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Geochemical perspectives on the petroleum habitat of the Cooper and Eromanga Basins, central Australia

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This thesis is submitted in fulfilment of the requirements for the degree of
DOCTOR OF PHILOSOPHY

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January 2002

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ABSTRACT

Geochemical and petrographic techniques have been used to investigate genetic relationships between potential source rocks and hydrocarbon accumulations in the Cooper (Late Carboniferous–Triassic) and Eromanga (Jurassic–Cretaceous) Basins of central Australia.

The liquid hydrocarbons trapped within the Cooper Basin were generated at varying maturation levels from terrestrial organic matter, principally within the Patchawarra Formation (Early Permian). The condensate-like Family 1 oils (46–50° API) which are exceptionally mature ($R_c \geq 0.99\%$; rearranged hopanes >> 17α-hopanes) are presently reservoired in the northern Patchawarra Trough (South Australia) where the maturity of the Patchawarra Formation is ≥ 1.0% R_o. Commercially produced crudes from the Tirrawarra Sandstone in the Tirrawarra, Fly Lake and Moorari/Woolkina Fields belong to this family. Matching rearranged hopane distributions in Cooper Basin coals are evidence that these high maturity oils were predominantly derived from local coals (via short-range migration), rather than shales which have a more conventional hopane distribution. The latter is a feature of the heavier Family 2 oils (34–36° API) which are reservoired along the western and southern margin of the Cooper Basin within various reservoirs at Daralingie, Gidgealpa, Malgoona and Sturt ($R_c \leq 0.91\%$; rearranged hopanes < 17α-hopanes) where the Patchawarra Formation is less deeply buried and less mature ($R_o = 0.75–1.0\%$).

Both Family 1 and Family 2 oils have permeated into the superjacent Eromanga Basin, but little pure Permian oil has survived therein. Notable exceptions in the South Australia sector include hydrocarbons trapped within the Hutton Sandstone (Family 1 affinity) at Reg Sprigg, and a very small oil pool trapped within the Murta Formation (quasi-Family 2 affinity) at Garanjanie. In Queensland, the Hutton Sandstone oils at Chookoo and Naccowlah South also represent pure Permian hydrocarbons and are related to Family 1.

The Birkhead Formation (Middle–Late Jurassic) is the major hydrocarbon source unit in the Eromanga Basin where its best source facies comprise coals containing Type II kerogen. It has contributed to Eromanga-reservoired oil over a wide area of the southern Cooper Basin. The Murta Formation (Early Cretaceous) also appears to be self-sourcing, and many Murta-derived oils migrated from their source rocks at the threshhold of the conventional oil window ($R_c = 0.7$ MPI + 0.22 = 0.5–0.6%). Murta oils with low R_c values include those trapped along the Murteree Ridge (South Australia) and the southeast extension of the Naccowlah-Jackson Ridge (Queensland). Notable exceptions are the Murta crudes at Big Lake ($R_c = 0.74\%$), Merrimelia ($R_c = 0.75\%$) and Gidgealpa ($R_c = 0.66\%$) for which higher maturities (and deeper source beds) are indicated. A predominant Jurassic (Birkhead Formation) source is implied for these oils. In contrast to crudes from the Murta Formation and Namur Sandstone, those in Birkhead and Hutton reservoirs generally have maturities that indicate they were expelled from their respective source rocks at somewhat higher maturation levels (South Australia: R_c = 0.50–1.22%; Queensland: $R_c = 0.61–1.08\%$).

A novel combination of aromatic source and maturity parameters has enabled the recognition of multiple petroleum systems; instances of migration from Permian kitchens into Jurassic and Cretaceous reservoirs; and Eromanga traps which have received charges from both Permian and Jurassic/Cretaceous source rocks. As such, mixing of Permian and Jurassic/Cretaceous hydrocarbons can be quantified using the biomarker ratios 2-MP/1-MP and 1-MP/9-MP. Two mixing curves are defined for oils in South Australia and a single mixing curve for crudes in Queensland. Regional analysis of oils of mixed origin has allowed the mapping of migration routes of Permian hydrocarbons into the Jurassic/Cretaceous sequence, thereby demonstrating long-distance lateral migration (> 50 km) of Cooper Basin hydrocarbons into the Eromanga succession and highlighting the potential of Eromanga-Eromanga source-reservoir couplets beyond the margins of the Cooper Basin.

The prospectivity of the Eromanga Basin beyond the Cooper Basin "zero edge" is further enhanced with the recognition of significant and widespread vitrinite reflectance suppression in resinite-impregnated coals of the Birkhead Formation as indicated by fluorescence alteration of multiple macerals (FAMM). Widespread (but less severe) vitrinite reflectance suppression in organic-rich lithologies of the Poolowanna and Murta Formations is also inferred.

DECLARATION

To the best of my knowledge and belief, this work contains no material which has been accepted for the award of any other degree or diploma in any university or other tertiary institute, nor does it contains any material previously published or written by another person, except where due reference has been made in the text.

I give consent to this copy of my thesis, when deposited in the University Library, being available for loan and photocopying.

BERND H. MICHAELSEN

24 DECEMBER 2001

ACKNOWLEDGEMENTS

I am indebted to Associate Professor David McKirdy for supervising this project. The work benefited from his knowledge of the hydrocarbon habitat of the Cooper and Eromanga Basins, his geochemical database and personal library. Many other people contributed to this project including:

- Professor L.A. Frakes (University of Adelaide) who accepted me as a student in the Department of Geology and Geophysics and acted as co-supervisor in the initial stages of the project;
- Dr D.I. Gravestock, Ms E.M. Alexander, Mr A.J. Hill, and Mr R. Frears (Primary Industries and Resources South Australia, PIRSA) who supplied many oil and rock samples, provided advice, and organised finance for much of the work in the western Cooper and Eromanga Basins (Chapters 2 to 5);
- Dianne Padley (University of Adelaide) and Yoji Hayasaka (Australian Wine Research Institute) who assisted with many aspects of the operation of the Varian 3400 GC and Finnigan TSQ-70 MS-MS;
- Gavin Springbett who provided expert advice regarding organic petrology;
- the personnel of the PIRSA Core Library;
- Dr Neil Sherwood and other CSIRO staff at North Ryde who conducted FAMM analyses;
- Professor J.M. Moldowan (Stanford University) who provided useful comments regarding rearranged hopanes and privately reviewed a manuscript submitted to *Geochimica et Cosmochimica Acta*;
- Drs M. Vliex, M. Radke, R.E. Summons, and H.L. ten Haven who reviewed a manuscript submitted to *Organic Geochemistry*;
- Coauthors of published papers, abstracts and technical reports, especially Dr D.M. McKirdy, Ms R. Paull, Dr P.J. Boult and Ms E.M. Alexander;
- Michael Dowling (Paradigm Instruments) who provided speedy back-up and advice for the Hewlett-Packard 6890 GC/GC-MS; and
- Wayne Mussared (University of Adelaide) who expertly prepared polished sections and provided other lapidary assistance.

During my candidature I was financially supported by an Australian Postgraduate Research Award. However, I particularly thank my parents Hilde and Günter Michaelsen, and Rosemary Paull who collectively provided much needed support and endured considerable hardship during the final stages of this research.

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ABBREVIATIONS AND SYMBOLS

AGSO	Australian Geological Survey Organisation
BOPD	barrels of oil per day (flow rate from well head)
28,30-BNH	28,30-bisnorhopane
BP-1	dimethylsiloxane (SGE, Australia)
CSIRO	Commonwealth Scientific Industrial Research Organisation
C_{29}^{*}	17α-30-nordiahopane
C_{30}^{*}	17α-diahopane
$C_{29}T_s$	18α-30-norneohopane
$C_{30}T_s$	18α-neohopane
DB-1	Durabond-1 (J & W Scientific, USA)
DB-5	Durabond-5 (J & W Scientific, USA)
DOM	dispersed organic matter
DNR	dimethylnaphalene ratio (see p. xxi)
DST	drill stem test
Eh	oxidising potential
FAMM	fluorescence alteration of multiple macerals
Fm	Formation
FT	flow test
GMI	Gidgealpa-Merrimelia-Innamincka
GC	(capillary) gas chromatograph(y)
GC-C-irMS	gas chromatography-combustion-isotope ratio-mass spectrometry
GC-FID	gas chromatography-flame ionization detector
GC-MS	gas chromatography-mass spectrometry
GC-MS-MS	gas chromatography-mass spectrometry-mass spectrometry
GOR	gas to oil ratio
Gp	Group
HI	hydrogen index (S_2/TOC: Rock-Eval pyrolysis)
i.d.	internal diameter
M^+	molecular ion
Ma	million years before present
My	million years (absolute)
Me	methyl
MESA	(Department of) Mines and Energy, South Australia
MID	multiple ion detection
MPI	methylphenanthrene index (see p. xxi)
MPR	methylphenanthrene ratio (see p. xxi)
MRM	multiple reaction monitoring
m/z	atomic mass-to-charge ratio
NJ	Naccowlah-Jackson
pH	hydrogen ion concentration ($-\log_{10}[H^+]$)
PI	production index (S_1/S_1+S_2: Rock-Eval pyrolysis)
PIRSA	(Department of) Primary Industries and Resources, South Australia
Prod.	production (sample of oil)
Pr/Ph	pristane/phytane ratio
Pr/*n*-C_{17}	pristane/*n*-heptadecane
Ph/*n*-C_{18}	phytane/*n*-octadecane
R_c	calculated vitrinite reflectance (from MPI or MPR)
$\overline{R}_c$	average of three calculated vitrinite reflectance calibrations based on MPI and MPR (see p. 36)
$\overline{\overline{R}}_c$	arithmetic mean of $\overline{R}_c$ for isometamorphic coal and shale pairs (see p. 38)
R_{est}	maturity (equiv. vitrinite reflectance) estimated from R_o, R_{re} and R_c
R_{re}	maturity estimated from Rock-Eval (T_{max} and HI data)
R_o	mean of maximum vitrinite reflectance (in oil)
R_r	mean of random vitrinite reflectance (in oil)

SA	South Australia
SIM	selected ion monitoring
SRM	selective reaction monitoring (Finnigan TSQ-70 mass spectrometer)
SCF/STB	standard cubic feet (of gas)/stock tank barrel (of oil)
Sst	Sandstone
T_m	17α-22,29,30-trisnorhopane
TNR	trimethylnaphthalene ratio (see p. xxi)
TOC	total organic carbon
T_{max}	maximum temperature (Rock-Eval pyrolysis)
T_s	18α-22,29,30-trisnorneohopane
Qld	Queensland
UV	ultra-violet

UNITS

° API	degree American Petroleum Industry (measurement of oil density)
° C	degree Celsius
cm	centimetre
eV	electron volt
kg	kilogram
kl	kilolitre (= m^3)
km	kilometre
kPa	kilopascal
m	metre
m^3	cubic metre
mg	milligram
min	minute
min^{-1}	per minute
mm	millimetre
nm	nanometre
s	second
s^{-1}	per second
$scan^{-1}$	per scan
V	volt
µA	microampere
µm	micrometre

KEY TO MATURITY AND SOURCE PARAMETERS

Aromatic hydrocarbon parameters

$$DNR = \frac{\text{2,6-DMN + 2,7-DMN}}{\text{1,5-DMN}} \qquad TNR = \frac{\text{2,3,6-TMN}}{\text{1,3,5-TMN + 1,4,6-TMN}}$$

$$MPI = \text{methylphenanthrene index} = \frac{1.5\,[\text{2-MP + 3-MP}]}{\text{P + 1-MP + 9-MP}} \qquad MPR = \frac{\text{2-MP}}{\text{1-MP}}$$

where 1,5-DMN = 1,5-dimethylnaphthalene ; 2,6-DMN = 2,6-dimethylnaphthalene

2,7-DMN = 2,7-dimethylnaphthalene ; 1,3,5-TMN = 1,3,5-trimethylnaphthalene

1,4,6-TMN = 1,4,6-trimethylnaphthalene ; 2,3,6-TMN = 2,3,6-trimethylnaphthalene

P = phenanthrene; 1-MP = 1-methyphenanthrene ; 2-MP = 2-methylphenanthrene

3-MP = 3-methylphenanthrene ; 9-MP = 9-methylphenanthrene

Drimane parameters

$$\frac{C_{15}}{C_{16}} = \frac{\text{drimane}}{\text{homodrimane}}$$

$$\frac{R}{N} = \frac{\text{rearranged drimanes}}{\text{drimanes}} = \frac{\text{8,8-dimethyl-10-desmethyldrimane\# + 9,9-dimethyl-10-desmethyldrimane\#}}{\text{drimane + homodrimane}}$$

\# Structures 1 and 2, Peters and Moldowan (1993, p. 167)

Hopane parameters

$$\frac{T_s}{T_m} = \frac{\text{18}\alpha\text{-22,29,30-trisnorneohopane}}{\text{17}\alpha\text{-22,29,30-trisnorhopane}} \; ; \; \frac{C_{29}T_s}{C_{29}\alpha\beta} = \frac{\text{18}\alpha\text{-30-norneohopane}}{C_{29}\alpha\beta = \text{17}\alpha\text{-30-norhopane}}$$

$$\frac{C_{30}T_s}{C_{30}\alpha\beta} = \frac{\text{18}\alpha\text{-neohopane}^{\S}}{\text{17}\alpha\text{-hopane}}$$ § $C_{30}T_s$ includes the coeluting C_{29} fernane (Michaelsen *et al.*, 1995f)

$$\frac{C_{30}^{*}}{C_{30}\alpha\beta} = \frac{\text{17}\alpha\text{-diahopane}}{\text{17}\alpha\text{-hopane}} \; ; \; \frac{C_{29}\alpha\beta}{C_{30}\alpha\beta} = \frac{\text{17}\alpha\text{-30-norhopane}}{\text{17}\alpha\text{-hopane}} \; ; \; C_{30}\frac{\alpha\beta}{\beta\alpha} = \frac{\text{17}\alpha\text{-hopane}}{\text{17}\beta\text{-hopane}}$$

$$C_{31}\frac{22S}{22R} = \text{homohopane}\frac{22S}{22R} \; ; \; \frac{BNH}{C_{30}\alpha\beta} = \frac{\text{17}\alpha\text{- and 17}\beta\text{-28,30-bisnorhopane}}{\text{17}\alpha\text{-hopane}}$$

Sterane parameters

$$C_{29}\frac{\alpha\beta\beta}{\alpha\alpha\alpha+\alpha\beta\beta} = \text{ethylcholestane (20S+20R)}\frac{\text{5}\alpha\text{,14}\beta\text{,14}\beta}{\text{5}\alpha\text{,14}\alpha\text{,17}\alpha+\text{5}\alpha\text{,14}\beta\text{,17}\beta}$$

$$C_{29}\frac{\beta\alpha}{\alpha\alpha\alpha+\alpha\beta\beta} = \frac{\text{13}\beta\text{,21}\alpha\text{-ethyldiacholestane}}{\text{5}\alpha\text{,14}\alpha\text{,17}\alpha+\text{5}\alpha\text{,14}\beta\text{,17}\beta\text{-ethylcholestane}}$$

$$\frac{C_{27}}{C_{29}} = \frac{\text{cholestane}}{\text{ethylcholestane}} \; ; \; \frac{Hop}{Ster} = \frac{Hopane}{Sterane} = \frac{\text{17}\alpha\text{-hopane + 17}\beta\text{-hopane}}{\text{ethylcholestane + ethyldiacholestane}}$$

CHAPTER 1

Introduction: Petroleum habitat of the Cooper and Eromanga Basins, central Australia

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1.1 HISTORY OF PETROLEUM EXPLORATION

The hydrocarbon province comprising the Cooper and Eromanga Basins of northern South Australia and southwestern Queensland is Australia's largest onshore petroleum production and exploration region (Fig. 1.1). Since the 1950s exploration in this area has been undertaken principally by the Delhi-Santos Ltd consortium which first discovered commercial reserves of Cooper Basin gas at Gidgealpa-2 (Toolachee Formation) in 1963 and oil at Tirrawarra-1 (Tirrawarra Sandstone) in 1970 (Fig. 1.2). The superjacent Eromanga Basin first yielded commercial gas from Namur-1 (Namur Sandstone) in 1976 and oil from Strzelecki-3 (Hutton Sandstone) in 1978. The 1200+ wells which have been drilled in this region of South Australia between 1960 and 2000 have resulted in the discovery of 25 oil fields and around 120 gas fields within the Cooper Basin, and 35 oil fields and 4 gas fields in the Eromanga Basin (Morton, 1996; Laws and Gravestock, 1998). The number of oil and gas fields which have been discovered in the Queensland sector of the Cooper Basin (*i.e.* northern Cooper Basin) demonstrates that exploration has been equally successful (Fig. 1.3).

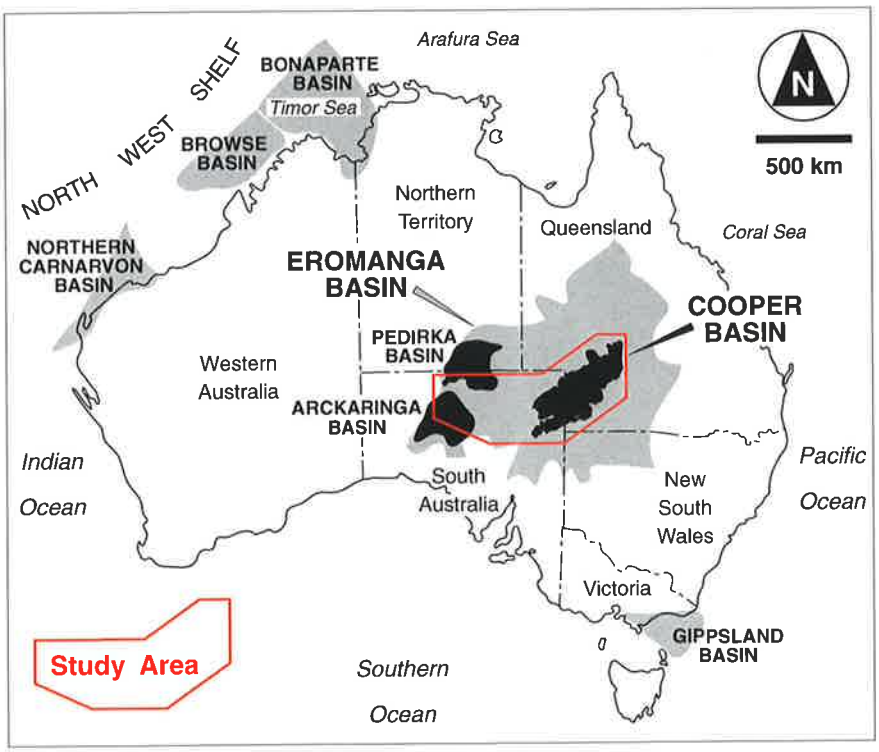


Figure 1.1 Locality of study area in central Australia with respect to selected Palaeozoic, Mesozoic and Cainozoic basins

1.2 TECTONIC AND STRUCTURAL SETTING

1.2.1 Cooper Basin

The Cooper Basin (Late Carboniferous–Triassic: Fig. 1.4), which straddles the South Australia/Queensland border, occurs entirely in the subsurface and is correlative with the Pedirka and Arckaringa Basins of northern South Australia (Figs 1.5 and 1.6). Gravestock and Jensen-Schmidt (1998, p. 49) described the Cooper Basin as "one of a number of remnant Late

Carboniferous–Early Permian depocentres which lay in the Australian interior of the Gondwana Supercontinent". The Cooper Basin itself is underlain by the Warburton Basin (Cambro–Ordovician) in South Australia (Figs 1.4 and 1.7), and in Queensland by the Warburton Basin in the southwest and the Adavale Basin (Devonian) in the far northeast. These Palaeozoic basins are underlain by even older bedrock including metamorphosed and igneous basement of Proterozoic age.

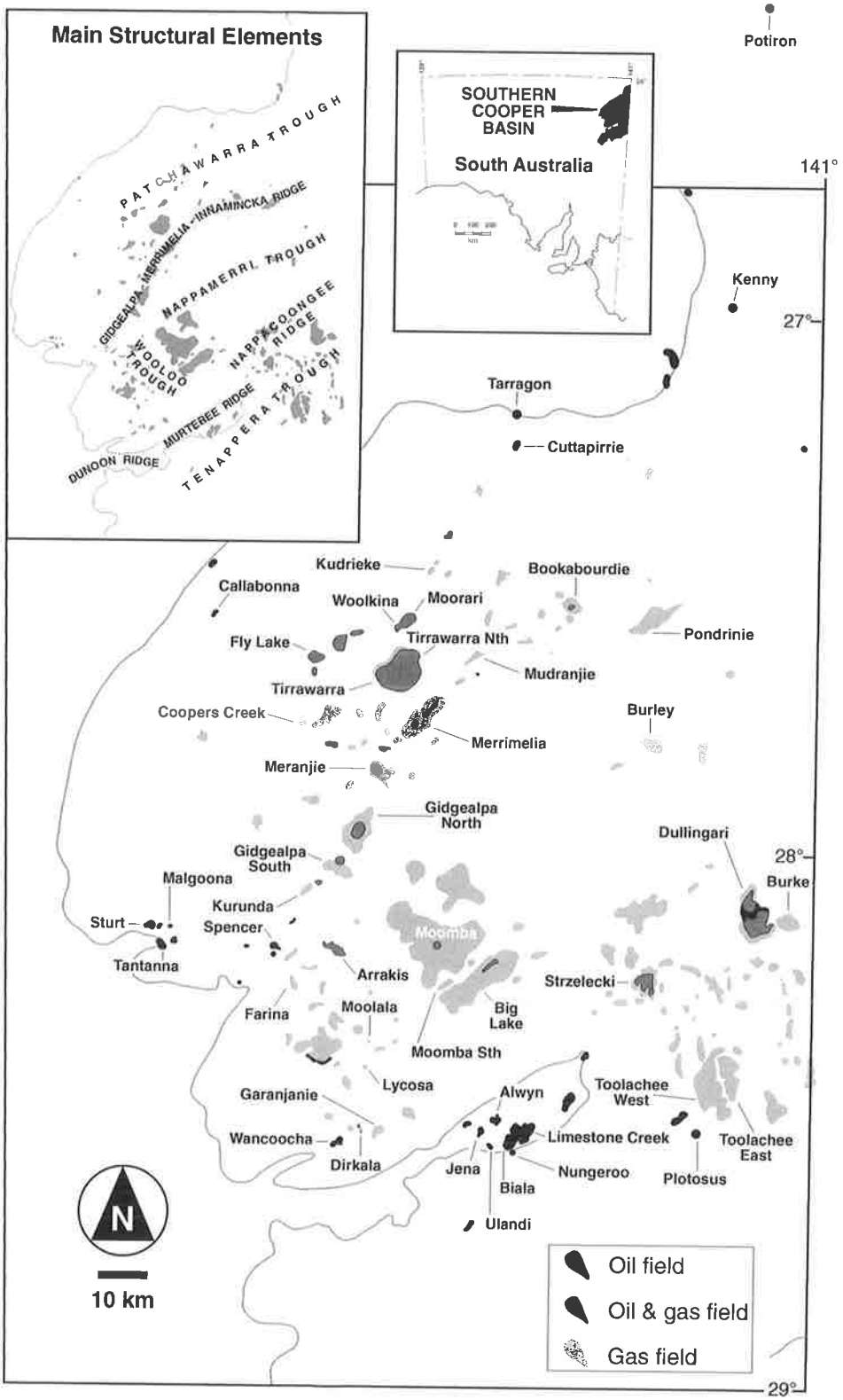


Figure 1.2 Locality of oil and gas fields in the Cooper and Eromanga Basins, South Australia

In contrast to Australia's other major petroleum producing basins [*viz* the offshore Gippsland Basin (Tertiary) in Victoria, and the Mesozoic basins comprising the North West Shelf of

Western Australia] which developed along the Australian continental margin (Fig. 1.1), the Cooper Basin is an intra-cratonic depocentre. Sediment accumulation commenced after the Devonian–mid-Carboniferous Alice Springs Orogeny and ceased at the end of the Middle Triassic, due to basin-wide compression resulting in folding and uplift (Harvey and Hibburt, 1999). Consequently three major depressions developed in South Australia, *viz* the Patchawarra, Nappamerri and Tenappera Troughs (Fig. 1.2). The Nappamerri Trough extends into Queensland (Fig. 1.3), but the Queensland extension of the Patchawarra depression is known as the Arrabury Trough (Yew and Mills, 1989). A third major structural and depositional depression, the Windorah Trough lies in the northeast of the Cooper Basin (Stanmore, 1989; Fig. 1.3).

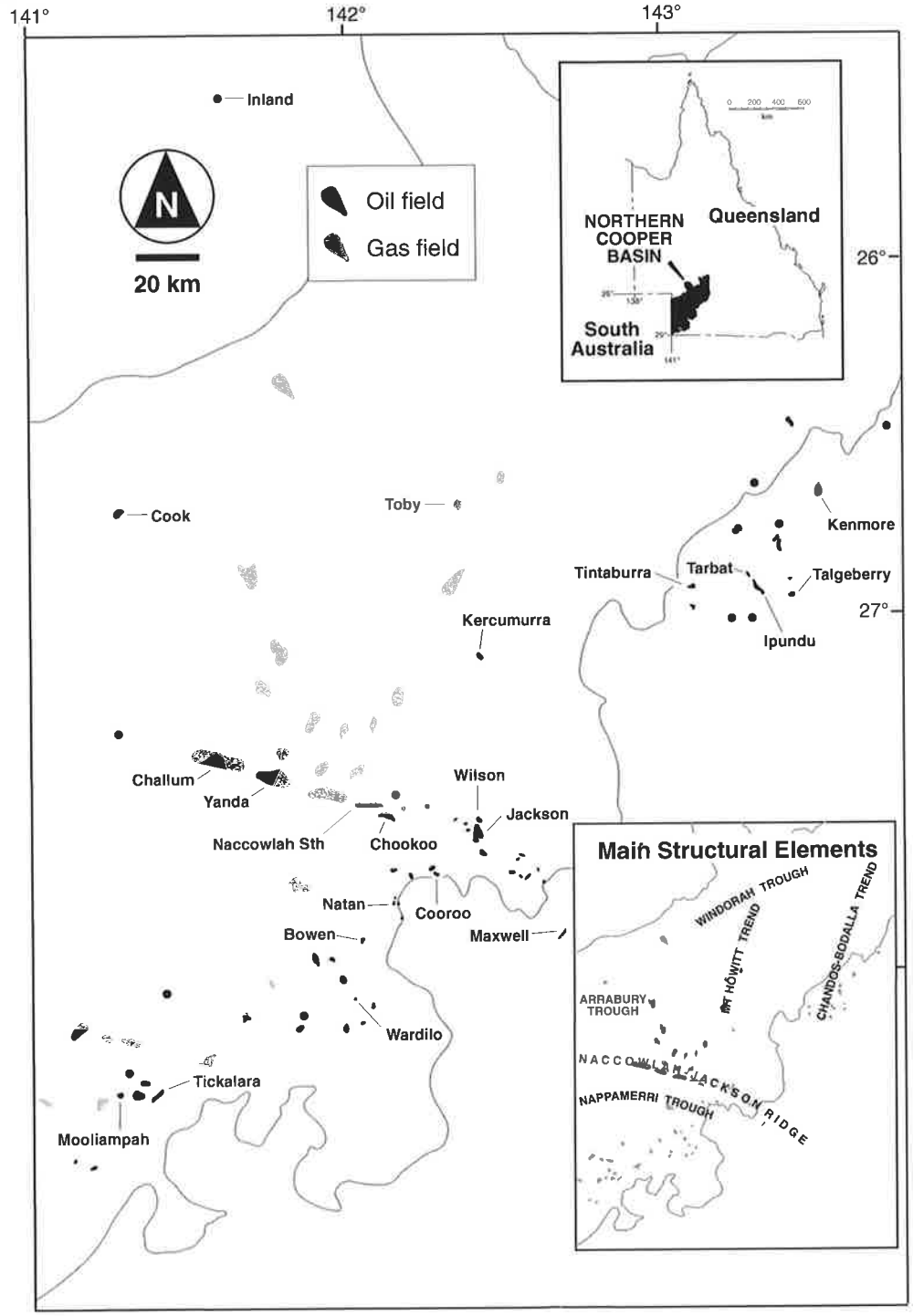


Figure 1.3 Locality of oil and gas fields in the Cooper and Eromanga Basins, Queensland

The troughs are separated by structural ridges which in places are bald of Permo–Triassic strata (Alexander and Jensen-Schmidt, 1996). In South Australia these are the Gidgealpa-Merrimelia-Innamincka (GMI) Ridge, Murteree Ridge and Nappacoongee Ridge (Armstrong and Barr,

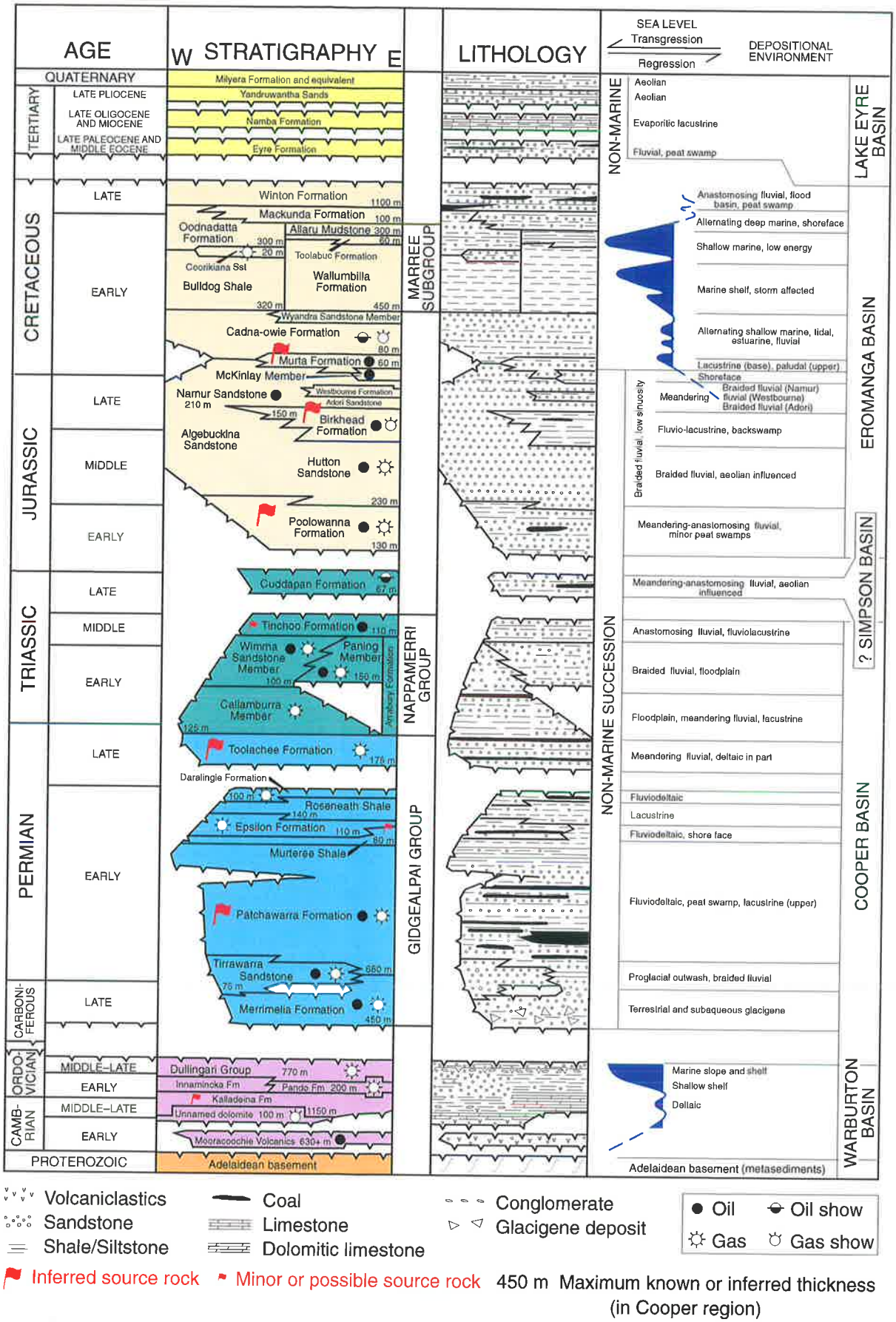


Figure 1.4 Generalised stratigraphic column of the Warburton, Cooper, Eromanga and Lake Eyre Basins with particular emphasis on the Cooper/Eromanga petroliferous sequence [adapted from Moussavi-Harami (1996) and Harvey and Hibburt (1999)]

1986; Fig. 1.2). In Queensland the main structural element is the Naccowlah-Jackson (NJ) Ridge (Fig. 1.3). Most hydrocarbon reservoirs are located along these structural highs. Moreover, many of the Cooper Basin oil fields, and most of the oil pools in the Eromanga Basin are located adjacent to faults zones which extend from the underlying Cooper sequence into the Eromanga Basin. It is possible that much of the oil reservoired in the overlying Eromanga Basin may have been derived from Cooper Basin kitchens and that the fault zones could have acted as conduits for hydrocarbon migration. Indeed, this is the main exploration model currently employed by petroleum companies searching for Eromanga oil (*e.g.* Beach Petroleum, 1999, p. 6).

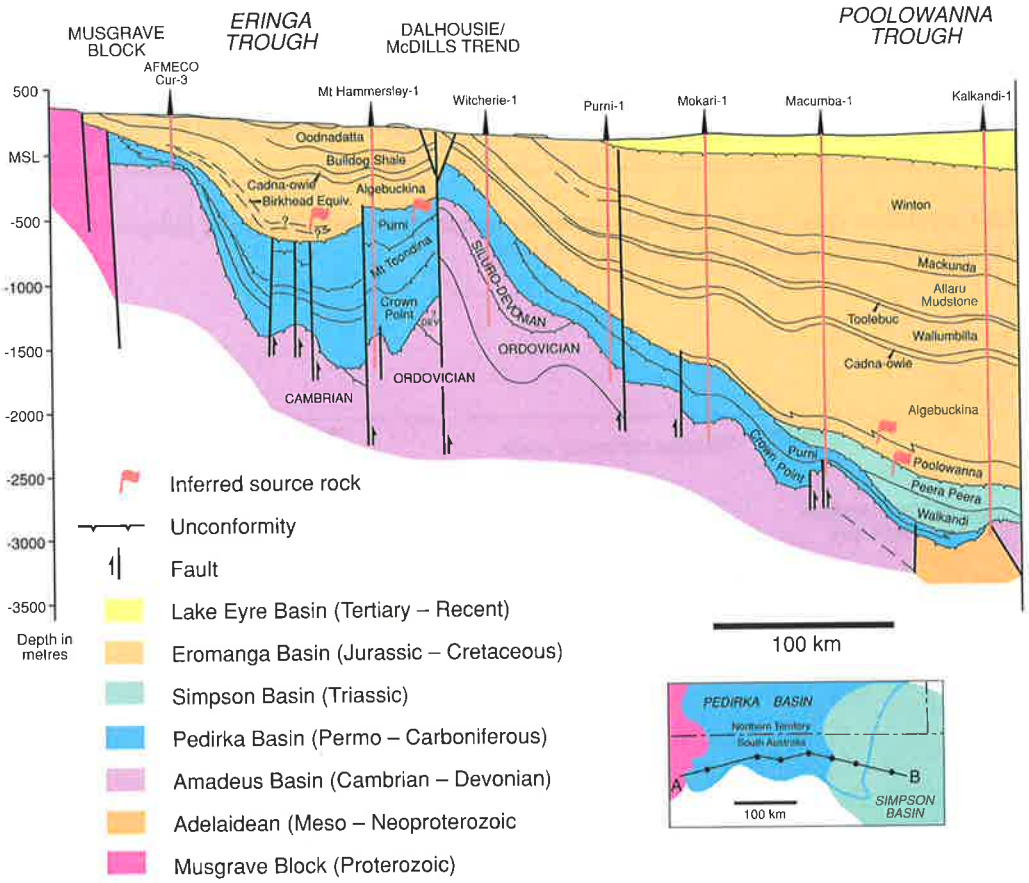


Figure 1.5 Schematic section across the Eromanga, Pedirka and Simpson Basins (Harvey and Hibburt, 1999)

Gavestock and Jensen-Schmidt (1998) argue that the Cooper Basin's structural style is a result of anisotropic regional stress and the product of variable (extensional and compressional) mechanisms of deformation. It is likely that the faulting and folding style of the Cooper and Eromanga Basins was initiated when underlying Proterozoic and Cambrian rocks were deformed during the Delamerian Orogeny (Late Cambrian–Early Ordovician). However, compressional tectonics of the Alice Springs Orogeny (Gravestock and Sansome, 1994), which caused significant crustal shortening and consequent erosion, is more likely to have endowed the region with its structural pattern. Late Triassic uplift resulted in the erosion of Permian and Triassic strata from the GMI and Murteree Ridges.

