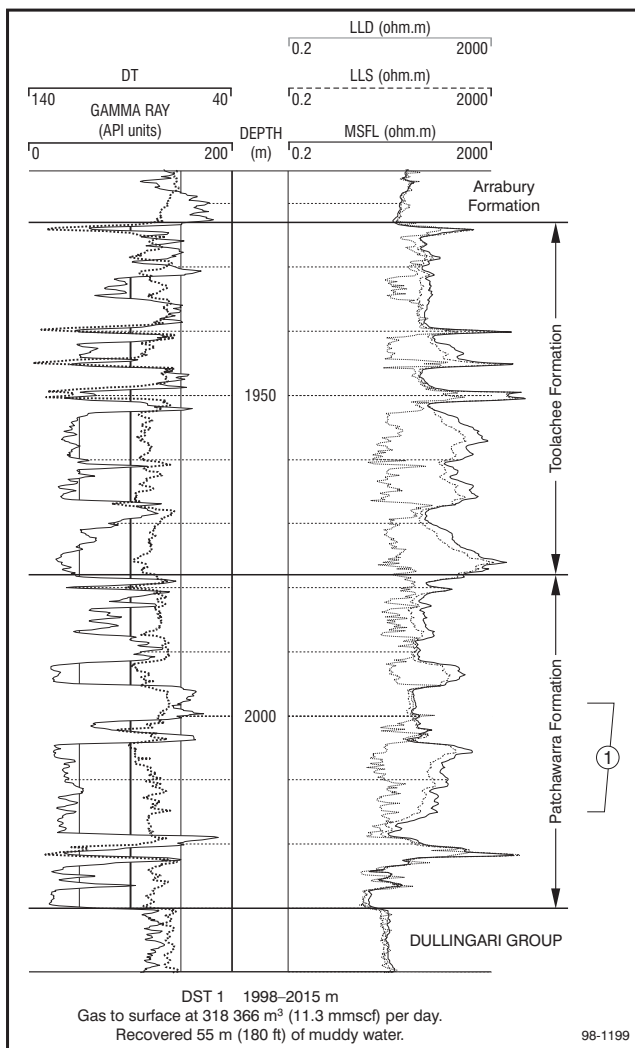


Fig. 12.6 Wireline logs across the Permian section, and Patchawarra Formation drillstem test data, Della 10.

68 km southeast of Moomba, is the fifth largest gas field in the Cooper Basin and consists of a number of elongated domes or ridges with multiple culminations (Fig. 12.8). The north-south strike of the ridges is distinctive (Stuart, 1976) and suggests that the underlying basement block differs from adjacent blocks either in composition or in deformation style. An east-west seismic section shows a number of minor faults with displacements of 5–10 m at the base of the Cooper Basin (Fig. 12.9). Thinning of the V–Z time interval is attributed to infill of topographic relief rather than to fault growth, although minor fault reactivation and slight Tertiary folding are also evident.

The wet-gas-bearing Patchawarra Formation consists of a succession of stacked fluvial channel and floodplain sediments which overlapped the ridges from east to west (Morton, 1983). These reservoirs are not in pressure communication and have distinct gas-water contacts.

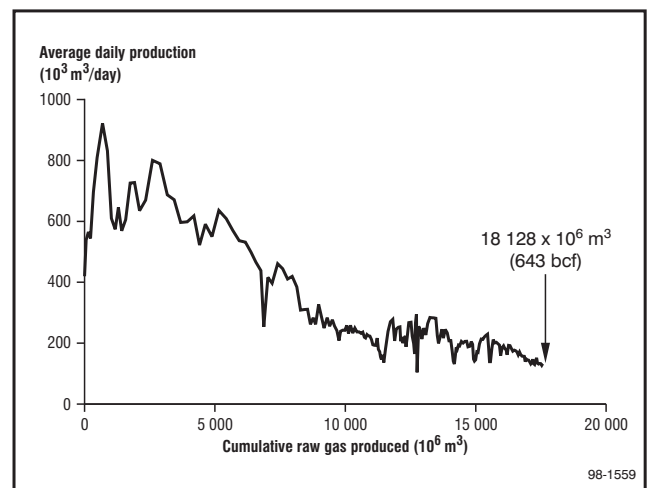


Fig. 12.7 Decline curve for co-mingled gas in the Toolachee and Patchawarra Formations, Della Field.

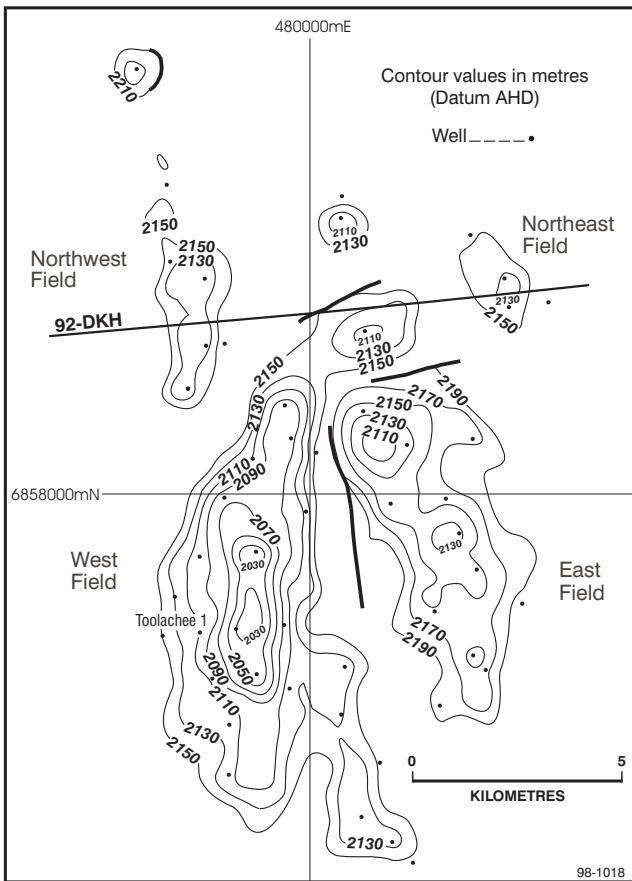


Fig. 12.8 Depth structure contour map on top Patchawarra Formation, Toolachee Field.



Drilling, Toolachee Field 1984. (Photo 43367)

Wireline logs of the Patchawarra interval in Toolachee 13 (Fig. 12.10) clearly illustrate the cyclic nature of sedimentation. Appraisal drilling led to the discovery of significant gas and condensate in the Epsilon and Daralingie

Formations although the overlying Toolachee Formation is generally wet. A decline curve for the Patchawarra Formation in the Toolachee East structure is shown in Figure 12.11, and additional gas data are listed in Table 12.3.

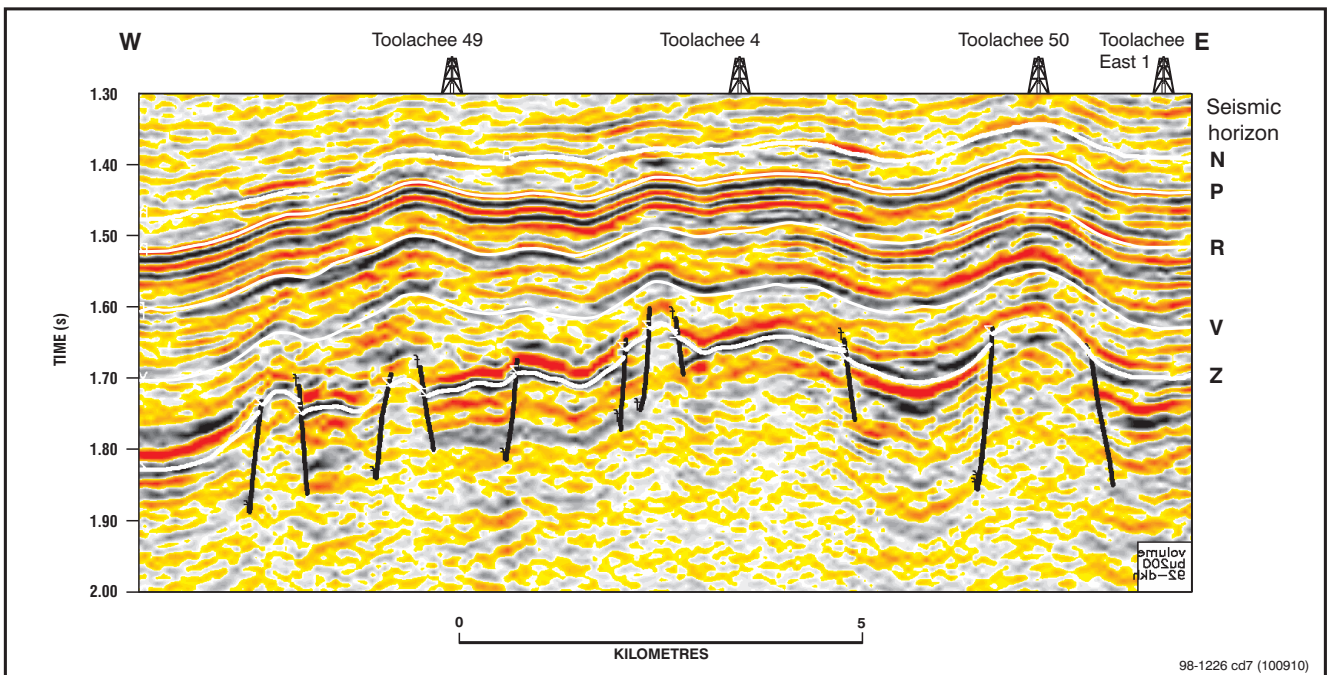


Fig. 12.9 Seismic section 92-DKH through the Toolachee Field. Top Patchawarra Formation is the V horizon. Line of section is located in 12.7.

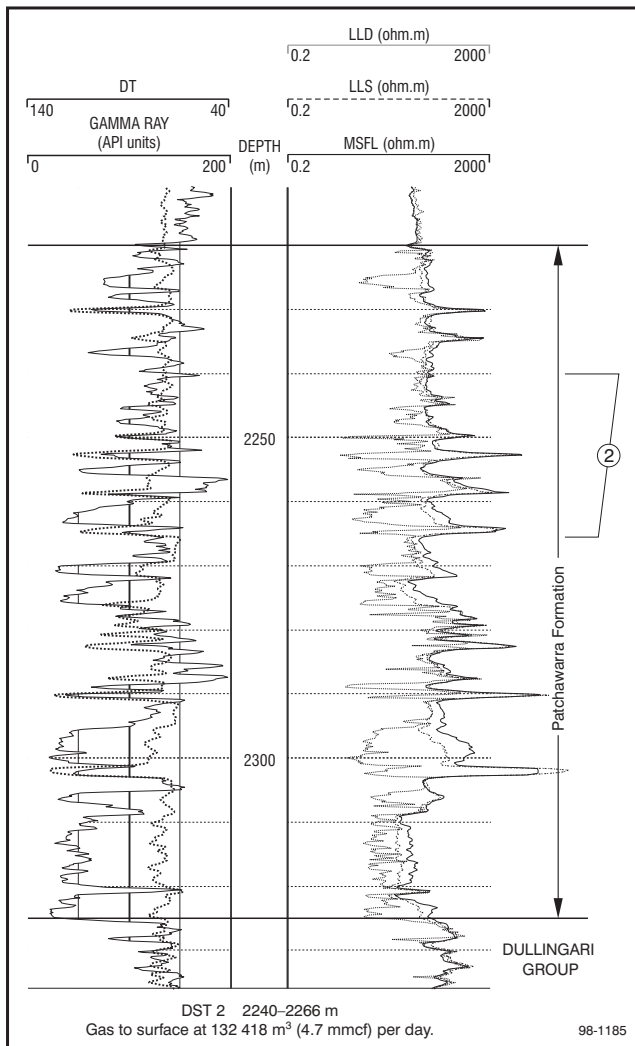


Fig. 12.10 Wireline logs across the Patchawarra Formation, and drillstem test data from the upper sandstone reservoirs, Toolachee 13.

Table 12.3 Production, reservoir and fluid data, Toolachee East gas field.

<b>Formation:</b> Epsilon Formation
<b>Cumulative production (31.1.98):</b> 22.52 x 10 <sup>6</sup> m <sup>3</sup> (799 mmcf)
<b>Production commenced:</b> 1.5.88
<b>Initial pressure:</b> 20 779 kPa
<b>Reservoir temperature:</b> 126°C
<b>Density:</b> 0.7307 kg/m <sup>3</sup>
<b>Ethane content:</b> 0.0957 m <sup>3</sup> /m <sup>3</sup>
<b>LPG content:</b> 285.456 kL/10 <sup>6</sup> m <sup>3</sup> (50.6 bbl/mmcf)
<b>Condensate content:</b> 224.296 kL/10 <sup>6</sup> m <sup>3</sup> (39.7 bbl/mmcf)
<b>Formation:</b> Patchawarra Formation
<b>Cumulative production (31.1.98):</b> 2713.34 x 10 <sup>6</sup> m <sup>3</sup> (96 bcf)
<b>Production commenced:</b> 1.5.84
<b>Initial pressure:</b> 22 241 kPa
<b>Reservoir temperature:</b> 141°C
<b>Density:</b> 0.5916 kg/m <sup>3</sup>
<b>Ethane content:</b> 0.0590 m <sup>3</sup> /m <sup>3</sup>
<b>LPG content:</b> 88.904 kL/10 <sup>6</sup> m <sup>3</sup> (15.8 bbl/mmcf)
<b>Condensate content:</b> 38.897 kL/10 <sup>6</sup> m <sup>3</sup> (6.9 bbl/mmcf)

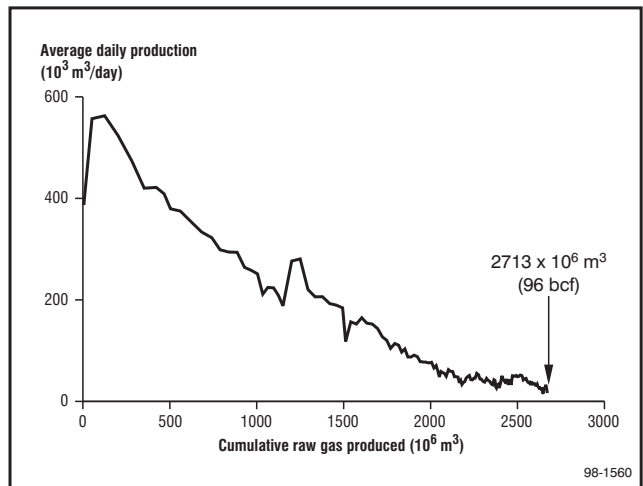


Fig. 12.11 Decline curve for gas in the Patchawarra Formation, Toolachee East Field.

## MUNKARIE FIELD

The Munkarie Field was discovered in 1978 with the drilling of Munkarie 1 which found gas trapped in the Early Permian Epsilon and Patchawarra Formations (Skerman, 1978).

The Munkarie structure is 83 km southeast of Moomba and consists of a simple dome with a northeast to north axial trend (Fig. 12.12). A seismic section (Fig. 12.13) emphasises the parallelism of most reflectors with marginal thinning over the crest of the dome in the V-Z (top Patchawarra Formation to top Warburton Basin) time interval.

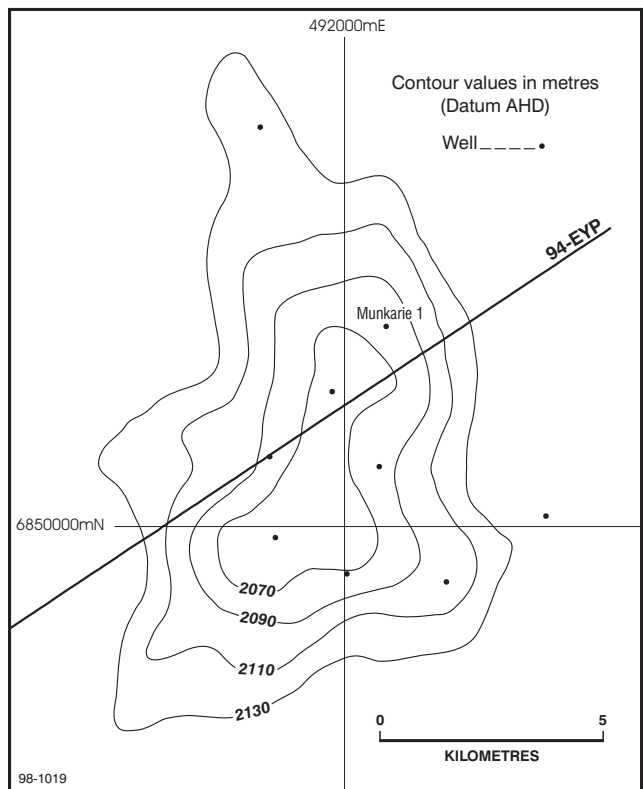
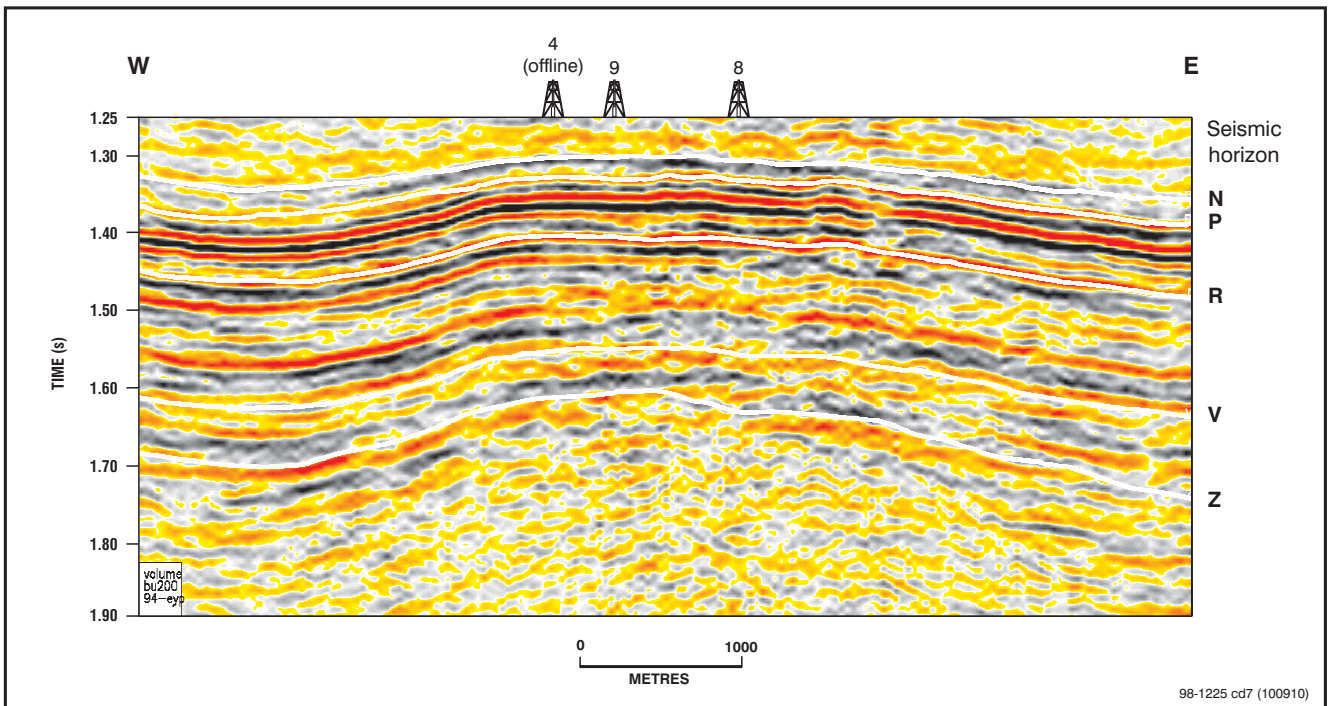


Fig. 12.12 Depth structure contour map on top Patchawarra Formation, Munkarie Field.