1.2.2 Eromanga Basin

The Eromanga Basin (Jurassic–Cretaceous: Fig. 1.4) attains thicknesses of up to *ca* 2200 m in the Nappamerri Trough and Patchawarra Trough depocentres and entirely covers the Cooper Basin and almost all of the Pedirka and Arckaringa Basins. In the southern Cooper Basin region it is thinnest (<1200 m) in the "Tinga Tingana Trough" (Moussavi-Harami, 1996), the southwest extension of the Tenappera Trough. The Eromanga Basin was described as epicratonic by Krieg (1995) and formed as a consequence of crustal sagging in the the Early Jurassic (Veevers *et al.*, 1991). As such many of the regional and local faults which are mapped in the underlying Cooper Basin extend into the Eromanga sequence (Fig. 1.8; Krieg, 1995, fig 9.22). There is little if any argument that faults have been reactivated at intervals throughout the depositional history of the Cooper and Eromanga Basins (*e.g.* Apak *et al.*, 1997).

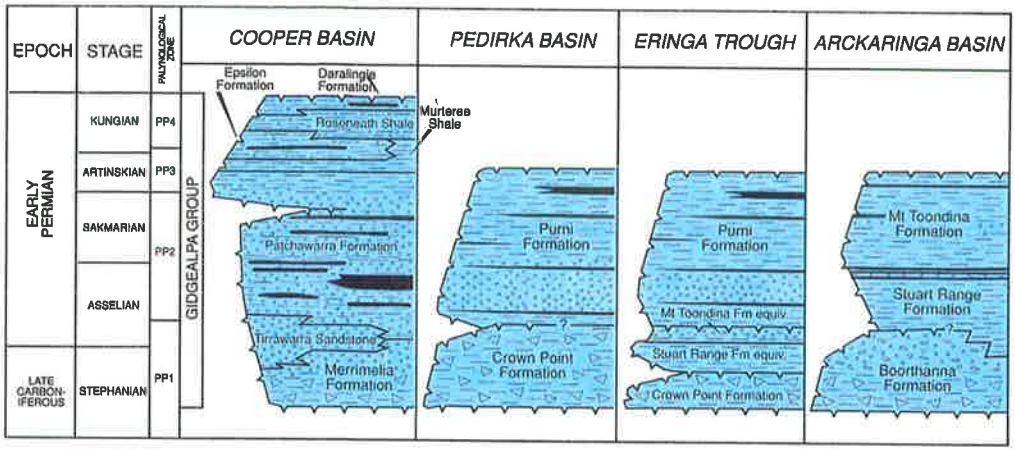


Figure 1.6 Correlation chart for late Palaeozoic strata in northern South Australia [adapted from Alexander and Sansome (1996) and Alexander and Jensen-Schmidt (1995)]

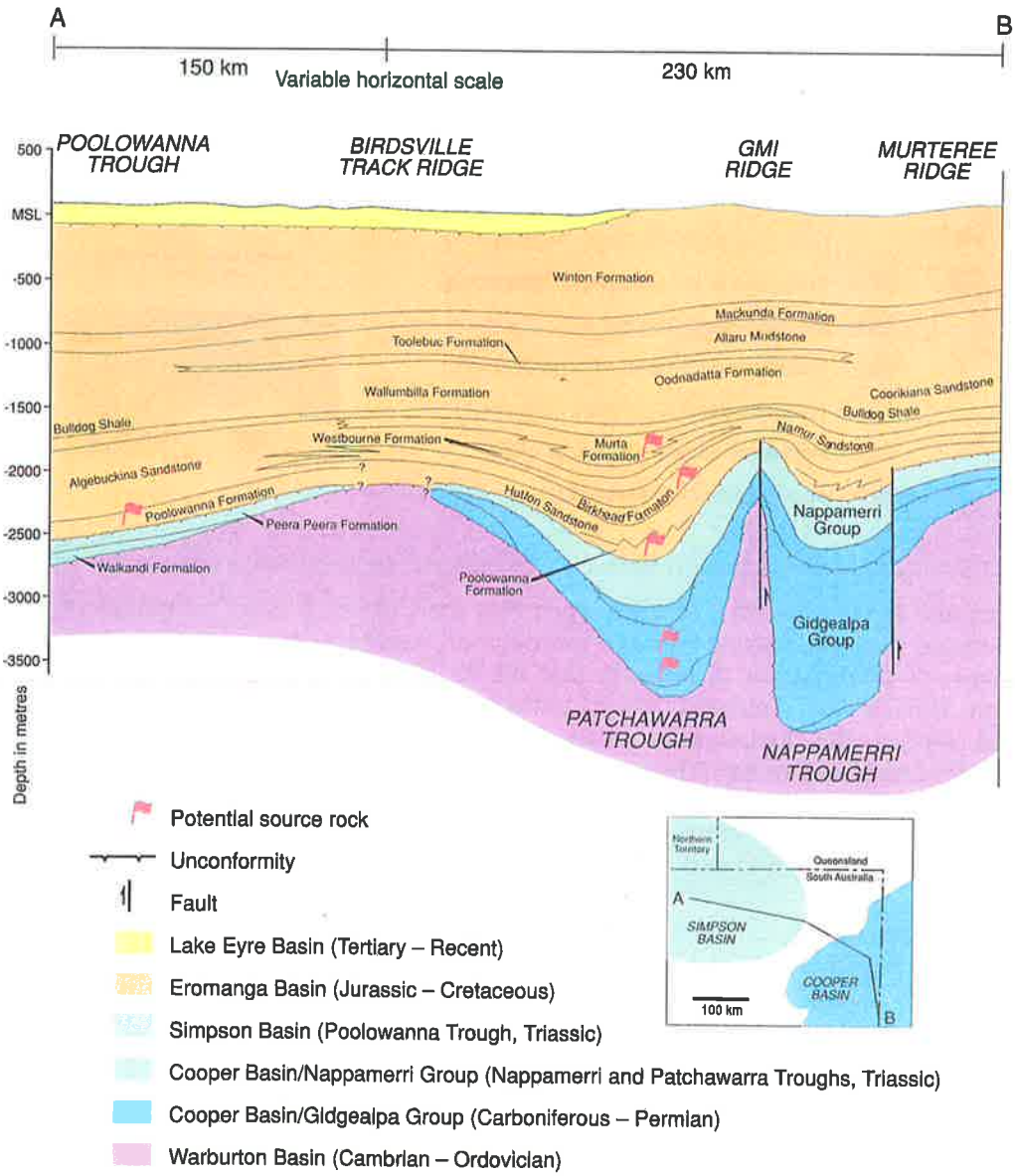


Figure 1.7 Schematic section through the southern Cooper Basin and superjacent Eromanga Basin (adapted from Krieg, 1995)

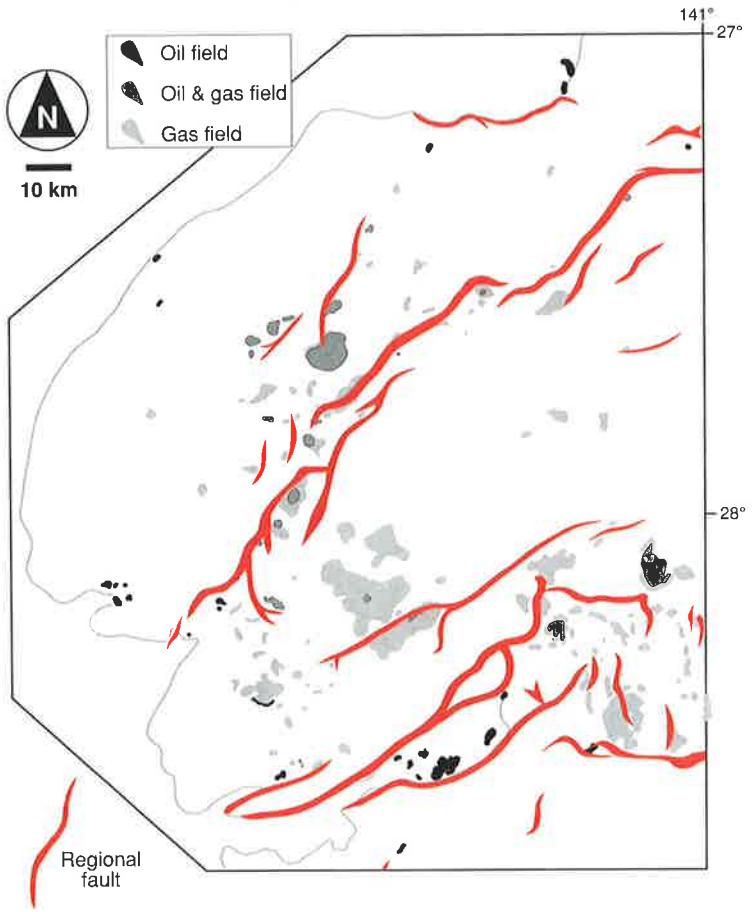


Figure 1.8 Oil and gas fields in the southern Cooper Basin (South Australia) and superjacent Eromanga Basin in relation to regional faulting (after Harvey and Hibburt, 1999)

1.3 Stratigraphy of the Cooper and Eromanga Basins region

1.3.1 Warburton Basin

The Warburton Basin (Cambro-Ordovician) underlies the Cooper Basin comprises volcaniclastic and marine sediments and sits unconformably over metasediments of Meso- and Neoproterozoic age (Adelaidean; Harvey and Hibburt, 1999). The latter were affected by the Alice Springs Orogeny and intruded by mid-Carboniferous (*ca* 300 Ma) granitoids (Gatehouse *et al.*, 1995) in the Nappamerri Trough. Oil was discovered within the basal Mooracoochie Volcanics (Early Cambrian; Figs 1.4) at Sturt in 1990 and gas was encountered at Lycosa (Dullingari Group) and Moolala (Pando Formation) in the same year (Fig. 1.2). The Sturt-6 (Mooracoochie Volcanics) oil has a distinctly marine geochemical signature (Kagya, 1997) and is therefore likely to have been sourced from algal/microbial organic matter in the Kalladeina Formation which comprises clastic and carbonate lithologies laid down in a shallow marine environment. However, the source potential of the Kalladeina Formation is inferred to be modest (≤ 0.85% TOC: Harvey and Hibburt, 1999). Consequently, undiscovered hydrocarbon pools are postulated to have been sourced down-dip from Cooper Basin source kitchens (Harvey and Hibburt, 1999).

1.3.2 Cooper Basin

1.3.2.1 Merrimelia Formation

Deposition at the base of the Gidgealpa Group of the Cooper Basin commenced with the Merrimelia Formation (Fig. 1.4) which comprises glacigenic sediments including diamictites and conglomeratic mudstones, siltstones and clean sandstones (Alexander, 1998). In the southern Patchawarra Trough, and the northern Nappamerri Trough the Merrimelia Formation may be up to 600 m thick (Alexander, 1998). Minor hydrocarbon accumulations within this unit are found at Malgoona, Farina and Tirrawarra (Fig. 1.9d) and these could only have been sourced down-dip from younger Cooper Basin source rocks to the east. Pondrinie is a major Merimelia-hosted gas accumulation (Fig. 1.2).

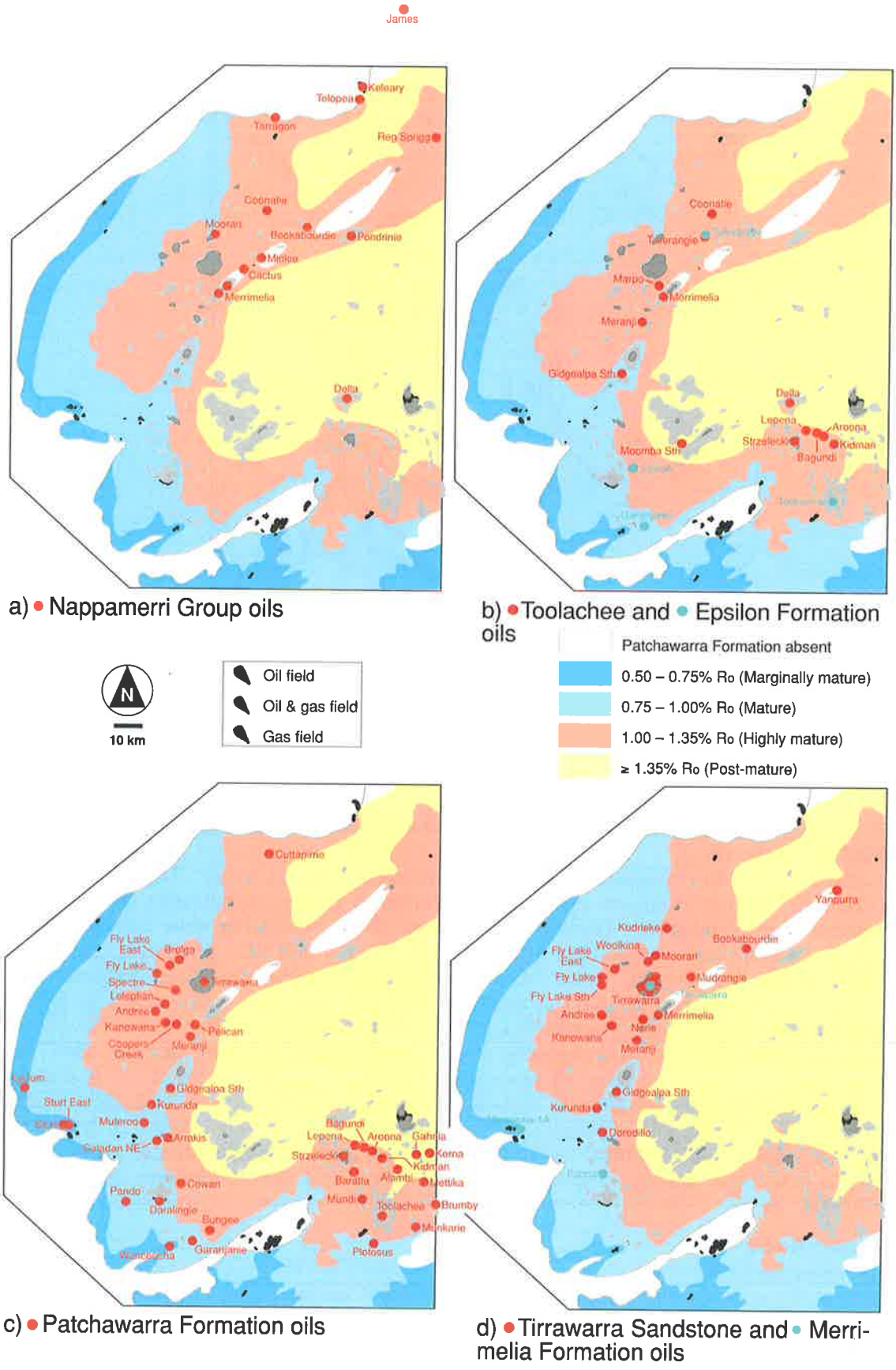


Figure 1.9 Maturity (% R_o) of base Patchawarra Formation (South Australia; after Burckhardt, 1990a) with superimposed oil and gas fields and localities of a) Nappamerri Group, b) Toolachee and Epsilon Formations, c) Patchawarra Formation, and d) Tirrawarra and Merrimelia Formations oils

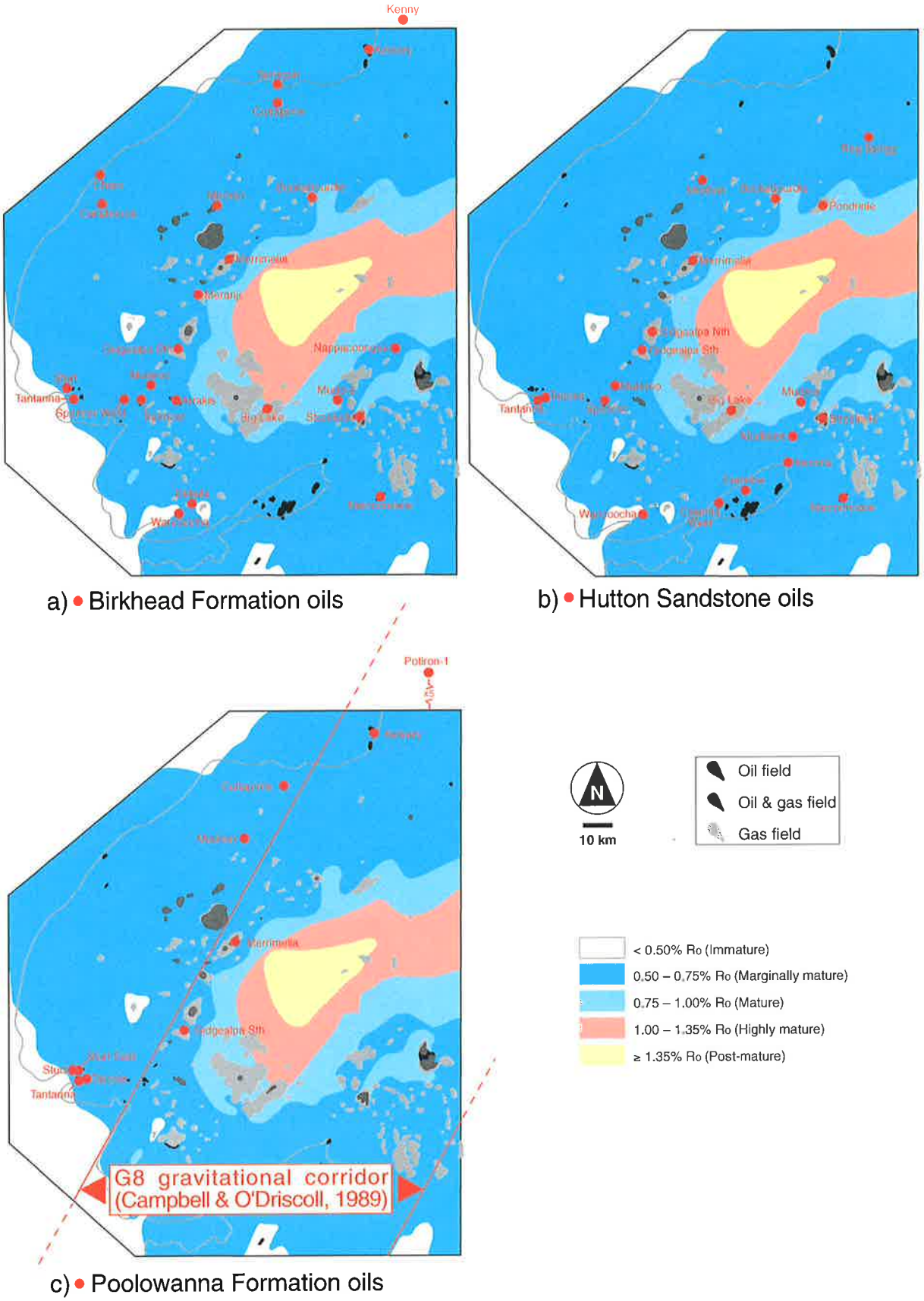


Figure 1.10 Maturity (% R_o) of mid Birkhead Formation (South Australia; after Burckhardt, 1990b) with superimposed oil and gas fields and localities of a) Birkhead Formation, b) Hutton Sandstone, and c) Poolowanna Formation oils

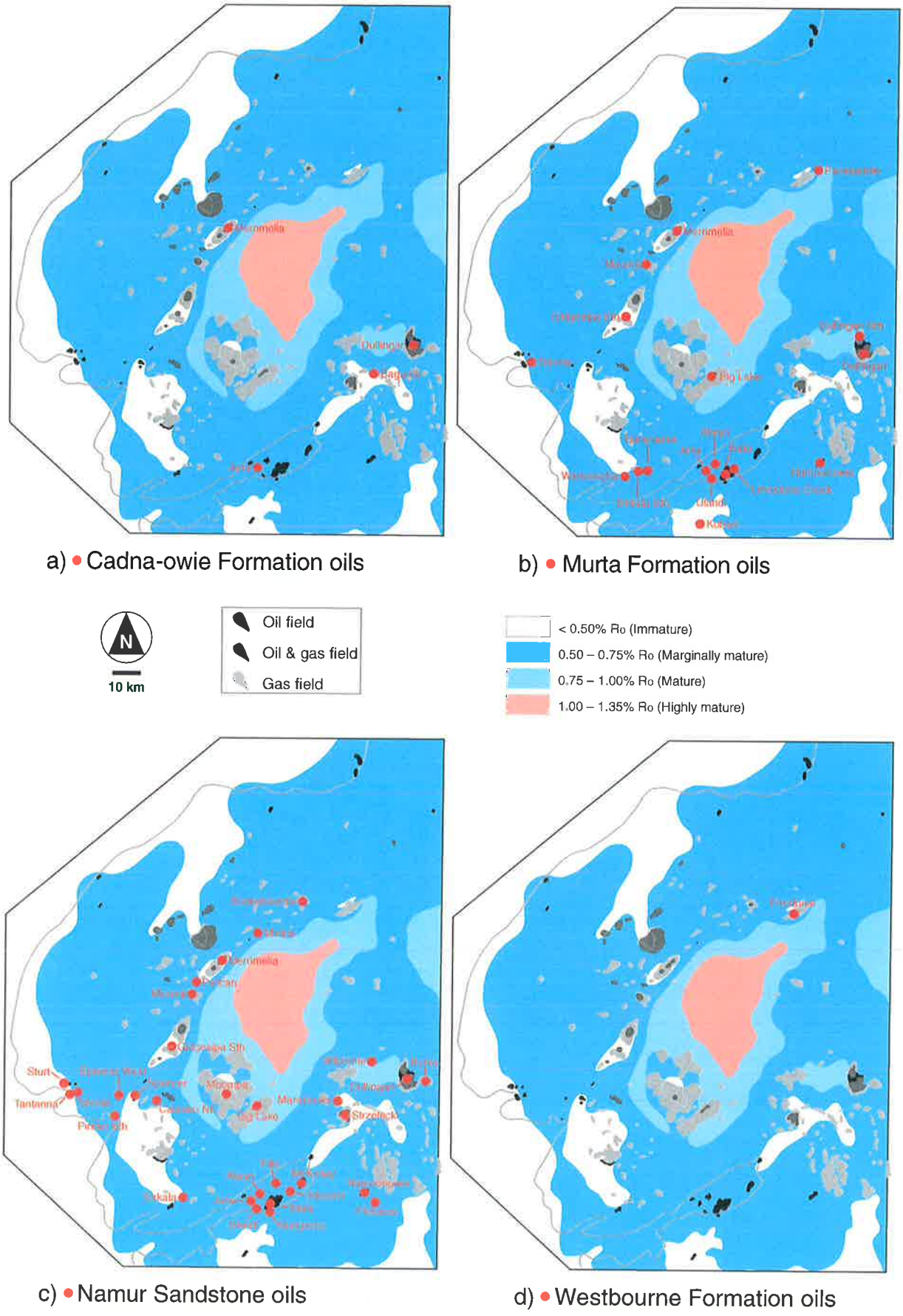


Figure 1.11 Maturity (% R_o) of base Murta Formation (South Australia; after Burckhardt, 1990c) with superimposed oil and gas fields and localites of a) Cadna-owie Formation, b) Murta Formation, c) Namur Sandstone and d) Westbourne Formation oils

1.3.2.1 Tirrawarra Sandstone
The Tirrawarra Sandstone, which is the main oil reservoir in the Cooper Basin, interfingers with (and in places is juxtaposed by) the Merrimelia Formation. In the southern Cooper Basin the Tirrawarra Sandstone can reach thicknesses of approximately 75 m. It is chiefly a sandstone unit comprising braided fluvial and fan-delta deposits (Harvey and Hibburt, 1999) with very minor thin coal seams and shale interbeds (Alexander, 1998). Approximately 80% of Cooper Basin's oil is trapped in the Tirrawarra Sandstone reservoir within the Tirrawarra Field. Most of the remainder is found within the nearby Tirrawarra Sandstone reservoirs at Fly Lake and Moorari/Woolkina (Gravestock *et al.*, 1998). In South Australia, Tirrawarra-reservoired oils are broadly restricted to the Patchawarra Trough area and Gidgealpa and Merrimelia Ridges (Fig. 1.9d). They are rare in Queensland where the Tirrawarra Sandstone is poorly developed (Fig. 1.12c). In South Australia, the Tirrawarra Sandstone is also an important gas reservoir at Pondrinie, Bookabourdie, Kurunda and Big Lake (Fig. 1.9d).

1.3.2.2 Pachawarra Formation
The upper boundary of the Tirrawarra Sandstone passes conformably into the Patchawarra Formation which comprises clean fine to medium-grained sandstones of fluvial origin, with interbedded lacustrine siltstones and shales (Fig. 1.4). Coals are important in the Patchawarra Trough where they account for more than 20% of the total Patchawarra Formation in the Sturt/Tantanna area and northwest of the Tirrawarra Field. Their cummulative thickness can exceed 40 m in the Sturt/Tantanna area and 60 m in the extreme southwest of the Cooper Basin (Alexander *et al.*, 1998, figs 6.6 & 6.7). These coals contain Type II and Type III kerogen (Boreham and Hill, 1998). Consequently, the Patchawarra Formation is commonly regarded as the main source kitchen for Cooper and Eromanga Basin hydrocarbons (*e.g.* Heath *et al.*, 1989). It is thickest (*ca* 660 m) in the deeply-buried and overmature Nappamerri Trough (Fig. 1.7). However, Patchawarra-reservoired oils are absent in this area (Fig. 1.9c). The upper Patchawarra Formation comprises argillaceous sediments which Hill and Gravestock (1995) interpreted to have been deposited under increasingly lacustrine conditions (Fig. 1.4). The unit also is the most important gas-condensate reservoir in the Cooper Basin. In South Australia, Patchawarra gas is produced from the giant gas field at Moomba, and other smaller fields including Coopers Creek and Garanjanie (Fig. 1.9c).

1.3.2.3 Murteree Shale
Conformably overlying the Patchawarra Formation is the Murteree Shale (Fig. 1.4) which is an argillaceous, laminated unit deposited under fresh-water (predominantly deep) lacustrine conditions. Despite its carbonaceous lithofacies, the Murteree Shale has only very minor hydrocarbon (gas) source potential due to the Type III/IV composition of its organic matter (*cf.* Boreham and Hill, 1998, fig. 8.5). However, in favourable situations it could act as a hydrocarbon seal.

1.3.2.4 Epsilon Formation and Roseneath Shale
The Epsilon Formation reaches a maximum thickness of *ca* 160 m in the Nappamerri Trough where it conformably overlies the Murteree Shale and marks a return to fluviodeltaic and shoreface lacustrine deposition of sandy lithologies (Alexander, 1998). Minor development of raised peat swamps has given rise to thin dispersed coal seams in some of which the kerogen is of Type II composition (Boreham and Hill, 1998, fig. 8.6). However, the Epsilon Formation is generally considered to contain insufficient organic matter to have sourced large quantities of hydrocarbons. Therefore it is not surprising that very little oil has been reported from this unit (Fig. 1.9b). The Epsilon Formation passes conformably into the overlying Roseneath Shale which was laid down under lacustrine conditions similar to those which prevailed during Murteree Shale deposition. The Roseneath Shale is estimated to have a maximum thickness of *ca* 140 m in the Nappamerri and Tenappera Troughs (Alexander, 1998). The Epsilon Formation is a gas reservoir at Cuttapirrie and Moomba (Fig. 1.9b).

1.3.2.5 Daralingie Formation
The Daralingie Formation attains a thickness of 100 m or more in the Nappamerri Trough and represents fluviodeltaic and shoreface lacustrine deposition similar to that of the Epsilon Formation. It is conformable and interfingers with the underlying Roseneath Shale. The Daralingie Formation is a gas reservoir at Moomba, Moomba South and Big Lake.

1.3.2.6 Toolachee Formation
An unconformity separates the Daralingie Formation from the overlying Toolachee Formation. The latter, which is the uppermost unit of the Gidgealpa Group, comprises clean sandstone, dark

grey siltstone, dark carbonaceous shale and coal (Alexander, 1998). The Toolachee Formation is best developed in the Nappamerri and Tennaperra Troughs where it is estimated to be 175 m thick. Coals constitute up to 60% of the unit where it is relatively thin in the Patchawarra Trough (Alexander, 1998, fig 6.31b). A meandering fluvial régime is inferred for its deposition. Toolachee sands are important gas reservoirs in the Moomba, Strzelecki, Toolachee and Meranji Fields (Fig. 1.9b).

1.3.2.7 Nappamerri Group (Arrabury and Tinchoo Formations)

The Arrabury Formation conformably overlies the Gidgealpa Group and is mainly Early Triassic in age (Fig. 1.4). It chiefly comprises organically lean, in-part sideritic mudstones and siltstones attaining a maximum thickness of *ca* 400 m in the Patchawarra Trough. Deposition on a floodplain with little or no peat swamp development is inferred (Alexander, 1998). The overlying Tinchoo Formation (Middle Triassic) is best developed in the northern Patchawarra Trough of South Australia where it attains a thickness of approximately 110 m (Alexander, 1998) and comprises fine to medium-grained sandstone with minor siltstone laid down in an anastomosing fluvial to fluviolacustrine environment (Alexander, 1995; Hill and Gravestock, 1998; Gravestock *et al.*, 1995). Although the Nappamerri sediments are commonly regarded as a regional seal to the underlying Gidgealpa Group reservoirs (*e.g.* Channon and Wood, 1989), oil has been trapped in intra-Nappamerri sandstones especially in the northern Patchawarra Trough (Figs 1.9a and 1.12a). Nappamerri gas is found at Pondrinie, Moorari, Burke and Merrimelia. The Nappamerri Group is correlative with the Walkandi Formation of the Simpson Basin (Alexander and Sansome, 1996; Fig. 1.4).

1.3.3 ? Simpson Basin (Cuddapan Formation)

The Cuddapan Formation (Late Triassic), a fluvial unit comprising sandstone, siltstone and coal, is generally thin (<67 m: Channon and Wood, 1989), and in South Australia is restricted to the Patchawarra Trough. It is broadly correlative with the Peera Peera Formation of the Simpson Basin (Fig. 1.5) and may be an eastern extension of that unit (Krieg, 1995).

1.3.4 Eromanga Basin

1.3.4.1 Poolowanna Formation

Deposition of the Eromanga Basin commenced with the laying down of the Poolowanna Formation, which in the Cooper Basin region is also known as the "Poolowanna facies" of the Hutton Sandstone (Alexander and Sansome, 1996). However, in this thesis only the term "Poolowanna Formation" will be used. These stata comprise carbonaceous siltstone, sandstone and minor coal which were laid down in a meandering to anastomosing fluvial régime with subordinate peat swamp development (Alexander and Sansome, 1996). In South Australia, Poolowanna-reservoired oils are restricted to a relatively narrow corridor extending from the Sturt/Tantanna area in the southwest to Potiron in the northeast (Fig. 1.10c). This distribution trend is curiously parallel or sub-parallel to the G8 structural corridor of Campbell and O'Driscoll (1989). Poolowanna accumulations in Queensland are scattered along the southeast margin of the Cooper Basin where Patchawarra source rocks are either absent (*e.g.* Tintaburra, Tarbat, Ipundu, Kenmore, Cooroo, Chookoo), overmature (Wandilo, Bowen, Natan) or highly mature (Toby, Kercumurra) for liquid hydrocarbon generation (Fig. 1.13).

1.3.4.2 Hutton Sandstone and Algebuckina Sandstone

The Hutton Sandstone conformable overlies and intertongues with the Poolowanna Formation. The former comprises mostly clean, fine to coarse-grained quartzose sandstone and consequently is the main oil and gas reservoir in the Eromanga Basin. West of the Birdsville Track Ridge, the Hutton Sandstone passes into the Algebuckina Sandstone. Both the Hutton and Algebuckina Sandstones were laid down in a braided fluvial environment (Moore, 1986a) with possible aeolian influence (Wiltshire, 1989). Whereas the Hutton Sandstone in the Cooper region is conformably overlain by Birkhead Formation, the Algebuckina Formation in the Simpson Basin (Poolowanna Trough) area is overlain by the Cadna-owie Formation (Figs 1.4 and 1.5). The Hutton Sandstone is the major oil reservoir along the GMI Ridge, and in the Patchawarra Trough and Murteree Ridge areas (*i.e.* around the perimeter of the Patchawarra Trough; Fig. 1.10b). Oil is absent from the Hutton Sandstone in the Nappamerri Trough where Cooper Basin sediments are overmature for liquid hydrocarbon generation. In Queensland, Hutton-reservoired oils are distibuted fairly evenly and are present even where the Patchawarra Formation is absent (Fig. 1.13b). Hutton oils do not occur where the Patchawarra Formation is overmature in the Nappamerri, Arrabury and Windorah Troughs.

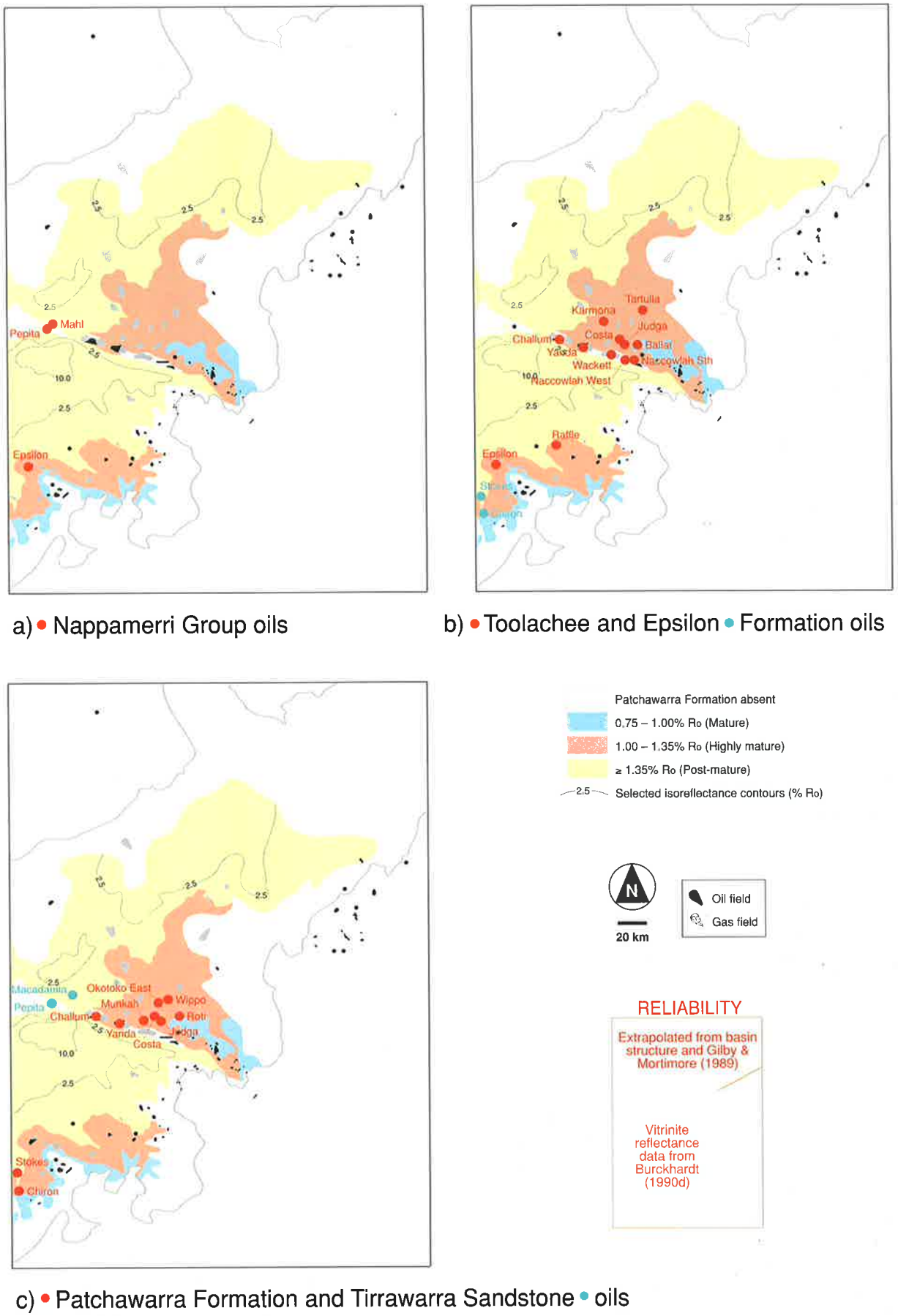


Figure 1.12 Maturity (% R_o) of base Patchawarra Formation (Queensland; after Burckhardt, 1990d) with superimposed oil and gas fields and localities of a) Nappamerri Group, b) Toolachee and Epsilon Formations, and c) Patchawarra and Tirrawarra Formations oils

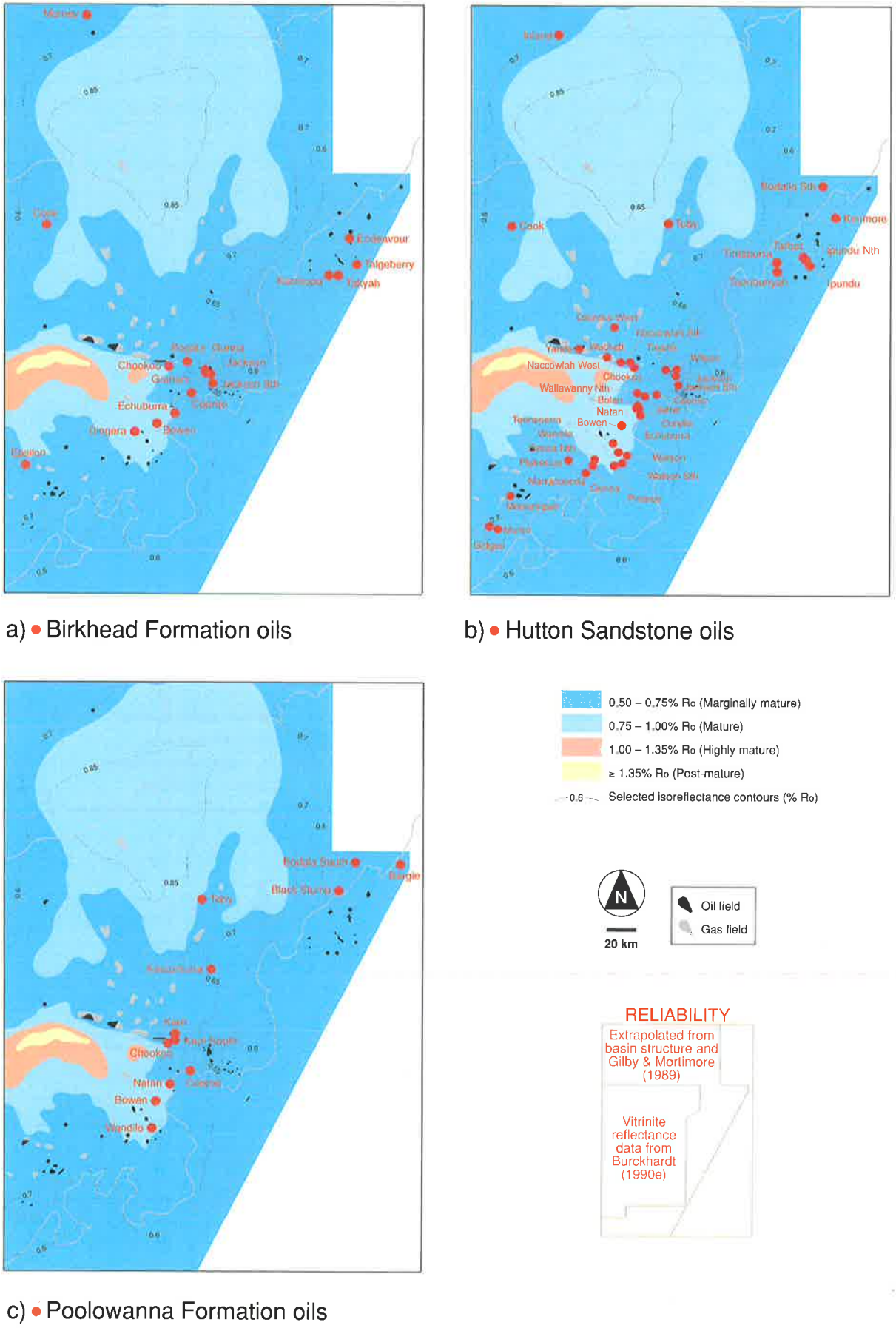


Figure 1.13 Maturity (% R_o) of mid Birkhead Formation (Queensland; after Burckhardt, 1990e) with superimposed oil and gas fields and localities of a) Birkhead Formation, b) Hutton Sandstone, and c) Poolowanna Formation oils

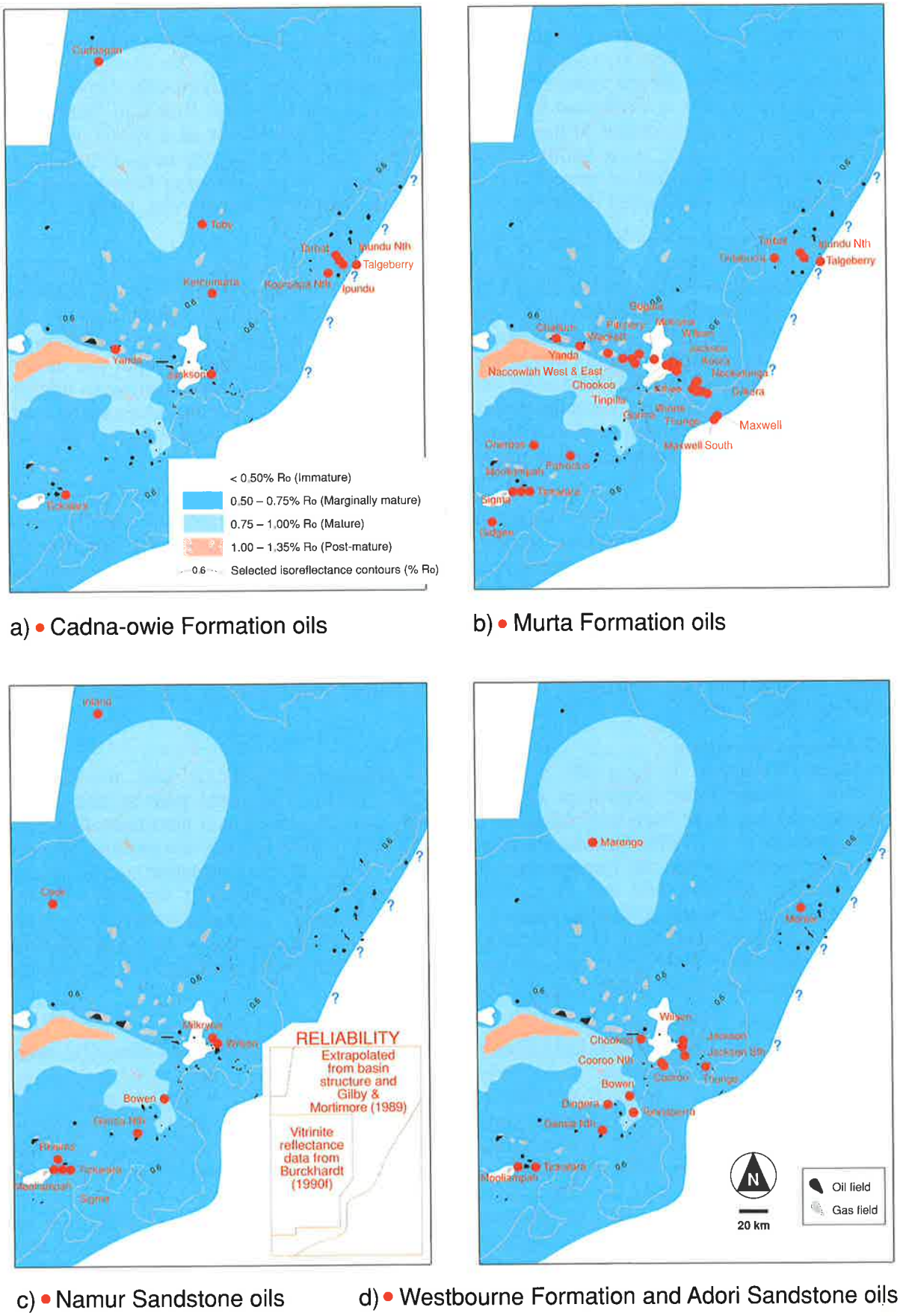


Figure 1.14 Maturity (% R_o) of base Murta Formation (Queensland; after Burckhardt, 1990f) with superimposed oil and gas fields and localities of a) Cadna-owie Formation, b) Namur Sandstone, and d) Westbourne Formation and Adori Sandstone oils

1.3.4.3 Birkhead Formation

The Birkhead Formation comprises interbedded sandstones and siltstones which were laid down in a braided fluvial environment. Organic-rich mudstones and siltstones were deposited under lacustine conditions that became progressively more dominant through time (Alexander and Sansome, 1996). Coals were also deposited in back-swamp environments. The change from the medium to high energy fluvial system that prevailed during Hutton deposition to a low energy fluvial/lacustrine régime is evidenced by the argillaceous deposits of the Birkhead Formation. The high organic matter content of the Birkhead Formation implicates it as a potential source rock (Fig. 1.4; *cf.* Chapter 3). In South Australia, Birkhead oil pools are similarly distributed to those in the Hutton Sandstone, except that examples of the former are also found along the northwest margin of the Cooper Basin (*e.g.* at Callabonna, Tarragon, Kenny; Fig. 1.10a).

1.3.4.4 Adori Sandstone and Westbourne Formation

As defined by Exon (1966), the Adori Sandstone comprises well sorted and highly cemented sandstones laid down in a braided fluvial environment. It conformably overlies the Birkhead Formation and underlies the Westbourne Formation. The Adori Sandstone passes laterally into the Namur Sandstone in the southern Cooper region. The Westbourne Formation is widespread throughout the Eromanga Basin in Queensland, but restricted to the northern Cooper and eastern Pedirka area in South Australia (Alexander *et al.*, 1996). A meandering fluvial setting is inferred for this unit which comprises interbedded shale, siltstone and minor sandstone (Alexander *et al.*, 1996). Adori and Westbourne oil accumulations are concentrated along the southern margin of the Cooper Basin in Queensland, and in the Jackson area (Fig. 1.14d).

1.3.4.5 Namur Sandstone

The Namur Sandstone is another major hydrocarbon reservoir comprising chiefly clean sandstones with minor argillaceous interbeds deposited in a braided fluvial environment (Alexander and Sansome, 1996). In South Australia, Namur oils are located above the giant gas fields at Moomba and Big Lake, and around the margins of the Nappamerri Trough extending to the Cooper Basin "zero edge" at Sturt/Tantanna (Fig. 1.11c). In these areas, the Birkhead and Murta Formations (see below) are marginally mature (0.50–0.75% R_o) for oil generation. In Queensland, Namur oil pools are scattered along the southwestern margin of the Cooper Basin between Mooliampah and Wilson on the NJ Ridge. Namur hydrocarbons also occur at Cook and Inland (Fig. 1.14c).

1.3.4.6 Murta Formation

The Murta Formation is generally a fine-grained organic-rich siltstone unit representing lacustrine and fan-deltaic deposition (Ambrose *et al.*, 1986). The basal part of the Murta Formation, known as the McKinlay Member (Fig. 1.4), was deposited as a lacustrine shoreface facies (Ambrose *et al.*, 1986; Gravestock *et al.*, 1995), and is lithologically transitional between the Namur Sandstone and the finer-grained lithologies of the Murta Formation *sensu stricto*. The McKinlay Member and the Murta Formation proper are important reservoirs in the Eromanga Basin. In South Australia, Murta oils (Fig. 1.11b) have a similar distribution to those in the Namur Sandstone (Fig. 1.11c). However, in Queensland the Murta oils are geographically more widespread than the Namur oils and occur from Challum in the northwest, to Maxwell at the southeast end of the NJ Ridge (Fig. 1.14b).

1.3.4.7 Cadna-owie Formation

The siltstones and fine-grained sandstone interbeds of the Cadna-owie Formation were deposited in a marginal marine and tidally influenced (shoreline) setting (Alexander and Sansome, 1996). The Wyandra Sandstone Member represents the upper sandy facies of the Cadna-owie Formation. The formation attains thicknesses of up to 115 m in the Nappamerri Trough but is more typically 75–100 m thick over the Cooper Basin (Alexander and Sansome, 1996). In South Australia, there are sub-economic reserves of hydrocarbons trapped within the Cadna-owie Formation at four localities, including above Murta oil pools at Dullingari and on the Murteree Ridge (Fig. 1.11a). In Queensland (Fig. 1.14a), there are more Cadna-owie oil accumulations in the northern Cooper Basin region (*e.g.* at Toby, Kercumurra, Talgeberry), than along the NJ Ridge (Jackson, Yanda) or further south (Tickalara).

1.3.4.8 Bulldog Shale and Wallumbilla Formation

The Bulldog Shale is restricted to South Australia and attains a maximum thickness of around 320 m (Fig. 1.4). It represents marine shelf sedimentation affected by currents and storms (Frakes and Francis, 1988) and is a predominantly argillaceous unit which conformably overlies the Cadna-owie Formation. The equivalent of the Bulldog Shale in eastern South Australia and

Queensland is the Wallumbilla Formation (maximum thickness *ca* 600 m in Patchawarra Trough: Alexander and Sansome, 1996). Both the Bulldog Shale and the Wallumbilla Formation are insufficiently buried for maturation of their dispersed organic matter to generate hydrocarbons (McKirdy *et al.*, 1986).

1.3.4.9 Oodnadatta Formation and Mackunda Formation

The Oodnadatta Formation attains a thickness of approximately 300 m in the Moomba area (Alexander and Sansome, 1996). It conformably overlies the Bulldog Shale and comprises predominantly well-laminated argillaceous mudstone which repesents shallow marine (low-energy) deposition. This unit is conformably overlain by the Mackunda Formation (maximum thickness *ca* 100 m). The latter comprises argillite and sandstone that represent alternating deeper water and shoreface conditions (Krieg, 1995). The maximum thickness of the Marree Subgroup (Bulldog Shale, Coorikiana Sandstone, Oodnadatta Formation) and Mackunda Formation is greater than 750 m in the Nappamerri and Patchawarra Troughs (Moussavi-Harami, 1996, fig. 9.8).

1.3.4.10 Winton Formation

The Winton Formation comprises non-marine sandstone, siltstone and thin coal that together represent the terminal phase of Eromanga deposition. The formation is thickest (*ca* 1100 m) in the Patchawarra Trough (Alexander and Sansome, 1996). As indicated in Figure 1.4, the Eromanga Basin is unconformably overlain by sediments of the Lake Eyre Basin which in the Cooper Basin region have a maximum thickness of up to 140 m (Alexander and Sansome, 1996).

In summary, most of the petroliferous Late Carboniferous–Middle Triassic (Cooper Basin) and Early Jurassic–Late Cretaceous (Eromanga Basin) succession is a sequence of alternating lacustrine, fluvial and paludal strata. The Cooper Basin is underlain by Cambro-Ordovician sediments of the Warburton Basin. This marine, volcaniclastic succession has only poor to fair hydrocarbon prospectivity. The younger part of the Eromanga sequence (*viz* Cadna-owie Formation, Marree Subgroup and Winton Formation is immature (< 0.5% R_o) for hydrocarbon generation (Kantsler *et al.*, 1986). The youngest economic oil pools have been found in the Early Cretaceous Murta Formation. Subeconomic oil shows are present in the overlying Cadna-owie Formation. Minor gas in the Coorikiana sandstone is the shallowest petroleum occurrence in the Eromanga Basin (Fig. 1.4).

Most units of the Cooper and Eromanga Basins attain their maximum thickness and depth of burial in the central Nappamerri and/or Patchawarra Troughs where the base of the Merrimelia Formation (the oldest unit in the Cooper Basin) reaches depths in excess of 3.5 km (Fig. 1.7). Consequently, the Cooper Basin succession is largely over mature for liquid hydrocarbon generation in the Nappamerri and Patchawarra Troughs of South Australia, and in the Nappamerri, Arrabury and Windorah Troughs of Queensland. That most of the Cooper and Eromanga oil is pooled around the margins of these structural depressions appears to be strongly controlled by source rock maturity (*cf.* Section 1.5). Furthermore, most of the oil pools in the Eromanga Basin occur close to the Permian "zero edge" (*e.g.* Sturt, Tantanna), within the vicinity of the Triassic "zero edge" (*e.g.* Dirkala, Wancoocha) or adjacent to faults that extend into the Cooper Basin (*e.g.* Big Lake, Cuttapirrie, Biala/Limestone Creek). In each situation derivation of the oil from the underlying (Permian) hydrocarbon kitchens seems likely.

1.4 TIMING OF HYDROCARBON EXPULSION

Burial history analysis of wells in the southern Cooper region of the Eromanga Basin (Moussavi-Harami, 1996) demonstrates that sedimentation rates for the Jurassic and Cretaceous sequence were generally less than 5 m/My. An exception was the accelerated subsidence and sedimentation which commenced at *ca* 120 Ma but peaked between 100 and 90 Ma when burial increased to *ca* 60 m/My in the southern Cooper region along the Murteree Ridge (*e.g.* Jena-1), and over 200 m/My in the northern Cooper region in the Patchawarra Trough (*e.g.* Cuttapirrie-1). These high rates of sedimentation concur with the proposition of Moore and Pitt (1984) that in the Nappamerri Trough, Late Jurassic source rocks (*i.e.* Birkhead Formation) reached peak maturity in the early Late Jurassic (100–90 Ma) during deposition of the relatively thick, pre-erosional Winton Formation. They claimed that other parts of the basin (*viz* Patchawarra Trough) did not reach maturity prior to the Late Cretaceous–early Tertiary (*ca* 65 Ma). Tupper and Burckhardt (1990) also inferred that peak expulsion of oil in the Eromanga Basin occurred during the Late Cretaceous. It was further postulated that the Eromanga source rocks first became fully mature in the Late Cretaceous–early Tertiary (*cf.* Kantsler *et al.*, 1986). However,

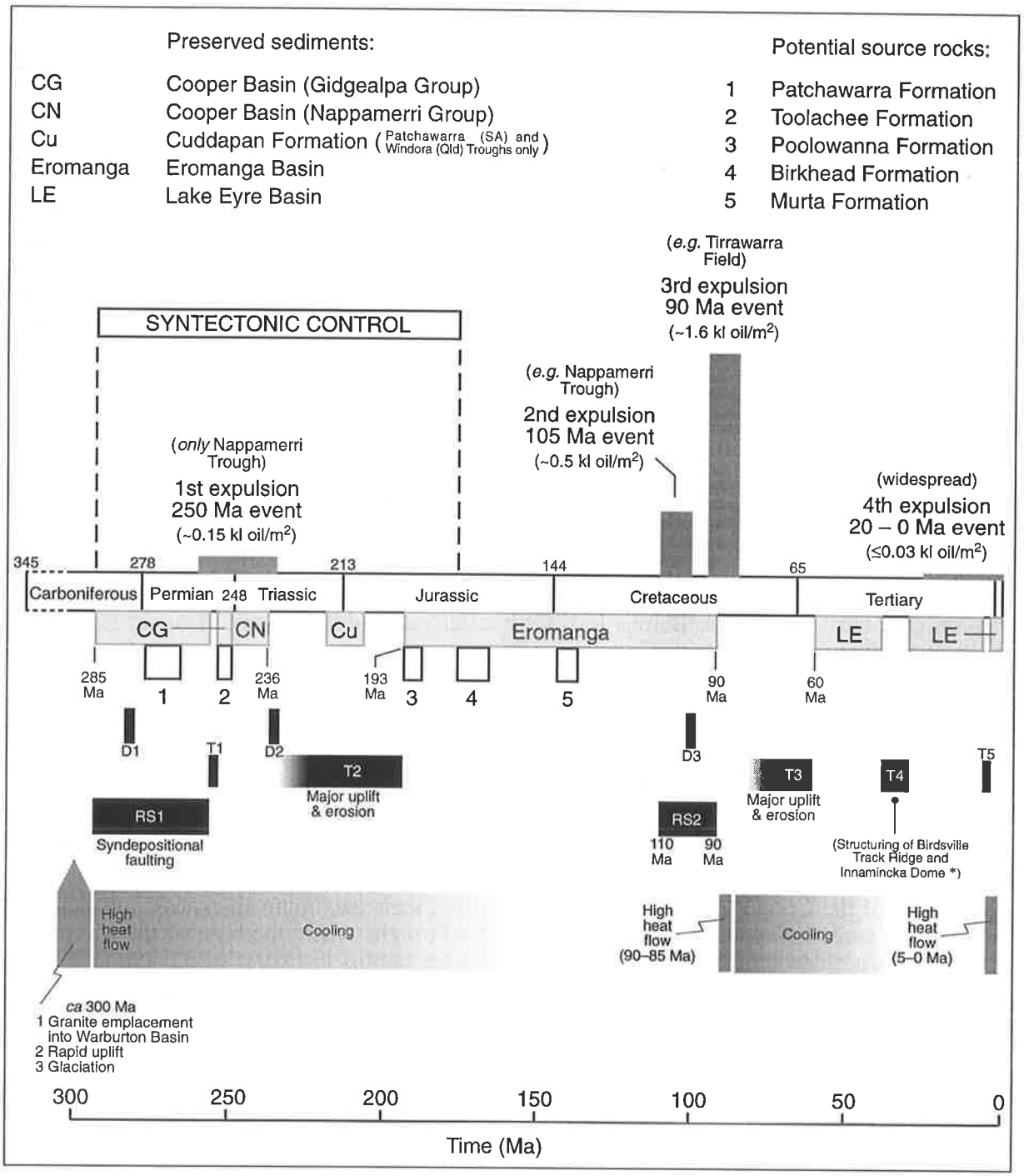


Figure 1.15 Generalised petroleum systems events chart for the Cooper, Eromanga and Lake Eyre Basins. Oil expulsion events are based on Deighton and Hill's (1998, fig. 9.32) summary diagram. Other data from Alexander and Jensen-Schmidt (1996), Moussavi-Harami (1996), Tingate and Duddy (1996), Rezaee *et al.* (1997) and Gravestock and Jensen-Schmidt (1998). Key to events shown in black: D1–D3 refer to siderite (± other mineral) diagenesis; T1–T5 refer to tectonism and structuring; RS1 & RS2 refer to rapid subsidence and sedimentation (* Innamincka Dome is the northeast extension of the GMI Ridge)

more rigorous computerised burial and thermal history modelling was undertaken by Deighton and Hill (1998) who showed that for most localities in the Cooper region of the Eromanga Basin in South Australia (and probably also in the Queensland sector), there were four periods of oil expulsion (Fig. 1.15):

- The first expulsion event (*ca* 250 Ma, Permo-Triassic) resulted from burial and maturation of the Patchawarra Formation organic matter in the Nappamerri Trough (*e.g.* Burley-2) but only minor quantities of oil and gas were expelled.
- The second expulsion event (*ca* 105 Ma, late Early Cretaceous) coincided with, or shortly followed the increased rate of burial of the entire Cooper and Eromanga sequence.

Consequently, hydrocarbons were expelled from the Patchawarra and Toolachee Formations in the Cooper Basin and expulsion commenced from Jurassic source rocks in some parts of the Eromanga Basin (*e.g.* Tirrawarra North-1). However, it is clear from the gas expulsion *versus* time curves published by Deighton and Hill (1998) that small amounts of gas had been expelled from Permian rocks since the early Middle Jurassic (*ca* 185 Ma), especially in the Nappamerri Trough (Burley-2) and at Dullingari. The former locality underwent earlier and greater heat flow due to the emplacement of granites at *ca* 300 Ma (Fig. 1.15).

- The third expulsion event (*ca* 90 Ma, early Late Cretaceous) coincided with the maximum rate of burial of the sequence, and resulted from Permian source rocks passing though the lower boundary of the main oil generation window (*ca* 1.1% R_o). In much of the region, Eromanga source rocks entered the main oil window at around 100 Ma and therefore contributed hydrocarbons to the third expulsion event (Deighton and Hill, 1998). Relatively large quantities of oil and gas were produced during the third event.
- The fourth expulsion event (20–5 Ma, late Tertiary) followed renewed burial, sedimentation and an increase in geothermal gradient. However, only very minor quantities of hydrocarbons were generated. Thermal modelling by Tingate and Duddy (1996), focusing in particular on the western Eromanga Basin, suggests an increase in geothermal gradient from 5 Ma to the present. Thus it is reasonable to postulate that hydrocarbon generation and expulsion continues to the present time (Moussavi-Harami, 1996).

More-or-less continual fault reactivation throughout the geological history of the area is not conducive to efficient and long-term entrapment of hydrocarbons. Furthermore, it is unrealistic to expect significant volumes of oil to have survived within the deeply buried and overmature Nappamerri Trough since the first expulsion event at 250 Ma. It is more likely that if any oil has survived the intervening period, it must have migrated into the shallower, less tectonically disturbed areas. The southern margin of the Cooper Basin may have been a suitable area for the entrapment and preservation of such oil. However, it is unlikely that sizeable accumulations of oil from the 250 Ma expulsion event have survived to the present day. If any unmixed oil remains from this time it is probably represented by very small accumulations which were fortuitously isolated from further hydrocarbon charges. As such, there are several small uneconomic or subeconomic oil pools present along the southern margin of the Nappamerri Trough (*e.g.* in the Patchawarra Formation at Plotosus, Fig. 1.9) which may conceivably contain oil from the first expulsion event.

Although the first expulsion event predated deposition of Eromanga sediments by around 60 My, it is possible that the resulting oil accumulated around the margins of the Nappamerri Trough, within Gidgealpa or Nappamerri Group sediments. Subsequently this oil may have been remobilised (tertiary migration *sensu* Tissot and Welte, 1984) into the Eromanga Basin, possibly as a consequence of increased burial coupled with hydrocarbon generation at 105 Ma which was the last *major* expulsion event to affect the Nappamerri Trough.

If Jurassic and Cretaceous source rocks have also contributed significantly to hydrocarbon accumulations in the Eromanga Basin (Alexander *et al.*, 1988; Jenkins, 1989; Michaelsen and McKirdy, 1989; Powell *et al.*, 1989) there is a reduced likelihood that a pure Permian oil from the first expulsion event has survived anywhere other than around the basin margin; and it is likely that such an accumulation would be very small.

One such oil pool might be that in the Murta Formation at Garanjanie (Fig. 1.11) which overlies a large Cooper Basin gas field. Also present is some very minor oil, presumably largely dissolved within gas in the Patchawarra Formation. One explanation for the Murta-reservoired Garanjanie oil is that it perculated into the intervening Eromanga sequence through breached Murteree Shale seals and is equivalent to the Patchawarra oil. If this is true, the Murteree Shale over the Garanjanie reservoir probably behaves as a capillary seal (*sensu* Boult, 1996). This interpretation is contrary to Tupper and Burckhardt's (1990) geochemically unsubstantiated supposition that the Garanjanie oil was possibly derived from Murta Formation source rocks. It is significant that other Murta oil accumulations along the Murteree Ridge (where Cooper Basin sediments were removed by erosion during the Late Triassic) are several orders of magnitude larger than the Garanjanie Murta oil pool and are *not* associated with gas, although there appears to be no *a priori* reason why the Murta anticlinal structures should be incapable of trapping gas. The empirical evidence suggests that these Murta oils (*e.g.* Alwyn, Biala, Limestone Creek and Ulandi) have a source and a secondary migration history which differ from those of the much smaller Garanjanie accumulation.

It is probable that most of the oil-generative potential of the deeply buried Permian source rocks (*viz* Patchawarra and Toolachee Formations) was heavily depleted or exhausted during the second and third expulsion events. This is obvious in the case of the overmature Nappamerri and northern Patchawarra Troughs in South Australia, and the Windorah and Arrabury Troughs in Queensland where present maturity levels are in excess of 1.35% R_o over large areas (Figs 1.9 and 1.12). Only around the margins of the Cooper Basin are the Patchawarra and Toolachee Formations presently within the oil window. Structures in place by the mid Early Cretaceous (*ca* 120–110 Ma) may have been suitable traps for the second (105 Ma) and third (90 Ma) expulsion events which yielded most of the basins' pooled hydrocarbons. However, ongoing fault activation will have invariably contributed to the loss of hydrocarbons. It is important to realise that the major faults shown in Figure 1.8 are not simply vertical planes about which the normal stratigraphic sequence has been displaced. Rather, the faults mapped are zones comprising numerous smaller-scale discontinuities. Displacement along individual faults is typically no more than 10 m (Gravestock and Jensen-Schmidt, 1998) and would not necessarily provide an easy conduit between the Permian and overlying Jurassic and Cretaceous strata. As such hydrocarbon migration through fault "zones" or "regional" faults would have followed a tortuous path, and was possibly highly inefficient.

Intuitively, most of the remaining liquid hydrocarbon potential is likely to reside within the least buried Birkhead and Murta Formations. Consequently, if oil generation has occurred in the late Tertiary and is continuing to the present day (fourth expulsion event), explorers should entertain play concepts which involve Birkhead-Hutton or Birkhead-Namur, and Murta-Murta or Murta-Namur source-reservoir couplets. Potential traps which formed as late as *ca* 20 Ma may be charged with Birkhead and Murta-sourced oil from the fourth expulsion event. Furthermore, it is conceivable that Murta-reservoired oils may be overrepresented with respect to the total hydrocarbons trapped in the Eromanga Basin. This is because the migration and trapping efficiency of a Murta-Murta or Murta-Namur source-reservoir couplet is likely to be greater than, for example, a Patchawarra-Murta or Patchawarra-Namur source-reservoir couplet.

As discussed earlier, ongoing fault reactivation is inconsistent with the notion of efficient hydrocarbon fault entrapment. Nevertheless, faults provide an important closural element for some hydrocarbon accumulations within the Cooper Basin (*e.g.* Merrimelia and Naccowlah South Fields). However, most of the oil in the Eromanga sequence is trapped within simple anticlinal domes (*e.g.* Limestone Creek, Spencer, Wancoocha: Gravestock, 1996) within the *vicinity* of faults. As such, the integrity of the trapping mechanism was not necessarily compromised by ongoing fault movement. In conclusion, it is easier to reconcile more-or-less ongoing structural accommodation of the region with Eromanga oil accumulations if much of the oil has been generated from Jurassic and Cretaceous source kitchens during a recent expulsion event.

The thermal history of the western Eromanga Basin was studied by Tingate and Duddy (1996) using apatite fission track analysis. They concluded that the Eromanga Basin overlying the Eringa Trough of the Pedirka Basin (Fig. 1.5) also entered the oil window at *ca* 100 Ma. Furthermore, it is clear that a 5–0 Ma heating event (equivalent to the fourth expulsion event in the Cooper region) also affected the western Eromanga Basin. Consequently, it is possible that recent hydrocarbon generation and expulsion has occurred from Permian strata in the Eringa Trough and also from deeply buried and organic-rich Eromanga rocks overlying the Eringa and Poolowanna Troughs.

1.5 MATURITY CONTROL ON THE DISTRIBUTION OF HYDROCARBONS

A series of maps showing distributions of oil pools with respect to formation have been constructed by the author (Figs 1.9–1.14). The oil pools are superimposed over isoreflectance maps which are based largely on Burckhardt's (1990a,b,c) compilations of vitrinite reflectance data. Also shown are the outlines of Cooper and Eromanga Basin oil and gas fields (*cf.* Figs 1.2 and 1.3). It is clear from the distribution of oil pools in both the Cooper Basin and superjacent Eromanga Basin that maturity is an important controlling factor, as suggested by Hunt *et al.* (1989). For example, there are no Cooper Basin oil pools indicated where the Patchawarra Formation is overmature ($\geq$ 1.35% R_o) for oil generation in South Australia (Fig. 1.9). In Queensland, only at Macadamia and Pepita (Tirrawarra Sandstone) on the NJ Ridge, and at Stokes (Patchawarra Formation) near the southern Patchawarra "zero edge" are there small quantities of liquid hydrocarbons trapped within or above overmature Patchawarra Formation (Fig. 1.12). Similarly, Eromanga oils are absent from areas where the Birkhead Formation is

highly mature (1.00–1.35% R_o) to post-mature (≥ 1.35% R_o) for liquid hydrocarbon generation (Figs 1.10, 1.11, 1.13 and 1.14). An obvious conclusion to be drawn from these observations is that most of the Cooper Basin hydrocarbons have been sourced from the Patchawarra Formation. Notwithstanding the availability of suitable trapping mechanisms, hydrocarbons have not migrated into, nor been preserved within, the Eromanga Basin in the area overlying the overmature Patchawarra Formation. By contrast, there are many Eromanga oil pools around the perimeter of the Cooper Basin where the Patchawarra Formation is more-or-less optimally mature for the generation and expulsion of liquid hydrocarbons (*ca* 0.75–1.00% R_o: Figs 1.9 and 1.12). However, in the same area, the Birkhead and Murta Formations lie within the early oil window (0.5–0.75% R_o: Figs 1.10, 1.11, 1.13 and 1.14). Therefore, it is also a reasonable proposition that many of the Eromanga oils have been derived from Eromanga source rocks at or near their present level of maturity.

Given the overwhelming preponderance of gas in the Cooper Basin (Figs 1.2 and 1.3; see Section 1.6), it is *possible* to interpret the paucity of gas in the Eromanga Basin (Northcott, 1996, fig. 12.1) to indicate a high sealing efficiency of the Nappamerri Group. Conversely, numerous small oil shows within the Nappamerri sequence (D.I. Gravestock, PIRSA, pers. comm., 1998) would suggest that hydrocarbons have leaked into the Eromanga Basin.

Using essentially the same Santos Ltd vitrinite reflectance data (*i.e.* Burckhardt, 1990a,b,c,d,e,f) as those summarised in Figures 1.9–1.14, Hunt *et al.* (1989) reported that traps were only filled to structural spill point when the source rock in the (immediate) drainage area had attained a maturity of 0.95% R_o. This suggests that most intra-Cooper oil migration has been over short distances (*ca* < 5 km). Furthermore, using the Toolachee Formation as an example, Hunt *et al.* (1989, fig. 3) demonstrated that gas wetness (% C_{2-4}/C_{1-4}) increases from less than 1% in the deeply buried Nappamerri Trough to greater than 30% along the western margin of the Patchawarra Trough; and with the exception of the deeply buried Windorah Trough in the north is typically high (> 20%) around the margins of the Cooper Basin. Put simply, apart from the mature northern Patchawarra Trough, the spatial distribution of gas wetness broadly reflects the maturity of the Patchawarra and Toolachee Formations. It is therefore unnecessary and unrealistic to invoke very long-range migration of gas (including liquids) from the presently overmature Nappamerri Trough into the shallow-lying (lesser mature) western flanks of the Cooper Basin and overlying Eromanga Basin.

Gas wetness in most of the northern Patchawarra Trough is typically higher than might be expected based on the observed trend over other parts of the basin (Yew and Mills, 1989, fig. 8). In the Telopea/Keleary area gas wetness is extrapolated to be *ca* 15–20% and the maturity of the Patchawarra Formation in this region is around 1.35% R_o (Fig. 1.9). This is at variance with most regional values where a gas wetness of only *ca* 10% is typical at this maturity, and *could* indicate that longer-range (either vertically and/or laterally) migration of gas and liquids has taken place in the northern Patchawarra Trough of South Australia.

It is interesting to note that oils reservoired within the Nappamerri Group are almost entirely restricted to the northern Patchawarra Trough, in areas where the Patchawarra Formation has a maturity in the range 1.00–1.35% R_o (*i.e.* the wet gas window: *cf.* Tissot and Welte, 1984; Fig. 1.9a). Given that the Nappamerri Group has generally poor source potential (Boreham and Hill, 1998), it is perhaps no surprise that the Nappamerri oils are restricted to this area of gas wetness — they almost certainly represent petroleum which was expelled from Gidgealpa Group source rocks and infiltrated the overpressured Nappamerri Group *via* up-dip migration. Other hydrocarbons (principally gas with minor liquids) from the Patchawarra Formation migrated up-dip to invade juxtaposed Tirrawarra Sandstone traps (*e.g.* Bookabourdie, Mudrangie, Kudrieke, Moorari). Thus empirical evidence suggests that the Callamburra Member (Arrabury Formation) at the base of the Nappamerri Group behaves as a capillary seal (Boult *et al.*, 1998; Gravestock *et al.*, 1998b) in the upper oil/wet gas window (1.00–1.35% R_o).

1.6 ECONOMIC GEOLOGY

1.6.1 Proven and probable reserves

The Cooper and Eromanga Basins extend across four states and territories, but are only important for their hydrocarbon resources in South Australia and Queensland. As at January 1998, the total recoverable hydrocarbon reserves in South Australia (since the 1963 discovery of Cooper Basin gas at Gidgealpa-2) were as follows:

	Sales gas x 10^9 m^3	Oil x 10^6 kl
Cooper Basin		
Discovered	229[1]	6.9[1]
Already exploited	129[1]	4.6[1]
Remaining	100	2.3[1]
Eromanga Basin		
Discovered	negligible	15.6[2]
Already exploited	negligible	12.4
Remaining	negligible	3.2[3]
Total: Cooper and Eromanga Basin		
Discovered	229	22.5
Already exploited	129	17.0
Remaining	100	5.5[2]

Data sources: 1, Morton (1998); 2, Harvey and Hibburt (1999); 3, Morton's (1998) Cooper data subtracted from Harvey and Hibburt's (1999) total data

Reserves (as at 30 June 1999) for the Queensland sector are indicated below:

	Sales gas x 10^9 m^3	Oil x 10^6 kl
Total: Cooper and Eromanga Basin		
Discovered	71	18.8
Already exploited	11	16.6
Remaining	60	2.2

Data source: P. Green, Queensland Department of Mines and Energy, pers. comm., 2000

Based on these figures, 76% of discovered gas and 54% of discovered oil in the Cooper and Eromanga Basins is from the South Australia sector. However, by world standards, the basins' liquid hydrocarbon reserves are small. In comparison, the Gippsland Basin (offshore Victoria; Fig. 1.1) contains giant oil fields which pre-production cumulatively held over 20 000 x 10^6 kl of recoverable oil.