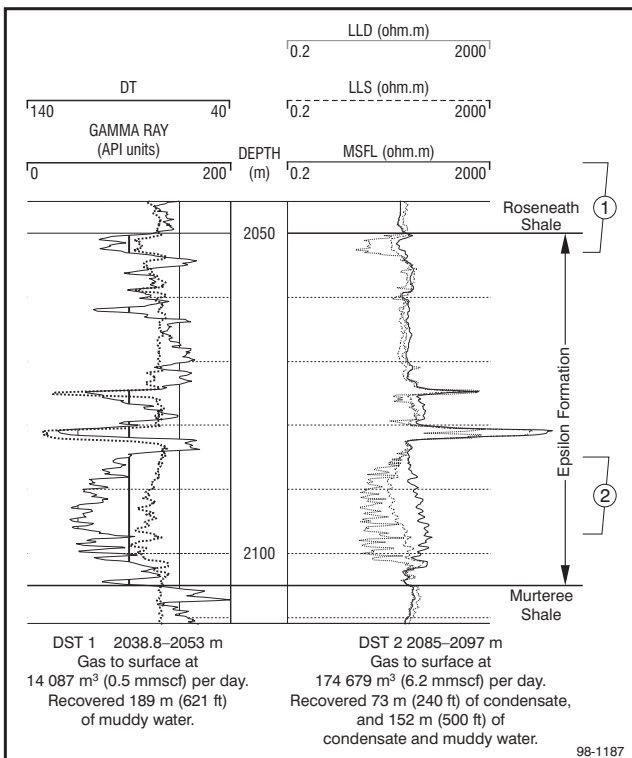


**Fig. 12.13** Seismic section 94-EYP through the Munkarie Field. Top Patchawarra Formation is the V horizon. Line of section is located in Figure 12.10.

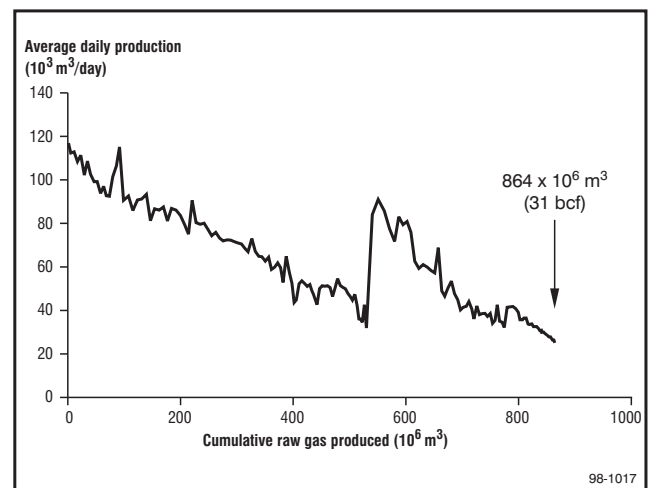
Munkarie 2, drilled in 1982, intersected a sand barrier complex in the lower part of the Epsilon Formation which flowed gas at 174 679 m<sup>3</sup> (6.2 mmscf) per day on test. Gamma ray, sonic and resistivity curves are shown for the Munkarie 2 Epsilon Formation interval in Figure 12.14. The barrier bar facies has also been recognised in the Toolachee Field (Morton, 1983), and similar transgressive-regressive

sands have been recognised as far away as Big Lake Field (Stuart, 1976; Taylor *et al.*, 1991; Fairburn, 1992). Munkarie 4, drilled in 1984, discovered gas in the Toolachee Formation which had previously been regarded as wet. Production from this unit has been minor. A decline curve of raw gas produced from the Epsilon Formation in the Munkarie Field is shown in Figure 12.15.

Gas from the Patchawarra Formation is condensate rich, and moderate amounts of condensate are also produced from the Epsilon Formation. Gas properties are shown in Table 12.4. Nine wells have been drilled on the Munkarie structure.



**Fig. 12.14** Wireline logs and drillstem test data in the Epsilon Formation, Munkarie 2.



**Fig. 12.15** Decline curve for gas in the Epsilon Formation, Munkarie Field.

**Table 12.4** Production, reservoir and fluid data, Munkarie gas field.

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**Formation:** Epsilon Formation  
**Cumulative production (31.1.98):**  $864.39 \times 10^6 \text{ m}^3$  (31 bcf)  
**Production commenced:** 1.2.85  
**Initial pressure:** 20 882 kPa  
**Reservoir temperature:** 134°C  
**Density:** 0.5740 kg/m<sup>3</sup>  
**Ethane content:** 0.0710 m<sup>3</sup>/m<sup>3</sup>  
**LPG content:** 144.269 kL/10<sup>6</sup> m<sup>3</sup> (25.6 bbl/mmcf)  
**Condensate content:** 26.809 kL/10<sup>6</sup> m<sup>3</sup> (4.8 bbl/mmcf)

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**Formation:** Patchawarra Formation  
**Cumulative production (31.1.98):**  $2304.89 \times 10^6 \text{ m}^3$  (82 bcf)  
**Production commenced:** 1.2.85  
**Initial pressure:** 21 786 kPa  
**Reservoir temperature:** 139°C  
**Density:** 0.6364 kg/m<sup>3</sup>  
**Ethane content:** 0.07557 m<sup>3</sup>/m<sup>3</sup>  
**LPG content:** 159.319 kL/10<sup>6</sup> m<sup>3</sup> (28.2 bbl/mmcf)  
**Condensate content:** 126.968 kL/10<sup>6</sup> m<sup>3</sup> (22.5 bbl/mmcf)

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# ECONOMICS of GAS FIELD DEVELOPMENTS

R.C.M. McDonough  
Chapter 13

## INTRODUCTION

### Existing infrastructure

Most Cooper Basin producing oil and gas fields lie within a 75 km radius of the main processing plant at Moomba (Fig. 1.2). A considerable network of flowlines and trunklines connects fields to satellite facilities and thence to the processing plant at Moomba. Cooper Basin gas may comprise over 35% by volume of CO<sub>2</sub>, so an important function of the Moomba plant is CO<sub>2</sub> removal. The plant also removes petroleum liquids and water to produce sales gas. Eleven gas satellites knock out free water and provide compression. Nine oil satellites remove free water from the oil before piping to Moomba.

The Moomba plant is designed to process 25.4 x 10<sup>6</sup> m<sup>3</sup> (900 mmscf) of raw gas and 6000 kL (42 000 bbl) of condensate and crude per day. A mixed stream of crude, condensate, LPG and a small volume of ethane is transported 659 km via pipeline to Port Bonython near the head of the Spencer Gulf (Fig. 1.1), where the streams are separated and sold.

Sales gas is sold from the Moomba plant to markets in Adelaide and Sydney. A second pipeline to Sydney transports ethane feedstock to the ICI petrochemical plant at Botany. The bulk of the remaining ethane is used in enhanced oil recovery projects; a minor amount is used as fuel at Port Bonython.

### Access to infrastructure

The *Natural Gas Pipelines Access Act 1995* and the *National Gas Pipelines (South Australia) Act 1998* provide a right of access to licensed gas pipelines in South Australia. Access is subject to available capacity and negotiation with the pipeline owners, with arbitration available if negotiations fail. The *Petroleum Act 1940* also provides a mechanism for access to all licensed pipelines (including oil pipelines). None of the raw gas gathering trunklines in the Cooper Basin are required to be licensed (except for the pipeline from Ballera in South-West Queensland to Moomba and the Stokes to Mettika trunkline).

There is currently no legislative requirement to provide access to other upstream infrastructure beyond that provided in Part IIIA of the *Trade Practices Act 1974* (Cwlth). This issue is under discussion between jurisdictions as part of the current gas reform process. There is uncertainty as to whether these provisions apply to upstream petroleum facilities. However, there is nothing to prevent a third party entering into negotiations for access. Assuming that there is spare capacity in the system, the key issue will be the price paid for access to that capacity. The economic study of gas

development in the Cooper Basin, by the former Mines and Energy Resources South Australia, was initiated to address this issue.

### Access to markets

Gas provides ~75% of South Australia's primary energy needs. Gas is used directly by domestic, commercial and industrial consumers, and is also used to generate ~50% of the State's electricity requirements. Current South Australian supply contracts begin to expire from 2004, although supplementary supplies have been obtained for part of consumer need beyond that date. Contracts to supply New South Wales markets fall below requirements from ~2001. Meanwhile, forecast gas demands are expected to rise with the introduction of competitive energy markets, and increased industrial commercial expansion (Fig. 13.1). In addition, in a deregulated market there are opportunities for gas swapping arrangements which will allow gas to be sold into markets not physically connected to the field. A Cooper Basin explorer will have the option to sell gas into Queensland or Victorian markets. Opportunities therefore exist for new discoveries to be sold into expanding markets.

### Economic study

A study of the cost of development of new discoveries in the Cooper Basin by parties independent of the current Cooper Basin Joint Venturers was carried out by McDonough (1997a, b).

A consulting engineering firm was engaged to provide costs to feasibility study level for the following development scenarios:

- gas field development totally independent of the current processing facilities, with and without recovery of LPG

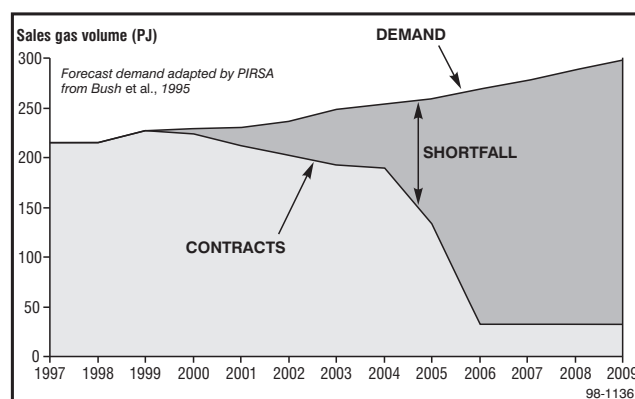


Fig. 13.1 Forecast sales gas demand of New South Wales and South Australia versus current contracts.

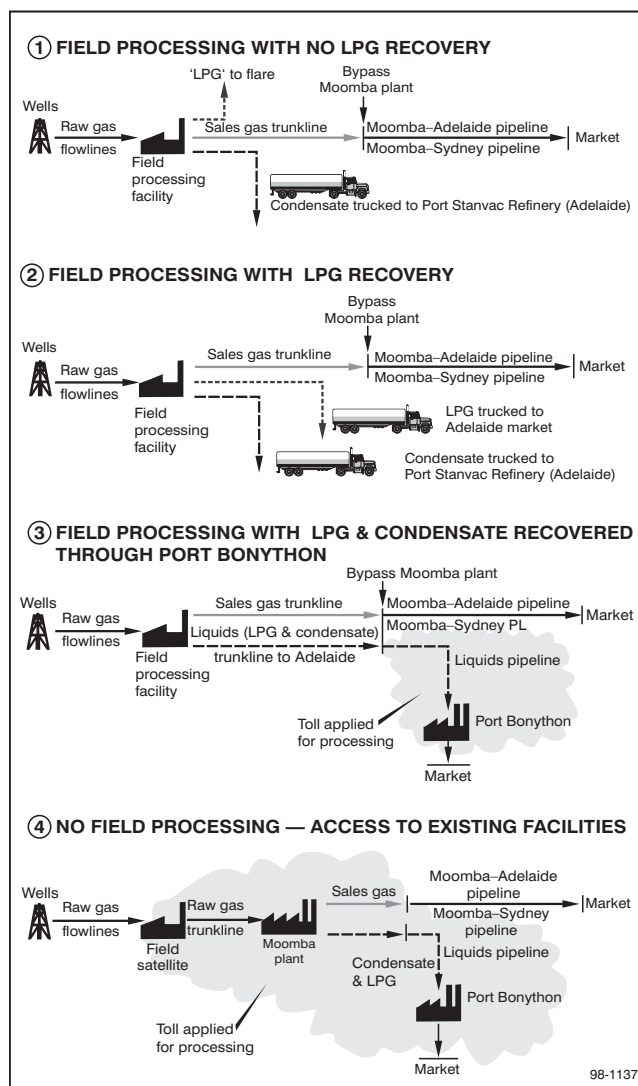


Fig. 13.2 Processing options for gas field discoveries post-1999.

- gas field development with access to the liquids pipeline and Port Bonython plant only (i.e. excluding the Moomba plant and satellite facilities)
- gas field development with access to all existing infrastructure

The different processing options are illustrated in Figure 13.2.

Cost studies were based on gas field production profiles which accounted for field size, deliverability, raw gas composition and distance from the head of the Moomba–Adelaide and Moomba–Sydney gas pipelines. Cost estimates were also provided for replacement of the existing facilities (satellite, trunkline, Moomba plant, liquids pipeline and Port Bonython plant), based on current technology. No optimisation of design was carried out and it was also assumed that exploration costs were sunk (cf. Ch. 14).

These data were used in cashflow studies of a range of gas field development options to provide estimates of:

- indicative tolling costs through the existing facilities using the replacement cost assuming modern technology and future estimated throughputs (a deprival value approach)

- minimum economic field size based on either stand-alone development or access to existing facilities

## DISCUSSION

### Cost of stand-alone processing

If access to existing facilities is not available or cannot be negotiated, new gas discoveries will need to be developed on a stand-alone basis. Obviously, it is not possible to anticipate the characteristics of every discovery made. Discovery scenarios were therefore chosen to describe an ‘envelope’ of possibilities, within which costs for likely discoveries will fall. Parameters which will impact on field development requirements and their values chosen are shown in Table 13.1. The distribution of gas wetness and CO<sub>2</sub> content are shown in Figures 8.1 and 8.2 respectively.

For this study, fields with high CO<sub>2</sub> have a CO<sub>2</sub> content greater than 30% by volume. Low CO<sub>2</sub> fields are those with a CO<sub>2</sub> content below 15% by volume. High liquids fields contain greater than 0.22 kL/m<sup>3</sup> (50 bbl/mm scf) of C<sub>5+</sub> and 0.18 kL/m<sup>3</sup> (40 bbl/mm scf) of LPG. Low liquids fields contain less than 0.02 kL/m<sup>3</sup> (5 bbl/mm scf) of C<sub>5+</sub> and 0.09 kL/m<sup>3</sup> (20 bbl/mm scf) of LPG. Fixed parameters were based on typical Cooper Basin figures.

It was assumed that a field would be fully developed before compression was installed. In addition, fields would be brought on-line in the year after they were discovered. Capital and operating costs were provided for the following:

- wellhead facilities and flowlines
- access roads and field camp
- compression
- processing plant
- trunklines
- condensate loading transportation

The economics of developing a cluster of small fields within a 10 km radius of a central processing field were also investigated (Table 13.1). For these cases, the maximum original gas-in-place (OGIP) of an individual field is 280 x 10<sup>6</sup> m<sup>3</sup> (10 bcf), with a maximum of five fields and a total OGIP of 1420 x 10<sup>6</sup> m<sup>3</sup> (50 bcf).

### Deprival value pricing

It can be argued that to achieve efficient use of resources, the pricing regime for each section of the gas supply chain should be set by a competitive market or be set so as to imitate a competitive market.

Where a ‘physical’ monopoly exists, pricing principles for access to that facility must imitate a competitive market. In a truly competitive market there will be many facilities competing for business, and the price for access will fall between the operating cost of a facility (when there is abundant spare capacity in the system) and the deprival value cost of the facility (when there is no spare capacity in the system). To imitate a free market, the players must be free to negotiate within these bounds.