The Cooper and Eromanga oil fields vary considerably in size. Of the Cooper Basin oil fields, the Tirrawarra Field (Tirrawarra Sandstone) is the largest and contains *ca* 25.9 x 10^6 kl of original oil-in-place (OOIP: Seggie *et al.*, 1994) of which *ca* 5.5 x 10^6 kl is recoverable using conventional and enhanced oil recovery methods (representing 80% of recoverable Cooper Basin oil: Frears, 1998). The Strzelecki Field is the largest Eromanga oil accumulation comprising McKinlay-Namur, intra-Namur and Birkhead-Hutton oil pools which cumulatively hold 3.9 x 10^6 kl OOIP (representing 25% of recoverable Eromanga Basin oil). Oil pools with less than 0.15 x 10^6 kl of oil (*e.g.* Nungeroo, McKinlay-Namur reservoir; Arrakis, Birkhead-Hutton reservoir) can be economic provided that reservoir sandstones have high porosities and permeabilities (Northcote, 1996).

1.6.2 Estimated undiscovered reserves

In the Cooper Basin of South Australia, undiscovered hydrocarbon reserves are estimated (50% probability) by PIRSA at 5.4 x 10^6 kl of recoverable oil, and 56 x 10^9 m^3 of sales gas (Harvey and Hibburt, 1999). It is also estimated (50% probability) that some 10.8 x 10^6 kl of recoverable oil are still to be discovered in the South Australian portion of the Eromanga Basin (Morton, 1996). If these statistics are reasonably accurate, then 36% of the remaining gas and 75% of the remaining oil reserves in the Cooper and Eromanga Basins in South Australia are undiscovered. Moreover, it is postulated that more than half of the undiscovered oil (8.4 x 10^6 kl = 52%) occurs in the western Eromanga Basin (Harvey and Hibburt, 1999), *i.e.* that part of the Eromanga Basin west of the Birdsville Track Ridge.

The undiscovered petroleum reserves (50% probability) in the Cooper and Eromanga Basins of South Australia are summarised below:

	Sales gas x 10^9 m^3	Oil x 10^6 kl
Cooper Basin	56	5.4
Eromanga Basin		
Cooper region	-	2.4
Western Eromanga region	-	8.4

The Queensland Department of Mines and Energy does not publish estimates for undiscovered hydrocarbon reserves in that state. However, it follows that further economic reserves of hydrocarbons also remain to be discovered in the Queensland sector, especially in the relatively underexplored northeastern Cooper Basin area.

1.6.3 Recent hydrocarbon production

In 1997 the production and sale of hydrocarbons from the Cooper and Eromanga Basins in South Australia was 3.98 x 10^9 m^3 of gas, 0.42 x 10^6 kl of condensate and 0.63 x 10^6 kl of crude oil (Harvey and Hibburt, 1999). However, production of the above commodities has declined significantly since 1990. For example, in 1989 oil production was greater than 1.5 x 10^6 kl. In Queensland, for the financial year 1998/1999, 2.90 x 10^9 m^3 of gas, 0.28 x 10^6 kl of condensate and 0.58 x 10^6 kl of oil were produced (P. Green, Queensland Department of Mines and Energy, pers. comm., 2000).

In summary, the remaining proven and probable reserves of recoverable oil in the South Australia sector of the Cooper and Eromanga Basins combined is only 5.5 x 10^6 m^3. Proven and probable reserves of gas are estimated at 100 x 10^9 m^3 since the Eromanga Basin's gas reserves are negligible with respect to those of the Cooper Basin. Therefore, based on current annual exploitation of approximately 0.6 x 10^6 kl of oil and 4.0 x 10^9 m^3 of gas, and unless additional petroleum resources are discovered, or production efficiency for existing fields is improved, oil reserves in South Australia will be depleted in fewer than 10 years and gas within 25 years. Based on current annual exploitation of around 0.5 x 10^6 kl of oil, and 2.9 x 10^9 m^3 of gas, the Queensland reserves of oil will be depleted in 4 years and gas within 21 years.

1.7 SCOPE OF THIS THESIS

This thesis describes an organic geochemical and petrographic investigation of the hydrocarbon habitat of the Cooper and Eromanga Basins, with particular emphasis on the South Australia sector. A small dataset from the Arckaringa and Pedirka Basins underlying the western Eromanga Basin is also described and interpreted in Chapter 4. Important concepts such as thermal maturity, biomarker geochemistry and oil-source correlations (*cf.* Stach *et al.*, 1982; Tissot and Welte, 1984 ; Peters and Moldowan, 1993) are investigated. It is anticipated that the work described in this thesis will enhance our understanding of the hydrocarbon habitat of the Cooper and Eromanga Basins, and should thereby reduce exploration risk. The techniques employed in this study include petrographic analyses (including vitrinite reflectance) of potential source rocks, gas chromatography (GC) and gas chromatography-mass spectrometry (GC-MS) of oils and rock extracts. Because analyses were conducted using different analytical hardware, the methodologies used are documented separately in each chapter. Individual chapters are written as stand-alone manuscripts and any publications or technical reports which have resulted from this work have been indicated accordingly.

- Chapter 2 describes the biomarker geochemistry of oils and potential source rocks from the Cooper Basin (Patchawarra Trough) in South Australia. The oils tested are representative of most of the recoverable oil in the Cooper Basin and were sampled from Merrimelia Formation, Tirrawarra Sandstone and Patchawarra Formation reservoirs in the Daralingie, Fly Lake, Gidgealpa, Tirrawarra, and Moorari/Woolkina Fields.
- Chapter 3 documents the source rocks of the Eromanga Basin, South Australia, and the petroleum geochemistry of its western sector where it is inferred that significant oil reserves remain undiscovered (Section 1.6.2).
- Chapter 4 compares conventional maturity parameters (*e.g.* R_o and MPI) with estimation of vitrinite reflectance suppression in potential hydrocarbon source rocks from the Arckaringa, Pedirka, and western Eromanga Basins by FAMM (fluorescence alteration of multiple

macerals). Major suppression of vitrinite reflectance is inferred for potential Eromanga source rocks.

- Chapter 5 documents the source rock and petroleum geochemistry of the predominantly lacustrine Murta Formation (Section 1.3.4.6) which appears to have generated hydrocarbons at incipient levels of maturity (0.5–0.6% R_o). The work presented in this chapter builds upon an earlier study which was originally submittted as a B.Sc. Honours thesis by the author (Michaelsen, 1986).
- Chapter 6 describes the identification of in-reservoir mixing of hydrocarbons from Cooper Basin and Eromanga Basin source rocks. It is clear that many Eromanga oil pools are products of multiple source rocks and multiple expulsion events that can be identified from aromatic hydrocarbon signatures.
- Chapter 7 presents additional data on the migration of Permian and Jurassic/Cretaceous hydrocarbons and their regional interpretation based on mixing curves described in Chapter 6.

Four appendices accompany the thesis text. Appendix 1 shows the molecular structures of the hydrocarbon biomarkers discussed in the text. Tabulated geochemical and petrographic data discussed in Chapters 2–6 are presented in Appendix 2. Appendix 3 is a microfiched manual of laboratory procedures (*e.g.* Soxhlet extraction and the chromatographic separation of hydrocarbon fractions) used in the Organic Geochemistry Laboratory (Department of Geology and Geophysics, Adelaide University) by the author to prepare samples prior to GC-MS analyses. Appendix 4 is a collation of relevant publications by the author.

The concepts advanced in this study will provide a better understanding of hydrocarbon generation, migration, mixing and entrapment and should thereby reduce exploration risk in the Cooper and Eromanga Basins, especially around and beyond the "zero edge" of the Cooper Basin where most future exploration will be probably be undertaken.

Although the geographic focus of this work is entirely upon the petroleum province of northern South Australia and western Queensland, many of the ideas that are advanced should have utility in other petroliferous basins where sequences containing land plant organic matter are present. In Australia, such areas include the Gippsland Basin (offshore Victoria; Fig. 1.1) where oil was sourced from Tertiary coals (*e.g.* Glenie, 1985), and the North West Shelf of Australia (northern Carnarvon, Browse and Bonaparte Basins) where terrestrial sediments of Triassic and Jurassic age are inferred to be the major hydrocarbon source rocks (*e.g.* Purcell and Purcell, 1988).

CHAPTER 2

Biomarker geochemistry and origin of Permian oils from the Cooper Basin

CHAPTER 2

Biomarker geochemistry and origin of Permian oils from the Cooper Basin*

* Parts of this chapter have been published (Appendix 4) and prepared as a technical report as follows:

McKirdy D.M., Michaelsen B.H., Kagya M.L.N. and Ryan M.J. (1997) Biomarker signatures of oils from the Patchawarra Trough, Cooper/Eromanga Basin, South Australia. *18th International Meeting on Organic Geochemistry, 22–26 September 1997, Maastricht, The Netherlands. Abstracts Part I*, pp. 415–416.

Michaelsen B.H., Kagya M.L.N., McKirdy D.M., Paull R. and Yu X. (1996b) Geochemical comparison of source rocks and oils from the western Cooper Basin and superjacent Eromanga Basin. *Report for Department of Mines and Energy South Australia.*

2.1 SUMMARY

Two families of geochemically distinct crude oils are described from the South Australian sector of the Cooper Basin. The Family 1 crudes are condensate-like (46–50° API), supermature ($R_c \geq$ 1.05%) and contain exceptionally high concentrations of 17α-diahopanes and 18α-neohopanes (rearranged hopanes >> 17α-hopanes). They appear to be restricted to the Tirrawarra Sandstone in the Patchawarra Trough. Biomarker analyses indicate that these Family 1 oils are derived predominantly from coals within the Patchawarra Formation that are demonstrated to be better source rocks for liquid hydrocarbons than contiguous shales. Analyses of coal/shale pairs from the Patchawarra Formation reveal that it is the coal lithofacies which contains the higher concentrations of rearranged hopanes.

Family 2 oils (34–36° API) are geographically more widespread. They exhibit a conventional hopanoid biomarker signature (*viz* 17α-hopanes > rearranged hopanes) and were probably sourced from both clastic and coaly source rocks at somewhat lower maturities (≤ 1.0% R_c) than Family 1 oils.

Based on maturity and biomarker correlations, Poolowanna-hosted oils (49–53° API) in the Sturt/Tantanna area of the Patchawarra Trough, adjacent to the Cooper Basin "zero edge", appear to be largely derived from Poolowanna source kitchens at maturities corresponding to the early oil window (0.65–0.80% R_o).

2.2 INTRODUCTION

2.2.1 Rationale of study

This chapter elaborates the results of a study commissioned by the former Department of Mines and Energy, South Australia (MESA). Its aims were twofold:

1. to geochemically describe a representative suite of Permian-reservoired oils and test for evidence of long-distance secondary migration of hydrocarbons within the southern Cooper Basin (Fig. 2.1); and
2. to determine which Permian lithofacies (coal or shale) has the greater source potential and, if possible, to elucidate the likely sources of the Cooper Basin oils.

2.2.2 Sample selection and vitrinite reflectance maps

MESA supplied 12 core samples purposely sampled as six coal/shale pairs (Table 2.1) from the Tirrawarra Sandstone (1 pair) and Patchawarra Formation (5 pairs) from the Daralingie-19, Fly Lake-3, Gidgealpa-17, Kanowana-1, Moorari-1, Tirrawarra-2, Tirrawarra-16 and Tirrawarra-17 exploration wells. In addition eight Cooper Basin production crudes (Table 2.2) were obtained from the Merrimelia Formation (Malgoona-1A), Tirrawarra Sandstone (Fly Lake-8, Gidgealpa-41, Moorari-1, Tirrawarra-2, Tirrawarra-8, Woolkina-1) and Patchawarra Formation (Daralingie-18). Supplementary to Figure 2.1 are additional larger scale maps showing the position of oil and gas fields with superimposed vitrinite isoreflectance contours for the base Patchawarra Formation in the southwestern corner of the southern Cooper Basin (Fig. 2.2; area A in Fig.

2.1), and for the top Patchawarra Formation in selected areas of the same region (Fig. 2.3; areas B, C and D in Fig. 2.1). These are copied and reduced in scale from Burckhardt's (1990a,b) original vitrinite reflectance compilations. A map showing isoreflectance contours for the mid-Birkhead Formation (Burckhardt, 1990c) is provided as an inset in Figure 2.3 (area C in Fig. 2.1). Outlines of the oil and gas fields are after Boucher (1997).

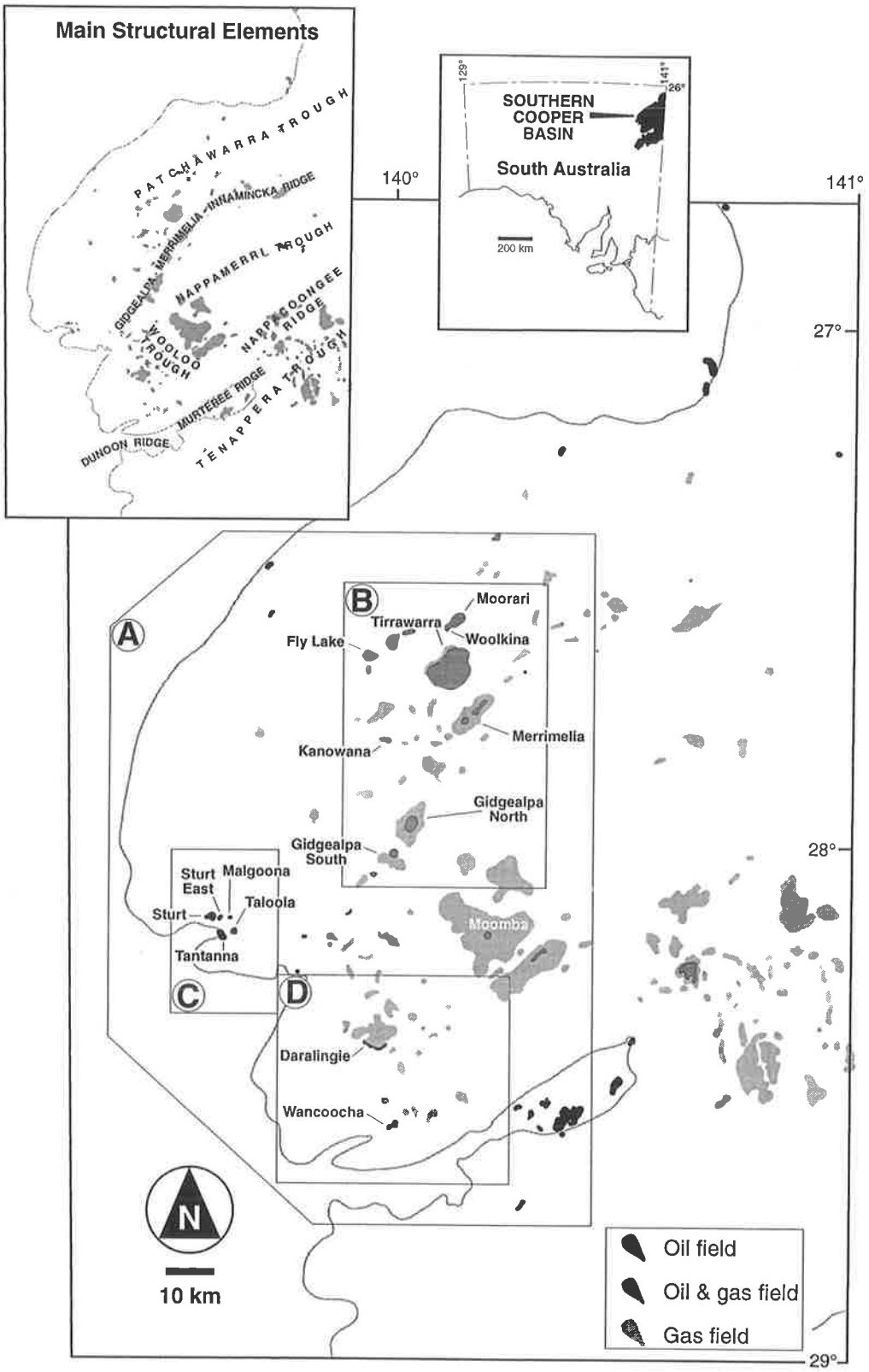


Figure 2.1 Map of study area showing the locations of oil and gas fields in the southern Cooper Basin (modified from Boucher, 1997, fig.8)

The sediment and oil samples described above were augmented by a suite of five Poolowanna Formation coal and shale extracts from the Sturt/Sturt East/Tantanna Fields (Fig. 2.1) and six Poolowanna-reservoired oils from the same area supplied by Santos Ltd. The oils from the Sturt/Tantanna area were chosen because of their close proximity to the Merrimelia oil pool at Malgoona-1A, thereby providing an ideal test of the Permian source paradigm of Heath *et al.* (1989; *cf.* Chapter 1). Indeed, the oil fields in the Sturt/Tantanna area were discovered by employing the Heath *et al.* (1989) "fill and spill" model which prescribes that oil at this locality has a Permian origin and has migrated past the Cooper Basin "zero edge" into the overlying Eromanga reservoirs of the Poolowanna and Birkhead Formations.

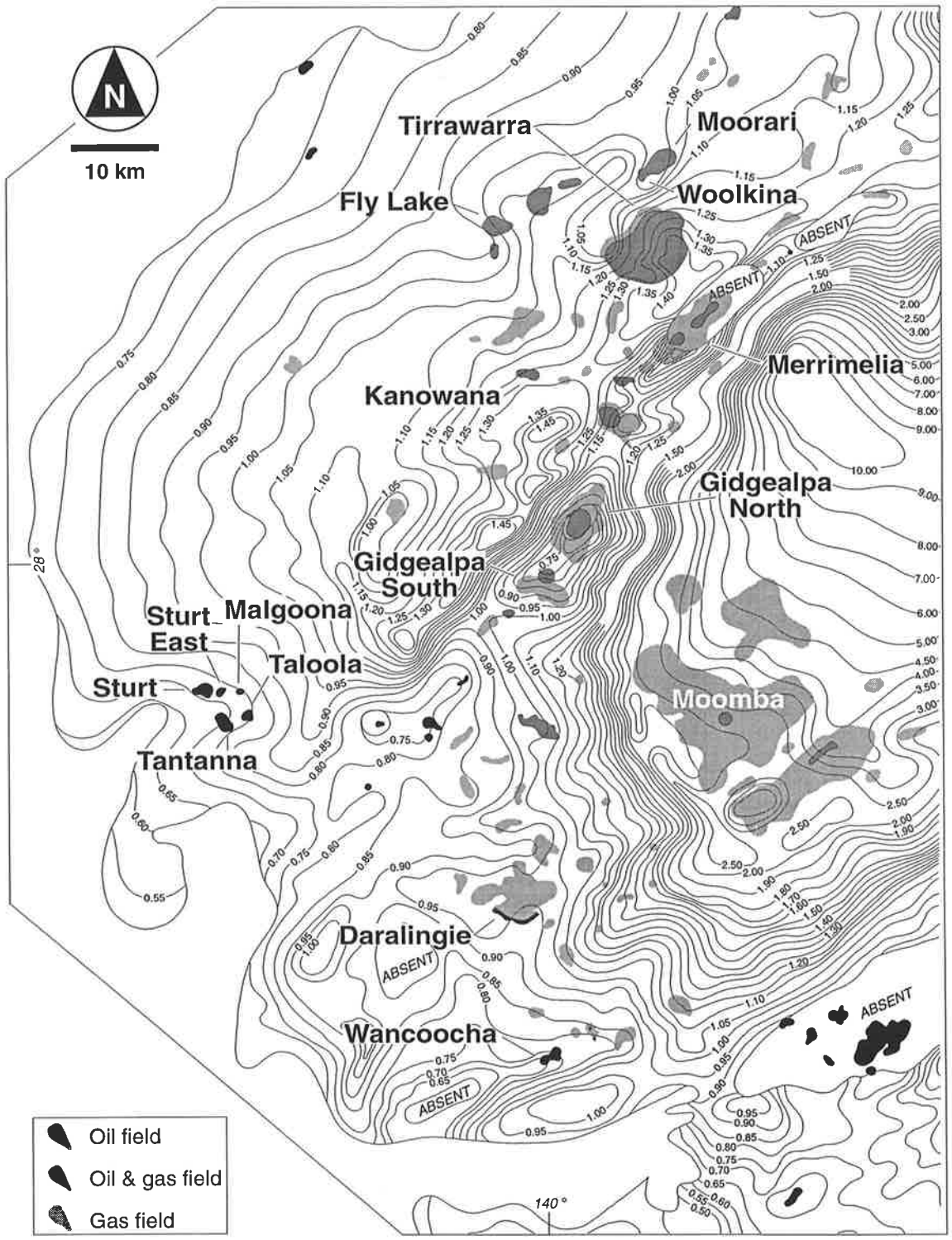


Figure 2.2 Map of area A (see Fig. 2.1) showing vitrinite isoreflectance contours (%) of base Patchawarra Formation (after Burckhardt, 1990a) superimposed upon oil and gas fields of the southwestern Cooper Basin (contour interval variable)

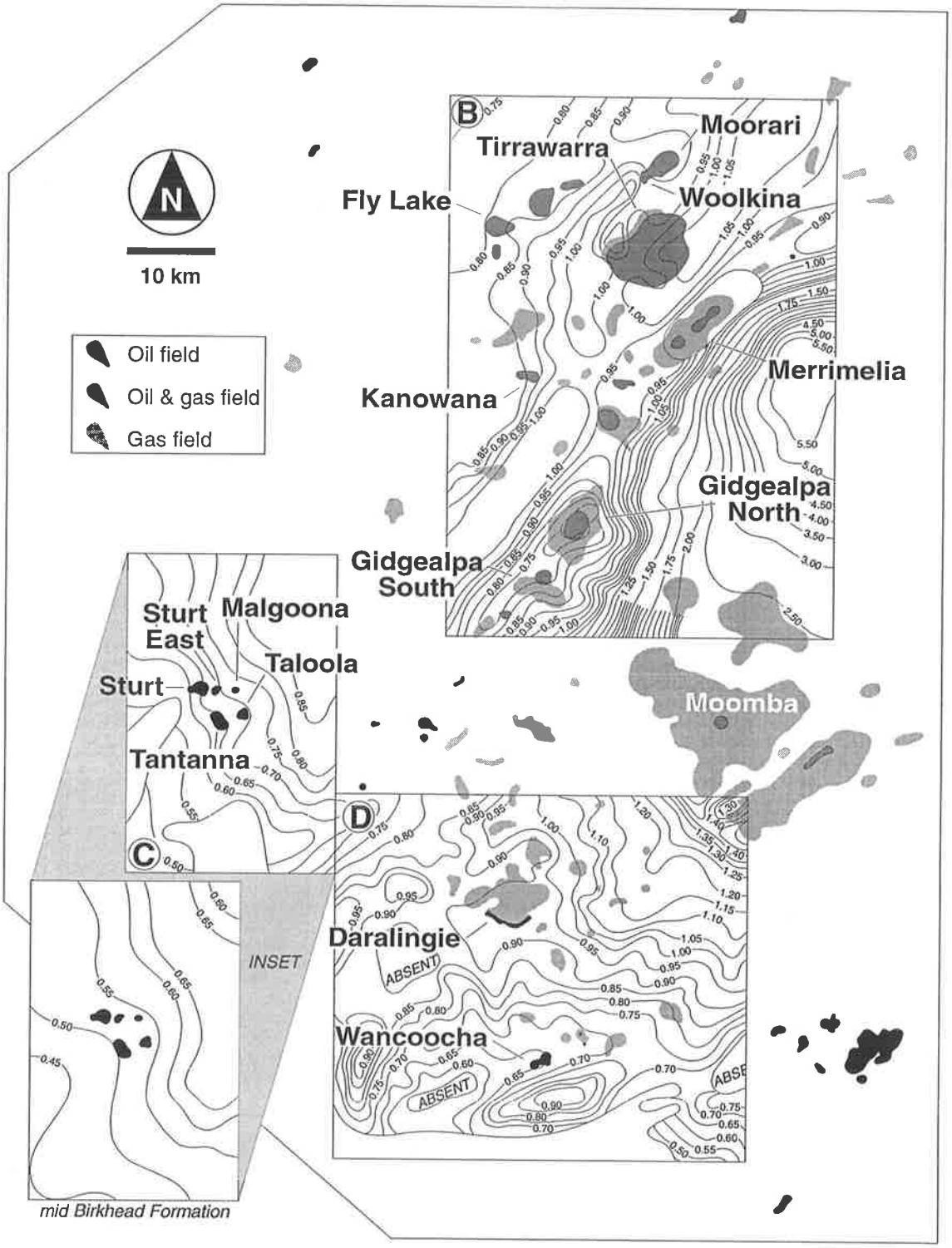


Figure 2.3 Maps of areas B, C and D (see Fig. 2.1) showing vitrinite isoreflectance contours (%) of top Patchawarra Formation (after Burckhardt, 1990b) superimposed upon oil and gas fields of the southwestern Cooper Basin (contour interval variable). Inset shows isoreflectance contours (%) of mid-Birkhead Formation (after Burckhardt, 1990c) for area C

The six oil samples and the five coal and shale samples from the Poolowanna Formation were originally analysed and described by Michaelsen *et al.* (1996b) and formed part of the database in Kagya's (1997) Ph.D. thesis. Only the data and interpretations of Michaelsen *et al.* (1996b) have been utilised herein.

2.3 EXPERIMENTAL

2.3.1 Sample preparation

All core samples were scraped and brushed clean to remove surficial contamination. Cuttings samples were washed in deionised water and hand-picked to remove contaminants. Sub-

specimens of the 13 core samples were cut perpendicular to bedding, mounted in Araldite resin and polished for petrographic analyses (Table 2.3). The four cuttings samples were prepared as grain mounts in resin. Vitrinite reflectance measurements were made using a Leitz Ortholux Pol BK microscope under conditions specified by the Standards Association of Australia (1989). The means of random vitrinite (% R_r) reflectance were converted to means of maximum vitrinite reflectance (% R_o) using Kilby's (1991) formula: $R_o = 1.083 \times R_r$ (Table 2.3). All samples were crushed to powder in a Siebtechnik mill, and then analysed for total organic carbon (TOC) using a Leco WR-12 Carbon Determinator, and by Rock-Eval pyrolysis using a Girdel IFP-Fina Mark II (cycle 1 mode) (*cf.* Espitalié *et al.*, 1977; Peters, 1986). TOC and Rock-Eval data are provided in Table 2.4.

The residual rock powders were extracted in Soxhlet apparatus (*cf.* Appendix 3) using an azeotropic solvent mixture (CH_2Cl_2:CH_3OH, 93:7). The extract was fractionated by open-column liquid chromatography on activated silica into saturated hydrocarbons, aromatic hydrocarbons and polar compounds (resins and asphaltenes) (see Tables 2.5 and 2.6). The Daralingie-18, Gidgealpa-41, and Malgoona-1A production oils were distilled to remove the light ends (< C_{12} fraction). They and the remaining 11 oil samples were then fractionated by liquid column chromatography into saturated hydrocarbons, aromatic hydrocarbons and polar compounds. For some samples, the saturated hydrocarbon fractions were molecular sieved using *silicalite*, to separate the cyclic biomarker (naphthene) fraction from the *n*-alkanes and branched alkanes (*iso*- and *anteiso*-alkanes).

2.3.2 Gas chromatography-mass spectrometry

2.3.2.1 Saturated hydrocarbons

The GC-MS analyses were undertaken using a Varian 3400 gas chromatograph interfaced to a Finnigan TSQ 70 mass spectrometer. The gas chromatograph was fitted with a 60 m x 0.25 mm i.d. fused silica column (DB-1, 0.25 μm film thickness; J & W Scientific). Helium was used as the carrier gas at an inlet pressure of approximately 23.5 psi. The temperature program of the oven was as follows: 50° C for 2 min, 50° to 120° C at 8° C min^{-1}, 120° to 300° C at 4° C min^{-1} and then held at 300° C for 35 min. The injector was held at 50° C for 3 seconds then ramped to 300° C at 180° C min^{-1}, and held at 300° C for 5 minutes. Mass spectrometer operating parameters included an ionisation voltage of 70 eV and a filament current of 200 μA. The photomultiplier voltage was set at 1800 V. The saturated hydrocarbon fractions were dissolved in *n*-hexane prior to injection and the mass spectrometer was programmed (multiple ion detection: MID) to monitor *inter alia m/z* 123 (sesquiterpenoids, triterpanes), *m/z* 163 (25,28,30-trisnorhopane), *m/z* 177 (demethylated hopanes), *m/z* 191 (hopanes, triterpanes), *m/z* 205 (homohopanes, methylhopanes), *m/z* 217 (steranes), *m/z* 218 (14β,17β-steranes), *m/z* 231 (A-ring methylsteranes), and *m/z* 259 (diasteranes). Some samples were analysed using a Hewlett Packard 5890 GC interfaced to a Hewlett 5972 MSD mass spectrometer, programmed to detect the same ions as listed above, and a 60 m x 0.25 mm i.d. fused silica column (DB-5, 0.25 μm film thickness; J & W Scientific). The temperature program of the column/oven was identical to that described above, but the temperature of the 2 μm splitless injector was maintained at 285° C. All saturated hydrocarbon GC-MS parameters were calculated using peak areas.

2.3.2.2 Aromatic hydrocarbons

For most samples, GC-MS conditions were identical to those used in the analysis of the saturated hydrocarbons except that the photomultiplier voltage was set to 1100 V. Aromatic fractions in CH_2Cl_2 were injected on-column. The mass spectrometer was programmed in multiple ion detection (MID) mode to monitor *m/z* 128 (naphthalene), *m/z* 141 and 142 (methylnaphthalenes), *m/z* 156 (dimethylnaphthalenes), *m/z* 170 (trimethylnaphthalenes), *m/z* 178 (phenanthrene), *m/z* 192 (methylphenanthrenes), *m/z* 206 (dimethylphenanthrenes), *m/z* 219 (retene), *m/z* 231 and 245 (monoaromatic steroids), and *m/z* 253 (triaromatic steroids). The following response factors were employed to normalise the data relative to the calibrated GC response: Phenanthrene (in calculating MPI-1: 0.69), TNR-1 (0.82), and 1,2,5-TMN/1,3,6-TMN (0.75). All other aromatic hydrocarbon GC-MS parameters were calculated using peak areas.

2.4 SOURCE ROCK EVALUATION

2.4.1 Cooper Basin

A summary of TOC and Rock-Eval pyrolysis data for the Tirrawarra Sandstone and Patchawarra Formation is presented in Table 2.4. A T_{max} *versus* HI cross-plot (Fig. 2.4) illustrates kerogen type and maturity for these samples.

2.4.1.1 Tirrawarra Sandstone

The Tirrawarra Sandstone is represented by a shaley coal/shale pair from the Tirrawarra-16 and 17 wells. Both the coal (HI = 143; TOC = 45.4%; $S_1 + S_2$ = 77.1 mg HC/g; EOM = 28 mg HC/g; 0.96% R_o) and the shale (HI = 163; TOC = 9.9%; $S_1 + S_2$ = 19.0 mg HC/g; EOM = 41 mg HC/g 1.04% R_o) samples are high yielding, good quality source rocks (Tables 2.3, 2.4 & 2.5) and contain Type II kerogen (Table 2.7) indicating that these rocks are oil-prone.

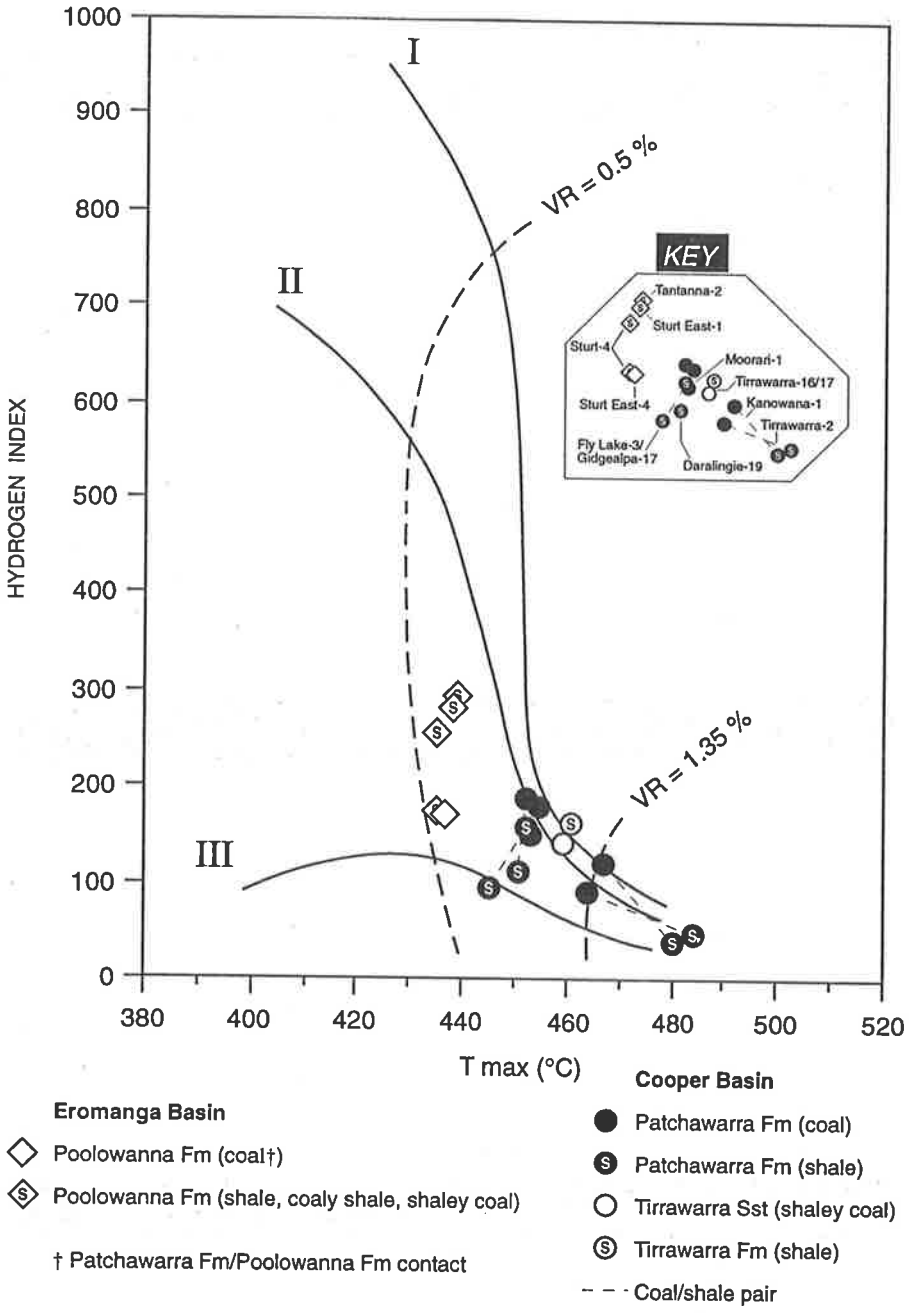


Figure 2.4 Kerogen type and maturity for Tirrawarra Sandstone, Patchawarra Formation and Poolowanna Formation

To facilitate discussion, two additional parameters require explanation. R_{re} is defined here as the maturity estimated from the Rock-Eval data plotted on the T_{max} *versus* HI cross-plot in Figure 2.4. R_{est} is the (average) estimated maturity when taking into account both R_o and R_{re}. R_o, R_{re} and R_{est} values are summarised in Table 2.8.

T_{max} values of 459 (shaley coal) and 461° C (shale) equate with maturities of *ca* 1.15% R_{re} (Table 2.8). However, the measured maturities are lower (0.96 and 1.04% R_o, respectively). In their entirety, the data suggest that these samples have maturities in the range 1.00–1.05% R_{est} (Table 2.8) and are therefore in the middle to late oil-generation window.

2.4.1.2 Patchawarra Formation

Organic richness

Organic richness for the Patchawarra Formation samples is highly variable. TOC content for the coals is in the range 69.6–84.5% (mean = 79.5%) compared to 1.3–4.6% (mean = 3.4%) for the shales (Tables 2.4 & 2.7). Accordingly, genetic potential ($S_1 + S_2$) is much less for the shales (1–19 mg/g; mean = 4 mg/g) than for the coals (77–180 mg/g; mean = 141 mg/g) (Tables 2.4 & 2.7). EOM yields per unit weight of TOC are also greater for coals (28–59 mg/g TOC; mean = 46) than for shales (21–48 mg/g TOC; mean = 36). These data suggest that, in the Patchawarra Formation, coals (not shales) are the richer hydrocarbon source rocks.

Source quality

Rock-Eval pyrolysis indicates that source quality for the Patchawarra coals (mean HI = 145) is greater than that of the shales (mean HI = 90; Table 2.7). With the exception of the coal (HI = 150) and shale (HI = 159) at Moorari-1 which have similar source potential, four of the five coals from the Patchawarra Formation have better source quality than their paired shales (Fig. 2.5a). The coals contain mature Type II kerogen (Table 2.7; Fig. 2.4) with good potential for liquid hydrocarbon generation, whereas the shales have diminished source potential due to the predominantly Type III composition of their organic matter and were probably only gas-prone prior to entering the oil window.

Production indices are generally similar for any given coal/shale pair (Table 2.4). However, one prominent exception is the pair from Daralingie-19. Here the coal which has a relatively high hydrogen index (HI = 187) also has an anomalously elevated production index (PI = 0.61). This could indicate staining from migrated hydrocarbons. However, it is more likely to be due to hydrocarbons which have been generated from the oil-prone coal itself, since the adjacent shale (non-oil prone) has a "normal" production index of 0.17 consistent with the expected rank of these sediments. PI values of between 0.13 and 0.19 for most samples are suggestive of the upper part of the oil window. The shale sample from Kanowana-1, which contains very poor quality organic matter (HI = 38), has probably been stained by migrated hydrocarbons because of its somewhat elevated PI value of 0.31.

Maturity

All the coal and shale samples are mature for liquid hydrocarbon generation (Table 2.8). At Daralingie-19, Kanowana-1, Moorari-1 and Tirrawarra-2, where the coal/shale pairs were obtained from closely juxtaposed lithologies, the coal and shale for each locality must be isometamorphic, despite discrepancies between their measured vitrinite reflectance and Rock-Eval-derived R_{re}.

In general, the measured vitrinite reflectance data (R_o) for the coal/shale pairs are in reasonable agreement (Tables 2.3 & 2.8). However, R_o values are higher in the coals from Daralingie-19 (1.03% R_o) and Fly Lake-3 (1.06% R_o). This is probably due to the fact that reflectance readings were obtained from an insufficient number of vitrinite phytoclasts in these organically lean shales. At Fly Lake, the isoreflectance contours of Figure 2.2 indicate a base Patchawarra maturity of between 0.95 and 1.05% R_o in the vicinity of the oil accumulation. This is in good agreement with the measured and estimated maturity of the Fly Lake-3 coal sample (1.06% R_o; 1.0% R_{re}; 1.05% R_{est}). Despite the paucity of vitrinite in the siltstone from Gidgealpa-17 (7164'5"), its measured maturity (0.86% R_o) is reasonably similar to that estimated from T_{max} (0.8% R_{re}) and consequently it has been assigned an R_{est} value of 0.85% (Table 2.8). Figure 2.2 shows that at Gidgealpa South (Gidgealpa-17) the maturity variation across the field at base Patchawarra level is relatively severe, varying between *ca* 0.75 on structure to *ca* 1.3% R_o within about 8 km to the southeast. Therefore, the maturity of the Patchawarra Formation at the Gidgealpa locality is probably less well constrained than at some of the other fields.

Where the reflectance values of juxtaposed, isometamorphic coal and shale samples differ, that of the (vitrinite-rich) coal can usually be considered more reliable. Based on this well-established premise, the shale sample from Daralingie-19 probably has a maturity higher than its measured maturity (0.90% R_o) and more like that of its paired coal sample (1.03% R_o). T_{max}-estimated maturities are similar for both the coal and shale samples (0.95% R_{re}). Consequently, R_{est} values of 0.95% are considered appropriate for the Daralingie-19 coal/shale pair. According to the interpolated data of Burckhardt (1990a; Fig. 2.2), a maturity of *ca* $\geq$ 0.95% R_o is typical for the base of the Patchawarra Formation across the Daralingie Field.

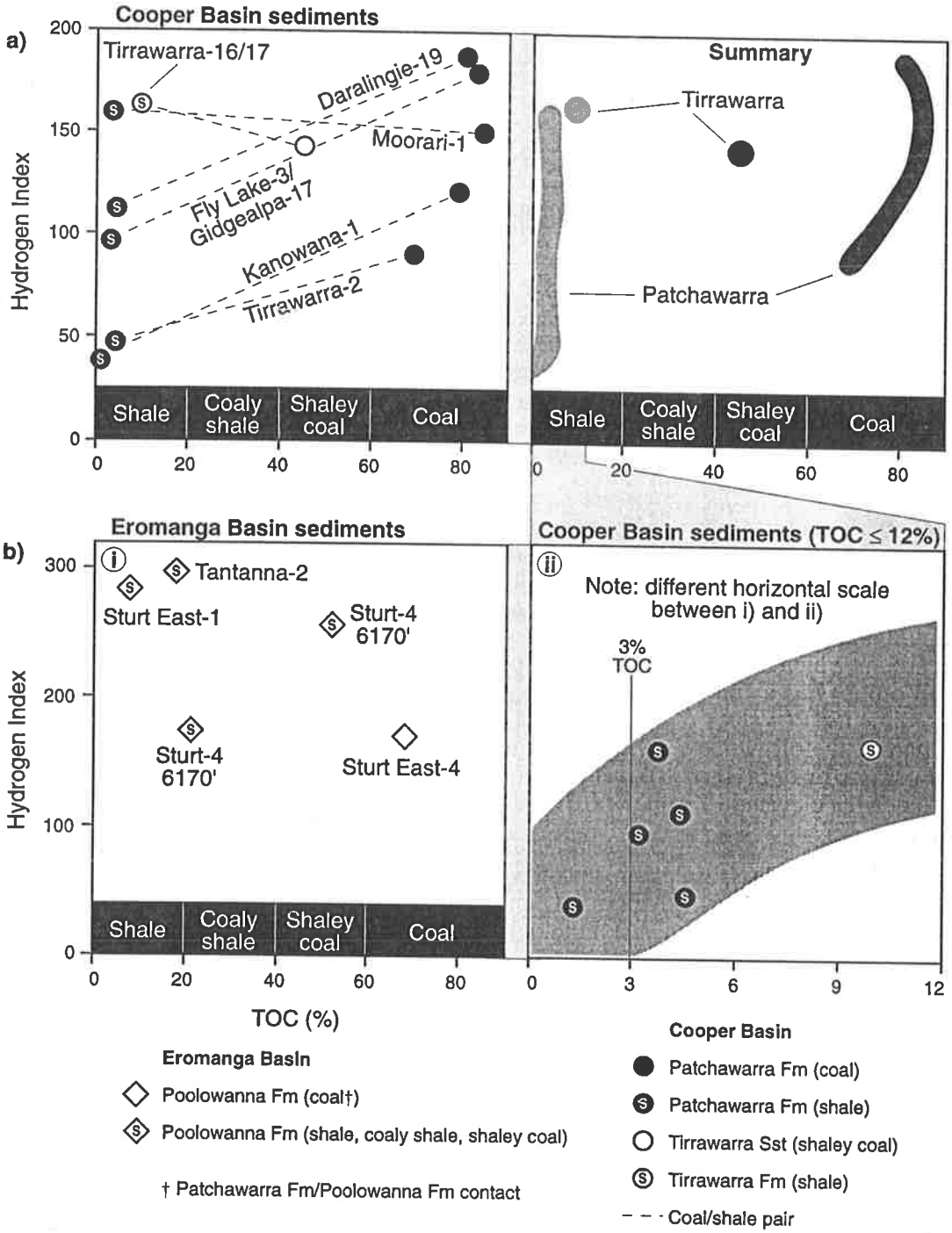


Figure 2.5 a) TOC *versus* hydrogen index for Cooper Basin sediments; b) TOC *versus* hydrogen index for i) Eromanga Basin sediments (TOC ≤ 90%), compared with ii) Cooper Basin sediments (TOC ≤ 12%)

Where the number of reflectance readings is high (*e.g.* > 20), as in the coal/shale pair from Moorari-1 (n = 35), there is good agreement between the measured vitrinite reflectances of the coal (0.92% R_o) and the shale (0.96% R_o). Consequently, R_{est} values of 0.95% have been assigned to these samples (Table 2.8). These measurements and estimates are in very good agreement with the documented regional maturity (Figs 2.2 and 2.3) of the Patchawarra Formation at the Moorari locality (base: *ca* 1.0% R_o; top: *ca* 0.9% R_o).

The T_{max} values of the two shale samples from Kanowana-1 (480° C; ≥ 1.4% R_{re}) and Tirrawarra-2 (484° C: ≥ 1.4% R_{re}) are unrealistically high due to their low kerogen pyrolysate yields (S_2 = 0.51 and 2.16 mg HC/g respectively). However, reliable R_o data for the Kanowana-1 coal (1.21% R_o) indicates that both the coal and shale samples from Kanowana-1 and Tirrawarra-2 are almost certainly less mature than indicated (1.20% R_{est}: Table 2.8). Maturities

of around 1.20% R_{est} are consistent with the data of Figure 2.2 which show that the average maturity for the base Patchawarra Formation in the Tirrawarra oil field is *ca* 1.3% R_o. Vitrinite isoreflectance contours for the base Patchawarra Formation at Kanowana similarly indicate a maturity of *ca* 1.25% R_o (Fig. 2.2) which is in excellent agreement with those estimated above.

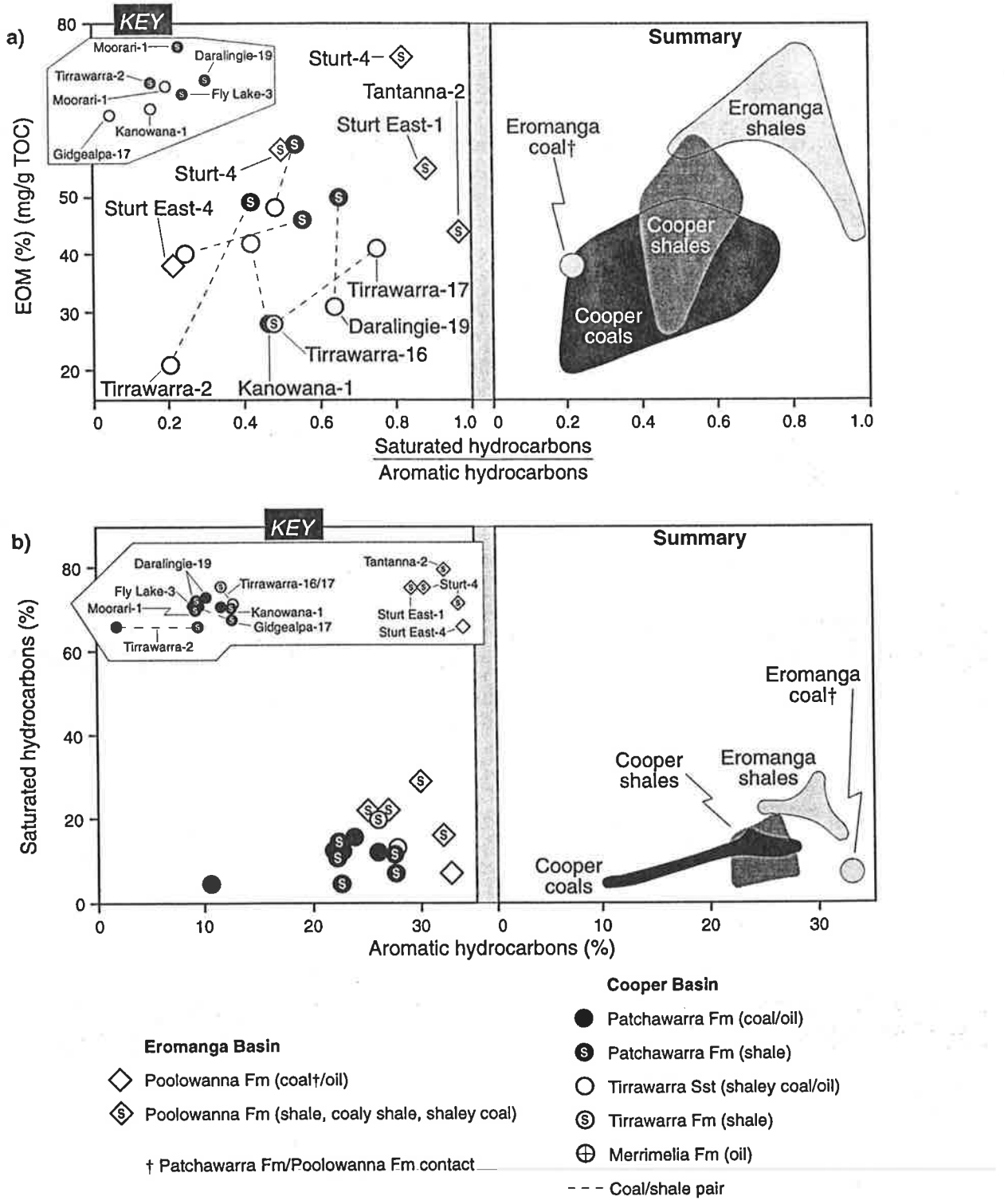


Figure 2.6 a) Ratio of saturated/aromatic hydrocarbons *versus* EOM for sediments; b) Aromatic *versus* saturated hydrocarbon content for sediments

All things considered, the maturities of the Patchawarra and Tirrawarra coals (oil-prone Type II kerogen) and shales (gas-prone Type III ± II kerogen) investigated in this study correspond to the "upper oil window" (*cf.* Table 2.8). Indeed, samples from Kanowana-1 and Tirrawarra-2 (1.20% R_{est}) have almost entered the "dry gas window" of hydrocarbon generation. Thus, the capacity of the coals in Kanowana-1 and Tirrawarra-2 to generate liquid hydrocarbons is probably almost exhausted.

2.4.2 Eromanga Basin

2.4.2.1 Poolowanna Formation

Organic richness

Five samples from the Poolowanna Formation have TOC values in the range 7.8–68.1%, S_1 + S_2 values of 23–148 mg HC/g of rock and EOM yields of between 38–74 mg/g TOC, all suggesting good to very good organic richness.

Source quality

Hydrogen indices for the Poolowanna samples vary between 170 and 296 representing fair to very good source quality for liquid hydrocarbon generation (Figs 2.4 & 2.5bi). The highest values are obtained from the most organically lean samples which are the two shales (mean HI = 290) from Sturt East-1 (TOC = 7.8%) and Tantanna-2 (TOC = 18.1%). By contrast, the Sturt East-4 coal (TOC = 68.1%) has the lowest recorded HI value (170) and hence the least source potential of the five samples (Fig. 5bi).

The observation that Poolowanna shales have higher source quality than do Poolowanna coals is interesting because it is at variance with the Patchawarra data (see above discussion) which indicate that its coals have superior source potential compared to argillaceous lithologies containing DOM (*cf.* Fig. 2.5a). Moreover, source quality as measured by HI for the Cooper Basin samples (Figure 2.5bii) is diminished where TOC values are particularly low (*viz* TOC < 3%), and is known to result from the adsorption of S_2 pyrolysate onto the mineral matrix during programmed Rock-Eval pyrolysis (*cf.* Orr, 1983; Powell *et al.*, 1989). However, the Poolowanna samples analysed herein are sufficiently rich (TOC >> 4%) to obviate the effects of pyrolysate adsorption.

Maturity

Measured vitrinite reflectances (0.61–0.69% R_o: Tables 2.3 & 2.8) indicate that all the Poolowanna samples in the Sturt/Sturt East area lie within the early oil generation window. Two adjacent coaly samples from Sturt-4 (which must be approximately isometamorphic) have somewhat disparate maturities (0.62% R_o for the deeper sample, 0.69% R_o for the shallower sample). Maturation levels estimated from T_{max} using Figure 2.4 (0.60–0.65% R_{re}) are consistent with the measured R_o values. By contrast, the shale from Tantanna-2 (5901') some 4–5 km to the south appears to be slightly more mature (0.73% R_o; 0.65% R_{re}; 0.70% R_{est}).

Burckhardt's (1990g) isoreflectance contour map (Fig. 2.3, area C) indicates that the Patchawarra Formation in the Sturt/Tantanna area has a maturity of between *ca* 0.68–0.73% R_o (base) and *ca* 0.60–0.70% R_o (top), and that at the same locality the mid-Birkhead Formation (Figure 2.3, area C inset) is between 0.50–0.55% R_o. Thus, a maturity level of *ca* 0.60–0.65% R_o for the Poolowanna Formation at this locality is entirely consistent with its stratigraphic position.

2.4.3 Extractable organic matter of coals and shales

Source potential for the Poolowanna Formation shales, as indicated by extractable organic matter (EOM: Table 2.5) is higher for the Eromanga shales (44–74 mg/g TOC) than for the Cooper Basin coals (28–50 mg/g TOC) or shales (21–48 mg/g TOC). EOM when measured in parts-per-million (ppm) is greater than 550 for all the Cooper Basin and Eromanga Basin samples (Table 2.5) and is therefore indicative of rocks at the main stage of oil generation (*cf.* Jenkins, 1989, fig. 5).

The saturated/aromatic hydrocarbon ratio of rock extracts is known to increase with greater burial and maturation (*e.g.* Tissot and Welte, 1984) and therefore it is conceivable that the higher values recorded for the Poolowanna Formation shales (0.21–0.97; Table 2.5) indicate a higher maturity than for the Cooper Basin coals (0.42–0.65) and shales (0.20–0.75; Fig. 2.6a). However, this interpretation is at variance with other maturity parameters discussed in this chapter.

2.5 PHYSICAL PROPERTIES OF OILS

2.5.1 API gravity

The work outlined in this chapter demonstrates that Cooper Basin oils can be subdivided into two families which are geochemically distinct from the Poolowanna oils. To facilitate discussion, the Cooper Basin crudes are herein assigned to either Family 1 or Family 2. A geochemical distinction between Family 1 and Family 2 oils is obvious from their disparate API gravities

(Table 2.2, Fig. 2.6b). The API gravities of the Family 1, Family 2 and Poolowanna oils are summarised below:

	Range (° API)	Mean (° API)	n
Family 1 oils	45.9–50.4	47.7	4
Family 2 oils	34.0–36.3	35.1	3
Poolowanna oils	48.8–53.0	50.2	6

Clearly, the Family 2 oils have API gravities typical of conventional crudes, whereas the Poolowanna and Family 1 crudes are very light, condensate-like oils.

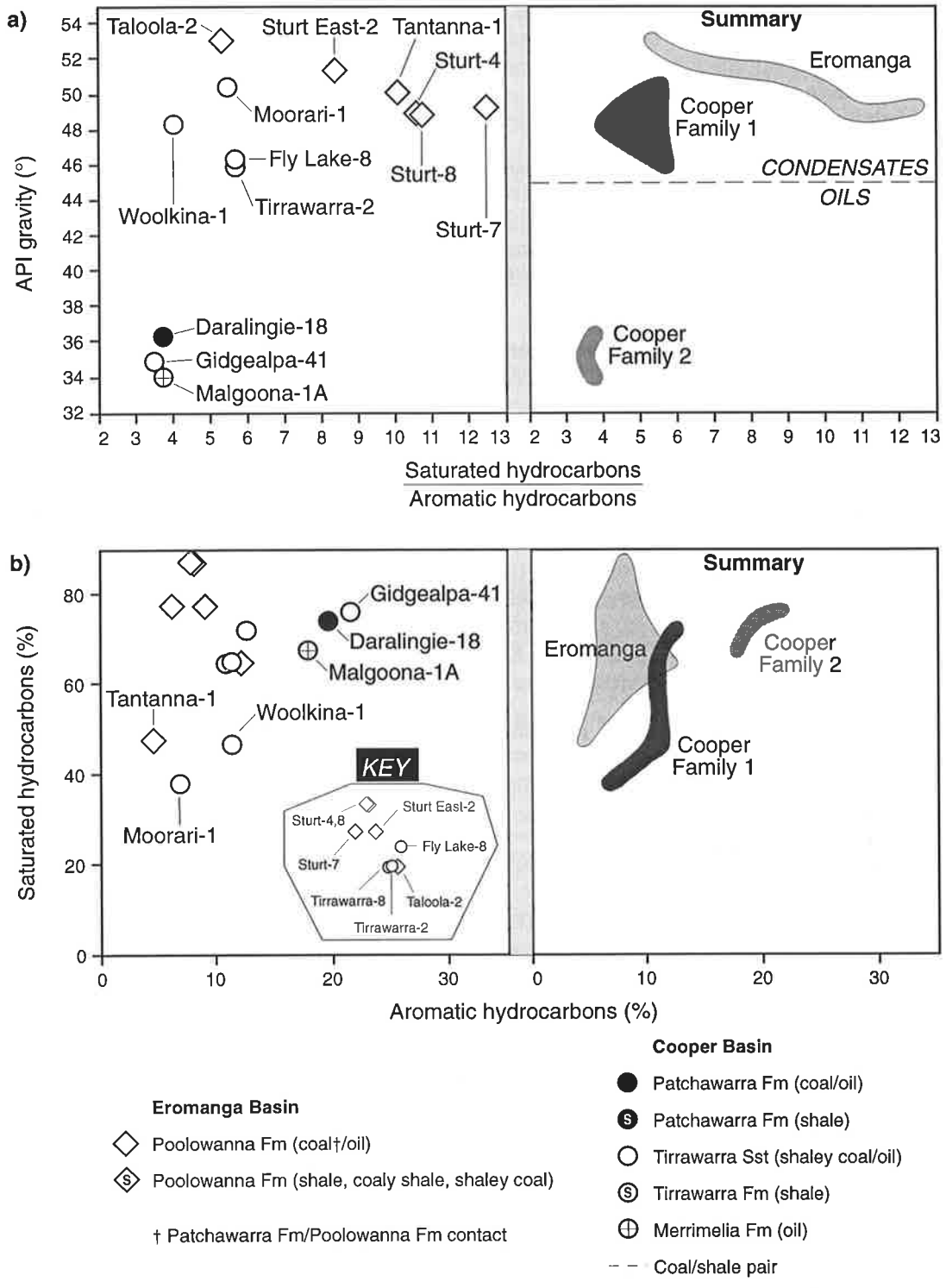


Figure 2.7 a) Ratio of saturated/aromatic hydrocarbons *versus* API gravity for sediments; b) Aromatic *versus* saturated hydrocarbon content for oils

Based solely on their API gravity, Poolowanna crudes from the Eromanga Basin appear similar to Family 1 oils from the Cooper Basin. However, based on their geographic distribution, it is unlikely that the Poolowanna oils are related to Family 1 oils unless very long-distance secondary migration is invoked, since Family 1 crudes occur in the Patchawarra Trough some *ca* 65–85 km to the northeast (Figs 2.1 & 2.2). It is easier to conceive that the Poolowanna oils may have migrated updip from the immediately subjacent (higher maturity) Patchawarra Formation (*cf.* Figs 2.2 & 2.3) of the Cooper Basin. However, the local Cooper Basin crude from Malgoona-1A (Patchawarra Formation), has a much lower API gravity (34.0°) which places it within Family 2. Put simply, API gravities suggest that the Patchawarra (Malgoona-1A) and Poolawanna crudes in the nearby Sturt/Tantanna area are dissimilar, and are therefore unlikely to be genetically related. If the Poolowanna oils from the Sturt/Tantanna area are partly or wholly derived from more-or-less nearby (down-dip) Cooper Basin sources, it is unlikely that they migrated from deeper Permian strata into the lower Eromanga Basin (Poolowanna Formation) without significant compositional alteration (*e.g.* loss of light-end hydrocarbons which in not supported by whole-oil GC analyses described in Chapter 6). Alternatively, the simplest explanation is that the Poolowanna oils may represent hydrocarbons which have been sourced from high quality Eromanga Basin (intra-Poolowanna) source rocks (Section 2.4.2).

Oils with high API gravities (*i.e.* ≥ 46°) and low viscosity are known to form from high maturity source rocks (*e.g.* some Gippsland Basin oils: Burns *et al.*, 1987; *cf.* Chapter 6). Cracking of longer chain *n*-alkanes to lower-molecular-weight compounds is also important in the formation of such mature oils (*e.g.* Waples, 2000). Therefore the maturity of these oils as measured by, for example, the methylphenanthrene index is critical to elucidating the origin of the Poolowanna oils (*cf.* Section 2.6).

2.5.2 Saturated and aromatic hydrocarbon fractions of oils

In Figure 2.7a the ratio of saturated/aromatic hydrocarbons, derived from liquid chromatographic fractionation of the oils, is plotted against their API gravities. As discussed above, the API gravities of the Family 1 oils are closer to those of the Poolowanna Formation. This similarity is reinforced by the saturated/aromatic hydrocarbon ratio which suggests that the Family 1 oils (4.1–5.9, mean = 5.4) are intermediate in composition between Family 2 (3.5–3.8, mean = 3.7) and the Poolowanna-reservoired crudes (5.3–12.5, mean = 9.6). The significance of this observation is uncertain, other than to suggest a tentative relationship between the Poolowanna and Cooper Basin Family 1 crudes. However, according to the hydrocarbon generation model described by Powell (1985), light oil, similar to that reservoired in the Poolowanna Formation, is the main maturation product of resinite-enriched terrestrial organic matter between maturities of 0.50 and 0.75% R_o, and as noted by Kagya (1997) many potential source rocks in the Poolowanna Formation are enriched in resinite (and alginite).

Figure 2.7b is an alternative method of presenting the saturated and aromatic hydrocarbon data. The Eromanga oils clearly have the lowest aromatic hydrocarbon contents (4.7–12.1, mean = 8.1) and are more similar to Cooper Basin Family 1 (6.9–12.6, mean = 10.6) rather than Family 2 (17.9–21.6, mean = 19.7) oils.

2.6 MATURITY OF SOURCE ROCKS AND OILS BASED ON AROMATIC HYDROCARBONS

Tables 2.9 and 2.10 contain a suite of maturity parameters based on the aromatic hydrocarbon fractions of rock extracts and oils analysed by GC-MS. Representative GC-MS mass fragmentograms of the aromatic fractions of selected sediment extracts and oils are presented in Figure 2.8. Calculated vitrinite reflectances have been determined in three ways using the Boreham *et al.* (1988) calibration, R_c (%) = 0.7 MPI + 0.22 (parameter **1**); the Radke and Welte (1983) calibration, R_c (%) = 0.6 MPI + 0.4 (parameter **2**); and the Radke *et al.* (1984) calibration, $R_c = 0.99 \log_{10}\text{MPR} + 0.94$ (parameter **3**). Because there is no reason to assume that any one of the parameters is superior, the following discussion utilises the *average* of the three calibrations ($\overline{R}_c$) which is assumed to be the most robust, or at least a useful, maturity estimate.

2.6.1 Cooper Basin source rocks

2.6.1.1 Tirrawarra Sandstone

The Tirrawarra-16,17 coal/shale pair has R_c values (coal: **1** = 0.86%, **2** = 0.95%, **3** = 1.17%; shale: **1** = 1.02%, **2** = 1.09%, **3** = 1.27%) which suggest a level of maturity close to 0.99% $\overline{R}_c$ for the coal and 1.13% $\overline{R}_c$ for the shale (Table 2.11). The $\overline{R}_c$ values are in excellent agreement with R_{est} values of 1.00% and 1.05% respectively (Section 2.4.1).

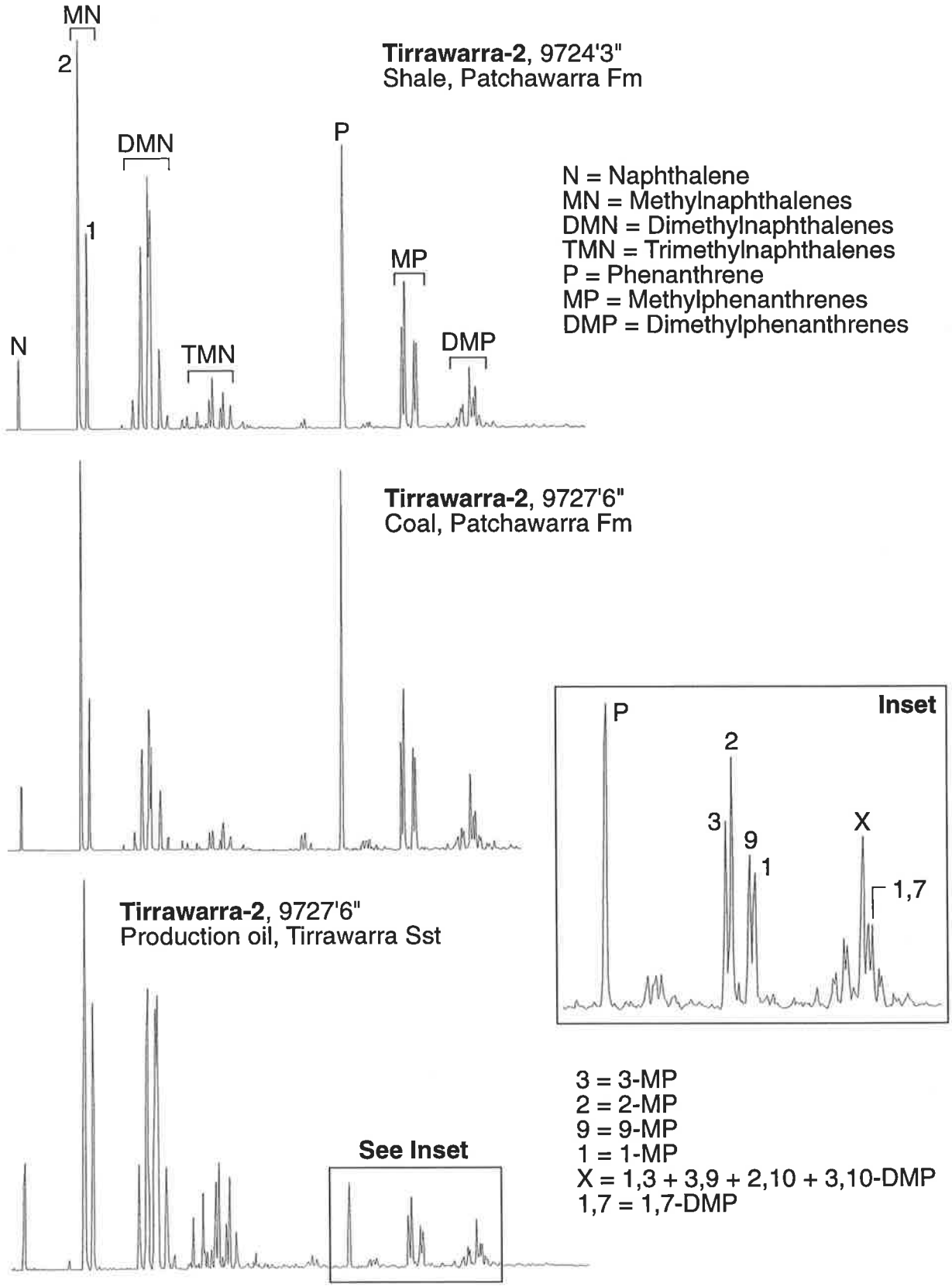


Figure 2.8 GC-MS mass fragmentograms (height normalised) showing naphthanene (m/z = 128), methylnaphthalenes (m/z = 142), dimethylnaphthalenes (m/z = 156), trimethylnaphthalenes (m/z = 170), phenanthrene (m/z = 178), methylphenanthrenes, (m/z = 192) and dimethylphenanthrenes (m/z = 206) in aromatic hydrocarbon fractions of selected sediment extracts and an oil from the Tirrawarra Field

2.6.1.2 Patchawarra Formation

Indicated maturities based on aromatic hydrocarbons for the coal/shale pairs from Daralingie-19, Fly Lake-3/Gidgealpa-17, Kanowana-1, Moorari-1 and Tirrawarra-2 are provided in Table 2.9. In addition to $\overline{R}_c$ values for individual coals and shales, where isometamorphic coal/shale pairs were sampled at Daralingie-19, Kanowana-1, Moorari-1 and Tirrawarra-2, an additional parameter, $\overline{\overline{R}}_c$, which is the arithmetic mean of $\overline{R}_c$ for the coal and shale (Table 2.11). It is reasonable to assume that such $\overline{\overline{R}}_c$ values provide a more realistic assessment of maturity than do the individual $\overline{R}_c$ values.

In all cases the $\overline{R}_c$ and $\overline{\overline{R}}_c$ values are lower than the corresponding maturities estimated from directly measured vitrinite reflectance and Rock-Eval pyrolysis (R_{est}: Table 2.8). The closest match between $\overline{R}_c$ (shale: 1.23%) and R_{est} (1.20%) is for samples of extreme maturity from Kanowana-1. Further, because the coal and shale samples from that well are only 12 feet (3.66 m) apart, for practical purposes, they may be considered isometamorphic. Thus, the apparent maturity discrepancy between the coal (1.12% $\overline{R}_c$) and shale (1.23% $\overline{R}_c$) in Kanowana-1 cannot be real. Likewise, the apparent maturity discrepancies between closely juxtaposed samples from Daralingie-19, Moorari-1 and Tirrawarra-2 are nonsense and therefore $\overline{\overline{R}}_c$ is preferred.

The calculated maturities for the isometamorphic coal/shale pairs from Daralingie-19 ($\overline{\overline{R}}_c$ = 0.87%), Moorari-1 ($\overline{\overline{R}}_c$ = 0.86%), Tirrawarra-2 ($\overline{\overline{R}}_c$ = 1.04%) are also significantly lower than the corresponding maturities estimated from directly measured R_o and Rock-Eval T_{max} (*viz* R_{est} = 0.95%, 0.95% and 1.20% respectively). The coal/shale pair from Fly Lake-3 (coal: $\overline{R}_c$ = 0.88%) and Gidgealpa-17 (shale: $\overline{R}_c$ = 0.82%) also gives values that are significantly lower than their corresponding R_{est} values (1.05 and 0.85%, respectively).

Therefore, it appears that the published calibrations of MPI and MPR provide lower estimates of maturity than do R_{est}. Inspection of the data (parameters **1–3**) in Table 2.9 indicates that MPR-derived R_c (parameter **3**) matches R_{est} most closely.

2.6.2 Eromanga Basin source rocks

2.6.2.1 Poolowanna Formation

Calculated maturities for the Sturt-4 cuttings (6100': $\overline{R}_c$ = 0.64%; 6170': $\overline{R}_c$ = 0.63%) are in good agreement with maturity estimates based on measured R_o and T_{max} (R_{est} = 0.60%). However, $\overline{R}_c$ and R_{est} values for the sediments from Sturt East-1($\overline{R}_c$ = 0.54%, R_{est} = 0.65%), Sturt East-4 ($\overline{R}_c$ = 0.71%, R_{est} = 0.60%) and Tantanna-2 ($\overline{R}_c$ = 0.52%, R_{est} = 0.70%) are in somewhat poorer agreement with one another. Probably the phenanthrene-derived parameters are less well calibrated at lower maturities.

2.7 OIL–SOURCE CORRELATIONS BASED ON MPI- AND MPR-DERIVED MATURITY

The averages of aromatic maturity parameters **1**, **2** and **3**, (*i.e.* $\overline{R}_c$) for each of the eight Cooper Basin oils analysed are given in Table 2.12 and indicate the maturities at which they appear to have been generated from their respective source rocks.

2.7.1 Cooper Basin oils

2.7.1.1 Merrimelia Formation

Calculated maturities for the Merrimelia-reservoired oil at Malgoona-1A (**1** = 0.98%, **2** = 1.05%, **3** = 1.01%, $\overline{R}_c$ = 1.01%) indicate generation from a hydrocarbon kitchen at approximately 1.0% R_o. However, the regional maturity of only *ca* 0.75% R_o (Figs 2.2 & 2.3) for the Patchawarra Formation suggests that this oil has migrated up-dip from more mature source rocks located to the northeast in the Patchawarra Trough.

2.7.1.2 Tirrawarra Sandstone

Tirrawarra-reservoired oils at Fly Lake-8 (oil partially recovered from the Patchawarra Formation: **1** = 0.84%, **2** = 0.93%, **3** = 0.97%, $\overline{R}_c$ = 0.91) and Gidgealpa-41 (**1** = 1.05%, **2** = 1.11%, **3** = 1.03%, $\overline{R}_c$ = 1.06%) were probably generated at maturities of around 0.90% and 1.05% R_o, respectively. These maturities are somewhat *higher* than those indicated for potential source rocks from the Fly Lake and Gidgealpa Fields (Section 2.6.1) or suggested by the regional maturity trends in the Figures 2.2 and 2.3. Therefore it is conceivable that the

Daralingie and Fly Lake reservoirs have been partly or wholly charged with hydrocarbons generated and expelled from slightly more mature Patchawarra source rocks.

An R_c value of 0.86% (parameter **2**) has previously been reported for the Patchawarra crude in Fly Lake-7 and a value of 0.95% (parameter **2**) was previously reported for Patchawarra-reservoired oil in Gidgealpa-7 (Michaelsen *et al.*, 1995d). By contrast, a maturity of 1.02% R_c (parameter **2**) was recorded for a Patchawarra condensate in Fly Lake-1 (McKirdy and Cox, 1987; Michaelsen *et al.*, 1995d).

By contrast, oils from the Tirrawarra Sandstone in the Tirrawarra Field and are even more mature: Tirrawarra-2 (**1** = 1.07%, **2** = 1.13%, **3** = 1.16%, $\overline{R}_c$ = 1.12%); Tirrawarra-8 (**1** = 1.05%, **2** = 1.11%, **3** = 1.09%, $\overline{R}_c$ = 1.08%). These oils were generated and expelled from their respective source rocks at exceptionally high maturities (*ca* 1.1% R_o), consistent with the average regional maturity of the Patchawarra Formation within the Tirrawarra Field (Figs 2.2 & 2.3) and the very high maturities estimated for the Patchawarra coal/shale pair at Tirrawarra-2 ($\overline{R}_c$ = 1.04%; R_{est} = 1.20%). Interestingly, calculated maturities for the oils from Tirrawarra-2 and 8 provide a good match with potential source rocks from Kanowana-1 which have an R_{est} value of 1.20%. However, there is no need to invoke long-distance secondary migration between source rocks at Kanowana and the Tirrawarra Field, since potential source rocks at Tirrawarra are sufficiently mature to account for the local oil accumulations. Curiously, a Patchawarra condensate sample from the same well has a reported maturity of only 0.97% R_c (parameter **2**: McKirdy and Cox, 1987; Michaelsen *et al.*, 1995d) suggesting that it may have been generated prior to attainment of present-day maturity levels.