In its simplest form, the deprival value approach values the utility of a facility. This value is not the literal replacement cost of the existing plant (i.e. the cost to replicate the physical facility), but rather the cost of

**Table 13.1** Assumed parameters for new gas field discoveries.

Parameter	Value
1. Raw gas composition	high liquids, high CO <sub>2</sub> high liquids, low CO <sub>2</sub> low liquids, high CO <sub>2</sub> low liquids, low CO <sub>2</sub>
2. Field size	single field OGIP = 2830 x 10 <sup>6</sup> m <sup>3</sup> (100 bcf) single field OGIP = 1420 x 10 <sup>6</sup> m <sup>3</sup> (50 bcf) single field OGIP = 280 x 10 <sup>6</sup> m <sup>3</sup> (10 bcf) multiple fields (located within 10 km radius of central field), individual field OGIP = 280 x 10 <sup>6</sup> m <sup>3</sup> (10 bcf), total OGIP = 570, 850, 1130 and 1420 x 10 <sup>6</sup> m <sup>3</sup> (20, 30, 40 and 50 bcf)
3. Maximum depletion rates	5% of OGIP/yr 10% of OGIP/yr
4. Gas processing requirements	sales gas specification according to <i>Natural Gas (Interim Supply) Act 1985</i> LPG flared or LPG recovered
5. Distance to transmission pipeline	20 km, 50 km, 100 km
6. Distance to existing infrastructure	20 km
7. Initial well rate	~210 x 10 <sup>6</sup> m <sup>3</sup> /day (6 mmscfd)
8. Well density	280 x 10 <sup>6</sup> m <sup>3</sup> /well (10 bcf/well)
9. Reservoir properties	depth = 2440 m, temperature = 121°C, pressure = 24.1 MPa (abs), flow capacity = 30.5 mD.m
10. Compression	Stage 1 = 7.9 MPa (gauge), Stage 2 = 3.8 MPa (gauge), Stage 3 = 1.7 MPa (gauge)
11. Transmission pipeline delivery pressure	6.9 MPa (abs)

replacing the service which is provided. It is assumed here that in a competitive market where little or no spare capacity exists, this is the cost of building a new facility using modern technology and current capacity requirements.

### Cost of processing through existing facilities

The capital cost of replacing the utility of the existing facilities was also estimated in A\$1995. This in turn was used to estimate both upper and lower limits on tolls. The upper limit is the price per unit volume of raw gas which must be charged to earn the plant owner's return on capital investment made to replace the utility of the existing facility. The lower limit is the operating cost of the plant. An independent producer will require access to:

- a satellite facility for initial water removal and compression (a typical large satellite with a capacity of 1130 x 10<sup>6</sup> m<sup>3</sup>/yr (40 bcf/yr) is assumed)
- a trunkline to the Moomba plant (a trunkline length of 50 km is assumed)
- the Moomba plant itself, producing sales gas, ethane, LPG and condensate (the capacity required for the Moomba plant is based on the contract sales gas volume in 1999 (~215 PJ/yr), and the associated ethane and liquids production)
- liquids transport via the Moomba – Port Bonython liquids line
- processing and unloading at the Port Bonython plant

Based on the capital and operating costs required to provide this entire service, the deprival value toll was calculated to fall in the range \$41 100 – 58 600/10<sup>6</sup> m<sup>3</sup> (\$1200–1700/mmscf) of raw gas processed. The facility

operating cost is estimated to be of the order of \$13 500/10<sup>6</sup> m<sup>3</sup> (\$380/mmscf) of raw gas.

The deprival value toll of processing liquids through the liquids pipeline and Port Bonython plant alone is estimated to be ~\$70/kL (\$11.10/bbl).

It should be noted that no allowance is made for apportionment of the toll price based on the processing requirements for differing raw gas compositions. For example, a liquids-rich, high CO<sub>2</sub> gas will require processing through the entire system, while liquids-poor, low CO<sub>2</sub> gas may require virtually no processing at all.

### Cash flow analyses

The Net Present Value (NPV) of pre-tax cash flows achieved by developing gas fields under the various processing options was calculated, based on costs and prices in A\$1995. A real discount rate of 12.5% was used to calculate the NPV. The sales gas price at the head of the Moomba–Adelaide and Moomba–Sydney pipelines was assumed to be \$2.00/GJ. This was set at less than the current price to account for the possibility that gas prices will be driven down in a competitive market. Liquids prices are based on current domestic market prices. Costs of acquiring additional seismic were ignored, based on the assumption that the current seismic coverage in the Cooper Basin is sufficient. Exploration failures (i.e. unsuccessful wildcats) were not accounted for. A wellhead royalty of 10% was taken into account in accordance with the relevant provisions of the *Petroleum Act*.

An example of the minimum economic field size (i.e. the field size for which the NPV of the pre-tax cash flow exceeds

zero) expressed in terms of million cubic metres (bcf) of recoverable raw gas for each of the cases investigated is shown in Table 13.2. The results assume that the field is located 50 km from the Moomba plant and 20 km from the nearest gas satellite. Minimum economic field size is quoted as a range to reflect the fact that the values presented are subject to uncertainty, depending on exploration company costs and rates of return, reservoir and gas properties, timing of developments, etc. The numbers presented are therefore indicative rather than definitive. However, they do provide an indication of relative economic field sizes for a given range of processing option (see also Fig. 13.3).

Given the assumptions listed, the following conclusions may be drawn:

- The economic viability of any discovery is highly dependent on the CO<sub>2</sub> and liquids content of the raw gas stream. Fields rich in liquids and low in CO<sub>2</sub> are the most economically attractive.
- If access to existing facilities (i.e. satellite–trunkline – Moomba plant – liquids pipeline – Port Bonython plant) is provided, liquids-rich fields with recoverable raw gas greater than 110–225 x 10<sup>6</sup> m<sup>3</sup> (4–8 bcf) will be economic (if situated within 20 km of an existing satellite, which is assumed to be 50 km from Moomba plant).
- If stand-alone facilities are used to develop a field, liquids-rich fields with recoverable raw gas exceeding 280–420 x 10<sup>6</sup> m<sup>3</sup> (10–15 bcf) will be economic (if situated within 50 km of a sales gas pipeline).
- Assuming the toll will fall in the range of \$41 100 – 58 600/10<sup>6</sup> m<sup>3</sup> (\$1200–1700/mmscf), it is always more economic to access the existing facilities than to build stand-alone facilities. The corollary of this is that if facilities access is allowed, smaller discoveries are economic. This conclusion is entirely to be expected, as the initial economic decision was to build the Moomba plant rather than a series of small plants scattered over the region.
- As a rule, the minimum economic field size with access to existing facilities is at least half of the minimum economic field size for stand-alone facilities (assuming similar processing requirements).
- Other factors which impact on economic viability are field size, deliverability and distance from existing facilities.
- For fields which are low in liquids, processing through existing facilities is generally uneconomic in the range of \$41 100 – 58 600/10<sup>6</sup> m<sup>3</sup> (\$1200–1700/mmscf), which is the expected toll range. However, it may be argued that lean fields would attract a lesser toll, as they would not require processing through the liquids pipeline and Port Bonython. (Conversely, one could then argue for a higher toll on rich fields to ensure that the return on total investment is constant.)
- For liquids-rich fields with an OGIP as large as 1000 x 10<sup>6</sup> m<sup>3</sup> (35 bcf; recoverable raw gas ~700 x 10<sup>6</sup> m<sup>3</sup> (25 bcf)), it is uneconomic to develop fields on a

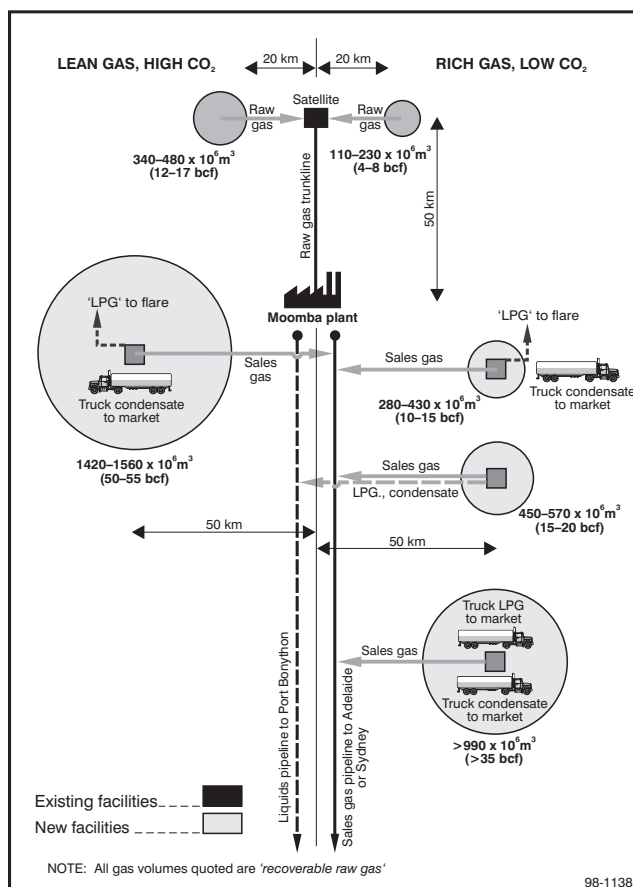


Fig. 13.3 Schematic of limiting field sizes under various composition and processing scenarios (assumes 10% original gas-in-place depletion rate).

stand-alone basis unless LPG is flared. However, if facilities access is granted, the economics of the development are significantly improved and LPG is recovered. Therefore, access to existing facilities is desirable on both economic and resource conservation grounds.

- Access to existing facilities is also desirable on environmental grounds, as it removes the requirement for a proliferation of independent facilities, thereby minimising the environmental impact of new discoveries.
- For multiple fields clustered within a 10 km radius with OGIP of 280 x 10<sup>6</sup> m<sup>3</sup> (10 bcf) per field (recoverable raw gas 200–230 x 10<sup>6</sup> m<sup>3</sup> (7–8 bcf) per field), between two and five fields can be developed economically on a stand-alone basis. Again, the actual number is dependent on the composition, with low CO<sub>2</sub>, high liquids fields being most economic.

## CONCLUSION

Provided that new gas field discoveries made after 1999 in the Cooper Basin are of sufficient volume (of the order of 700 x 10<sup>6</sup> m<sup>3</sup> (25 bcf) recoverable raw gas), they will be economic to develop on a stand-alone basis if LPG is recovered. The economics of developing small fields on a stand-alone basis is also dependent on whether or not LPG is flared. For stand-alone plants it is more economic to flare LPG than recover it. This is undesirable on both

**Table 13.2** Minimum economic field size for fields located 50 km from Moomba.

FIELD TYPE	MAXIMUM DEPLETION RATE	CO <sub>2</sub> CONTENT	LIQUIDS CONTENT	MINIMUM ECONOMIC FIELD SIZE (recoverable raw gas <sup>a, b, c, d</sup> )									
				STAND-ALONE FACILITIES				FACILITIES ACCESS (LPG recovered @)					
				LPG not recovered		LPG recovered <sup>e, f</sup>		\$35 300/ 10 <sup>6</sup> m <sup>3</sup>	(\$1000/ mmscf)	\$49 400/ 10 <sup>6</sup> m <sup>3</sup>	(\$1400/ mmscf)	\$63 600/ 10 <sup>6</sup> m <sup>3</sup>	(\$1800/ mmscf)
10 <sup>6</sup> m <sup>3</sup>	(bcf)	10 <sup>6</sup> m <sup>3</sup>	(bcf)	10 <sup>6</sup> m <sup>3</sup>	(bcf)	10 <sup>6</sup> m <sup>3</sup>	(bcf)	10 <sup>6</sup> m <sup>3</sup>	(bcf)				
single	5% of OGIP/yr	low	lean	710–850	(25–30)	not applicable	(not applicable)	450–570	(15–20)	uneconomic	(uneconomic)	uneconomic	(uneconomic)
			rich	450–570	(15–20)	710–850	(25–30)	110–230	(4–8)	110–230	(4–8)	110–230	(4–8)
single	10% of OGIP/yr	low	lean	480–620	(17–22)	not applicable	(not applicable)	280–430	(10–15)	uneconomic	(uneconomic)	uneconomic	(uneconomic)
			rich	280–430	(10–15)	450–570 <sup>g</sup>	(15–20) <sup>g</sup>	110–230	(4–8)	110–230	(4–8)	110–230	(4–8)
single	5% of OGIP/yr	high	lean	1980–2120	(70–75)	not applicable	(not applicable)	510–650	(18–23)	uneconomic	(uneconomic)	uneconomic	(uneconomic)
			rich	770–910	(27–32)	990–1130	(35–40)	110–230	(4–8)	110–230	(4–8)	110–230	(4–8)
single	10% of OGIP/yr	high	lean	1420–1560 <sup>h</sup>	(50–55) <sup>h</sup>	not applicable	(not applicable)	340–480	(12–17)	uneconomic	(uneconomic)	uneconomic	(uneconomic)
			rich	510–650	(18–23)	850–990 <sup>g</sup>	(30–35) <sup>g</sup>	110–230	(4–8)	110–230	(4–8)	110–230	(4–8)
multiple <sup>i</sup>	71 x 10 <sup>6</sup> m <sup>3</sup> /yr (2.5 bcf/yr)	low	lean	850–990	(30–35)	not applicable	(not applicable)	marginal <sup>j</sup>	(marginal) <sup>j</sup>	uneconomic	(uneconomic)	uneconomic	(uneconomic)
			rich	280–430	(10–15)	570–710	(20–25)	200–430	(7–15)	200–430	(7–15)	200–430	(7–15)
multiple <sup>i</sup>	71 x 10 <sup>6</sup> m <sup>3</sup> /yr (2.5 bcf/yr)	high	lean	uneconomic	(uneconomic)	not applicable	(not applicable)	marginal <sup>j</sup>	(marginal) <sup>j</sup>	uneconomic	(uneconomic)	uneconomic	(uneconomic)
			rich	930–1080	(33–38)	1190–1390	(42–49)	200–430	(7–15)	200–430	(7–15)	200–430	(7–15)

a Based on project NPV calculated at 12.5% real discount rate.

b Gas price at head of pipeline \$2.00/GJ, LPG price delivered to Adelaide \$335/t, condensate price at Adelaide Refinery \$160/kL (\$25/bbl). All prices are in A\$1995.

c Gas field is 50 km from Moomba and 20 km from nearest satellite.

d Recoverable raw gas based on recovery factor from nearest profitable case (generally 1400 x 10<sup>6</sup> m<sup>3</sup> (50 bcf)).

e For 'Stand-alone, LPG recovered' case, condensate and LPG are tolled through the Liquids Pipeline and Port Bonython at \$70/kL (\$11.10/bbl).

f For the case in which LPG is recovered by stand-alone facilities and then trucked to Adelaide (Fig. 13.3), fields with an OGIP of 1400 x 10<sup>6</sup> m<sup>3</sup> (50 bcf) or less will not be economic. Results for this processing option are therefore not included on this table.

g Estimate based on 'LPG not recovered' case.

h Estimate based on 'low CO<sub>2</sub>, lean liquids' case.

i For multiple field cases, individual field OGIP is 280 x 10<sup>6</sup> m<sup>3</sup> (10 bcf) each.

j 'Marginal' implies that at a 12.5% discount rate, multiple fields of all sizes are close to economic. For multiple field case with lean compositions, minimum economic recoverable raw gas >420 x 10<sup>6</sup> m<sup>3</sup> (15 bcf) if project NPV is evaluated at a 10% real discount rate, with facilities access \$35 300/10<sup>6</sup> m<sup>3</sup> (\$1000/mm scf).

environmental and resource conservation grounds. However, if access to existing facilities can be negotiated, LPG is recovered and economics are markedly improved so that smaller fields will be able to be developed and more reserves recovered.

Given that recent discoveries have been relatively small, it is likely that the gas producer will require access to the existing facilities to produce fields which would otherwise be uneconomic. There is also high incentive for access from the public interest perspective, as it ensures that the economic recovery of the petroleum resource is maximised.

Third-party access to existing facilities should be negotiated on pricing principles which imitate a competitive market. Tolls in this instance should lie between the operating cost of the facility as a minimum and the deprival value cost as a maximum. Field sizes of the order of  $110\text{--}225 \times 10^6 \text{ m}^3$  (4–8 bcf) recoverable raw gas would be economic given access to existing facilities on the basis of deprival value ('replacement' cost) tolls.

This chapter is based on McDonough (1997a, b) which provided prospective explorers with a suite of data upon which to make initial decisions regarding the economics of gas exploration in the Cooper Basin. This study (McDonough, 1997a) is based on data available in the public and commercial arenas and thus demonstrates that it is possible for any company to develop their own data for development and negotiation purposes.

# UNDISCOVERED PETROLEUM RESOURCES

J.G.G. Morton

## Chapter 14

### INTRODUCTION

Estimating undiscovered petroleum resources of the Cooper Basin in South Australia is of value in that it gives some quantitative expression of the potential, and some basis for comparison with other basins. The potential for oil discoveries in the overlying Eromanga Basin has been reviewed previously (Morton, 1996). Some oil in Eromanga fields may have been sourced from the underlying Cooper Basin, and the estimate given here for undiscovered oil potential in the Cooper Basin may, in fact include some of the oil already discovered in the Eromanga Basin.