Crudes from the Moorari/Woolkina Fields have somewhat disparate maturities. The Woolkina-1 oil (**1** = 1.04%, **2** = 1.10%, **3** = 1.10%, $\overline{R}_c$ = 1.08%) appears to be more mature than the Moorari-1 oil (**1** = 0.93%, **2** = 1.01%, **3** = 1.03%, $\overline{R}_c$ = 0.99%) attesting to likely hydrocarbon departmentalisation within the Tirrawarra Sandstone reservoir at this locality. However, based on the maturity of the regional Patchawarra source rocks (Figs 2.2 & 2.3) and the Moorari-1, coal/shale pair (R_{est} = 0.95%; $\overline{\overline{R}}_c$ = 0.86%), it is conceivable that both the Moorari-1 and Woolkina-1 (Tirrawarra Formation) oils have been sourced from the Patchawarra Formation within and/or immediately adjacent to the Moorari/Woolkina oil pool.

Examination of data previously collated by Michaelsen *et al.* (1995d) shows that all the Tirrawarra-reservoired oils analysed to date appear to have R_c values (parameter **2**) greater than 0.93%. The oils in question are from Fly Lake-1 (0.96%), Fly Lake-2 (0.93%), Moorari-1 (1.03%), Tirrawarra-30 (0.98%) and Yanpurra-1 (1.03%) and their maturities are consistent with the R_c values for the Cooper Basin crudes (Table 2.12).

2.7.1.3 Patchawarra Formation

Patchawarra oil from Daralingie-18 has calculated maturities (**1** = 1.10%, **2** = 1.16%, **3** = 1.10%, $\overline{R}_c$ = 1.12%) which are internally consistent and imply generation and explusion from its source rock at *ca* 1.1% R_o. This is considerably greater that the regional maturity of the Patchawarra Formation in the Daralingie Field (Figs 2.2 & 2.3) and of the coal/shale pair from Daralingie-19 (R_{est} = 0.95%; $\overline{\overline{R}}_c$ = 0.87%). Thus it is likely that most of the Daralingie oil has migrated from more mature source rocks deeper in the Nappamerri Trough.

For many oil fields where hydrocarbon generation appears to have taken place at maturities greater than or equal to 1.0% R_o, maturity parameter **3** (based on MPR) provides a better correlation between Cooper Basin oils and potential source rocks, than do parameters **1** or **2**. Even so, selection of a so-called "best" maturity parameter is subjective and fraught with difficulties because there is no *a priori* reason why an exact maturity match should exist between an oil and a potential source rock if that oil was generated basinward of the trap where correlative facies could reasonably be expected to occur at a maturity greater than representative rocks within the reservoir where the well was drilled.

Based on broadly matching levels of maturity between potential source rocks and oils, it is *reasonable* (but not demonstrated) that many of the Cooper Basin oils were generated more-or-less locally from source rocks at or near their current levels of maturity, and are thus products of *in situ* generation. However, apart from the geologically improbable situation wherein an oil-bearing reservoir was charged entirely from immediately adjacent source rocks, there is unlikely

to be an exact maturity match between a given oil and potential source rocks which have been penetrated by the same (or nearby) well from which oil was sampled for geochemical analysis. This fact can be exploited to estimate secondary migration distances between source kitchen and oil trap.

By comparing crude oil maturity ($\overline{R}_c$) with source rock ($\overline{R}_c$ or $\overline{\overline{R}}_c$) and regional maturity maps (Figs 2.2 & 2.3) it is possible to semi-quantitatively estimate migration distance between potential hydrocarbon kitchens and hydrocarbon reservoirs. Based *soley on these data*, the Cooper Basin oils analysed appear to have the following lateral migration distances:

	Oil type (Family)	Average calculated maturity (% $\overline{R}_c$)	Local or near-local (< 5 km)	Short-distance 2° migration (5–8 km)	Long-distance 2° migration (≥ 10 km)
Merrimelia reservoir					
Malgoona-1A	2	1.01			xxx
Tirrawarra reservoir					
Gidgealpa-41	2	1.06	?	xx	
Moorari-1	1	0.99	xxx		
Woolkina-1	1	1.08	xxx		
Tirrawarra-2	1	1.12	xxx		
Tirrawarra-8	1	1.08	xxx		
Tirrawarra and basal Patchawarra reservoir					
Fly Lake-8	1	0.91	?	xx	
Patchawarra reservoir					
Daralingie-18	2	1.12		xxx	

Key: xx = likely; xxx = very likely

2.7.2 Eromanga Basin oils

2.7.2.1 Poolowanna Formation

The six oil samples from this formation in the Sturt, Tantanna, Taloola and Tantanna Fields have calculated maturities considerably lower than those of oils from the underlying Cooper Basin.

Oils from Sturt-4 (**1** = 0.63%, **2** = 0.75%, **3** = 0.79%, $\overline{R}_c$ = 0.72%), Sturt-7 (**1** = 0.62%, **2** = 0.75%, **3** = 0.66%, $\overline{R}_c$ = 0.68%), Sturt-8 (**1** = 0.65%, **2** = 0.77%, **3** = 0.79%, $\overline{R}_c$ = 0.74%) and Sturt East-2 (**1** = 0.58%, **2** = 0.71%, **3** = 0.63%; $\overline{R}_c$ = 0.64%) appear to have been expelled from their source rocks in the early oil window, *i.e.* between 0.60 and 0.74% R_o (Table 2.12). These maturities are only a moderately good match for the $\overline{R}_c$ and R_{est} values of intra-Poolowanna shales and coals at Sturt-4 (6100': $\overline{R}_c$ = 0.64%, R_{est} = 0.60%; 6170': $\overline{R}_c$ = 0.63%, R_{est} = 0.60%), Sturt East-1 ($\overline{R}_c$ = 0.54%, R_{est} = 0.65%) and Sturt East-4 ($\overline{R}_c$ = 0.71%; R_{est} = 0.60%), suggesting derivation of the oils from near-local source rocks of slightly higher maturity.

In the Tantanna Field, there is a considerable discrepancy between the maturity of the Tantanna-1 oil (**1** = 0.71%, **2** = 0.82%, **3** = 0.89%, $\overline{R}_c$ = 0.81%) and the Poolowanna cuttings sample from Tantanna-2 ($\overline{R}_c$ = 0.52%, R_{est} = 0.70%). Although, there is good agreement between R_{est} (0.70%) of the Tantanna-2 cuttings sample and parameter **1** (0.71%) of the oil, the maturity of the Tantanna-1 oil (as indicated by $\overline{R}_c$) is marginally greater than that of the Sturt/Sturt East oils, suggesting its derivation from Early Jurassic source rocks slightly basinward of the Tantanna Field.

To summarise, the MPI-derived R_c values of the Patchawarra and Tirrawarra-reservoired oils and condensates match very closely the measured vitrinite reflectances of nearby intra-formational coals and shales. However, calculated vitrinite reflectance for these Early Permian coals and shales in many cases is lower than their corresponding measured vitrinite reflectance. The overall similarity between the maturities of the hydrocarbon liquids (both oils and condensates) and the present maturities of the adjacent coals and shales (*i.e.* 0.95–1.10% R_o), demonstrates that *the Cooper Basin crudes have been generated from local Early Permian*

source rocks. Six oils from the Poolowanna Formation in the Sturt and Tantanna Fields have R_c values which indicate expulsion from their respective source rocks at considerably lower maturities. As in many Cooper Basin rock samples, the MPI-based maturities of coals, shales and siltstones in the Poolowanna Formation appear unduly low. However, *the calculated maturities (R_c) of the Poolowanna oils are broadly equivalent to the petrographically measured maturities of the coals and shales in the Poolowanna Formation* (*i.e.* 0.60–0.70% R_o).

Sections 2.8–2.10 discuss alternative calibrations of MPI, MPR and maturation parameters based on DNR (dimethylnaphthalene ratio; p. xxi) and TNR (trimethylnaphthalene ratio; p. xxi).

2.8 ALTERNATIVE MATURITY CALIBRATIONS BASED ON MPI AND MPR

2.8.1 Rock extracts

Figure 2.9 graphically represents alternative calibrations of MPI and $\log_{10}$MPR (Table 2.13) with R_o for the potential source rocks. Lines of best fit were drawn through the data points using the Macintosh computer programme *Cricket Graph III* (version 1.5) and their equations are also derived from this programme. Visual comparison of the Figure 2.9a with Figure 2.9b suggests that the correlation between R_o and MPI is better than with $\log_{10}$MPR, notably for the Poolowanna rocks which have a greater scatter for their $\log_{10}$ MPR values.

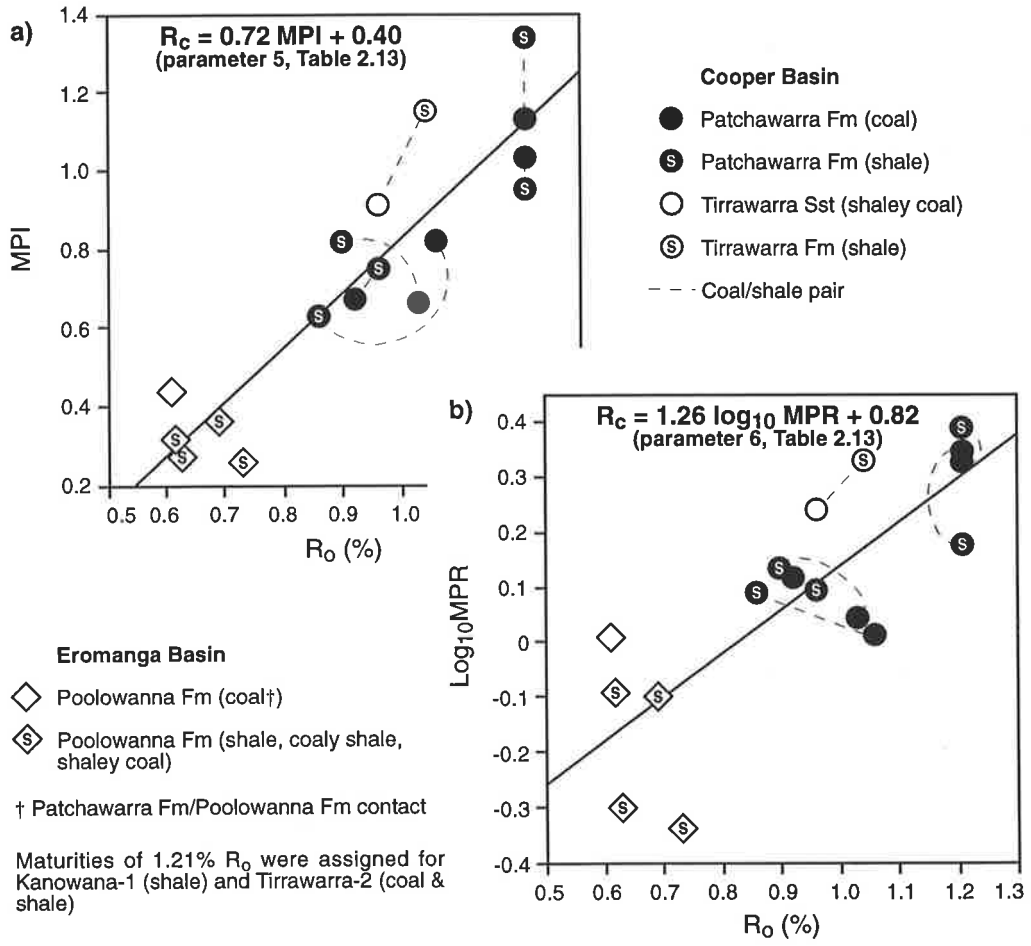


Figure 2.9 Alternative calibrations of measured vitrinite reflectance (R_c) *versus* a) MPI and b) $\log_{10}$MPR for sediments

2.8.2 Oils

The alternative calibrations determined above (R_c = 0.73MPI + 0.39; R_c = 1.26$\log_{10}$MPR + 0.82) were applied to the MPR and MPI oil data in Table 2.10. The alternative MPI- and MPR-based calibrations for R_c are listed in Table 2.13 as parameters **5** and **6** respectively.

Parameter **5** (Table 2.13), based on MPI, provide systematically *higher* maturity estimates for the oils than does either Boreham *et al.*'s (1988) calibration (parameter **1**) or Radke and Welte's (1983) calibration (parameter **2**). On the other hand, parameter **6**, based on MPR, provides

systematically lower maturity estimates than does Radke *et al.*'s (1984) calibration (parameter **3**: Table 2.10).

Based on this relatively small suite of oils, there is little or no evidence that the new calibrations based on MPI or MPR (parameters **5** and **6**) provide a more accurate assessment of maturity than do the published calibrations of Boreham *et al.* (1988; parameter **1**), Radke and Welte (1983, parameter **2**) or Radke *et al.* (1984, parameter **3**). Indeed, the relative similarity of parameters **1** and **2** (both MPI-based) and **3** (MPR-based), for both the Cooper and Eromanga oils (Table 2.10) strongly suggests that the published calibrations should be preferred over the new parameters **5** and **6**. Consequently, only the published calibrations of Boreham *et al.* (1988), Radke and Welte (1983) and Radke *et al.* (1984) are utilised in this thesis.

2.9 MATURITY AND OIL–SOURCE ROCK CORRELATIONS BASED ON DNR

2.9.1 Source rocks

Figure 2.10 comprises two cross-plots of DNR *versus* TNR for sediments and oils. A summary of DNR and TNR values for sediment extracts and oils is provided in Tables 2.9 and 2.10.

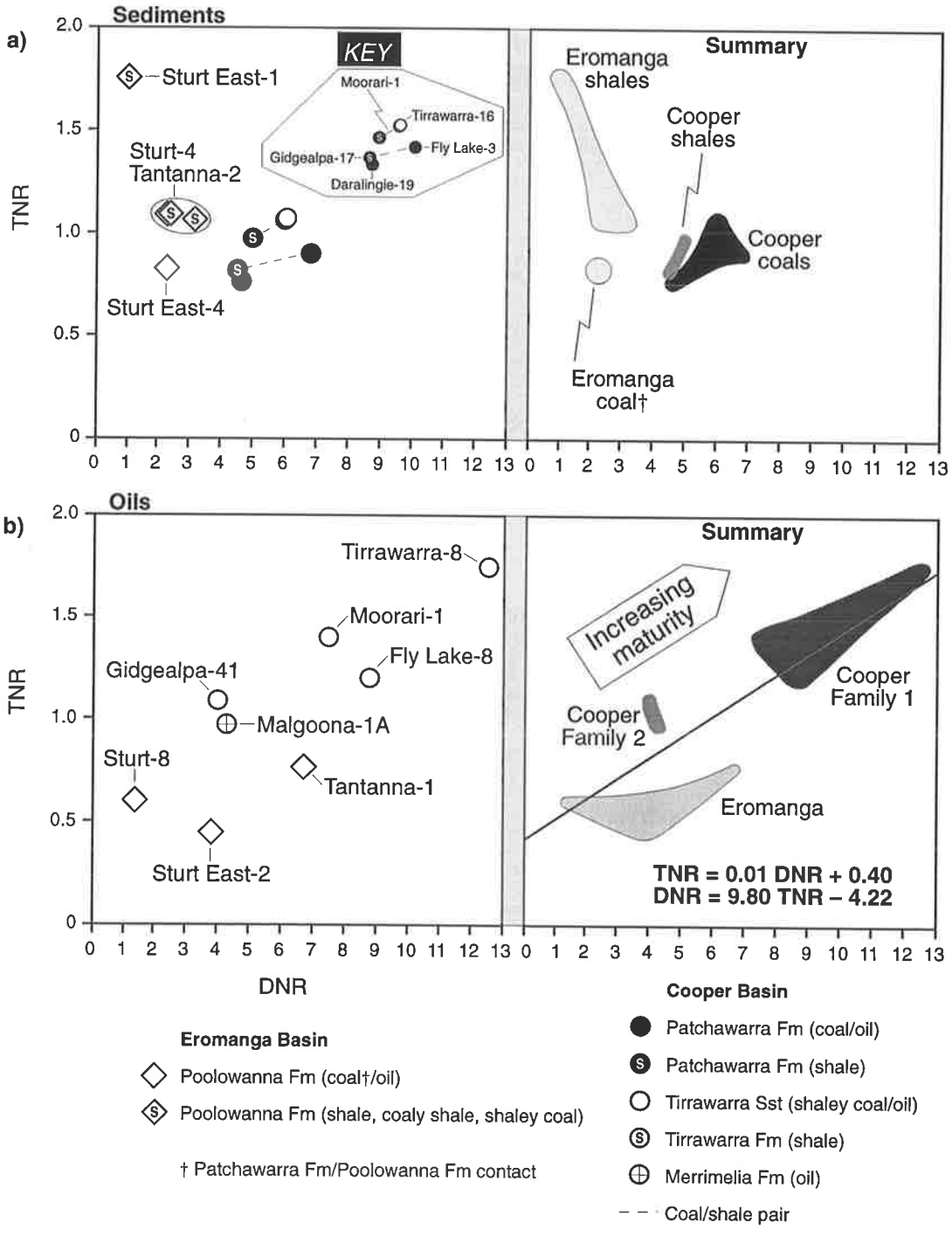


Figure 2.10 Dimethylnaphthalene ratio (DNR) *versus* trimethylnaphthalene (TNR) for sediments and oils

DNR values of the Cooper Basin shales (*e.g.* Patchawarra Formation: 4.5–5.0, mean = 4.8) and coals (*e.g.* Patchawarra Formation: 4.6–6.8, mean = 5.9) are higher than those of the Eromanga shales (1.0–3.2, mean = 2.2) and coal (2.3), consistent with their higher thermal maturity as measured by vitrinite reflectance. However, the difference in DNR values between the Cooper Basin coals and shales (Fig. 2.10a) indicates that this parameter is influenced not only by thermal maturity but also organic facies (*i.e.* organic matter type and depositional environment).

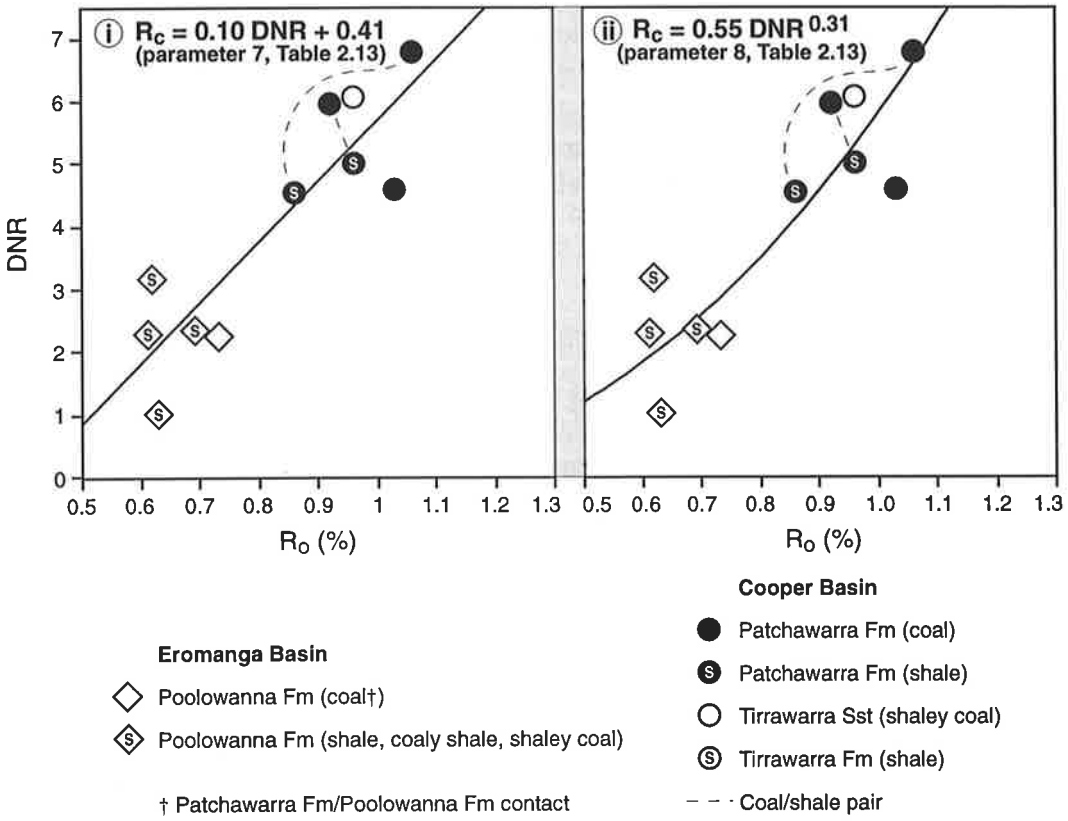


Figure 2.11 Alternative calibrations of vitrinite reflectance (R_C) *versus* dimethylnaphthalene ratio (DNR) for sediments

Calculated maturities for the sediments based on DNR (Radke and Welte, 1983; Radke *et al.*, 1984: R_c = 0.046DNR + 0.89) are provided in Table 2.9 as parameter **4**. Overall, DNR-based R_c values for the sediments (*e.g.* Daralingie-19, coal: **4** = 1.10%) are considerably higher than those estimated from MPI and MPR (**1** = 0.68%; **2** = 0.80%; **3** = 0.98%). They are also much greater than maturities estimated from Rock-Eval and measured vitrinite reflectance (*e.g.* Daralingie-19, coal: R_{est} = 0.95%), and the documented regional maturity (Figs 2.2 & 2.3). It appears therefore that the published calibrations of DNR used in Table 2.9 is less than ideal for Cooper and Eromanga Basin sediments.

2.9.2 Oils

Based on DNR, there is a clear separation between Family 1 oils (most mature), and Family 2 and Eromanga oils (less mature) (Fig. 2.10b). Parameter **4** values for the Cooper oils (Table 2.10) also seem to be anomalously high in many instances (*e.g.* Tirrawarra-8: **4** = 1.47%; Fly Lake-8: **4** = 1.29%). An alternative calibration of R_o against DNR based on sediment extracts is shown in Figure 2.11 (R_c = 0.10DNR + 0.41, parameter **7**, Table 2.13: Fig. 2.11a).

Parameter **7** provides somewhat high R_c values for Family 1 crudes when DNR > *ca* 5.5 (*i.e.* R_c > *ca* 1.0%). This is particularly obvious for the Tirrawarra-8 crude for which DNR = 12.5 (**7** = 1.66%) and the Fly Lake-8 oil where DNR = 8.7 (**7** = 1.28%). Conversely, Family 2 oils such as those from Gidgealpa-41 (DNR = 4.0; **7** = 0.81%) and Malgoona-1A (DNR = 4.3; **7** = 0.84%) have calculated maturities which appear to be unduly low with respect to most of the other parameters tested and discussed in Section 2.7. Consequently an additional calibration for the sediment extracts was determined and is based on the exponential function R_c = 0.55 $DNR^{0.31}$ (parameter **8**, Table 2.13: Figure 2.11b). When applied to the oils in question (Table

2.13), the exponential calibration gives more reasonable (lower) maturity estimates for some of the Family 1 crudes, namely Tirrawarra-8 (**8** = 1.20%) and Fly Lake-8 (**8** = 1.08%).

As is clear from Figure 2.10b that Poolowanna crudes have DNR values which are on average similar to those of Family 2 oils, and consequently have similar DNR-derived maturities (Tables 2.10 & 2.13), although the Sturt-8 crude appears to be an early expulsion product based on parameters **7** & **8** (0.55 & 0.61% R_c) which are at variance with its parameter **4** value (0.95%), but nevertheless consistent with MPI-derived maturity estimates. Based on the DNR calibrations, the Tantanna-1 crude is clearly the most mature of the Poolowanna oils (**4** = 1.20%; **7** = 1.08%; **8** = 0.97%).

In summary, maturity parameters **4**, **7** and **8** based on DNR provide higher estimates of maturity than MPI- and MPR-based calculations (parameters **1–3**, **5** & **6**). Parameter **8** which is based on a non-linear calibration, provides lower maturity estimates for Family 1 oils than do parameters **4** and **7**, and is more in line with MPI- and MPR-based parameters. Overall the DNR data indicate that Family 1 oils were expelled from their source rocks at maturities greater than those for Family 2 crudes.

2.10 Maturity and Oil–Source Rock Correlations Based on TNR

2.10.1 Source rocks

The coals and shales for which both DNR and TNR were determined (Table 2.9) are plotted in Figure 2.10a. Although this diagram has been constructed using only two Cooper Basin shales, the distribution of data points more or less implies that Cooper Basin coals (0.8–1.9, mean = 1.1) and shales (0.8–2.2, mean = 1.4) are identical on the basis of TNR data. Curiously, the TNR values of the Eromanga shales (1.1–1.8, mean = 1.3) and coal (0.8) are similar to those of the Cooper Basin rocks. Obviously TNR cannot be used as a maturity discriminator for the potential source rocks tested and therefore it is unsuitable for calibration against measured vitrinite reflectance (R_o).

2.10.2 Oils

Figure 2.10b is a cross-plot of DNR *versus* TNR for the oils under consideration (Table 2.10). Family 1 oils have by far the highest TNR values (1.2–1.9, mean = 1.5) confirming that they were generated at greater maturities than the Family 2 oils (1.0–1.1, mean = 1.0). The Poolowanna oils (0.4–0.8, mean = 0.6) have the lowest TNR values suggesting generation earlier in the oil window. However, there is a poor match between the TNR values of the Poolowanna rocks and oils suggesting that these hydrocarbons were not entirely sourced from local Early Jurassic source rocks.

Although it is well known that TNR increases with higher maturity (*e.g.* Radke and Welte, 1983), to the best of the author's knowledge, no calibration between TNR (TNR-1: Radke and Welte, 1983) and vitrinite reflectance has yet been reported in the literature. Given that TNR for the oils discriminates well between Cooper Basin and Eromanga Basin reservoirs it is potentially useful to obtain a calibration between it and R_o.

However, given that a meaningful calibration between measured vitrinite reflectance (R_o) and TNR is not possible for the rock extracts data (Fig. 10a; Section 2.10.1), it is necessary to substitute the equation DNR = 9.80 TNR – 4.22 (derived from Fig.10b) into, for example, calibrations **7** and **8** to provide two alternative calibrations of TNR against R_c (*viz* **9** & **10**: Table 2.13). Not surprisingly, the most realistic calibrations are obtained from equations **10** which is based on the non-linear relationship of maturity with DNR (Section 2.9.2).

In summary, the DNR- and TNR-based maturity estimates suggest that Family 1 crudes were generated from their respective source rocks above *ca* 1.05% R_o, whereas Family 2 oils were expelled at maturities less than *ca* 1.00% R_o. TNR data suggest that the Poolowanna oils were generated from their respective source rocks at maturities less than for the Family 2 crudes.

2.11 Oil–Source and Oil–Oil Correlations Based on (Araucariacean) Aromatic Hydrocarbon Biomarkers

The four source-dependent aromatic hydrocarbon ratios 1,2,5-TMN/1,3,5-TMN, 1-MP/9-MP, retene/9-MP and 1,7-DMP/X (where X = 1,3 + 3,9 + 2,10 + 3,10-DMP) first used by Alexander *et al.* (1988) to distinguish oils of Permian and Jurassic source affinity in the Cooper/Eromanga Basin are among the parameters of the present suite of coals, shales and oils listed in Tables 2.9 and 2.10 (see key to maturity and source parameters, p. xxi). Summaries of

these parameters are presented in Table 2.14 and their log values are plotted in Figures 2.12 and 2.13.

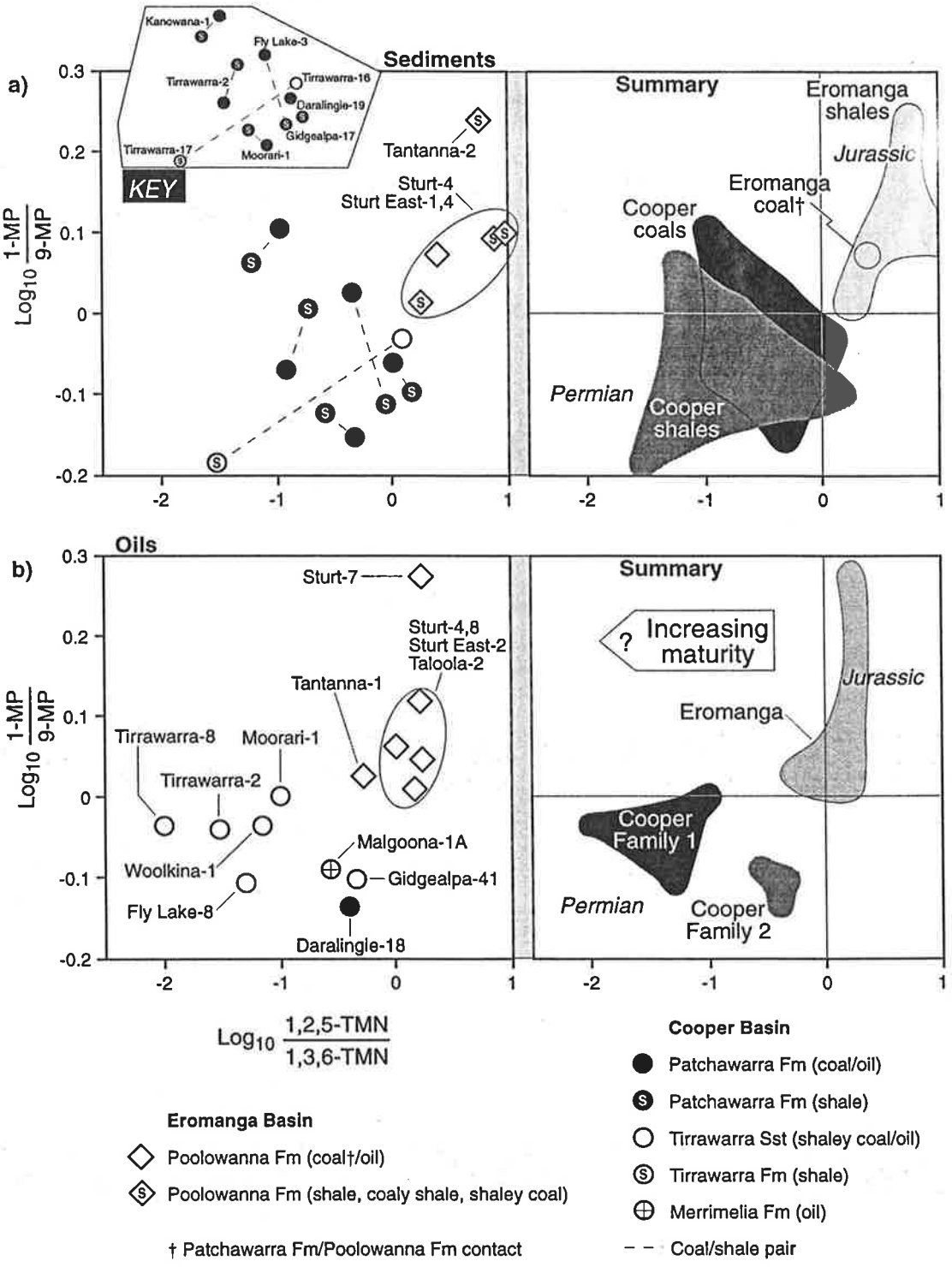


Figure 2.12 Log 1,2,5-TMN/1,3,6-TMN *versus* log 1-MP/9-MP cross-plots for sediments and oils

2.11.1 Cooper Basin source rocks

2.11.1.1 Tirrawarra Sandstone

Figure 2.12a plots log(1,2,5-TMN/1,3,5-TMN) against log (1-MP/9-MP) for the shale and coal extracts. For the coal/shale pair from the Tirrawarra Formation at Tirrawarra-16 and 17 the relative concentrations of 1-MP and 1,2,5-TMN are in very much higher in the coal (1-MP/9-MP = 0.93; 1,2,5-TMN/1,3,6-TMN = 1.25) than the shale (Table 2.9). In fact the shaley coal sample is so enriched in 1-MP and 1,2,5-TMN that it almost plots in the "Jurassic" field. The araucariacean plant acids which gave rise to high specific inputs of 1-MP and 1,2,5-TMN did not evolve until the Early–Mid Jurassic (Alexander *et al.*, 1988). Thus it is evident that other land plant precursors may have contributed 1,2,5-TMN and 1-MP in the Tirrawarra coal swamp.

Alternatively, it is conceivable that under certain circumstances 1,2,5-TMN and 1-MP may be microbially concentrated and preserved in the sedimentary record.

Figure 2.13a plots log (1,7-DMP/X) against log (retene/9-MP) for sediment extracts. The coal sample from the Tirrawarra Formation has a higher 1,7-DMP/X ratio (0.40) but a lower retene/9-MP value (< 0.004) than does its shale counterpart (1,7-DMP/X =0.31; retene/9-MP = 0.004). These data are consistent with the pre-Jurassic age of these rocks.

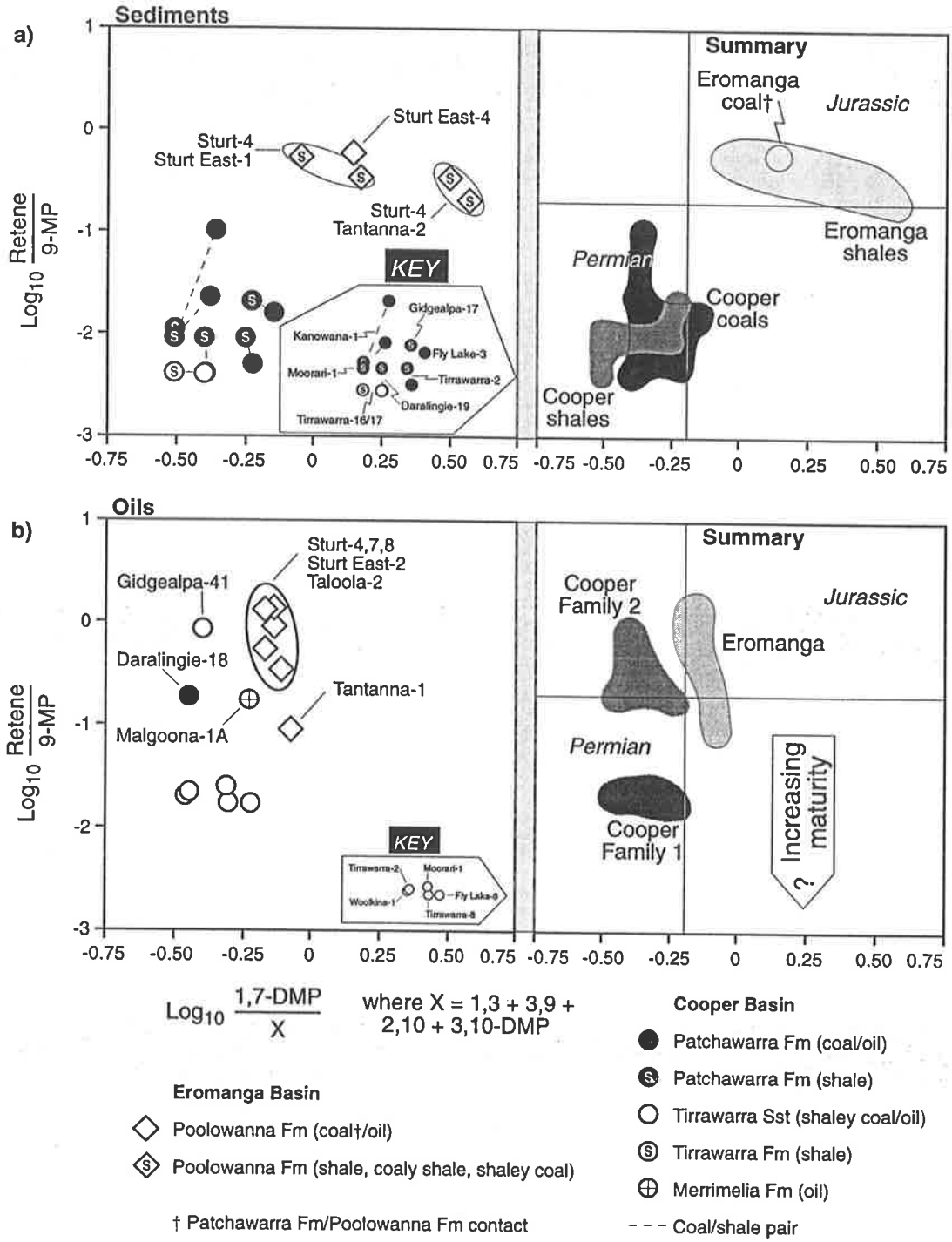


Figure 2.13 Log 1,7-DMP/X *versus* log retene/9-MP cross-plots for sediments and oils

2.11.1.2 Patchawarra Formation

In this Permian formation, shales appear to have on average slightly higher concentrations of 1,2,5-TMN relative to 1,3,6-TMN. The mean value of 1,2,5-TMN/1,3,6-TMN is only 0.44 for the coals compared to 0.58 for the shales. However, coals from three of the five coal/shale pairs have 1-MP/9-MP values which are greater than those of the shales and on average the coals have

slightly higher 1-MP/9-MP ratios (mean = 0.95) than do the shales (mean = 0.90). The exceptions are the coal/shale pairs from Moorari-1 and Tirrawarra-2.