The present discovered recoverable raw gas reserves (at 1.1.98) of the Cooper Basin are  $229 \times 10^9 \text{ m}^3$  (8.2 tcf) comprising  $129 \times 10^9 \text{ m}^3$  (4.6 tcf) of produced gas and  $101 \times 10^9 \text{ m}^3$  (3.6 tcf) of gas yet to be produced from known discoveries. The average recovery factor for gas fields is 64%. The present discovered recoverable oil reserves (at 1.1.98) of the basin are  $6.9 \times 10^6 \text{ kL}$  (43.9 mmstb) comprising  $4.6 \times 10^6 \text{ kL}$  (29.1 mmstb) of produced oil and  $2.3 \times 10^6 \text{ kL}$  (14.8 mmstb) of oil yet to be produced from known discoveries. The combined average primary and secondary recovery factor for oil fields is 21%. More than 80% of the oil reserves are contained in the Tirrawarra Field.

The potential undiscovered petroleum resources of the Cooper Basin have been assessed using a variety of methods, most of which have been summarised by Griffiths (1997). All of these methods may have biases that produce either optimistic or conservative estimates, but if broadly coincidental, give confidence in forecasting the potential of the basin. The methods are described briefly below.

Potential undiscovered resources should not be compared to traditional proved, probable and possible reserves in known discoveries. Undiscovered resources are calculated to give a quantitative indication of the potential of the basin, and require considerable exploration to establish their existence.

### METHODS

#### BASIN ANALOGUE

The simplest method of estimating the undiscovered petroleum potential of a basin is to find a geological analogue that has been sufficiently explored that the resource potential has been fully realised. This method has limited reliability — no two basins are geologically alike, there are few basins where it is certain that all the resources have been identified, and the method ignores nearly all known information about the basin to be assessed. It may be of most use in a basin with little available geological information. Griffiths (1997) estimated the potential of the

Cooper Basin using the Oligocene fluvial play in the Texas Gulf Coast Basin (Frio Formation) in the United States as an analogue. This basin has discovered reserves of  $1.27 \times 10^{12} \text{ m}^3$  (45 tcf) of gas and  $1.25 \times 10^9 \text{ kL}$  ( $7.86 \times 10^9$  bbl) of oil, and it is estimated that a further  $0.327 \times 10^{12} \text{ m}^3$  (11.6 tcf) of gas and  $0.215 \times 10^9 \text{ kL}$  ( $1.35 \times 10^9$  bbl) of oil are still to be discovered (Galloway *et al.*, 1982). The total rock volume of the basin is  $175\,227 \text{ km}^3$ . The total volume of the Cooper Basin is about  $21\,000 \text{ km}^3$  (Griffiths, 1997) which, by comparison with the Frio Formation, would give the potential of the Cooper Basin as between  $154.3 \times 10^9$  and  $193.5 \times 10^9 \text{ m}^3$  (5.5–6.9 tcf) of gas and between  $157 \times 10^6$  and  $176 \times 10^6 \text{ kL}$  (1003–1123 mmstb) of oil. As the present discovered gas reserves of the basin are in excess of these estimates this model (method 1) is regarded as very unreliable.

A second approach (method 2) using the analogue approach and some discovery information is that of Klemme (1984), who used worldwide statistics to suggest that an intracratonic basin would have 20–30% of the total resources in the five largest fields. In the Cooper Basin the five largest gas fields are (in decreasing order) Big Lake, Moomba Central, Della, Toolachee West, and Tirrawarra, with combined raw gas reserves of  $101.2 \times 10^9 \text{ m}^3$  (3.6 tcf). This would give an ultimate basin gas potential of between  $337.3 \times 10^9$  and  $506 \times 10^9 \text{ m}^3$  (12–18 tcf). The five largest oil fields are (in decreasing order) Tirrawarra, Moorari, Fly Lake, Teloepa, and Broлга, with combined recoverable oil reserves of  $6.5 \times 10^6 \text{ kL}$  (41.3 mmstb). This would give a total basin oil potential of between  $21.7 \times 10^6$  and  $32.5 \times 10^6 \text{ kL}$  (137.7–206.5 mmstb). Klemme's (1984) method is somewhat crude, as it is heavily dependent on the assumptions that the five largest fields have been discovered and that their reserves are accurately known. In addition the definition of a 'field' is subjective, and the above estimate would have been increased if the original field definitions of Moomba and Toolachee were used. Chen and Sinding-Larsen (1994) further refined this method using an underlying Pareto distribution to estimate the number of fields likely to be discovered and their size distribution.

#### BASIN PLAYS

This method of estimating undiscovered resources consists of identifying all of the petroleum 'plays' that may exist, either by discoveries made so far, or by analysis of the available data (e.g. drillhole, geophysical). The oil or gas potential of a basin is calculated by the following formula:

$$P_t = A_p \times AB \times h \times NG \times NR \times Por \times S_h \times FVF \times SR \times RF$$

$P_t$  total potential recoverable oil or gas reserves of the basin

$A_p$  prospective area of the basin

AB	anticline to total basin area ratio
h	average gross reservoir thickness
NG	net to gross pay ratio
NR	average number of reservoirs per field
Por	porosity (fraction)
S <sub>h</sub>	hydrocarbon saturation (1 - water saturation)
FVF	formation volume factor
SR	exploration drilling success ratio
RF	recovery factor

A range of values is attributed to each parameter based on the available data, and these are combined using Monte Carlo techniques. The method uses much more of the known geological information of a basin, but does not use discovery information, therefore is better suited to basins with limited exploration and few discoveries (Morton, 1995, 1996, 1997). Where large amounts of data are available, as in the Cooper Basin, the method should at least predict the same order of magnitude of reserves as are currently identified.

There are many plays that have proven potential for discoveries in the Cooper Basin, mostly as individual high sinuosity fluvial sands within the major formations of the Gidgealpa and Nappamerri Groups, although the Tirrawarra Sandstone has more massive low-sinuosity braided fluvial sands, and bar sands are known from the upper Patchawarra and Epsilon Formations. As these are too numerous (and to a certain extent are co-dependent) to model independently, an 'average' field has been modelled using the input parameters in Table 14.1, and the results are summarised in Table 14.2.

## SOURCE GENERATION

This method estimates the amount of hydrocarbon that may have been generated from the known source rocks. The amount is then modified to an estimate of the trapped resources (i.e. in fields, discovered and undiscovered) by expulsion efficiency, migration timing, seal potential and retention factor. As these factors are very subjective, this method is not often used to estimate the undiscovered potential of an area, but it is useful in providing an upper constraint to other methods. Griffiths (1997), using data compiled by Apak (1994), estimated that the Malabine Coal of the Patchawarra Formation (the major coal seam up to 30 m thick) may have generated between 5600 x 10<sup>9</sup> and 27 200 x 10<sup>9</sup> m<sup>3</sup> (198–961 tcf) of original gas-in-place. The modal estimate was 10 300 x 10<sup>9</sup> m<sup>3</sup> (364 tcf) of original gas-in-place.

The main hydrocarbon source for the Cooper Basin fields is considered to be the coals and shales of the Toolachee, Daralingie, Epsilon, and Patchawarra Formations.

At minimum maturity, one tonne (0.625 m<sup>3</sup>) of Cooper Basin coal would contain a carbon content of 830 kg (i.e. a total organic carbon (TOC) content of 83%) and have a hydrogen index of 200 mg/g (C.J. Boreham, AGSO, pers. comm., 1998). At maximum maturity, this coal could be expected to generate between 38.2 and 76.4 kg of gas (57–114 m<sup>3</sup> (2–4 cf) at standard conditions) and up to 127.8 kg of oil (0.161 kL (1 bbl)). The total volume of mature coal for the basin is 688 km<sup>3</sup> (Toolachee 213 km<sup>3</sup>, Daralingie 20 km<sup>3</sup>, Epsilon 52 km<sup>3</sup>, Patchawarra 403 km<sup>3</sup>).

The shales of the major formations have varying organic contents and hydrogen indices (Table 14.3). Assuming the shales have an average density of 2.7 tonnes/m<sup>3</sup>, the sum of the coal and shale data would give the total generative potential of the basin as indicated in Table 14.4.

Clearly, source is not a constraint on the ultimate producible reserves from the basin. However, the trapping efficiency, in either the Cooper Basin itself, the underlying Warburton Basin or the overlying Eromanga Basin is the critical factor. McDowell (1975) concluded that the amount of hydrocarbon that resides in reservoirs is between 0 and 25% of the total hydrocarbon generated. This would suggest

**Table 14.1** Input parameters for estimating undiscovered petroleum resources in the Cooper Basin, basin plays method.

	Minimum	Mean	Maximum
<b>Gas</b>			
Prospective area of the basin (km <sup>2</sup> )	24 664	29 059	33 459
Anticline to total basin area ratio	0.1	0.27	0.45
Average gross reservoir thickness (m)	2.9	4.6	7.3
Net to gross pay ratio	0.64	0.8	0.96
Number of reservoirs per field	1	3	6
Porosity (fraction)	0.08	0.1	0.11
Water saturation (fraction)	0.35	0.45	0.55
Formation volume factor	179	185	192
Exploration drilling success ratio	0.27	0.41	0.56
Recovery factor	0.58	0.64	0.71
<b>Oil</b>			
Prospective area of the basin (km <sup>2</sup> )	24 664	29 059	33 459
Anticline to total basin area ratio	0.1	0.27	0.45
Average gross reservoir thickness (m)	2.9	4.6	7.3
Net to gross pay ratio	0.64	0.8	0.96
Number of reservoirs per field	0	1	2
Porosity (fraction)	0.08	0.1	0.11
Water saturation (fraction)	0.35	0.45	0.55
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.06	0.08	0.1
Recovery factor	0.14	0.21	0.28

**Table 14.2** Potential undiscovered petroleum resources in the Cooper Basin (for all plays), basin plays method.

	Probability that the ultimate potential will exceed the stated value		
	90%	50%	10%
Gas 10 <sup>6</sup> m <sup>3</sup> (bcf)	0 (0)	25 000 (900)	215 000 (7700)
Oil 10 <sup>3</sup> kL (mmstb)	0 (0)	13 700 (87)	41 500 (264)

**Table 14.3** Shale source rock characteristics of the Cooper Basin.

Formation	Total shale volume (km <sup>3</sup> )	Total organic carbon (initial) (%)	Hydrogen index (initial) (kg hydrocarbon/tonne TOC)
Toolachee	579	5.35	203
Daralingie	369	5.26	230
Epsilon	906	4.44	162
Patchawarra	2735	6.6	198

**Table 14.4** Potential hydrocarbon generation from source rocks of the Cooper Basin.

Formation	Coal source			Shale source			Total		
	Minimum gas 10 <sup>9</sup> m <sup>3</sup> (tcf)	Maximum gas 10 <sup>9</sup> m <sup>3</sup> (tcf)	Oil 10 <sup>9</sup> kL (10 <sup>9</sup> bbl)	Minimum gas 10 <sup>9</sup> m <sup>3</sup> (tcf)	Maximum gas 10 <sup>9</sup> m <sup>3</sup> (tcf)	Oil 10 <sup>9</sup> kL (10 <sup>9</sup> bbl)	Minimum gas 10 <sup>9</sup> m <sup>3</sup> (tcf)	Maximum gas 10 <sup>9</sup> m <sup>3</sup> (tcf)	Oil 10 <sup>9</sup> kL (10 <sup>9</sup> bbl)
Toolachee	19 426 (699)	38 851 (1399)	54.9 (347)	5827 (210)	11 654 (420)	16.5 (104)	25 253 (909)	50 505 (1818)	71.4 (451)
Daralingie	1824 (66)	3648 (131)	5.2 (33)	4136 (149)	8273 (298)	11.7 (74)	5960 (215)	11 921 (429)	16.9 (107)
Epsilon	4742 (171)	9485 (342)	13.4 (85)	6045 (218)	12 090 (435)	17.1 (108)	10 787 (388)	21 575 (777)	30.5 (193)
Patchawarra	36 754 (1323)	73 507 (2646)	103.8 (656)	33 118 (1192)	66 237 (2385)	93.6 (591)	69 872 (2515)	139 744 (5031)	197.4 (1247)
<b>Total</b>							<b>111 872 (4027)</b>	<b>223 745 (8055)</b>	<b>316.2 (1997)</b>

that, unless the Cooper Basin has a particularly low rate of retention of hydrocarbons, the total potential of the basin may be ~5000 x 10<sup>9</sup> m<sup>3</sup> (180 tcf) of recoverable gas or 9.5 x 10<sup>9</sup> m<sup>3</sup> (60 000 mmbbl) of recoverable oil — assuming a 3% retention rate in reservoirs (as found in the west Texas Permian Basin by McDowell, 1975). Although this figure indicates a potential considerably above even the most optimistic of other methods, this figure may give a hint as to the potential of currently poorly explored play types (e.g. Warburton Basin, low-permeability reservoirs, stratigraphic traps, coal seam methane). Alternatively, these figures suggest that seal integrity is a key parameter in the Cooper Basin.

**DISCOVERY TREND**

Discovery trend methods are based on the generally observed phenomenon in other exploration areas worldwide that exploration effectiveness (both field size and success rate) decline with advancing exploration effort.

There are two broad methods used to describe observed field size distributions, either lognormal type, or Pareto (J-shaped) type. The major difference between these is that the Pareto distribution predicts a very large number of very small undiscovered fields. The lognormal distribution was first used by Arps and Roberts (1958) and has been used to model discovered field sizes in western Canada (Lee and Wang, 1985, 1986), the North Sea (Band, 1987), the southern United States (Davis and Chang, 1989) and Australia (Forman and Hinde, 1985, 1986). Schuenemeyer and Drew (1983) and Attanasi and Drew (1985) suggested that the lognormal distribution may describe the sampled distribution, but did not adequately describe the parent population due to economic truncation of the data set and/or sampling bias (large fields tend to be discovered early). This sampling bias has been called the ‘creaming’ phenomenon and is a measure of exploration efficiency, which the Australian Bureau of Resource Sciences (Forman and Hinde 1985, 1986) uses in conjunction with the lognormal model.

The Pareto equation (Zipf-type) used here to describe the parent population is:

$$F_s = \frac{a}{N_d + 1}$$

- F<sub>s</sub> field size
- N<sub>d</sub> field discovery number
- a an empirically determined constant

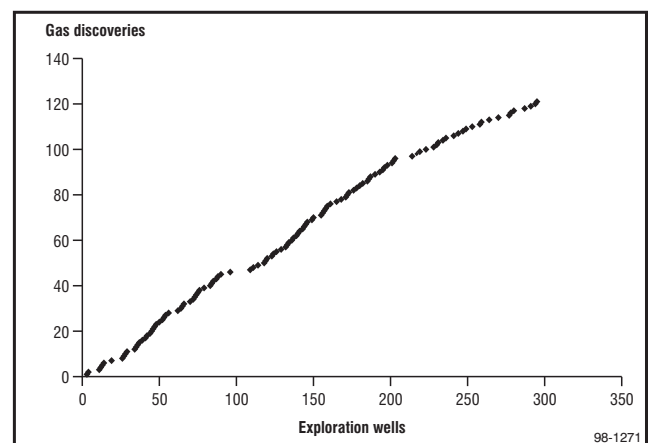
In contrast to the method used by the Bureau of Resource Sciences, the model is deterministic. However, minimum (most pessimistic), average and maximum (most optimistic) models can be developed for the data.

**Success ratio — Pareto models**

The historical overall success ratio for both oil (including Eromanga discoveries) and gas in Cooper Basin targeted wells in South Australia has recently declined from 1:1.7 to 1:3.7. This success ratio is dominated by gas discoveries (Fig. 14.1). If Cooper oil discoveries are considered alone, the success rate has been relatively constant at about 1:12 (Fig. 14.2). For future exploration, it is assumed that the gas success rate will drive exploration, (i.e. a future success rate of 1:4 exploration wells) and that oil discoveries will be made in the ratio of one oil discovery per five gas discoveries.

**Limiting discovery**

As the Pareto distribution predicts a large number of small fields to be discovered, it is sensitive to the limiting field size chosen, i.e. the point beyond which it would be uneconomic to continue exploration. This is broadly a



**Fig. 14.1** Success ratios for gas fields in the Cooper Basin.

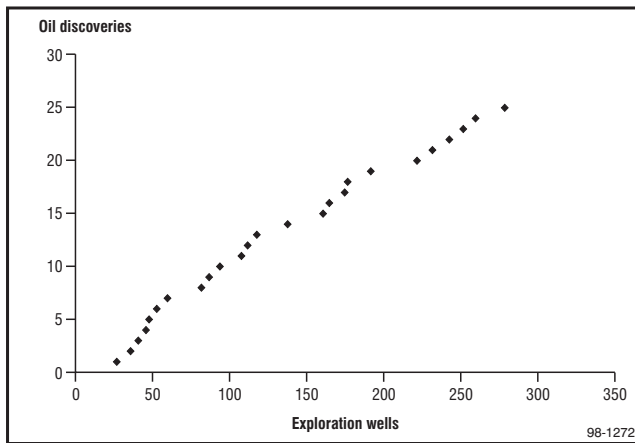


Fig. 14.2 Success ratios for oil fields in the Cooper Basin.

combination of two factors; the cost of exploration (dry wells and seismic acquisition), and the cost of development of a new discovery. The amount of seismic acquired compared to prospects drilled is shown in Figure 14.3. Historically, seismic acquisition has averaged 283 km of 2D seismic per exploration well. However, a significant part of this acquisition is attributable to development of newly discovered fields. For the purposes of determining the limiting field size, it is assumed that at the limit no further exploration seismic will be acquired per exploration well.

An economic model has been developed that is simpler than the one used in Chapter 13. It assumes:

- an average gas composition
- no seismic acquisition per exploration well
- three dry wells will be drilled for each discovery
- 5 km of flowline to connect the gas discovery to existing facilities
- marginal operating costs
- 1/5 of an average oil field (60 900 kL (383 000 bbl) recoverable, excluding Tirrawarra Field) will also be discovered for each gas field discovered.

Using this model, the limiting economic field size is ~104.2 x 10<sup>6</sup> m<sup>3</sup> (3.7 bcf) of gas.

**Gas**

There have been 121 discovered Cooper Basin gas fields in South Australia up to 1.1.98 from 298 new field wildcats.

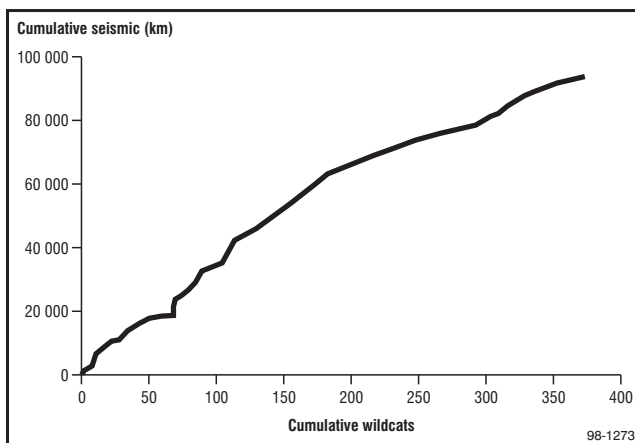


Fig. 14.3 Seismic acquisition versus exploration wells in the Cooper and Eromanga Basins.

The models based on the historical data (recoverable raw gas) are:

Minimum

$$F_s (10^6 \text{ m}^3) = \frac{37\,765}{N_d + 1}$$

Most likely

$$F_s (10^6 \text{ m}^3) = \frac{40\,527}{N_d + 1}$$

Maximum

$$F_s (10^6 \text{ m}^3) = \frac{43\,811}{N_d + 1}$$

The models are shown graphically against the historical data in Figure 14.4 and summarised in Table 14.5.

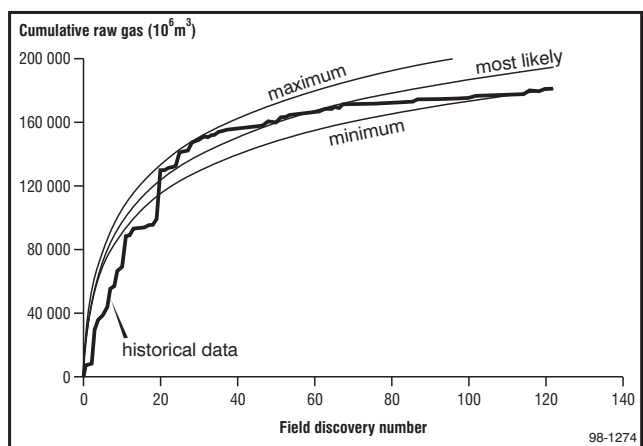


Fig. 14.4 Pareto models against historical gas discoveries in the Cooper Basin.

Table 14.5 Potential undiscovered recoverable petroleum resources in the Cooper Basin, Pareto method.

Model	Number of fields to be discovered	Undiscovered recoverable resource	
Gas		10 <sup>6</sup> m <sup>3</sup> (bcf)	
minimum	240	41 072	(1458)
most likely	267	60 260	(2139)
maximum	298	83 204	(2954)
Oil		10 <sup>3</sup> kL (mmstb)	
minimum	48	2049	(12.9)
most likely	53	5453	(34.3)
maximum	60	20 294	(127.6)

**Oil**

There have been 25 Cooper Basin oil fields discovered in South Australia up to 1.1.98 from 297 new field wildcats.

The models based on the historical data (recoverable oil) are:

Minimum

$$F_s (10^3 \text{ kL}) = \frac{2100.4}{N_d + 1}$$

Most likely

$$F_s (10^3 \text{ kL}) = \frac{2848.0}{N_d + 1}$$

Maximum

$$F_s (10^3 \text{ kL}) = \frac{6125.5}{N_d + 1}$$

The models are shown graphically against the historical data in Figure 14.5 and summarised in Table 14.5.

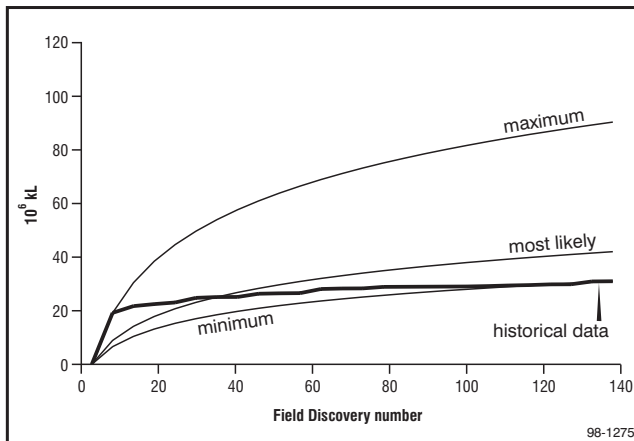


Fig. 14.5 Pareto models against historical oil discoveries in the Cooper Basin.

Although for gas at least, the number of fields to be discovered would appear to be excessive, this must be viewed in the context that the Cooper Basin is not yet fully explored when compared to similar basins in mature exploration areas. For example, Figure 14.6a (after Caldwell, 1994) shows the gas field discoveries in Texas District 3, United States, from 1932 to 1991. In total there are over 900 gas pool discoveries, with the largest pools of the order of  $28 \times 10^9 \text{ m}^3$  (1000 bcf) in size. Significantly, the rate of pool size decline is reduced after the first 100 to 200 discoveries, and large fields (over  $2.8 \times 10^9 \text{ m}^3$  (100 bcf)) were being discovered beyond discovery number 800. Figure 14.6b shows the South Australian Cooper Basin gas

field data at a similar scale, which suggests that it is underexplored by comparison.

### Field size profile

Using the Pareto models above, field size profiles can be generated for the Cooper Basin (Figs 14.7, 14.8). These indicate the likelihood of discovering fields of various sizes assuming efficient exploration. In all cases fields smaller than those predicted by the models have been found, and this risk has not been factored into the probabilities summarised in Table 14.6.

### Lognormal model

The Bureau of Resource Sciences has used the lognormal model for many years, however the assessments for gas are considered here to be pessimistic. The most recent gas assessment for the South Australian part of the Cooper Basin (Bureau of Resource Sciences, 1996) ranges from  $7155 \times 10^6$  to  $19\,071 \times 10^6 \text{ m}^3$  (254–677 bcf), with an average estimate of  $11\,916 \times 10^6 \text{ m}^3$  (423 bcf).

Bradshaw *et al.* (1998) recently published an estimate using similar techniques based on a 1988 database of reserves for the whole of the Cooper and Eromanga Basins (South Australia and Queensland). They concluded that from 1988, a further 60 fields would be discovered with a potential of  $16\,200 \times 10^6 \text{ m}^3$  (576 bcf) of recoverable gas. Since 1988, in the South Australian portion of the basin alone, there have been 35 discoveries with total recoverable reserves attributed of  $7\,200 \times 10^6 \text{ m}^3$  (254 bcf). Significant discoveries have also been made in the Queensland portion of the basin in that time, and this suggests that the Bradshaw *et al.* estimate is also pessimistic.

The Bureau of Resource Sciences' (1996) undiscovered recoverable oil estimates for the Cooper Basin, South Australia range from  $0.32 \times 10^6$  to  $4.29 \times 10^6 \text{ kL}$  (2–27 mmbbl), with an average estimate of  $1.59 \times 10^6 \text{ kL}$  (10 mmbbl).

### ANALYTICAL PETROLEUM RESOURCE APPRAISAL SYSTEM (APRAS)

The Analytical Petroleum Resource Appraisal System (APRAS) was developed by the United States Geological

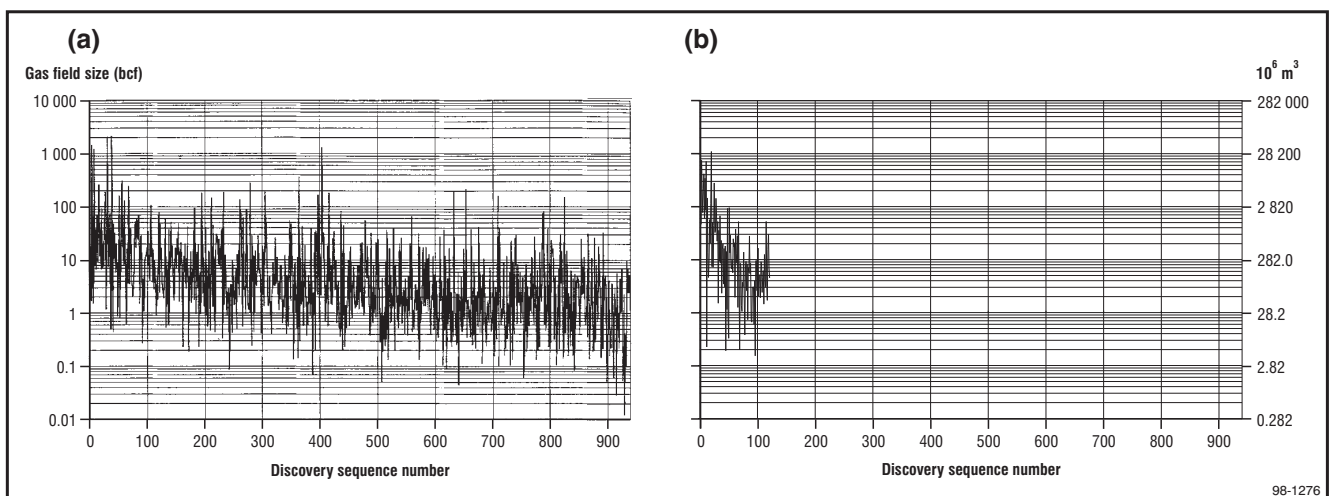


Fig. 14.6 Discovery sequence plots. (a) Texas District 3 gas pools, 1932–91 (from Caldwell, 1994). (b) Cooper Basin gas fields, 1963–97 (at same scale to Fig. 6a).

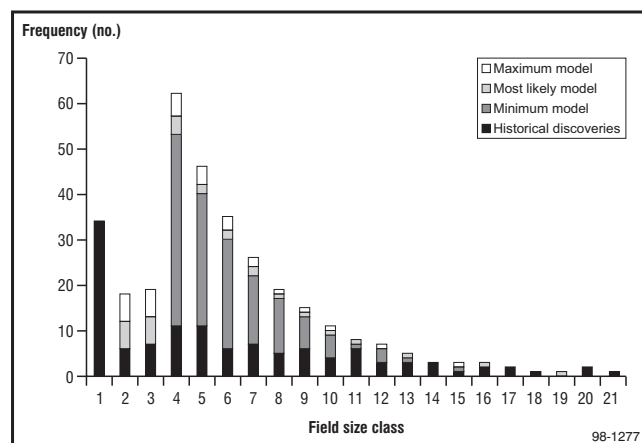


Fig. 14.7 Gas field size profile. Field size classes are given in Table 14.6 and are logarithmic.

Survey. It is similar to the basin play method in that it uses Monte Carlo simulation to manipulate probabilities. However, APRAS uses an analytical combination of five fractiles of the observed distribution (usually lognormal) for each parameter, which makes it faster to run. Each play to be assessed is assigned a set of distributions which model oil and gas accumulation sizes, reservoir depths and number of accumulations. In addition, the probabilities for source, timing, migration, reservoir facies, marginal play probability and conditional probability of at least one undiscovered accumulation in the play are provided. The methodology is summarised in Crovelli and Balay (1988, 1992) and Griffiths (1997). Griffiths (1997) developed two models for the Cooper Basin — a pessimistic and an optimistic case that differed in the number of large accumulations that are still to be found.

The result of Griffiths' assessment is summarised in Table 14.7 (converted from his original gas-in-place and original oil-in-place to remaining recoverable raw gas and recoverable oil). He concluded that most of the gas potential was in the Patchawarra Formation, and most of the oil potential in the Tirrawarra Sandstone. The assessment did not predict the volume of resources already discovered at some probability levels (the zero estimates in Table 14.7).

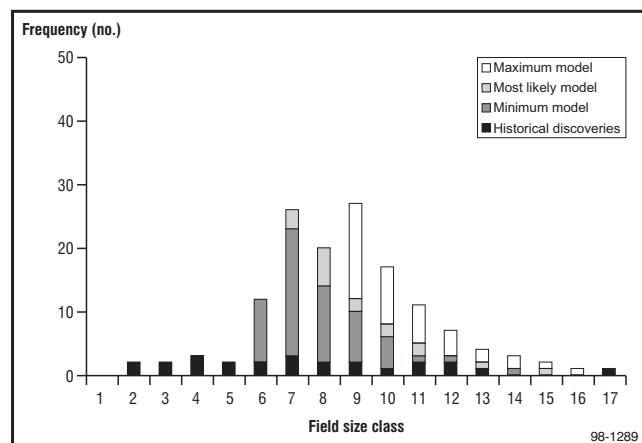


Fig. 14.8 Oil field size profile. Field size classes are given in Table 14.6 and are logarithmic.

Table 14.6 Potential undiscovered petroleum fields in the Cooper Basin, Pareto method.

Class	Field size Range	Probability of finding a field in this size class (%)		
		Minimum	Most likely	Maximum
<b>Recoverable gas 10<sup>6</sup> m<sup>3</sup> (bcf)</b>				
1	75–100 (3–4)	–	–	–
2	100–133 (4–5)	26	26	25
3	133–178 (5–6)	23	23	23
4	178–237 (6–8)	15	15	15
5	237–316 (8–11)	10	10	10
6	316–422 (11–15)	9	9	9
7	422–562 (15–20)	5	6	6
8	562–750 (20–27)	4	4	4
9	750–1000 (27–35)	3	3	3
10	1000–1334 (35–47)	2	2	2
11	1334–1778 (47–63)	0	1	1
12	1778–2371 (63–84)	1	1	1
13	2371–3162 (84–112)	0	1	1
14	3162–4217 (112–150)	0	0	0
15	4217–5623 (150–200)	0	0	1
16	5623–7499 (200–266)	0	0	0
17	7499 – 10 000 (266–355)	0	0	0
18	10 000 – 13 335 (355–473)	0	0	0
19	13 335 – 17 783 (473–631)	0	0	0
20	17 783 – 23 714 (631–842)	0	0	0
21	23 714 – 31 623 (842–1123)	0	0	0
<b>Oil-in-place 10<sup>3</sup> kL (mmbbl)</b>				
1	10–16 (0.06–0.10)	–	–	–
2	16–25 (0.10–0.16)	–	–	–
3	25–40 (0.16–0.25)	–	–	–
4	40–63 (0.25–0.40)	–	–	–
5	63–100 (0.40–0.63)	–	–	–
6	100–159 (0.63–1.00)	17	0	0
7	159–252 (1.00–1.59)	34	35	0
8	252–399 (1.59–2.51)	21	28	15
9	399–633 (2.51–3.98)	14	15	33
10	633–1003 (3.98–6.31)	9	11	21
11	1003–1590 (6.31–10.00)	2	5	12
12	1590–2520 (10.00–15.85)	2	2	7
13	2520–3994 (15.85–25.12)	0	2	4
14	3994–6329 (25.12–39.81)	2	2	4
15	6329 – 10 031 (39.81–63.10)	0	2	3
16	10 031 – 15 899 (63.10–100.00)	0	0	1
17	15 899 – 25 198 (100.00–158.49)	0	0	0

Table 14.7 Potential undiscovered recoverable petroleum resources in the Cooper Basin, APRAS method.

	Probability that the ultimate potential will exceed the stated value		
	95%	50%	5%
<b>Low estimate</b>			
Gas 10 <sup>6</sup> m <sup>3</sup> (bcf)	0 (0)	123 600 (3481)	628 000 (17 688)
Oil 10 <sup>3</sup> kL (mmstb)	0 (0)	0 (0)	3218 (20.2)
<b>High estimate</b>			
Gas 10 <sup>6</sup> m <sup>3</sup> (bcf)	96 000 (2704)	332 500 (9365)	747 600 (21 056)
Oil 10 <sup>3</sup> kL (mmstb)	0 (0)	0 (0)	5 460 (34.3)

## SUMMARY

The results of reasonably reliable methods for calculating potential undiscovered petroleum resources are summarised in Table 14.8. Basin analogue (method 1) and source generation are considered unreliable. Some of the potential attributed to the Cooper Basin may have already been discovered in the Eromanga Basin. The current discovered recoverable oil reserves of the Eromanga Basin in the Cooper Basin region are  $14.5 \times 10^6$  kL (92.5 mmstb). If most of the oil in the Eromanga is Cooper Basin sourced (see Chs 8 and 10 for a discussion on this), then the remaining oil potential for the Cooper Basin may be quite limited.

**Table 14.8** Comparison of potential undiscovered recoverable petroleum resources in the Cooper Basin. Results are presented in decreasing order of the average estimate.

Method	Estimate <sup>1</sup>					
	Low		Average		High	
<b>Gas <math>10^9 m^3</math> (tcf)</b>						
Basin analogue <sup>2</sup>	108	(3.8)	193	(6.8)	277	(9.8)
APRAS (average)	39	(1.4)	228	(6)	688	(19)
Pareto	41	(1.5)	60	(2)	83	(3)
Basin plays	0	(0)	25	(1)	215	(8)
Lognormal	7	(0.3)	12	(0.4)	19	(0.7)
<b>Oil <math>10^6</math> kL (mmstb)</b>						
Basin analogue <sup>2</sup>	15	(94)	20	(300)	26	(163)
Basin plays	0	(0)	14	(87)	42	(264)
Pareto	2.0	(13)	6	(34)	20	(128)
Lognormal	0.3	(2)	2	(10)	4	(27)
APRAS (average)	0	(0)	0	(0)	4	(27)

<sup>1</sup> Estimate categories are generalised — refer to tables above for detail.