The concentration of 1,7-DMP relative to X is higher in all five coal samples (Fig. 2.13a) and it appears therefore that this parameter is likely to be influenced by organic matter type *and* depositional milieu. The average 1,7-DMP/X ratio for the coals is 0.52 compared to 0.44 for their shale counterparts. However, values for the retene/9-MP ratio are more variable between the coals and shales. The concentration of retene is greater than 9-MP in only two of the five coals. However, the average values for the retene/9-MP ratio are still marginally greater for the coals (mean = 0.030) than the shales (mean = 0.012).

Overall, the data indicate that there may be a possible diagenetic influence on the formation of 1,7-DMP in potential source rocks of the Cooper Basin. However, the relative concentration of the other araucariacean biomarkers 1,2,5-TMN, 1-MP and retene do not appear to be lithofacies dependent.

2.11.2 Eromanga Basin source rocks

2.11.2.1 Poolowanna Formation

Relative to the Cooper Basin rock extracts, those of the Poolowanna Formation have consistently higher levels of 1-MP and 1,2,5-TMN as reflected in higher values of 1-MP/9-MP ratio (mean = 1.29) and 1,2,5-TMN/1,3,6-TMN ratio (mean = 5.40). This is consistent with the finding of Alexander *et al.* (1988) that source rocks of Jurassic age in the Cooper/Eromanga Basin system have elevated concentrations of these compounds which may be explained by the emergence of araucariacean conifers during the Early Jurassic. These land plants first appeared midway through the deposition of the Poolowanna Formation. Their resin acids, upon diagenesis in paludal environments, give rise to several characteristic aromatic biomarkers including 1,2,5-TMN and 1-MP. Consequently, the Poolowanna rock extracts plot in the "Jurassic" field of Figure 2.12a.

The Poolowanna rock extracts likewise contain higher relative concentrations of 1,7-DMP and retene (two other araucariacean biomarkers) than do the Cooper Basin coals and shales (Fig. 2.13a). Their values of 1,7-DMP/X (mean = 2.12) and retene/9-MP (mean = 0.40) are considerably higher than those exhibited by the Cooper Basin samples, placing them in the "Jurassic" field of Figure 2.13b.

2.11.3 Cooper Basin oils

2.11.3.1 Merrimelia Formation

The Merrimelia reservoir at Malgoona-1A contains oil which has 1-MP/9-MP and 1,2,5-TMN/1,3,6-TMN values (0.81 and 0.27, respectively) consistent with its derivation from Cooper Basin (Patchawarra Formation) source rocks (Fig. 2.12a). Accordingly, it plots in the "Permian" field of Figure 2.12b. The Malgoona-1A oil also has conventional "Permian" values for 1,7-DMP/X and retene/9-MP (Table 2.10).

2.11.3.2 Tirrawarra Sandstone

The concentration of 1-MP relative to 9-MP and 1,2,5-TMN relative to 1,3,6-TMN in oils from reservoirs of the Tirrawarra Sandstone is similar to that in extracts of the Patchawarra Formation (see above). The values of 1-MP/9-MP (mean = 0.89) and 1,2,5-TMN/1,3,6-TMN (mean = 1.31) are typical of non-araucariacean source input and as such most of the samples plot clearly in the "Permian" field in Figure 2.12b. The Tirrawarra-reservoired oils (Fig. 13b) have values of 1,7-DMP/X (mean = 0.55) and retene/9-MP ratios (mean = 0.16) that are consistent with their derivation from Permian (Patchawarra) source rocks (Fig. 2.13a).

2.11.3.3 Patchawarra Formation

The Patchawarra-reservoired oil from Daralingie-18 has a 1-MP/9-MP value of 0.73 that is also typical of Permian-derived hydrocarbons. The same oil has 1,7-DMP/X (0.36) and retene/9-MP (0.19) values which closely match those of the Patchawarra coals and shales and therefore imply an intra-Patchawarra source.

It is interesting that regardless of the formation from which they were recovered, the low API gravity, conventional oils (*viz* Family 2: Daralingie-18, Gidgealpa-41, Malgoona-1A) clearly have different aromatic biomarker signatures to those of the condensate-like, higher API gravity oils; (Family 1: Fly Lake-8, Moorari-1, Woolkina-1, Tirrawarra-2 and 8) (Figs 2.12b & 2.13b).

Specifically, Family 2 oils have higher concentrations of 1,2,5-TMN relative to 1,3,6-TMN (Family 2: 0.27–0.39, mean = 0.37; Family 1: 0.01–0.10, mean = 0.05) but generally lower 1-

MP/9-MP ratios (Family 2: 0.73–0.81, mean = 0.78; Family 1: 0.78–1.00, mean = 0.91). Furthermore, retene/9-MP ratios are much higher in Family 2 than Family 1 oils (see Tables 2.13 & 2.14; Fig. 2.13b). However, the ratio 1,7-DMP/X for both Family 1 (0.35–0.60) and Family 2 (0.36–0.59) oils is essentially identical. It is thus apparent that Family 1 and Family 2 oils must have been:

1. sourced from organic facies containing different precursor organic matter; or
2. generated from source rocks of varying maturition levels.

However, it is unlikely that 1,2,5-TMN/1,3,6-TMN and retene/9-MP are affected by source facies, since these parameters are essentially unaffected by the lithology (Section 2.11.1). The findings discussed in Sections 2.6–2.10 showed that Family 1 oils are more mature than those of Family 2, and therefore it is reasonable to deduce that *the variation in 1,2,5-TMN/1,3,6-TMN and retene/9-MP ratios between Family 1 and Family 2 oils is attributable to a maturity differential alone*. This interpretation is consistent with the work of van Aarsen *et al.* (1999) who support the proposition that the thermodynamic stability of 1,2,5-TMN is less than that of1,3,6-TMN (*i.e.* the 1,2,5-TMN/1,3,6-TMN ratio is a maturity parameter). Further, it is very likely that retene preferentially demethylates to 9-MP in very high maturity oils (S. George, CSIRO, pers. comm., 2002).

2.11.4 Eromanga Basin oils

2.11.4.1 Poolowanna Formation

The six Poolowanna oils have 1-MP/9-MP ratios (mean = 1.25) which are appreciably greater than those of the oils from Cooper Basin reservoirs (Family 1: mean = 0.91; Family 2: mean = 0.78) and match very closely the 1-MP/9-MP values obtained for intra-Poolowanna source rocks (see above; Figure 2.12a,b). However, on average the Poolowanna oils have 1,2,5-TMN/1,3,6-TMN ratios (mean = 1.62) that are slightly lower than those of potential source rocks from the Poolowanna Formation (coal: 1.18; shales: mean = 1.32). In this respect their aromatic hydrocarbon signatures are *intermediate* between those of potential source rocks from the Patchawarra and Poolowanna Formations. A simplistic interpretation of this fact is that the Poolowanna oils represent a mixture of hydrocarbons derived from Jurassic and Permian source rocks. However, it follows from the argument laid out above (Section 2.11.3.3), that the lower 1,2,5-TMN/1,3,6-TMN values for the Poolowanna oils indicate that they were expelled from Poolowanna source rocks at maturities above those of the local source rocks tested. Indeed calculated maturities of the Poolowanna oils (mean $\overline{R}_c$ = 0.71%) are on average 0.10% greater than for the local Poolowanna rocks (mean $\overline{R}_c$ = 0.61%) suggesting that they have migrated into their hydrocarbon traps from more mature source rocks deeper in the Patchawarra Trough. Considering the Poolowanna oils in isolation from Family 1 and Family 2 oils, it is the Tantanna-1 crude that has the lowest 1,2,5-TMN/1,3,6-TMN ratio and it is this oil which, as previously discussed, is clearly the most mature ($\overline{R}_c$ = 0.81%).

Based on their retene/9-MP values (0.09–1.33, mean = 0.74) Poolowanna oils correlate reasonably well with Cooper Basin Family 2 oils (0.17–0.84, mean = 0.40) (Fig. 13a,b). However, 1,7-DMP/X values for the Poolowanna oils (0.67–0.84, mean = 0.74) are too high to be a good match for those of Cooper Basin Family 2 (0.36–0.59, mean = 0.45; Fig. 2.13b). By way of contrast 1,7-DMP/X and retene/9-MP values of the Poolowanna oils appear to be intermediate between those recorded for the Patchawarra and Poolowanna sediments, suggesting a *possible* co-sourcing from these formations. Consistent with the higher maturity of the Tantanna-1 oil, is its retene/9-MP ratio which is depressed relative to the other Poolowanna oils (Table 2.10).

In summary, the aromatic source parameters based on araucariacean biomarkers indicate that the Poolowanna-hosted oils in the Sturt, Sturt East, Taloola and Tantanna Fields were derived from Jurassic source kitchens, *i.e.* they are predominantly Eromanga Basin expulsion products. Although the Eromanga oils are clearly distinct from both Family 1 and Family 2 oils, they are nevertheless more similar to Family 2 oils especially in their retene/9-MP ratios (Fig. 2.13b) and partially in their 1,2,5-TMN/1,3,6-TMN ratios (Fig. 2.12b), suggesting a *possible* genetic link between the two. Alternatively a proportion of some are all of the Poolowanna oils may be derived from the lower Poolowanna Formation, where araucariacean flora was absent, or at less abundant, and consequently the relative concentration of araucariacean biomarkers is lower. It is impossible to preclude a *minor* contribution to the Poolowanna oils by hydrocarbons derived from Permian source rocks, although the slightly disparate chemistry of the Poolowanna oils and sediments is probably due to the more advanced maturity of the former. Furthermore, there

is no precise match between the Cooper Basin sediments with Family 1 or Family 2 oils, and therefore it is not possible to decide with any certainty whether the two Cooper Basin oil families have shale or coal source affinities.

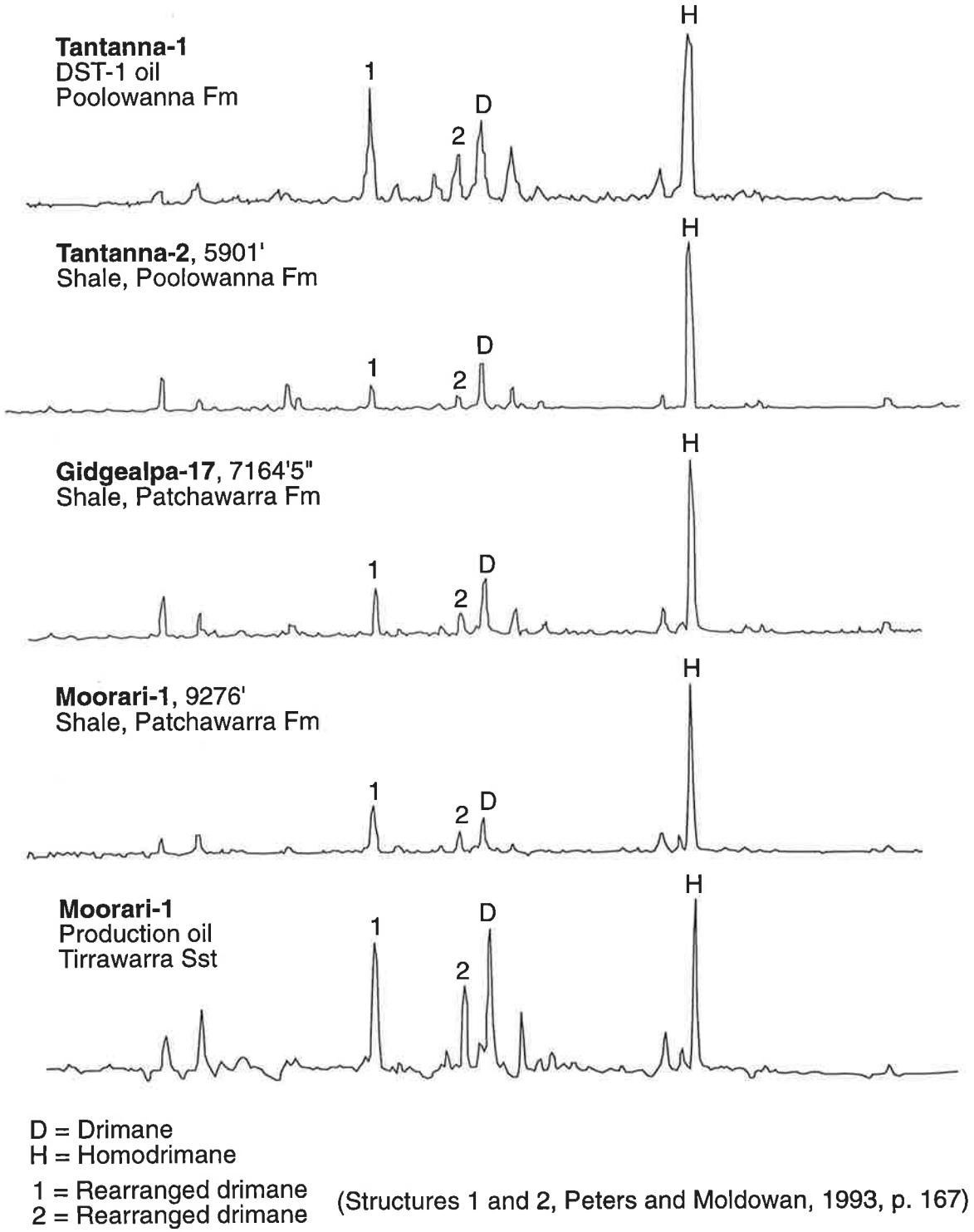


Figure 2.14 GC-MS mass fragmentograms showing drimanes (m/z = 123) in saturated hydrocarbon fractions of selected sediment extracts and oils

2.12 OIL–SOURCE AND OIL–OIL CORRELATIONS BASED ON DRIMANES

Selected maturity-sensitive biomarker and source-dependent ratios determined from GC-MS of the saturated hydrocarbon fraction are presented in Tables 2.15 (source rocks) and 2.16 (oils) and are summarised in Table 2.17.

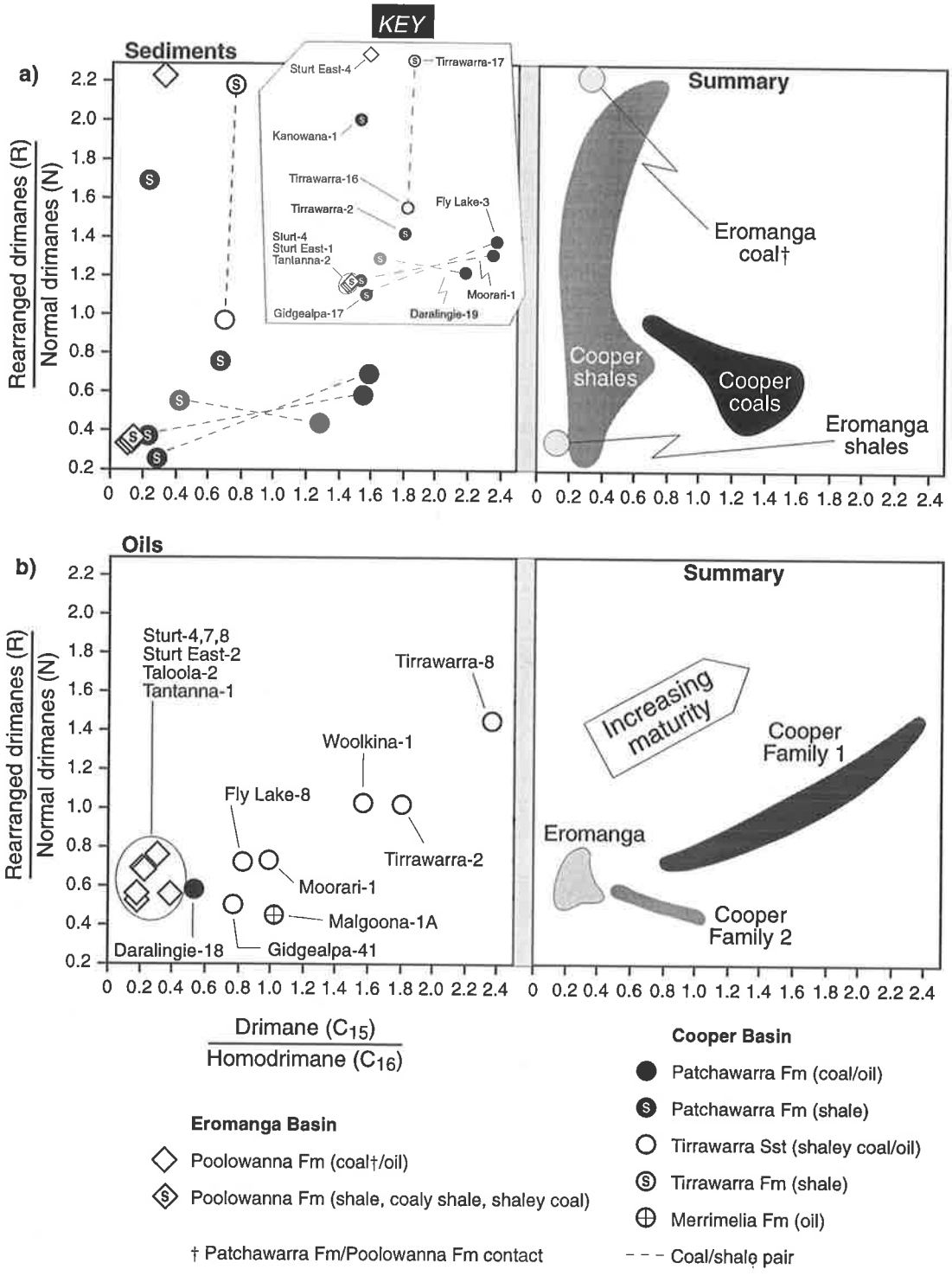


Figure 2.15 Sesquiterpenoid (drimane) cross-plots for sediments and oils

The drimane distributions as determined by GC-MS are shown in Figure 2.14 for selected sediment extracts and oils. Little is published in the literature regarding sesquiterpenoid (drimane) hydrocarbons in oils and source rocks. Nevertheless, it is commonly accepted that drimane-like sesquiterpenoids have a bacterial origin (Alexander *et al.*, 1983, 1984; Noble *et al.*, 1986) largely because of their ubiquity in Australian source rocks and oils. Moreover, it is conceivable that hydrocarbons with drimane-type carbon skeletons are a consequence of microbial degradation of hopanoids (*e.g.* in source rocks and possibly oils: D.M. McKirdy,

D.M. McKirdy, University of Adelaide, pers. comm., 1988). The drimane/homodrimane (C_{15}/C_{16}) ratio has previously been demonstrated to be a useful maturity parameter in some Australian basins, including the Cooper and Eromaga Basins (Hunter, 1985). An additional parameter, the ratio of rearranged drimanes/normal drimanes (R/N; see Key to Maturity and Source Parameters, p. xxi) is conceivably also a maturity parameter and was formerly used by ANALABS Pty Ltd (Perth, W.A.) in oil-source rock correlation studies (*e.g.* Tybor, 1986a). The utility of both these parameters is explored here.

2.12.1 Source rocks

The relative concentration of drimane to homodrimane (C_{15}/C_{16}) is approximately the same in the Tirrawarra Sandstone coal from Tirrawarra-16 (0.70) as it is in the shale from Tirrawarra-17 (0.76). However, the ratio of rearranged drimanes to unrearranged drimanes (R/N: Table 2.15) in the same shale (0.97) is less than half of that in the coal (2.18). By contrast, the C_{15}/C_{16} ratio for the Patchawarra Formation samples varies between 0.23 (Kanowana-1, shale) and 1.55 (Moorari-1, coal). In fact, the ratio is significantly higher in the coals (mean = 1.47) than in the matching shales (mean = 0.37). For example, C_{15}/C_{16} values in the coals at Daralingie-19 (1.28), Fly Lake-3 (1.59), and Moorari-1 (1.55) are between 3 and 6.5 times greater than in their shale counterparts (0.43, 0.29 and 0.24, respectively). On the other hand the R/N ratio which on average is only slightly greater for the shales (mean = 0.72) than the coals (mean = 0.57). Given that most of the coal/shale pairs are isometamorphic, the difference in drimane composition between Cooper Basin coals and shales must reflect differences in the bacterial milieu between peat swamps (coals) and clastic depositional environments (shales).

In Figure 2.15a the Eromanga shales plot tightly between 0.11 and 0.14 (mean = 0.13) for C_{15}/C_{16}, and in the range 0.33–0.36 (mean = 0.34) for R/N. Thus in terms of C_{15}/C_{16}, shales from the Cooper Basin (0.23–0.76, mean = 0.44) are intermediate between shales from the Eromanga Basin and the Cooper Basin coals (Fig. 2.15). Of the Poolowanna sediments, the Sturt East-4 coal sample has the highest C_{15}/C_{16} ratio (0.32) and in this respect it is similar to the Cooper Basin shales. However, its R/N value (2.23) is strikingly at variance with the Eromanga Basin shales and also the Cooper Basin shales (Fig. 2.16). It is obvious that the R/N ratio by itself is a weak discriminator, except perhaps between Eromanga Basin shales and coals.

The lower C_{15}/C_{16} drimane ratios for the Poolowanna shales and coal possibly reflect the maturity contrast between the Cooper Basin and Eromanga Basin rocks (Sections 2.6–2.10). Due to its its smaller structure, it is conceivable that C_{15} drimane is more thermodynamically stable than C_{16} homodrimane and therefore increased maturation can be expected to drive the C_{15}/C_{16} ratio to higher values similar to those observed in the Tirrawarra and Patchawarra sediments. However, it is obvious that in the sediments tested, C_{15}/C_{16} is highly dependent on lithofacies.

2.12.2 Oils

On average the C_{15}/C_{16} ratio for the Family 2 oils (0.53–1.02, mean = 0.77) is significantly less than for Family 1 oils (0.83–2.36, mean = 1.51). Likewise the R/N ratio is very much lower for Family 2 (0.44–0.58, mean = 0.51) than for Family 1 (0.72–1.45, mean = 0.99) oils (Tables 2.15 & 2.17). Curiously, the lower rank Eromanga (Poolowanna) crudes are of somewhat intermediate composition (0.52–0.76, mean = 0.63) with respect to R/N suggesting that this ratio is not entirely maturity dependent. However, the Jurassic crudes clearly have the lowest C_{15}/C_{16} compositions (0.18–0.38, mean = 0.25) and therefore it is likely that this parameter is predominantly maturation-related in the case of these oils. Figure 2.16 provides four cross-plots of two aromatic hydrocarbon-based maturity parameters (R_c and TNR) against C_{15}/C_{16} and R/N. If one ignores the conventional oils (*i.e.* Family 2 oils) it is possible to define several relationships between the aforementioned parameters (see Fig. 2.16). As discussed in Section 2.10, TNR is arguably the best aromatic maturity parameter although hitherto it has not been calibrated against vitrinite reflectance. There is an obvious relationship between TNR and C_{15}/C_{16} whereby $TNR_c = 0.66\ (C_{15}/C_{16}) + 0.49$ (Fig. 2.16a,ii) and upon inspection of Figure 2.16, it is apparent that this relationship may be even valid for Family 2 oils. Therefore, based on the evidence assembled here, C_{15}/C_{16} may have considerable utility as a maturity parameter in the Cooper/Eromanga Basin system. Amongst the Eromanga oils, the highest value of C_{15}/C_{16} (0.38) is recorded for Sturt East-2 oil and this is a good match for the Sturt East-4 coal which has a similarly high value (0.32). This may indicate that at least some of the Sturt East-2 oil is derived from local intra-Poolowanna source rocks. The R/N ratio for the Poolowanna oils is fairly

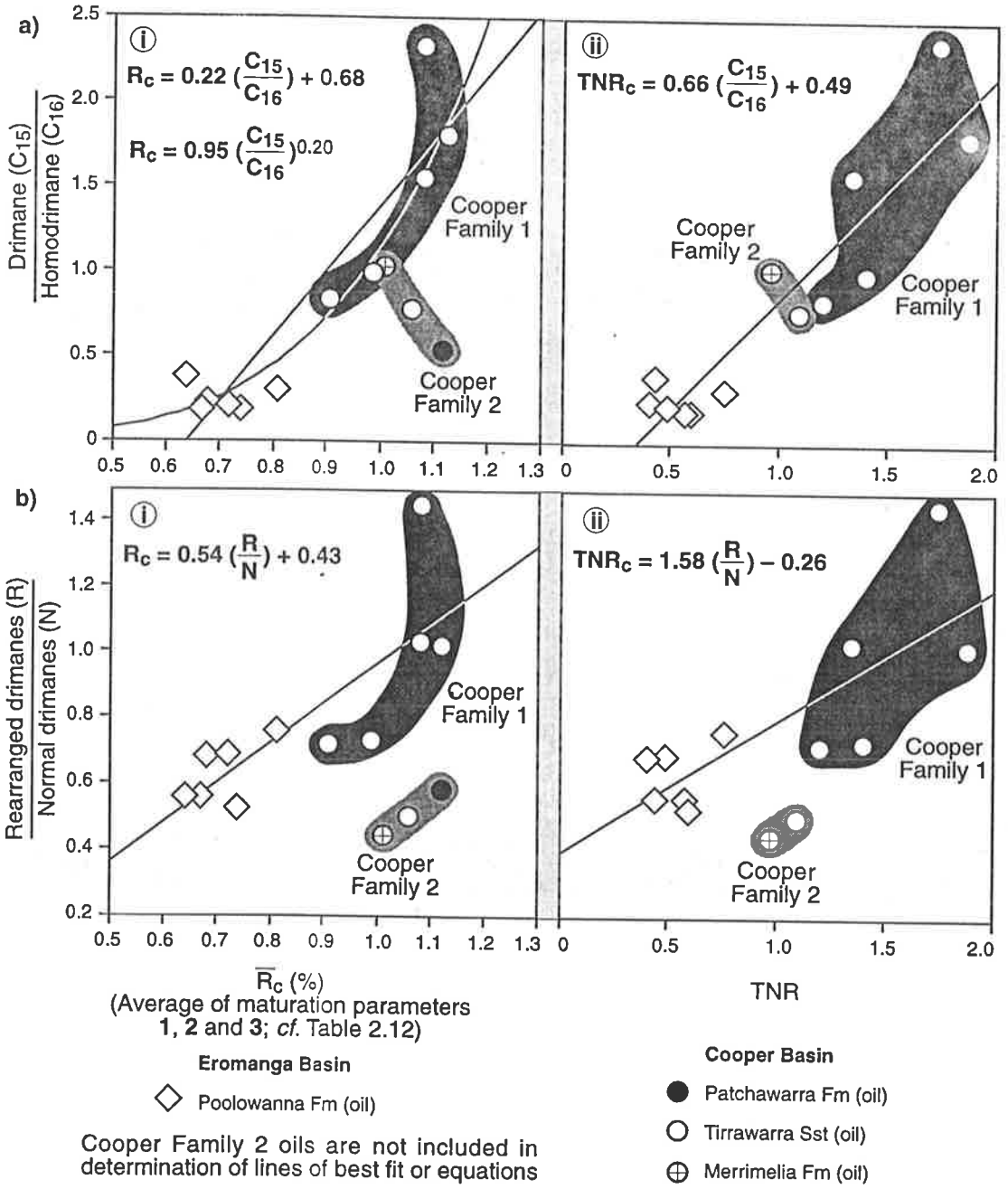


Figure 2.16 Cross-plots of $\overline{R}_c$ *versus* drimane/homodrimane and rearranged drimans/normal drimanes for oils

uniform (0.52–0.76, mean = 0.63). With respect to this parameter these Jurassic oils are intermediate in composition between the Permian Family 1 and Family 2 crudes. Clearly therefore, the R/N ratio is little affected by maturation, and is predominantly a "facies" parameter.

In summary, the drimane/homodrimane (C_{15}/C_{16}) and rearranged drimanes/normal drimanes (R/N) ratios can be employed to discriminate between source rocks and oils from the Cooper and Eromanga Basins. The drimane/homodrimane ratio is particularly dependent on maturity (for oils) and is potentially useful in oil-source rock correlation studies. Comparison of oil data (Fig. 2.16b) with rock extract data (Fig. 2.16a) suggests that Cooper Family 1 oils were sourced predominantly from Cooper Basin coals. However, based on these criteria, it is not possible to say whether Family 2 oils were sourced from coaly or clastic rocks.

2.13 OIL–SOURCE AND OIL–OIL CORRELATIONS BASED ON HOPANES

Biomarker parameters based on hopanoid hydrocarbons for sediments and oils are provided in Tables 2.15 and 2.16 respectively. Four of the hopane ratios (*viz* T_s/T_m, $C_{29}T_s/17\alpha$-30-norhopane, 17α-diahopane/17α-hopane and 17α-30-norhopane/17α-hopane) for each

formation, lithology and oil family are summarised in Table 2.17 and hopane (m/z = 191) mass fragmentograms of selected sediment extracts and oils are presented in Figure 2.17.

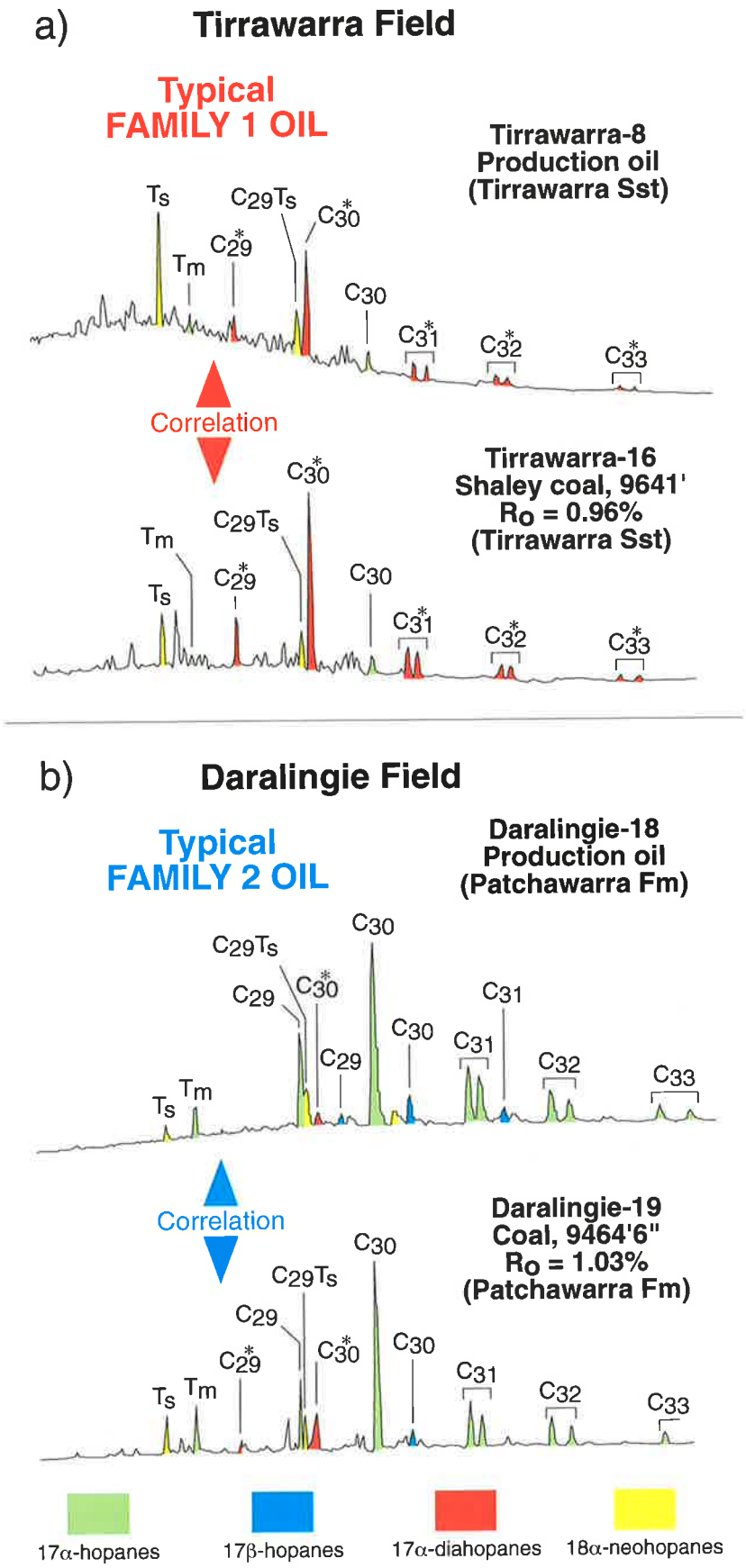


Figure 2.17 GC-MS mass fragmentograms showing hopanes (m/z = 191) in saturated hydrocarbon fractions of selected sediment extracts and oils

2.13.1 Source rocks

The values of the ratios T_s/T_m and $C_{29}T_s/17\alpha$-30-norhopane are higher in the coal from Tirrawarra-16 ($T_s/T_m = 4.01$, $C_{29}T_s/17\alpha$-norhopane = 2.36) than in the shale from Tirrawarra-17 ($T_s/T_m = 0.80$, $C_{29}T_s/17\alpha$-30-norhopane = 2.29) (Fig. 2.18a). At face value this may imply that the coal is more mature (*e.g.* Peters and Moldowan, 1993) than its shale counterpart. However, the 17α-diahopane/17α-hopane ratio (Fig. 2.19) is considerably greater for the shale (11.6) that the coal (6.93) suggesting the opposite (Moldowan *et al.*, 1991) and is in agreement with R_{est} values (Table 2.8) which indicate that the shale is probably more mature than the coal. Therefore it appears that the relative concentration of T_s, $C_{29}T_s$ and/or 17α-diahopane in these Tirrawarra Sandstone samples may be as much facies as maturity dependent.