<sup>2</sup> Method 2



# APPENDIXES

## APPENDIX 1 A brief chronology of petroleum exploration and development in the Cooper and Eromanga Basins, South Australia

Year	Event
<b>1900</b>	
	<ul style="list-style-type: none"> <li>• First discovery of natural gas in the Eromanga Basin during water drilling at Roma (Qld).</li> </ul>
<b>1914</b>	
	<ul style="list-style-type: none"> <li>• Patchawarra Bore on Innamincka Station, drilled in search of water, provided first useful information on oil in the Eromanga Basin.</li> </ul>
<b>1924</b>	
	<ul style="list-style-type: none"> <li>• Dr R. Lockhart Jack, while mapping northeast SA for water supplies, noted a fold structure and the presence of gentle folds in the Cordillo Downs area.</li> </ul>
<b>1940</b>	
	<ul style="list-style-type: none"> <li>• Zinc Corporation commissioned a geological review of the oil prospects of northeast SA and the adjoining States by J.P. De Verteuil but the prospects were not rated positively.</li> </ul>
<b>1941</b>	
July	<ul style="list-style-type: none"> <li>• SA's <i>Mining (Petroleum) Act 1940</i> came into effect.</li> </ul>
<b>1945</b>	
	<ul style="list-style-type: none"> <li>• Quinyambie New Homestead Bore, completed for water supplies at the southern edge of the Great Artesian Basin (GAB) near the SA–NSW border, revealed flammable gas.</li> </ul>
April	<ul style="list-style-type: none"> <li>• The first Oil Exploration Licence under the <i>Mining (Petroleum) Act</i>, OEL 1, was granted to A.J. Keast on behalf of the Zinc Corp. Ltd. It covered 10 360 km<sup>2</sup> between Lake Frome and the NSW border, within the southern margin of the Cooper Basin.</li> </ul>
<b>1947</b>	
January	<ul style="list-style-type: none"> <li>• M. Mawby, on behalf of the Australian Mining and Smelting Co. Ltd (an associate of Zinc Corp.), was granted OEL 3 for two years over 126 910 km<sup>2</sup> of the northeast of SA, covering the area of the now known Cooper and Eromanga Basins' petroleum discoveries.</li> </ul>
December	<ul style="list-style-type: none"> <li>• OELs 2 and 3 were transferred to the Frome–Broken Hill Co. Pty Ltd which had been formed so that Zinc Corp. could introduce international expertise and assistance to the petroleum search.</li> </ul>
<b>1948</b>	
June	<ul style="list-style-type: none"> <li>• OEL 3 was reissued to Frome–Broken Hill.</li> </ul>
<b>1954</b>	
January	<ul style="list-style-type: none"> <li>• Australian Mining and Smelting Co. Ltd took up OEL 6 for two years over the Lake Frome and GAB areas, including the area covered by the earlier OELs 2 and 3.</li> </ul>
September	<ul style="list-style-type: none"> <li>• OEL 7, granted to R. Bristowe in March 1954, was transferred to Santos. The licence initially adjoined OEL 6 but when the Australian Mining and Smelting surrendered OEL 6 Santos applied successfully to have the area included in OEL 7. The area then totalled 507 397 km<sup>2</sup>. The Santos holdings in SA and Qld then totalled 860 000 km<sup>2</sup>.</li> </ul>
<b>1956</b>	
June and July	<ul style="list-style-type: none"> <li>• Reconnaissance gravity and magnetic surveys undertaken by Geosurveys for Santos between Birdsville and Marree. Jack's 1924 observations were recalled when Geosurveys' geologist Dr Heli Wopfner mapped large structures near Oodnadatta west of the GAB.</li> </ul>
<b>1957</b>	
February	<ul style="list-style-type: none"> <li>• Observations by Dr A.I. Levorsen (from Tulsa, Oklahoma) were critical to extending the search in the northeast.</li> </ul>
March	<ul style="list-style-type: none"> <li>• During a ground and air reconnaissance survey in the northeast Wopfner mapped fold deformations similar to Jack's observations.</li> </ul>
12 December	<ul style="list-style-type: none"> <li>• Federal Government's <i>Petroleum Search Subsidy Act</i> providing financial incentives to company exploration passed.</li> </ul>
<b>1957–58</b>	
October–January	<ul style="list-style-type: none"> <li>• Geosurveys drilled five structural/stratigraphic bores for Santos across the east limb of the Nappamilkie anticline and the Haddon syncline in the Cordillo Downs area to confirm structures in depth.</li> </ul>

This appendix was compiled by B.J. O'Neil as a preliminary working document with the intention of building up a comprehensive chronology of events relating to the Cooper and Eromanga Basins, South Australia. Contributions, corrections and comments are invited and should be sent to the Director, Petroleum Group, PIRSA.

Year	Event
<b>1958</b>	
6 May	<ul style="list-style-type: none"> <li>• Checkerboarding Agreement between Santos and Delhi. Santos had attracted overseas interest in its efforts and Delhi-Taylor Oil Corporation joined Santos as its partner in the search. Delhi was the explorer until 1987.</li> </ul>
<b>1959</b>	
1 March	<ul style="list-style-type: none"> <li>• Upon expiry of OEL 7, OELs 20 and 21 were issued.</li> </ul>
28 March	<ul style="list-style-type: none"> <li>• Spudding of Innamincka 1, the first oil and gas well in the GAB.</li> </ul>
4 November	<ul style="list-style-type: none"> <li>• The <i>Petroleum Search Subsidy Act</i> was extended under a new <i>Petroleum Search Subsidy Act</i>.</li> </ul>
November	<ul style="list-style-type: none"> <li>• Drilling of Innamincka completed: Permian sediments discovered beneath the Mesozoic.</li> </ul>
<b>1962</b>	
	<ul style="list-style-type: none"> <li>• Seismic work and drilling Dullingari 1 in the Strzelecki Desert 65 km south of Innamincka.</li> </ul>
<b>1963</b>	
March–July	<ul style="list-style-type: none"> <li>• Pandieburra 1 (~100 km south of Birdsville) and Putamurdie 1 (~57 km southeast of Birdsville) were drilled.</li> </ul>
31 December	<ul style="list-style-type: none"> <li>• Discovery of potentially economic gas accumulation at Gidgealpa 2 confirmed the prospectivity and extent of Permian strata assigned to Coopers Creek Basin.</li> </ul>
<b>1966</b>	
March	<ul style="list-style-type: none"> <li>• The name Cooper's Creek Basin informally becomes the Cooper Basin through usage.</li> <li>• Discoveries by Delhi-Santos of natural gas at Moomba 1 followed by Moomba 2 indicated a large reserve of natural gas. Moomba was 30 km south of Gidgealpa. Further drilling to prove up reserves included Moomba 6 in November 1967.</li> </ul>
November	<ul style="list-style-type: none"> <li>• Delhi-Santos gas sales contract with Sagasco.</li> </ul>
<b>1967</b>	
November	<ul style="list-style-type: none"> <li>• Natural Gas Pipelines Authority of SA (PASA) established by State Government legislation.</li> <li>• Discovery of first condensate-rich gas in Daralingie 1, and Daralingie 2 also produced positive results.</li> </ul>
<b>1968</b>	
	<ul style="list-style-type: none"> <li>• Amendments to the <i>Mining (Petroleum) Act</i> were passed.</li> <li>• Construction of gas processing facility at Moomba begins.</li> </ul>
<b>1969</b>	
30 January	<ul style="list-style-type: none"> <li>• Contracts signed between Delhi-Santos, Electricity Trust of SA (ETSA), Sagasco and some industrial users of gas. Late in the year Sagasco began converting the metropolitan area to natural gas.</li> </ul>
28 February	<ul style="list-style-type: none"> <li>• First Petroleum Production Licences (PPLs 1–5) issued to Delhi-Santos and gas produced for sale.</li> </ul>
March	<ul style="list-style-type: none"> <li>• OELs 20 and 21 were reissued as Petroleum Exploration Licences (PELs) 5 and 6. The licensees reduced their area by surrendering the offshore region of the western coast of Eyre Peninsula. PELs 5 and 6 were issued for a guaranteed 20 years without area relinquishments and with nominal exploration requirements and the right of renewal for a further 20 years. These rights were protected by a covenant to the amended <i>Mining (Petroleum) Act</i> passed in 1968.</li> </ul>
July	<ul style="list-style-type: none"> <li>• Delhi-Santos Toolachee 1 flowed natural gas from sands in the lower 'Gidgealpa' (=Patchawarra) Formation.</li> </ul>
10 November	<ul style="list-style-type: none"> <li>• 750 km Moomba-Adelaide pipeline (0.56 m outside diameter) completed. Officially opened in November.</li> <li>• Gas sold to first customer, Sagasco.</li> </ul>
<b>1970</b>	
July	<ul style="list-style-type: none"> <li>• Discoveries of gas at Packsaddle, Tirrawarra, Della, Merrimelia, Mudrangie and Strzelecki. Some of these discoveries were made by farmin companies such as Crusader and Pursuit Oil NL.</li> <li>• Discovery of light crude oil by Bridge at Tirrawarra, the first to flow to the surface in SA, overturns view that Cooper Basin would be gas only. The associated gas discovery there also upgraded the natural gas reserves of the Cooper Basin and set the scene for more exploration.</li> </ul>
<b>1970–71</b>	
c. November–October	<ul style="list-style-type: none"> <li>• Flooding from Strzelecki and Cooper Creeks interrupted drilling.</li> </ul>
<b>1971</b>	
26 May	<ul style="list-style-type: none"> <li>• Santos appointed Operator of the gas production facilities and camp at Moomba.</li> <li>• Agreement signed between Alliance, Basin, Bridge, Delhi International, Pursuit, Reef, Santos, Total, Vamgas and AGL to supply gas to Sydney from 1976 to 2006.</li> </ul>
<b>1971–72</b>	
	<ul style="list-style-type: none"> <li>• Permian gas was discovered at Big Lake, Coonatie, Dullingari, Burke, Brumby and Kanowana and oil and gas at Fly Lake, Brolga and Moorari.</li> </ul>
<b>1972</b>	
September	<ul style="list-style-type: none"> <li>• AGL agreement became binding after sufficient gas reserves (56 x 10<sup>9</sup> m<sup>3</sup> (2 tcf)) had been established. SA wanted to reserve sufficient reserves for a petrochemical plant; Qld agreed to dedicate three small gas fields (all that had been discovered in SW Qld) to the AGL Agreement.</li> </ul>

Year	Event
<b>1973</b>	<ul style="list-style-type: none"> <li>AGL and the SA Government agreed to a request from the Producers to raise the gas price for which there would be an expanded gas exploration program. PASA took over the responsibility from the Producers for gas sales to SA consumers and purchased the gas from the Moomba plant. Development of the gas fields in the Cooper Basin was enhanced when an integrated supply system replaced the dedicated field approach which took into account the mechanics of production and depletion of gas fields, the economy of scale in production and to allow for an increase in gas production to support gas liquids development. This was ostensibly in the interests of the Producers and the consumers. Contracts were then rearranged.</li> <li>Gas pipeline to NSW under construction.</li> </ul>
<b>1973–74</b>	<ul style="list-style-type: none"> <li>Exploration and development drilling was all but abandoned and few seismic surveys were conducted.</li> </ul>
<b>1974</b>	<ul style="list-style-type: none"> <li>Flooding of Moomba and Lake Eyre, worst in recorded history with a recorded rainfall of 864 mm.</li> <li>Delhi International Oil Corporation offered to sell 50% of its production interests and 25% of its exploration interests. Purchased by Petroleum and Minerals Authority (PMA) for the Federal Government.</li> </ul>
28 February	<ul style="list-style-type: none"> <li>Renewal of PELs 5 and 6 between Minister of Development and Mines, Delhi International and Santos.</li> </ul>
30 June	<ul style="list-style-type: none"> <li>Federal Government's Petroleum Search Subsidy scheme terminated (but work-in-progress payments continued to 1976).</li> </ul>
<b>1975</b>	<ul style="list-style-type: none"> <li>SA Government became involved in working PELs 5 and 6 when it acquired the PMA's interests from the Federal Government.</li> </ul>
1 January	<ul style="list-style-type: none"> <li>Cooper Basin Unit Agreement between Alliance, Basin, Bridge, Delhi International, Pursuit, Reef, Santos and Vamgas.</li> </ul>
16 October	<ul style="list-style-type: none"> <li>Cooper Basin Indenture between the State of SA, Minister of Mines and Energy, Santos, Delhi International, Alliance, Basin, Bridge, Pursuit, Reef and Vamgas for PELs 5 and 6.</li> </ul>
11 December	<ul style="list-style-type: none"> <li><i>Cooper Basin Ratification Act</i> (and Indenture) came into effect after passing the SA Parliament in November.</li> </ul>
<b>1976</b>	<ul style="list-style-type: none"> <li>Gas was discovered at Namur 1. This was the first evidence of gas migration from Permian to Cretaceous strata.</li> </ul>
18 December	<ul style="list-style-type: none"> <li>Supply of gas to AGL in NSW commenced.</li> </ul>
21 December	<ul style="list-style-type: none"> <li>Exploration Indenture for PELs 5 and 6; Producers Unitisation; Interim Gas Sales; and PASA Future Sales Requirement Agreements were signed. (The parties were Alliance, Basin, Bridge, Delhi International, Pursuit, Reef, Santos, Total, Vamgas, Commonwealth of Australia, PASA and Minister of Mines and Energy.)</li> </ul>
<b>1977</b>	<ul style="list-style-type: none"> <li>Oil was discovered at Poolowanna 1.</li> </ul>
August–October	<ul style="list-style-type: none"> <li>South Australian Oil and Gas Corporation (SAOG) was incorporated. Created in, and separated in August 1977 from, the Mines Department as the South Australian Petroleum Exploration Group, SAOG was to undertake an independent major exploration program in the Cooper Basin.</li> </ul>
<b>1978</b>	<ul style="list-style-type: none"> <li>Santos's shareholders receive first dividend payment, 2c per share.</li> </ul>
23 June	<ul style="list-style-type: none"> <li>A flow of 382 kL (2400 bbl) of oil per day from Strzelecki 3 established the Eromanga Basin's oil potential.</li> </ul>
September–October	
<b>1979</b>	<ul style="list-style-type: none"> <li>Santos became the sole operator for the development drilling, production, processing, maintenance and servicing of the gas and condensate fields while Delhi became the exploration operator. The exploration rights granted to Delhi–Santos were modified when the companies volunteered to halve PELs 5 and 6 to 284 086 km<sup>2</sup> and the area was divided into three sectors, the Cooper, Pedirka and Arrowie Sectors. The Cooper Sector is not subject to any relinquishment provisions until 1999 when the exploration rights to the whole Cooper Basin must be relinquished, without the right to renewal.</li> </ul>
1 January	
28 February	<ul style="list-style-type: none"> <li>Renewal of PELs 5 and 6 between Minister of Mines and Energy, Delhi and Santos.</li> </ul>
August–October	<ul style="list-style-type: none"> <li>Oil was discovered at Dullingari North 1.</li> </ul>
<b>1980</b>	<ul style="list-style-type: none"> <li>Oil was discovered at Cuttapiirrie 1.</li> </ul>
March–May	
<b>1981</b>	<ul style="list-style-type: none"> <li><i>Stony Point (Liquids Project) Ratification Act</i> passed SA Parliament and Cooper Basin Liquids Project commenced.</li> <li>CSR Ltd purchased the Australian petroleum interests of Delhi.</li> <li>First 3D seismic survey over Cuttapiirrie oil and gas field by SAOG.</li> <li>Strzelecki 4, drilled in the same stratigraphic unit as Strzelecki 3, recorded the largest oil flow to 1983 from a single sand unit on continental Australia.</li> <li>McKinlay 1 discovered oil on the Murteree Ridge, the first of many fields on the structure.</li> <li>Jackson 1 oil discovery in the Qld sector of the Cooper and Eromanga Basins, the largest onshore oilfield in Australia.</li> </ul>
January–February	
May–June	
November	
26 November	<ul style="list-style-type: none"> <li>Stony Point Liquids Project Indenture between the State of SA, the Minister of Mines and Energy, Santos, Delhi, SAOG, Basin, Total, Reef, Vamgas, Alliance, Crusader, Bridge and Bridge Oil Developments.</li> </ul>
<b>1982</b>	<ul style="list-style-type: none"> <li>Moomba – Stony Point high pressure vapour liquids pipeline construction commenced.</li> <li>659 km Moomba – Stony Point liquids pipeline completed.</li> <li>First crude oil production began, from Strzelecki Field.</li> </ul>
15 January	
October	
December	

Year	Event
<b>1982–83</b>	
	<ul style="list-style-type: none"> <li>SAOG's experimental massive hydraulic fracturing programs in the Tirrawarra sandstone reservoir of the Big Lake Field proved successful and paved the way for other fracture stimulation programs.</li> </ul>
<b>1983</b>	
4–6 February	<ul style="list-style-type: none"> <li>First export shipments of condensate through liquids pipeline from Cooper Basin from Stony Point.</li> </ul>
11 March	<ul style="list-style-type: none"> <li>First shipment of crude oil from Port Bonython.</li> </ul>
June	<ul style="list-style-type: none"> <li>Stony Point renamed Port Bonython.</li> </ul>
16 December	<ul style="list-style-type: none"> <li>Official opening of new camp at Moomba.</li> </ul>
<b>1983–85</b>	
	<ul style="list-style-type: none"> <li>An Accelerated Gas Program was conducted through the State Government as part of its agreement with the Producers over the 1982 gas price arbitration.</li> </ul>
<b>1984</b>	
	<ul style="list-style-type: none"> <li>First enhanced oil recovery (EOR) scheme initiated: water injected into Eromanga Basin sediments, Dullingari Field.</li> <li>Under the conditions of renewal, PELs 5 and 6 were reduced to 231 948 km<sup>2</sup> and Delhi-Santos were required to drill 18 wells and acquire 7100 line km of seismic in the Pedirka and Arrowie Sectors, and 54 wells and 4000 line km in the Cooper Sector.</li> </ul>
28 February	<ul style="list-style-type: none"> <li>Renewal of PELs 5 and 6 between Minister of Mines and Energy, Delhi and Santos. At five-yearly intervals, the Pedirka (west of Cooper Basin) and Arrowie (north of Lake Frome) sectors were now subject to 25% relinquishment.</li> </ul>
June	<ul style="list-style-type: none"> <li>First Code of Environmental Practice prepared for petroleum, seismic and drilling operations by Delhi, Santos and the Department of Mines and Energy.</li> </ul>
21 June	<ul style="list-style-type: none"> <li>LPG production began at Port Bonython.</li> </ul>
July	<ul style="list-style-type: none"> <li>First sale of LPG to the Australian market.</li> </ul>
September	<ul style="list-style-type: none"> <li>First export shipment (to Japan) of LPG produced at Port Bonython and official opening of the plant.</li> </ul>
<b>1985</b>	
	<ul style="list-style-type: none"> <li>Initiation of development of new environmental operating techniques (such as rolling of seismic lines in gibber plains).</li> <li>Eleven drilling rigs operated simultaneously in SA (over 100 wells drilled).</li> </ul>
<b>1986</b>	
	<ul style="list-style-type: none"> <li>Tirrawarra and Moorari Fields EOR scheme initiated: fracture stimulation and ethane injection.</li> <li>Multiple land use concept introduced for Innamincka Pastoral Lease.</li> <li>As the world oil price collapsed, from about A\$277 to \$101/kL (A\$44 to \$16/bbl), exploration in Australia was halved.</li> </ul>
March	<ul style="list-style-type: none"> <li>Joint Operations Management Group (JOMG, including Santos, Delhi and Department of Mines and Energy) formed to manage environmental and safety aspect of operations.</li> </ul>
<b>1987</b>	
1 September	<ul style="list-style-type: none"> <li>Santos becomes exploration and production operator for all of its involvement in SA.</li> </ul>
<b>1988</b>	
	<ul style="list-style-type: none"> <li>1000th petroleum well drilled in SA.</li> <li>20th anniversary of uninterrupted gas supply from the Cooper Basin.</li> <li>1 000 000th barrel of liquids shipped from Port Bonython.</li> <li>Agreement signed by government Ministers and Producers over operational procedures in the Coongie Lakes Control Zone.</li> </ul>
February	<ul style="list-style-type: none"> <li>PELs 5 and 6 were reduced to 111 756 km<sup>2</sup>.</li> </ul>
May–July	<ul style="list-style-type: none"> <li>Discovery of Taloola, Sturt, Sturt East and Tantanna oil fields in Lake Hope block of the Eromanga Basin near the southwestern edge of the Cooper Basin.</li> </ul>
15 June	<ul style="list-style-type: none"> <li>Second renewals of PELs 5 and 6 granted to Delhi and Santos.</li> </ul>
17 June	<ul style="list-style-type: none"> <li>SAOG changed its name to Sagasco Resources Ltd.</li> </ul>
September	<ul style="list-style-type: none"> <li>James 1 flowed oil from the upper Triassic sequence in the Patchawarra East block of PELs 5 and 6.</li> </ul>
23 November	<ul style="list-style-type: none"> <li>Santos and Delhi applied for the second renewal of PELs 5 and 6 and in so doing, surrendered 92 995.19 km<sup>2</sup> of the licence area, with the option of surrendering a further ~12 000 km<sup>2</sup> within the first six months of the renewed licences. The remaining area of the licences: <ul style="list-style-type: none"> <li>Pedirka 38 479.61 km<sup>2</sup></li> <li>Cooper 76 381.59 km<sup>2</sup></li> <li>Arrowie nil</li> <li>Total 114 861.20 km<sup>2</sup></li> </ul> </li> </ul>
22 December	<ul style="list-style-type: none"> <li>The Simpson Desert and Innamincka Regional Reserves were proclaimed.</li> </ul>
<b>c.1989–90</b>	
	<ul style="list-style-type: none"> <li>PELs 5 and 6 again reduced, to 73 202 km<sup>2</sup>.</li> </ul>
<b>1990</b>	
	<ul style="list-style-type: none"> <li>Permian-sourced oil (Sturt 6) and gas (Lycosa 1 and Moolalla 1) discovered in early Palaeozoic reservoirs of the Warburton Basin.</li> </ul>

Year	Event
<b>1991</b>	
	<ul style="list-style-type: none"> <li>Contract signed to sell SW Qld gas to SA. Competition resulting from interconnection of the SA, Victorian and NSW electricity transmission systems led to decrease in use of Cooper Basin gas by ETSA.</li> <li>Highest ever petroleum royalty in SA of \$61.5 million received from the Producers (due to higher crude oil prices as a result of the Gulf War and the renegotiated royalty system).</li> <li>Santos completes takeover of Vamgas.</li> <li>Sale of Sagasco Holdings Ltd, which includes Sagasco Resources, to Boral means SA Government sold its exploration and operating interest in the Cooper Basin.</li> <li>First modern 3D seismic survey program in the Cooper Basin undertaken over Gidgealpa Field.</li> <li>New Australian drilling bit record achieved — 1962 m at an average of 8.75 m/hour using a Longyear polycrystalline diamond compact drill bit.</li> </ul>
1 January	<ul style="list-style-type: none"> <li>In assuming operatorship for exploration in the Qld sector of the Cooper and Eromanga Basins, Santos becomes the operator for all exploration, development and production activities in the Qld and SA sectors of these basins.</li> </ul>
April	<ul style="list-style-type: none"> <li>Naphtha replaces condensate production from Port Bonython.</li> </ul>
September	<ul style="list-style-type: none"> <li>Environmental Management Groups supersede JOMG in environment, and includes a representative from Department of Environment and Planning.</li> </ul>
<b>1994</b>	
February	<ul style="list-style-type: none"> <li>Santos Environmental Management System initiated.</li> <li>Gas production commenced from SW Qld to SA via Moomba.</li> </ul>
<b>1995</b>	
	<ul style="list-style-type: none"> <li>PASA sold to Tenneco Gas (now Epic Energy); includes Moomba–Adelaide pipeline system.</li> <li>To facilitate active upstream industry competition, the SA Government confirmed no rights of renewal would apply to PELs 5 and 6 upon their expiry in 1999.</li> <li>Sagasco Resources changed its name to Boral Energy Resources Ltd.</li> </ul>
September	<ul style="list-style-type: none"> <li>Coongie Lakes Control Zone Management Group formed to administer operations in Coongie Lakes region.</li> </ul>
<b>1996</b>	
	<ul style="list-style-type: none"> <li>Santos announced a \$200 million exploration program in the SA sector of the Cooper and Eromanga Basins over a three-year period.</li> <li>Ethane production commenced from Moomba to ICI plant at Botany Bay via a new pipeline. Ethane, previously stored in depleted reservoirs at State Government request for a petrochemical plant, released for sale to NSW also.</li> </ul>
May	<ul style="list-style-type: none"> <li>A record 916.7 km of seismic recorded by Geco-Prakla (Australia) for Santos in the Cooper Basin.</li> </ul>
5 December	<ul style="list-style-type: none"> <li>Fixed Factor Settlement Agreement between Santos, Delhi, Santos Petroleum, Boral, Vamgas, Crusader, Bridge Oil Developments, Santos (BOL), Reef, Alliance and Basin.</li> </ul>
<b>1997</b>	
3 November	<ul style="list-style-type: none"> <li>Minister signs PPLs for Santos in the Nappamerri Trough.</li> </ul>
<b>1999</b>	
28 February	<ul style="list-style-type: none"> <li>PELs 5 and 6 expire.</li> </ul>

## APPENDIX 2 Oil geochemistry parameters of selected Cooper–Eromanga wells, South Australia and Queensland

Well	Top (m)	Base (m)	Test <sup>a</sup>	AGSO sample no. <sup>b</sup>	API <sup>c</sup>	<C <sub>15</sub> <sup>c</sup> (%)	Pr/Ph <sup>d</sup>	Pr/C <sub>17</sub> <sup>d</sup>	Ph/C <sub>18</sub> <sup>d</sup>	OEP(1) <sup>e</sup>
<b>Wyandra Sandstone</b>										
Ipundu 1	798.6	829.7	DST 5	10142 *	50.9	27.1	5.59	0.77	0.15	1.05
Talgeberry 4	842.0	867.0	DST 3	10145	–	–	4.76	0.52	0.11	1.03
<b>Cadna-owie Formation</b>										
Cuddapan 1	1521.1	1533.1	DST 1	10140 *	–	26.6	6.85	0.74	0.09	1.03
Tickalara 10	1191.8	1202.1	DST 3	10097 *	44.6	12.6	4.26	0.33	0.07	1.09
Toby 1	1088.4	1125.0	DST 1	10149 *	–	–	4.49	0.23	0.05	1.07
<b>McKinley Formation</b>										
Morney 3	–	–	–	10221	48.6	23.6	3.76	0.45	0.13	1.04
<b>Murta Formation</b>										
Chookoo 1	1370.1	1377.7	DST 1	333 *	51.1	36.5	3.83	0.24	0.06	1.08
Dullingari 19	1483.8	1496.3	DST 1	200 *	52.3	29.9	5.51	0.39	0.08	1.08
Dullingari 22	1505.7	1514.9	DST 3	199 *	52.5	27.8	5.47	0.37	0.08	1.08
Dullingari 26	1482.9	1507.2	DST 2	10163	–	–	4.65	0.37	0.09	1.08
Ethel 1	–	–	–	10246	–	12.5	4.76	0.56	0.09	1.11
Ipundu North 1	886.0	908.5	DST 2	10143 *	–	–	5.44	0.72	0.14	1.04
Jackson 1	1104.9	1113.4	DST 1	2 *	48.4	21.7	6.46	0.42	0.08	1.11
Jackson 13	1106.4	1114.0	DST 1	10114	–	–	6.06	0.42	0.08	1.11
Kihee 2	968.7	978.0	DST 1	421 *	44.6	17.3	6.34	0.43	0.08	1.10
Limestone Creek 3	1206.7	1218.3	DST 2	342 *	41.2	7.7	3.94	0.32	0.07	1.07
Merrimelia 6	1559.1	1589.8	DST 3	1 *	50.0	28.2	4.99	0.36	0.08	1.07
Mooliampah 2	1231.4	1249.1	DST 1	10084	–	–	4.43	0.33	0.07	1.08
Naccolwah 2	1346.9	1351.5	DST 4	10088 *	44.4	11.0	6.16	0.45	0.08	1.14
Narcoonowie 3	1324.4	1348.7	DST 2	10176	–	–	5.86	0.58	0.11	1.11
Nockatunga 1	1005.2	1011.7	DST 1	307 *	47.5	21.4	6.98	0.44	0.08	1.13
Nockatunga 4	1006.0	1016.7	DST 1	308 *	47.5	20.6	6.37	0.44	0.08	1.11
Talgeberry 2	926.3	931.5	DST 2	10146	–	–	4.50	0.46	0.10	1.03
Taloola 1	1353.6	1384.1	DST 3	10157 *	45.7	6.6	6.92	1.09	0.16	1.09
Thungo 1	1004.3	1008.6	ST 1	305 *	45.7	1.6	5.51	0.45	0.08	1.08
Thungo 1	1003.5	1016.7	FT	309 *	46.6	18.0	5.35	0.45	0.09	1.08
Tickalara 7	1188.7	1207.9	DST 2	10093	–	–	3.69	0.30	0.07	1.10
Tickalara 10	1243.0	1252.7	DST 2	10096 *	44.2	13.2	4.02	0.31	0.07	1.08
Utopia 1	1010.0	1023.0	–	10201	46.8	18.7	4.84	0.54	0.11	1.04
Wilson 2	1139.6	1148.8	DST 1	10103	–	–	6.49	0.44	0.08	1.14
Winna 1	993.2	1017.4	FT	316 *	46.3	17.1	5.11	0.46	0.09	1.08
Yanda 4	1508.8	1522.5	DST 1	10106 *	42.5	10.4	4.63	0.36	0.08	1.12
<b>Namur Sandstone Member</b>										
Big Lake 55	1697.7	1716.0	DST 1	10162	–	–	4.48	0.42	0.09	1.05
Dullingari 22	1507.5	1516.7	DST 3	10164	–	–	4.64	0.37	0.09	1.09
Dullingari 29	1488.9	1507.8	DST 1	4 *	52.5	29.1	5.81	0.36	0.07	1.08
Inland 1	1246.6	1257.6	DST 2	10129 *	50.4	29.2	4.52	0.39	0.09	1.05
McKinlay 1	1232.0	1245.4	DST 1	6 *	41.6	1.9	3.45	0.28	0.07	1.08
Merrimelia 8	1597.2	1608.7	DST 2	7 *	50.4	18.9	5.26	0.37	0.08	1.08
Mooliampah 1	1322.2	1329.5	DST 3	10083	–	–	3.16	0.25	0.07	1.07
Mooliampah 2	1322.8	1329.2	DST 5	10085	–	–	3.31	0.26	0.07	1.07
Strzelecki 6	1413.1	1419.2	DST 1	5 *	49.3	36.6	4.40	0.30	0.06	1.07
Tickalara 7	1280.2	1291.4	DST 3	10094 *	45.3	15.3	3.54	0.26	0.06	1.11
Tickalara 10	1276.5	1284.1	DST 1	10095	–	–	3.49	0.25	0.07	1.11
Wilson 1	1210.7	1216.8	DST 6	337 *	54.9	31.5	9.00	0.53	0.10	1.10
<b>Westbourne Formation</b>										
Chookoo 7	1619.1	1629.5	DST 1	10075	–	–	3.44	0.24	0.06	1.07
Cooroo 5	1629.5	1666.0	DST 3	10077 *	50.9	28.5	5.30	0.44	0.09	1.08
Jackson 1	1331.4	1350.0	DST 5	195 *	40.8	5.4	3.46	0.27	0.07	1.09
Jackson 1	1314.3	1331.1	DST 4	196 *	40.8	4.7	3.62	0.27	0.06	1.08
Jackson 3	1315.2	1342.3	DST 2	10111	–	–	3.29	0.27	0.07	1.10
Jackson 3	1343.6	1358.5	DST 3	10112	–	–	3.15	0.26	0.07	1.09

Well	Top (m)	Base (m)	Test <sup>a</sup>	AGSO sample no. <sup>b</sup>	API <sup>c</sup>	<C <sub>15</sub> <sup>c</sup> (%)	Pr/Ph <sup>d</sup>	Pr/C <sub>17</sub> <sup>d</sup>	Ph/C <sub>18</sub> <sup>d</sup>	OEP(1) <sup>e</sup>
Jackson 3	1315.2	1342.3	DST 3	8 *	38.6	42.7	3.51	0.26	0.06	1.10
Jackson 11	1316.7	1347.2	DST 2	10113	–	–	3.10	0.27	0.07	1.09
Jackson 20	1335.0	1352.7	DST 3	10116	–	–	3.51	0.29	0.07	1.08
Jackson 21	1342.6	1347.2	DST 2	10117	–	–	3.31	0.27	0.07	1.07
Jackson 22	1338.4	1359.7	DST 1	10118	–	–	3.23	0.26	0.07	1.09
Jackson 26	1342.3	1350.9	DST 1	10119	–	–	3.19	0.26	0.07	1.08
Jackson 28	1346.3	1357.0	DST 2	10120	–	–	3.24	0.27	0.07	1.08
Jackson 30	1429.5	1445.4	DST 1	10121	–	–	4.05	0.36	0.08	1.09
Jackson 30	1315.2	1339.6	DST 2	10122	–	–	3.31	0.27	0.07	1.08
Jackson 35	1316.7	1341.1	DST 1	10123	–	–	3.18	0.26	0.07	1.07
Jackson 38	1360.9	1371.0	DST 1	10124	–	–	3.20	0.26	0.07	1.08
Jackson 39	1311.2	1335.6	DST 1	10125	–	–	3.12	0.26	0.07	1.07
Jackson 42	1321.6	1342.6	DST 2	10127	–	–	3.22	0.26	0.07	1.08
Jackson South 1	1298.4	1311.5	DST 3	9 *	41.8	7.6	3.56	0.26	0.06	1.10
Wilson 1	1344.2	1360.9	DST 3	338 *	43.5	12.3	3.48	0.26	0.06	1.09
Wilson 7	1344.2	1360.9	DST 1	10104	–	–	3.20	0.26	0.07	1.08
<b>Birkhead Formation</b>										
Big Lake 37	1960.5	1970.2	DST 1	10161	–	–	5.43	0.54	0.11	1.04
Bookabourdie 5	2140.0	2146.0	DST 1	10154 *	44.4	13.6	7.07	1.33	0.19	1.11
Bookabourdie 8	2139.1	2158.9	DST 1	10155 *	47.9	24.0	7.16	1.33	0.19	1.11
Bowen 2	1703.2	1716.0	DST 2	10073 *	48.1	16.3	3.79	0.25	0.07	1.05
Cooroo 5	1744.7	1751.4	DST 4	10078	–	–	5.45	0.42	0.08	1.08
Echuburra 1	1706.9	1710.8	DST 3	10080	–	–	5.58	0.47	0.09	1.09
Endeavour 2	1302.0	1330.2	DST 1	10141	–	–	4.19	0.42	0.10	1.03
Gidgealpa 17	1803.5	1813.9	DST 3	10172 *	42.5	1.5	4.32	0.36	0.09	1.06
Jackson 18	1446.3	1452.4	DST 2	10115 *	40.0	3.2	3.13	0.28	0.08	1.08
Keleary 2	2084.8	2122.6	DST 5	10156	–	–	5.18	0.44	0.09	1.09
Merrimelia 9	1862.3	1885.5	DST 2	11 *	50.9	53.1	4.96	0.38	0.08	1.08
Moorari 4	2150.4	2162.6	DST 2	10 *	47.9	30.8	9.45	2.46	0.26	1.16
Strzelecki 5	1682.8	1692.3	DST 3	13 *	43.8	8.1	3.77	0.32	0.07	1.10
Talgeberry 1	1175.6	1186.3	DST 7	10147 *	44.2	13.0	4.73	0.51	0.11	1.04
<b>Hutton Sandstone</b>										
Big Lake 36	1971.5	1977.5	DST 2	10160	–	–	4.02	0.38	0.09	1.07
Bodalla South 2	1464.0	1460.0	?DST 4	10132 *	44.8	5.4	5.07	0.43	0.09	1.04
Chookoo 2	1720.3	1722.1	DST 1	10074	–	–	3.35	0.24	0.07	1.07
Cook 3A	1965.0	1977.5	DST 1	10076 *	48.8	29.1	4.91	0.43	0.09	1.07
Gidgealpa 17	1823.6	1829.4	DST 4	10173 *	42.9	3.3	4.25	0.34	0.08	1.06
Gidgee 2	1454.5	1464.3	DST 2	10081	–	–	5.43	0.43	0.09	0.92
Inland 1	1579.2	1597.5	DST 1	10130 *	50.0	27.6	4.71	0.39	0.09	1.04
Jackson 1	1428.6	1454.8	DST 7	191 *	40.7	0.8	3.72	0.28	0.06	1.09
Jackson 1	1428.9	1436.5	DST 6	197 *	40.2	1.0	3.25	0.27	0.07	1.09
Jackson 2	1438.4	1445.4	DST 1	10110	–	–	3.25	0.27	0.07	1.09
Jackson 2	1438.3	1445.4	DST 1	12 *	40.0	2.8	3.51	0.28	0.07	1.09
Jackson 2	1442.3	1450.8	PT	192 *	40.2	0.8	3.35	0.26	0.07	1.08
Jackson 39	1438.7	1451.5	DST 2	10126	–	–	3.25	0.27	0.07	1.08
Jackson 42	1442.6	1448.4	DST 3	10128	–	–	3.02	0.26	0.07	1.08
Jarrar 2	–	–	DST 1	10082	–	–	4.05	0.26	0.07	1.06
Kenmore 1	1514.2	1519.0	?DST 2	10131	–	–	4.41	0.37	0.09	1.04
Merrimelia 8	1859.3	1879.1	DST 3	193 *	50.2	27.3	5.02	0.35	0.08	1.09
Munro 2	1442.0	1449.9	DST 1	10087	–	–	4.47	0.33	0.07	1.11
Muteroo 2	1714.5	1722.1	PT	10175	–	–	4.62	0.37	0.08	1.08
Naccowlah South 1	1670.3	1682.3	DST 2	339 *	48.6	27.7	3.69	0.25	0.06	1.07
Naccowlah South 7	1694.4	1704.9	DST 1	10089	–	–	3.15	0.24	0.07	1.07
Naccowlah West 13	1688.0	1694.1	DST 2	10092	–	–	3.25	0.27	0.07	1.10
Tintaburra 3	1068.9	1084.2	DST 1	10148 *	–	–	3.52	0.33	0.09	1.01
Toobunyah 3	–	–	–	10151 *	44.8	8.6	3.52	0.34	0.09	1.02
Wandilo 2	1620.3	1628.2	DST 4	10100	–	–	4.54	0.36	0.08	1.06
Watson South 1	1605.4	1611.8	–	10101 *	46.4	5.6	6.54	0.91	0.15	1.05
Wilson 1	1478.3	1488.6	DST 5	10102	–	–	3.06	0.26	0.07	1.07

Well	Top (m)	Base (m)	Test <sup>a</sup>	AGSO sample no. <sup>b</sup>	API <sup>o</sup>	<C <sub>15</sub> <sup>c</sup> (%)	Pr/Ph <sup>d</sup>	Pr/C <sub>17</sub> <sup>d</sup>	Ph/C <sub>18</sub> <sup>d</sup>	OEP(1) <sup>e</sup>
Wilson 1	1478.3	1488.6	DST 5	335 *	40.2	2.7	3.48	0.26	0.06	1.09
Wilson 7	1460.0	1476.2	DST 2	10105	–	–	3.09	0.27	0.07	1.08
<b>Poolowanna Formation</b>										
Bargie 1	1609.5	1615.1	?DST 2	10134 *	46.6	17.0	5.07	0.45	0.09	1.04
Black Stump 1	1621.3	1632.2	?DST 1	10135 *	45.0	6.2	5.40	0.49	0.09	1.08
Bodalla South 5	1603.0	1610.0	?DST 3	10133 *	46.6	21.1	4.61	0.39	0.08	1.03
Chookoo 6	1795.3	1801.4	DST 1	10138 *	36.7	0.6	3.10	0.26	0.07	1.06
Cooroo 5	1824.5	1830.9	DST 1	10139	–	–	3.83	0.32	0.09	1.05
Cuttapirrie 1	2443.3	2452.4	DST 12	15 *	45.9	21.3	6.65	0.68	0.11	1.07
Cuttapirrie 1	2439.0	2468.6	DST 3	420 *	44.6	19.2	6.09	0.69	0.11	1.08
Keleary 2	2325.0	2344.5	DST 2	10165	–	–	3.92	0.31	0.08	1.07
Sturt 7	1871.2	1875.7	DST 3	10167 *	49.5	24.5	6.40	1.07	0.17	1.04
Toby 1	1740.7	1746.8	DST 5	10150 *	42.1	32.3	4.52	0.21	0.04	1.09
Wandilo 2	1679.4	1685.5	DST 3	10099	–	–	3.86	0.28	0.08	1.03
<b>Nappamerri Group</b>										
Coonatie 1	2839.8	2850.2	DST 1	27 *	42.3	14.7	4.05	0.24	0.07	1.05
Della 4	1910.8	1951.0	–	169 *	–	0.0	2.91	0.24	0.08	1.06
Merrimelia 7	2146.4	2161.6	DST 5	16 *	36.6	0.3	4.17	0.34	0.07	1.08
<b>Tinchoo Formation</b>										
Keleary 2	2383.5	2405.5	DST 4	10166 *	47.5	30.3	3.24	0.28	0.08	1.05
<b>Toolachee Formation</b>										
Durham Downs 1	2534.0	2574.0	DST 2	114 *	51.1	39.5	4.74	0.44	0.11	1.04
Gidgealpa 2	2083.9	2085.4	PT	171 *	42.7	10.5	4.69	0.32	0.08	1.07
Gidgealpa 2	2083.9	2312.2	PT	394 *	48.8	46.0	4.53	0.32	0.08	1.06
Karmona 1	2273.8	2334.8	DST 1	133 *	–	5.4	3.27	0.28	0.08	1.06
Naccowlah South 10	1903.5	1912.6	DST 1	10090 *	39.4	1.0	3.25	0.26	0.07	1.05
Strzelecki 10	1936.7	1943.4	DST 3	17 *	37.3	1.4	3.41	0.25	0.06	1.07
Yanda 7	2245.8	2253.1	DST 1	10108 *	–	0.9	3.14	0.27	0.07	1.06
<b>Patchawarra Formation</b>										
Brolga 1	2816.1	2853.5	DST 4	25 *	48.6	35.7	6.66	0.36	0.06	1.05
Brolga 1	2769.1	2798.1	DST 3	59 *	49.0	30.0	5.72	0.44	0.09	1.05
Costa 1	–	–	DST 3	10079	–	–	4.50	0.30	0.08	1.02
Daralingie 1	2152.5	2185.4	DST 4	121 *	53.2	48.6	4.18	0.35	0.09	0.99
Daralingie 18	2267.9	2269.9	PT	10181 *	37.1	0.8	3.23	0.36	0.09	1.07
Fly Lake 1	2618.5	2795.0	PT	29 *	39.8	2.7	5.24	0.47	0.10	1.06
Gidgealpa 3	2229.0	2234.2	DST 5	26 *	–	1.3	1.98	0.14	0.09	0.84
Gidgealpa 17	2164.1	2264.1	DST 6	10174 *	37.9	1.5	3.57	0.34	0.09	1.07
Kanowana 1	2766.7	2768.5	PT 4	21 *	53.0	66.9	5.93	0.36	0.07	1.08
Kanowana 1	2817.9	2824.3	PT 3	22 *	35.9	0.8	3.75	0.38	0.10	1.04
Kanowana 1	2834.6	2850.2	PT 1	23 *	47.5	62.5	3.04	0.46	0.17	0.98
Munkah 4	2266.5	2276.9	DST 4	10086 *	53.2	50.5	3.69	0.25	0.07	1.04
Sturt 6	1883.7	1898.3	DST 3	10158 *	49.7	31.2	5.72	0.86	0.16	1.04
Toolachee 1	2088.5	2122.6	PT	31 *	44.0	4.1	5.29	0.34	0.07	1.07
Toolachee 6	2277.2	2322.3	PT	49 *	39.0	0.5	3.81	0.30	0.09	1.03
Toolachee 7	2229.6	2244.9	PT	30 *	44.0	2.1	6.48	0.36	0.07	1.08
Wancoocha 2	1730.7	1751.4	DST 3	10177 *	43.1	2.6	4.65	0.38	0.08	1.06
<b>Tirrawarra Sandstone</b>										
Fly Lake 2	2905.4	2914.5	PT	88 *	34.2	1.0	6.32	0.75	0.12	1.05
Fly Lake 8	2890.4	2907.8	PT	10182 *	48.1	30.2	5.73	0.69	0.12	1.06
Gidgealapa 41	2224.4	2233.3	PT	10183	–	–	4.17	0.36	0.08	1.04
Moorari 1	2895.6	2991.9	–	18 *	49.9	49.5	7.94	0.63	0.09	1.05
Moorari 1	2913.9	2970.3	PT	10185	–	–	6.07	0.61	0.11	1.03
Pepita 1	2218.3	2248.2	DST 2	10144 *	38.6	1.8	3.29	0.27	0.06	1.17
Tirrawarra 2	2978.2	3001.1	PT	10186	–	–	5.55	0.64	0.11	1.06
Tirrawarra 8	2915.4	2935.5	PT	10187	–	–	5.94	0.65	0.11	1.07
Woolkina 1	2999.2	3007.8	PT	10188	–	–	5.97	0.64	0.11	1.06
Yanpurra 1	2894.1	2896.8	DST 7	28 *	43.3	19.4	7.27	1.02	0.14	1.03

Well	Top (m)	Base (m)	Test <sup>a</sup>	AGSO sample no. <sup>b</sup>	API <sup>c</sup>	<C <sub>15</sub> <sup>c</sup> (%)	Pr/Ph <sup>d</sup>	Pr/C <sub>17</sub> <sup>d</sup>	Ph/C <sub>18</sub> <sup>d</sup>	OEP(1) <sup>e</sup>
<b>Merrimelia Formation</b>										
Chandos 1	2303.1	2312.2	–	393 *	49.3	16.3	6.24	0.65	0.12	1.07
Malgoona 1A	2264.7	2268.9	PT	10184	–	–	5.49	0.80	0.16	1.07
<b>Pre-Permian</b>										
Sturt 6	1883.7	1919.0	DST 5	10159 *	52.3	35.5	5.93	0.89	0.16	1.04

a DST drillstem test, FT formation test, PT production test.

b Asterisk indicates oil analysed for saturated biomarkers and  $\delta^{13}\text{C}$  of saturated and aromatic hydrocarbons (AGSO and GeoMark Research, in prep.).

c <C<sub>15</sub> = % weight loss of the whole oil by evaporation of volatile components over a 24-hour period at room temperature.

d Pr pristane, Ph phytane.

e  $\text{OEP}(1) = \text{C}_{21} + 6\text{C}_{23} + \text{C}_{25} / (4\text{C}_{22} + 4\text{C}_{24})$ .

### 3 ABBREVIATIONS, MEASUREMENTS AND WELL SYMBOLS

#### Company and organisation names

ACCC	Australian Competition and Consumer Commission
AGL	Australian Gas Light Co.
AGSO	Australian Geological Survey Organisation
API	American Petroleum Institute
BMR	Bureau of Mineral Resources (now AGSO)
ETSA	Electricity Trust of South Australia
EWS	Engineering and Water Supply Department
ICI	Imperial Chemical Industry
PASA	Natural Gas Pipelines Authority of South Australia
PIRSA	Primary Industries and Resources South Australia
PMA	Petroleum and Minerals Authority
SAOG	South Australian Oil and Gas Corporation
SAPEG	South Australian Petroleum Exploration Group

#### General

2D	two-dimensional
3D	three-dimensional
<sup>12</sup> C, <sup>13</sup> C	carbon isotopes
abs	absolute
AFTA	apatite fission track analysis
APRAS	Analytical Petroleum Resource Appraisal System
C horizon	near top of Cadna-owie Formation seismic horizon
CO <sub>2</sub>	carbon dioxide
C <sub>org</sub>	carbon from organic sources
DBT	dibenzothiophene
DMP	dimethylphenanthrene
DST	drillstem test
DOM	dispersed organic matter
DT	sonic log
DW	deviated well
EOR	enhanced oil recovery
GAB	Great Artesian Basin
GIS	geographic information system
GMI Ridge	Gidgealpa–Merrimelia–Innamincka Ridge
GOR	gas–oil ratio
GR	gamma ray log
H	horizontal well
HI	hydrogen index
J horizon	top of the Nappamerri Group seismic horizon
JOMG	Joint Operations Management Group
KB	kelly bushing
LLD	deep laterolog resistivity
LLS	shallow laterolog resistivity
LPG	liquefied petroleum gas
Ma	million years
MAI	methyl adamantane index
MP	methylphenanthrene
MPI-1	methylphenanthrene index
MSFL	microspherically focused log resistivity
NGMA	National Geoscience Mapping Accord
NPV	Net Present Value
NSW	New South Wales
OEL	oil exploration licence
OGIP	original gas-in-place
OI	oxygen index
P	phenanthrene
P horizon	near top of Permian coal seismic horizon
PEL	petroleum exploration licence
PEPS	Petroleum Exploration and Production System (database)
PPL	petroleum production licence

Pr/Ph	pristine/phytane ratio
Qld	Queensland
R horizon	Daralingie unconformity seismic horizon
RTSTM	rate too small to measure
R <sub>c</sub>	calculated vitrinite reflectance
R <sub>o</sub>	measured vitrinite reflectance
Rw	(formation) water resistivity
SA	South Australia
SADME	South Australian Department of Mines and Energy
sd	standard deviation
<i>sensu stricto</i>	in the narrow sense
S <sub>1</sub> , S <sub>2</sub>	potential yield (kg of hydrocarbon per tonne of rock)
SIS	seismic increment of strata
TD	total depth
TeMN	tetramethylnaphthalene
T <sub>max</sub>	temperature of maximum generation of S <sub>2</sub> hydrocarbons (°C)
TMN	trimethylnaphthalene
TOC	total organic carbon
U horizon	approximates the top of the Murteree Shale seismic horizon
V horizon	top of the Patchawarra Formation seismic horizon
Vc	Patchawarra coal seismic horizon
VR	vitrinite reflectance
W horizon	top Merrimelia Formation and/or Tirrawarra Sandstone seismic horizon
Z horizon	the base of the Cooper Basin or top of Warburton Basin seismic horizon

#### Measurement

Most units of measurement used in this volume are those of the International System of Units (SI) and are not included in this glossary. Units outside the SI which have been authorised for use within Australia's metric system, and units having general application are given.

‰	parts per mil (per thousand)
°C	degree Celsius (the Celsius temperature)
cP	centipoise (10 <sup>-2</sup> P; viscosity; P = 10 <sup>-4</sup> Pa.s (pascal second))
GJ	gigajoule (10 <sup>9</sup> joule)
J	joule (energy; 1 kg.m <sup>2</sup> /s <sup>2</sup> )
kL	kilolitre (volume; = 1 m <sup>3</sup> )
kPa	kilopascal (10 <sup>3</sup> Pa)
Ma	million years
mD	millidarcies (permeability)
MPa	megapascal (10 <sup>6</sup> Pa)
mW	milliwatt (10 <sup>-3</sup> watt)
Pa	pascal (pressure; Pa = 1 kg /m.s <sup>2</sup> )
PJ	petajoule (10 <sup>15</sup> joule)
sm <sup>3</sup>	standard cubic metre
t	tonne (mass; = 10 <sup>3</sup> kg)
W	watt (power; 1 kg.m <sup>2</sup> /s <sup>3</sup> )

#### Conversions

1 cubic metre (m <sup>3</sup> )	= 1 kilolitre (kL)
1 cubic metre (m <sup>3</sup> )	= 35.49373 cubic feet (standard conditions are assumed for conversions of gas: 15°C and 101.325 kPa)
1 square kilometre	= 247.1 acres
1 kilolitre (kL)	= 6.2898 barrels
1 kilopascal (kPa)	= 0.1450 pound-force per square inch (psi)

#### Imperial

bbl	barrel
bcf	billion cubic feet (10 <sup>9</sup> )

bopd	barrels of oil per day
mmbbl	million barrels
mm(s)cf	million (standard) cubic feet
mmcf/d	million cubic feet per day
mmstb	million stock tank barrels
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
scf	standard cubic feet
tcf	trillion cubic feet (10 <sup>12</sup> )

## **Well symbols**

### *Petroleum*

⊖	dry
○	oil show
⊗	gas show
●	oil
⊛	gas
✱	oil and gas

### *Other*

- mineral, stratigraphic, water



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