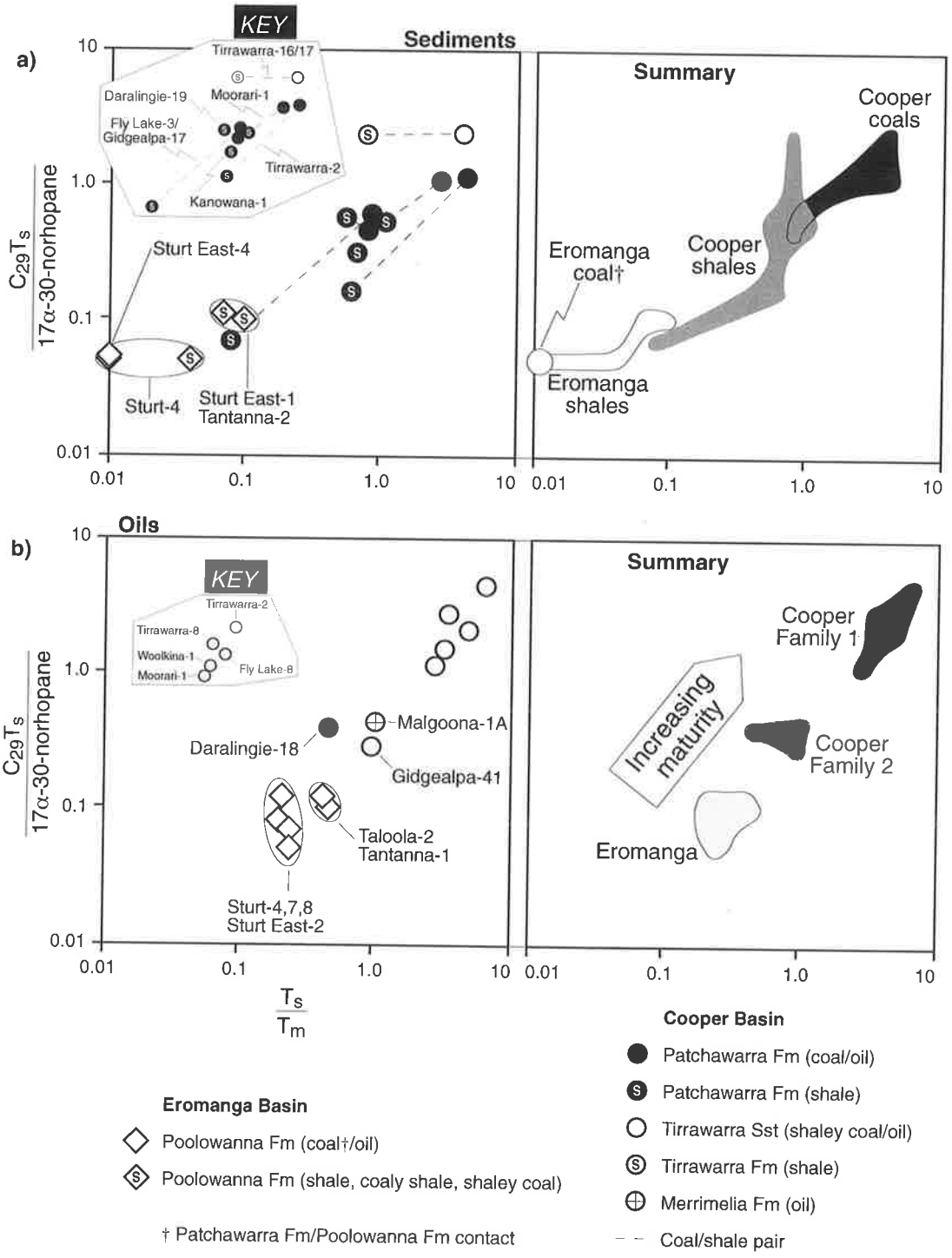


Figure 2.18 T_s/T_m *versus* $C_{29}T_s/17\alpha$-30-norhopane cross-plots for sediments and oils (logarithmic axes)

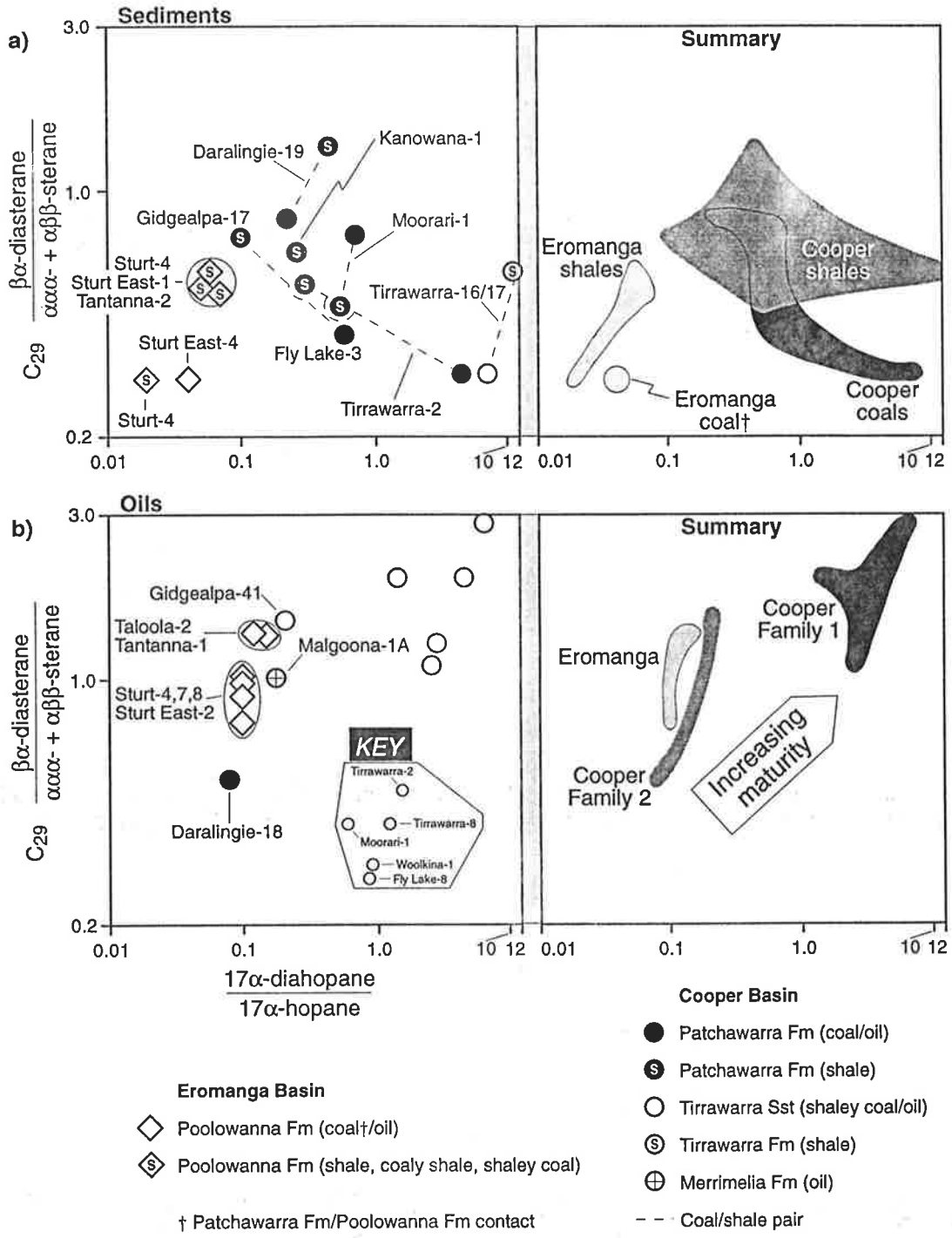


Figure 2.19 17α-diahopane/17α-hopane *versus* βα-diasterane/(ααα + αββ-sterane) cross-plots for sediments and oils

With respect to the Patchawarra Formation, average values of T_s/T_m, $C_{29}T_s$/17α-30-norhopane and 17α-diahopane/17α-hopane are significantly higher in the coals (2.19, 0.81 and 1.52, respectively) than in the shales (0.61, 0.33 and 0.33, respectively; Tables 2.15 & 2.17). As discussed previously, most of these coal/shale pairs are isometamorphic, and therefore the considerable variability in the biomarker ratios observed must be entirely facies dependent. It is well documented (*e.g.* Peters and Moldowan, 1993) that the formation of rearranged hopanes (*i.e.* 18α-neohopanes and 17α-diahopanes) from unrearranged hopanes (*i.e.* 17α-hopanes) is driven by clay-catalysed reactions under acid conditions, and therefore higher concentrations of these compounds can be expected in argillaceous, clastic source rocks where the concentration of clay minerals is obviously greatest. Based on computer modelling, the relative thermodynamic stability of the hopanoid series is 17α-diahopanes > 18α-neohopanes > 17α-hopanes

(Kolaczkowska *et al.*, 1990; Moldowan *et al.*, 1991). Therefore, the 18α-neohopanes, and especially the 17α-diahopanes, have a propensity to form under conditions of high thermal stress. In these samples, thermal maturation is clearly the critical factor controlling the formation of rearranged hopanes. However, it is obvious that in the Cooper Basin, clay-mediated reactions alone cannot account for the formation of the higher concentrations of 18α-neohopanes and 17α-diahopanes in the coals.

The relative concentrations of the rearranged hopanes in the Poolowanna rocks are uniformly low (T_s/T_m = 0.01–0.10; $C_{29}T_s$/17α-30-norhopane < 0.11, 17α-diahopane/C_{30} 17α-hopane = 0.02–0.07) consistent with maturities in the early "oil window" and in marked contrast with values exhibited by the Cooper Basin rocks (Figs 2.18 & 2.19). Another feature of the Poolowanna extracts that is consistent with a lower maturity is their hopane/moretane (17α-hopane/17β-hopane; Table 2.15) ratios which range 2.7–4.0, in contrast to the higher values for the more mature Cooper Basin coals (3.4–8.2) and shales (4.0–8.1).

The 22*S*/22*R* C_{31} 17α-homohopane values of the Poolowanna extracts (1.3–1.8: Table 2.15) are generally higher than those of the Cooper Basin samples (0.99–1.50). This is incongruous, because with advanced maturity the biologically produced isomer (22*R*) is known to convert to the geological isomer (22*S*), and therefore the parameter increases with greater maturity. The 22*S*/22*S* + 22*R* C_{31} homohopane ratio has been shown to equilibrate at *ca* 0.6 (equivalent to 22*S*/22*R* C_{31} homohopane ≈ 1.5) at a maturity of 0.6% R_o (Seifert and Moldowan, 1986) which is consistent with the rank of most of the Poolowanna sediments based on measured vitrinite reflectance and aromatic maturity data (Sections 2.6–2.10; *e.g.* Tables 2.8 & 2.11). Clearly, there are unexplained geochemical factors preventing the equilibration of homohopanes in the Cooper Basin sediments.

In Figure 2.20a the ratio 17α-30-norhopane/17α-hopane is plotted against hopane/sterane for sediment extracts. Based on their 17α-30-norhopane/17α-hopane values the Cooper Basin coals and shales are barely distinguishable, although the latter have marginally higher values (Tables 2.15 & 2.17). This must be due to facies variability because most of the coal-shale pairs are isometamorphic. Such a finding is not entirely unexpected since the 17α-30-norhopane/17α-hopane ratio is known to be lithofacies dependent (*e.g.* ten Haven *et al.*, 1987).

The Eromanga shales and coal have values which are marginally greater than those of the shales from the Cooper Basin, but clearly greater than those of the Cooper Basin coals (Fig. 2.20a). Kolaczkowska *et al.* (1990) demonstrated that 17α-30-norhopane (C_{29}) is thermodynamically more stable than 17α-hopane (C_{30}). It is therefore conceivable that at high rank (*i.e.* > 1.0% R_o) the C_{30} hopane is preferentially converted to rearranged hopanes *prior to* the onset of similar reactions for the C_{29} hopane. (Alternatively, both C_{29} and C_{30} 17α-hopanes may diminish in abundance by cracking to other non-biomarker species, but that the cracking of C_{30} 17α-hopane occurs faster than for C_{29} 17α-hopane). Thus, the 17α-30-norhopane/17α-hopane ratio may diminish at these maturities and thereby act as a *de facto* maturity parameter in the late oil window. The higher values of the C_{29}/C_{30} hopane ratio observed in Eromanga sediments cannot be attributed to the maturity differential previously described, but must be entirely dependent upon differences in depositional environment and/or precursor organic matter.

2.13.2 Oils

Arguably the most conspicuous feature of the Cooper Basin oil biomarker database is the hopane chemistry of the Tirrawarra Sandstone-reservoired oils from Fly Lake-8, Moorari-1, Tirrawarra-2, Tirrawarra-8 and Woolkina-1 (*i.e.* Family 1 oils). These oils are devoid of the extended hopanes and moretanes (Fig. 2.18b) and are almost entirely depleted in the C_{27} (T_m), C_{29} and C_{30} 17α-hopanes. To the best of the author's knowledge, examples of oils with such extreme neohopane and diahopane-dominated signatures are unreported in the literature, but are entirely consistent with hydrocarbons that have been generated at maturities approaching the base of the oil window (*viz* 1.1–1.3% R_o). The (*m/z* = 191) mass fragmentograms of the Family 1 oils (*e.g.* Tirrawarra-8 production crude; Fig. 17a) are an almost exact match with those of the coal extracts from Fly Lake-3, Tirrawarra-2 and Tirrawarra-16 (Fig. 17a), and the shale extract from Tirrawarra-17. The obvious conclusion to be drawn from these data is that the Family 1 oils are locally sourced, mostly from coals rather than shales. Conversely, Family 2 oils, with more-or-less conventional hopane distributions, have predominantly shale source affinities.

A notable feature of the hopane (*m/z* 191) fragmentograms of Family 1 oils and their likely source rocks (*e.g.* Fig. 17a) is a series of diahopanes with extended C_{31} to C_{33} structures (*cf.* Moldowan *et al.*, 1991; Peters and Moldowan, 1993, p. 163). The obvious depletion of the normal extended hopanes in the same samples is evidence that the 17α-homodiahopanes form by structural rearrangement of the former. However, the reduced signal to noise ratio in samples with high concentrations of rearranged hopanes (*e.g.* Fig. 17a) probably indicates that many of the 17α-hopanes were also converted to hydrocarbons (*e.g.* drimanes) other than rearranged hopanes.

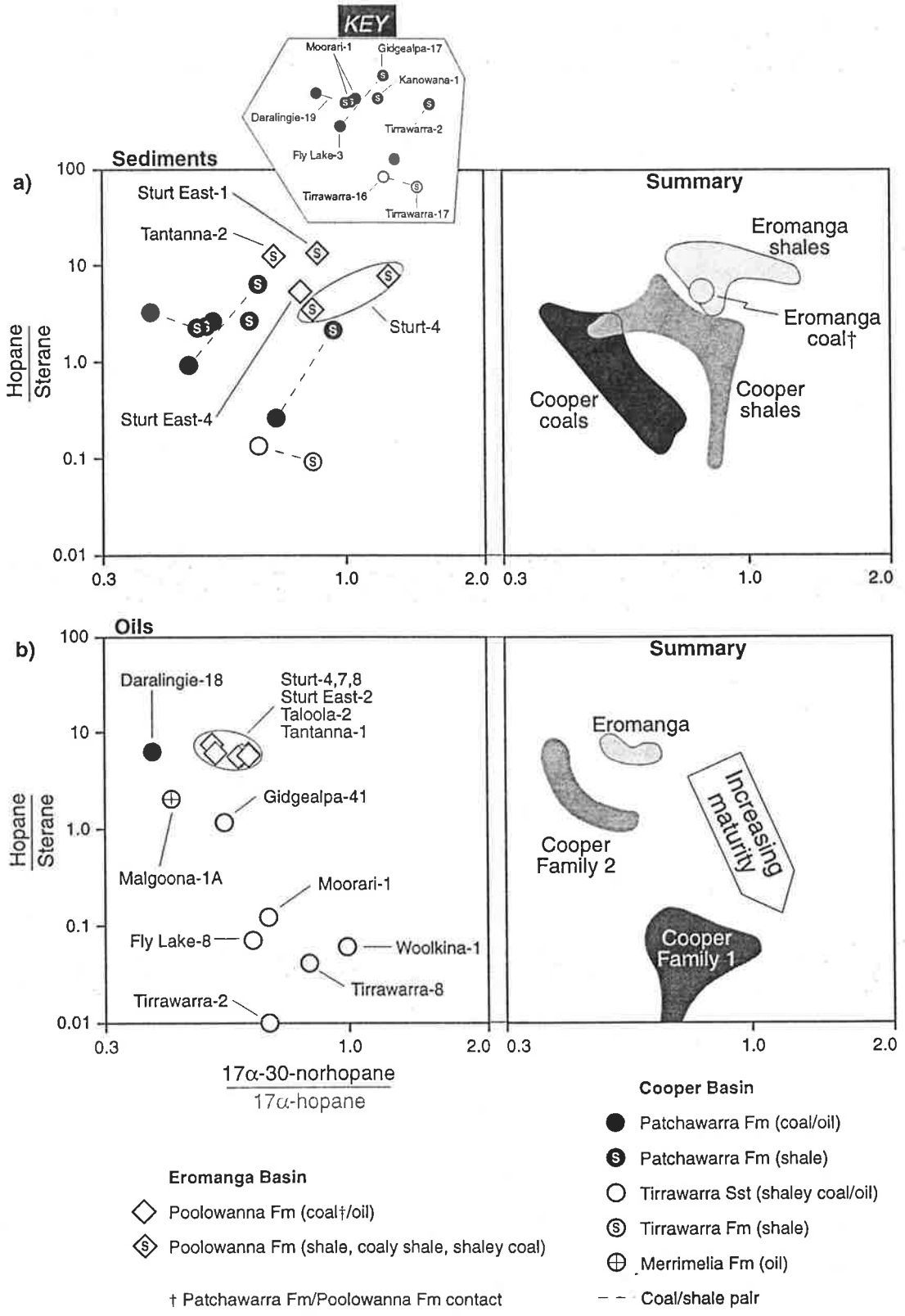


Figure 2.20 17α-30-norhopane/17α-hopane *versus* hopane/sterane cross-plots for sediments and oils (logarithmic axes)

Comparison of the *m/z* 191 fragmentograms of the conventional oil from Daralingie-18 and the shale extract from Daralingie-19 (Fig. 2.17) demonstrates a possible genetic link. However, the fact that both the Daralingie-19 coal and the shale are a good match for the oil suggests possible co-sourcing (Fig. 2.18a,b). On the other hand, comparison of the rearranged hopane chemistry of the Tirrawarra-8 oil with those of the coal and shale from Tirrawarra-16 suggests a very strong genetic relationship with only the coal (Fig. 2.17b & Fig 2.18a,b). In rock extracts and oils where the 17α-hopanes have been almost entirely depleted in favour of the rearranged hopanes, the doublet which corresponds to C_{31} homodiahopane (labelled $C_{31}^{\cdot}$) shows the earlier eluting peak (presumably the 22*S* epimer) in almost the same concentration as the later eluting peak (22*R*). Similarly, the 22*S* and 22*R* epimers for the C_{32} and C_{33} 17α-homodiahopane (labelled $C_{32}^{\cdot}$ and $C_{33}^{\cdot}$) are in approximately equal abundance. This is unexpected because it is well established that the 22*S*/(22*S* + 22*R*) equilibrium value for homohopanes in mature oils is around 0.6 (0.57 to 0.62: Seifert and Moldowan, 1986). Therefore another conclusion to be drawn from these data is that the 22*S*/(22*S* + 22*R*) ratio for C_{31-33} homodiahopanes (labelled $C_{31}^{\cdot}, C_{32}^{\cdot}, C_{33}^{\cdot}$ equilibrates at around 0.5.

The highest T_s/T_m (6.5), $C_{29}T_s$/17α-norhopane (4.3) and 17α-diahopane/17α-hopane (6.5) ratios are recorded for the Tirrawarra-2 oil which is consistent with it being the most mature of the Family 1 oils (Figs 2.18b & 2.19b). The lowest recorded values of T_s/T_m (2.8) and $C_{29}T_s$/17α-norhopane (1.1) are from Moorari-1 suggesting that this is the least mature of the condensate-like Cooper Basin oils.

Family 2 oils have significantly lower concentrations of rearranged hopanoids which is compelling evidence that they were generated and expelled from their respective source rocks at maturities less than those of Family 1 (Tables 2.16 & 2.17; Figs 2.18 & 2.19). In this respect the rearranged hopanes convey a similar picture to that of the DNR and TNR data described in Sections 2.9 and 2.10; namely a maturity contrast between Family 1 and Family 2 oils which is obscured if one relies solely on MPI- and MPR-based maturity estimates (*i.e.* $\overline{R}_c$ of Table 2.12). For example, the Daralingie-18 crude is probably the least mature (see Figs 2.18 & 2.19) of the Family 2 oils which is totally at variance with its maturity as measured by aromatic hydrocarbon distributions ($\overline{R}_c$ = 1.12%; Table 2.12).

The Fly Lake-8 oil has a similar hopanoid distribution to that of the Tirrawarra-8 crude ($\overline{R}_c$ = 1.08%; Fig. 2.18b), but a low calculated maturity ($\overline{R}_c$ = 0.91%; Table 2.12). This maturity estimate is probably erroneously low because other Fly Lake oils have been reported with considerably higher R_c values (*cf.* Michaelsen *et al.*, 1995d), and certainly the TNR, hopane and sterane data of the Fly Lake-8 oil indicate that its maturity is at least comparable with the Tirrawarra-8 and Woolkina-1 crudes (both $\overline{R}_c$ = 1.08%). A series of homodiahopanes was recently reported by Davies (1996) in mature oils of Cretaceous/Tertiary age from the Bredasdorp Basin, South Africa. Based on MPI, these oils also have R_c values around 1.05%, which are similar to the inferred maturities of many of the oils here. Given their absence in Cooper Basin/Eromanga Basin crudes with maturities ≤ 0.95% R_c, it appears that 17α-homodiahopanes may start to form in source rocks as early as *ca* 1.00% R_o, although they appear to be more typically present in oils and source rocks with maturities greater than 1.05% R_o.

The Poolowanna oils, like those crudes belonging to Cooper Family 2 have more-or-less conventional hopanoid distributions. The T_s/T_m (mean = 0.46) and $C_{29}T_s$/17α-30-norhopane (mean = 0.09) ratios for the Poolowanna oils are much less than those of Family 2 (T_s/T_m: mean = 0.82; $C_{29}T_s$/17α-30-norhopane: mean = 0.37) implying lesser maturity (Fig. 2.18b). On the other hand, the 17α-diahopane/17α-hopane ratios for the Poolowanna and Family 1 oils are essentially identical (Table 2.17; Fig. 2.19b), suggesting that neither have reached maturities corresponding to the upper oil window (*i.e.* > 1.0% R_o) where this parameter is expected to be effective due to the thermodynamic differential between these two compounds.

It is interesting that Family 1 oils have 17α-30-norhopane/17α-hopane ratios clearly higher than those of either Family 2 or the Eromanga oils (Table 2.17; Fig. 2.20b). Overall there is little obvious correlation between the sediment extracts (Fig. 2.20a) and the oils (Fig. 2.20b). It is

proposition which has been argued earlier. By contrast, the Family 2 oils are less mature, and this is evident from their lower 17α-30-norhopane/17α-hopane values.

2.14 OIL–SOURCE AND OIL–OIL CORRELATIONS BASED ON STERANES

Biomarker parameters based on steranes are provided in Tables 2.15 (sediment extracts) and 2.16 (oils) and are summarised in Table 2.17. Cross-plots of various biomarker parameters based on steranes and other hydrocarbons are represented in Figures 2.21 and 2.22.

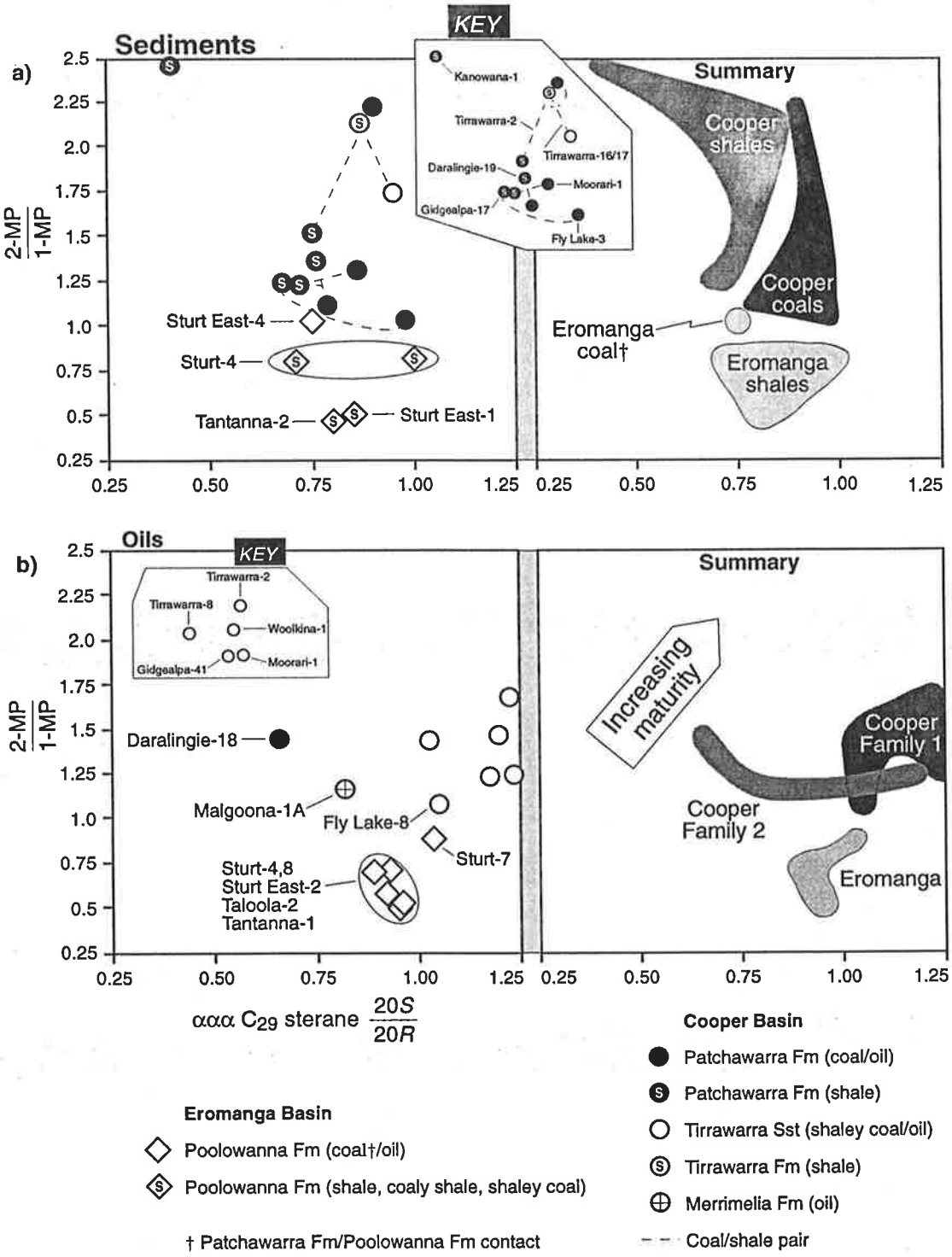
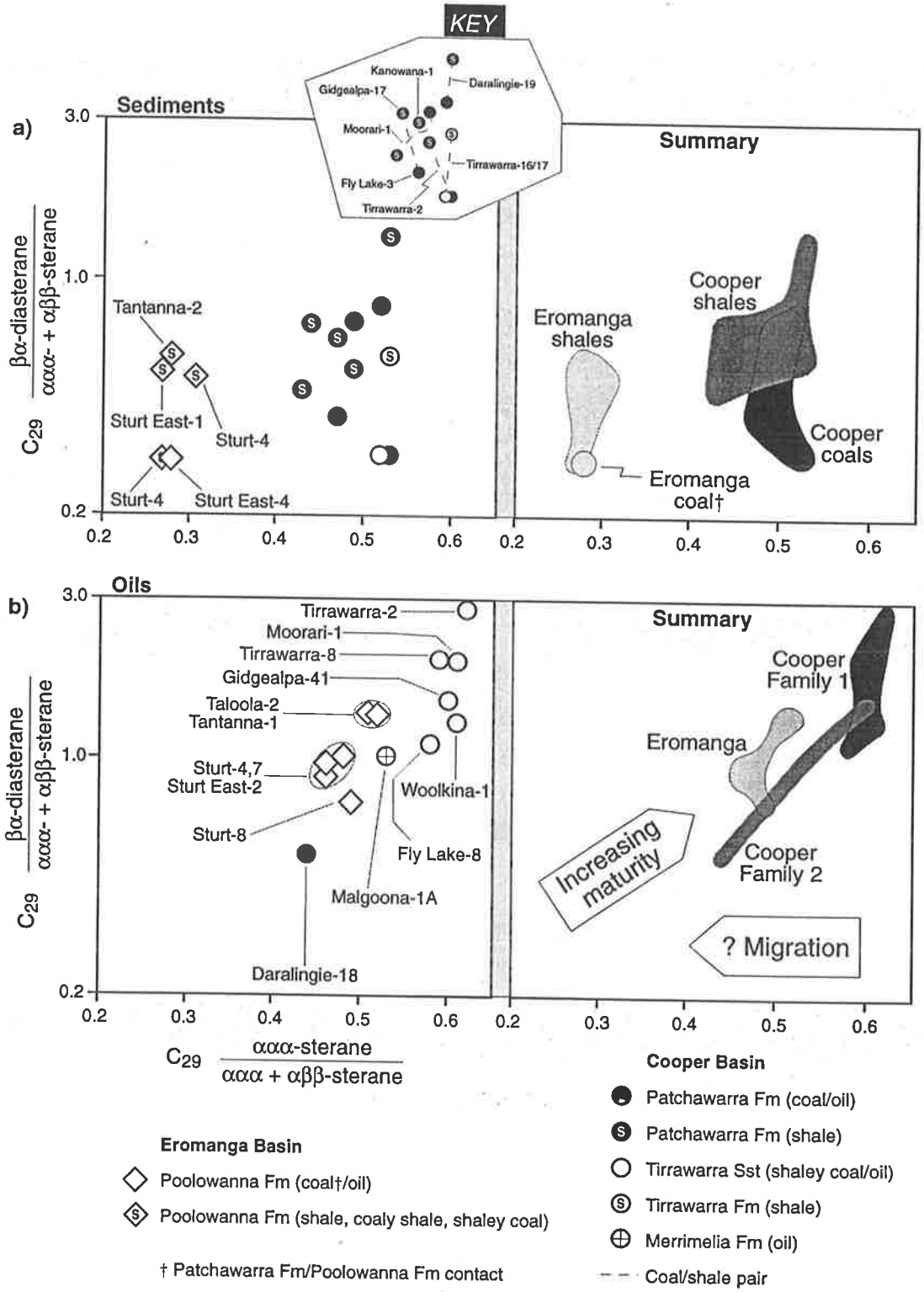


Figure 2.21 ααα C_{29} sterane (20*S*/20*R*) *versus* 2-MP/1-MP cross-plots for sediments and oils

2.14.1 Source rocks

In Figure 2.21a the ratio of 20*S*/20*R* ααα C_{29} sterane is plotted against 2-MP/1-MP (MPR) for sediment extracts. The 20*S*/20*R* ratio is well known to increase with maturation (*e.g.* Seifert and Moldowan, 1986). Equilibrium values of 20*S*/20*R* ≈ 1.2 [20*S*/(20*S* + 20*R*) ≈ 0.55] are generally expected in source rocks and oils at maturity levels corresponding to 0.8–0.9% R_o (Peters and

Moldowan, 1993). From Figure 2.21a it is clear that the 20*S*/20*R* values of the Cooper coals (*e.g.* Patchawarra mean = 0.88) are on average greater than those of the Cooper shales (*e.g.* Patchawarra mean = 0.66; Table 2.17). Indeed, for any given coal/shale pair, the coal always has the greater 20*S*/20*R* value and thus this ratio appears to be highly lithofacies-dependent in these Cooper Basin rocks. Although the Poolowanna extracts are less mature (based on their measured vitrinite reflectance and aromatic hydrocarbon distributions), they have similar



20*S*/20*R* values (shale mean = 0.84). Therefore it must be concluded that this sterane ratio is not particularly useful as a maturity parameter for these Jurassic and Permian source rocks.

Figure 2.22 C_{29} ααα-sterane/(ααα + αββ-sterane) *versus* βα-diasterane/(ααα + αββ-sterane) cross-plots for sediments and oils

The ratio C_{29} sterane (ααα/ααα + αββ) is plotted against C_{29} βα-diasterane/(ααα + αββ-sterane) in Figure 2.22. The latter is also used as the vertical axis in Figure 2.19 (Section 2.13). C_{29} sterane ααα/(ααα + αββ) appears to be an excellent discriminator between the coals (*e.g.* Patchawarra mean = 0.50) and shales (*e.g.* Patchawarra mean = 0.47) on the one hand, and the Poolowanna extracts (mean = 0.28) on the other (Fig. 2.22). This parameter is clearly little, if at all, affected by source lithofacies and would seem to be controlled almost exclusively by maturity.

The ratio C_{29} (βα-diasterane/ααα + αββ-sterane) is another maturity-dependent parameter (Seifert and Moldowan, 1978, 1986) and is greater in Cooper shales (*e.g.* Patchawarra mean = 0.75) than in coals (*e.g.* Patchawarra mean = 0.57). Diasteranes form *via* clay-catalysed reactions and therefore might be expected to occur in higher relative concentrations in clastic rocks than in coals (*cf.* discussion in Peters and Moldowan, 1993). Similarly the Poolowanna coal, as might be expected, has a lower C_{29} βα-diasterane/(ααα + αββ-sterane) value than do the Poolowanna shales (Table 2.17). Overall, the similarity of the C_{29} (βα-diasterane/ααα + αββ-sterane) values observed in these Cooper and Eromanga sediments shows that this parameter is unsuitable to assess their maturity. Thus it seems reasonable to conclude that in this petroleum province sterane-based maturity parameters are unreliable due to lithofacies variability, and consequently such data should only be used with considerable caution.

The hopane/sterane ratio (see key to maturity and source parameters, p. xxi) is a parameter which can be used to semiquantitatively assess the relative contributions of prokaryotic (hopanoid-producing) micro-organisms and eukaryotic (steroid-producing) biota to a given sedimentary milieu. It is therefore regarded as a classic "source" parameter (*e.g.* Peters and Moldowan, 1993).

The shaley coal/shale pair from the Tirrawarra Sandstone at Tirrawarra-16/17 have very low hopane/sterane values (0.09–0.13: Table 2.17; Fig. 2.20). By contrast, ratios for the Patchawarra Formation are all considerably higher. Hopane/sterane values in the coals (0.26–3.1, mean = 1.7) are slightly lower than in the shales (2.1–6.1, mean = 3.0) indicating that microbial reworking of terrestrial and aquatic organic matter in the Early Permian peat swamps or mires (Alexander, 1998) was less intensive than in the coeval lacustrine/floodplain facies (Fig. 2.20a). The Poolowanna shales (3.4–13.2, mean = 9.1) and coal (5.2) clearly have the greatest hopane/sterane values. There appears to be a trend of increasing hopane/sterane ratio with decreasing stratigraphic age. One possible explanation for this observation could be that there was a secular increase in bacterial reworking of primary organic matter across the Palaeozoic–Mesozoic transition, from the earliest Early Permian (Tirrawarra time), through middle Early Permian (Patchawarra time), to Early Jurassic (Poolowanna time). A more reasonable explanation is that the hopane/sterane ratio reflects the documented regional decrease in maturity upwards through the geological succession (see discussion below).

2.14.2 Oils

Family 1 oils have ααα C_{29} sterane (20*S*/20*R*) values (1.0–1.2) which suggests that this parameter has reached equilibrium, consistent with them being the most mature crudes (Fig. 2.21b). However, the Family 2 and Poolowanna crudes generally have lower values (Table 2.17) and are indistinguishable using this ratio. This suggests that neither have reached the critical maturity threshold (*ca* 0.8–0.9% R_o) where this parameter is generally accepted to have equilibrated. Likewise, the Poolowanna and Family 2 oils are similar on the basis of their C_{29} sterane ααα/(ααα + αββ) values, whilst Family 1 oils are inferred to be of greater maturity based on this parameter, which is highest in the Tirrawarra-2 oil (Fig. 2.22b.

Alternatively, it is possible to interpret the C_{29} sterane ααα/(ααα + αββ) ratio as a *geochromatography* parameter based on Seifert and Moldowan's (1981) proposition that the αββ stereoisomer migrates more readily than does the ααα stereoisomer. Therefore the lower C_{29} sterane ααα/(ααα + αββ) values for the Family 1 oils can be interpreted to indicate that they are less migrated than the Family 2 oils and the crudes from the Poolowanna Formation (Fig. 2.22b). This is consistent with the findings discussed in Section 2.7.1 whereby the Family 1 oils from the Tirrawarra and Moorari/Woolkina Fields appear to have local or near-local sources based on matching vitrinite reflectance and methylphenanthrene-based maturity data. Of the Family 1 oils, Fly Lake-8 with the lowest C_{29} sterane ααα/(ααα + αββ) ratio appears to be the most migrated, arguably consistent with the aromatic hydrocarbon data. The Tirrawarra-2 oil with a C_{29} sterane ααα/(ααα + αββ) ratio of 0.62 appears to be the least migrated oil

(Table 2.16). Based on this premise, of the Family 2 oils, those from Daralingie-18 and Malgoona-1A have migrated further than the Gidgealpa-41 crude. Within the Poolowanna suite, the Taloola-2 and Tantanna-1 crudes would seem to be more migrated than the remaining four oils from the Sturt/Sturt East Fields. In the case of the Tantanna-1 crude, this is once again in agreement with interpretations based on vitrinite reflectance and aromatic maturity data.

The diasterane/sterane C_{29} $\beta\alpha/(\alpha\alpha\alpha+\alpha\beta\beta)$ ratio for the Tirrawarra-2 oil (2.80) is exceptionally high, consistent with this oil being the most mature of the Family 1 crudes. However, it is clear that many Family 1, Family 2 and Eromanga oils cannot be distinguished using this parameter (Fig. 2.22).

From Figure 2.20b it is apparent that Family 1 oils can be distinguished from Family 2 and Poolowanna oils not only by the *de facto* maturity parameter 17α-30-norhopane/17α-hopane (Section 2.13), but also by virtue of the hopane/sterane ratio which readily discriminates between Cooper and Eromanga Basin oils (and source rocks) because 17α-hopane and 17β-hopane (moretane) are depleted in the more mature Cooper samples. Evidently the steranes are more thermally robust than the hopanes (*cf.* Kolaczkowska *et al.*, 1990), consistent with the findings of Eglington and Douglas (1988) who observed the destruction of hopanes prior to steranes during various hydrous pyrolysis experiments on kerogens and whole rock samples. Although it is well-established that the hopane/sterane ratio is *source-related*, at high rank (> 1.0% R_o) this ratio must be interpreted as a *maturity* parameter.

2.15 MPR (2-MP/1-MP) as a combination source and maturity parameter

In Section 2.7, MPR (2-MP/1-MP) was used to estimate the maturity of sediment extracts and oil fractions. Figures 2.21a and 2.21b are cross-plots of ααα C_{29} sterane 20*S*/20*R* *versus* MPR for sediments and oils respectively. Unlike most of the saturated and aromatic hydrocarbon ratios previously discussed, 2-MP/1-MP is apparently independent of lithofacies (Fig. 2.21a) in that values are effectively identical for the Cooper coals (*e.g.* Patchawarra: 1.0–2.2, mean = 1.6; Table 2.14) and shales (*e.g.* Patchawarra: 1.2–2.2, mean = 1.6). Values for this ratio are uniformly less for the lower maturity Poolowanna shales (0.46–0.81, mean = 0.64) and coal (1.0). Thus *2-MP/1-MP appears to be influenced entirely by maturity and the age of the rock* and consequently it behaves as an excellent geochemical discriminator between Cooper- and Eromanga-derived oils (Fig 2.21b).

The Poolowanna rocks contain elevated concentrations of 1-MP by virtue of their high content of araucariacean resins, whereas the Patchawarra and Tirrawarra extracts lack this conifer-specific input of 1-MP. In the more mature Cooper Basin samples, the 2-MP/1-MP ratio increases as thermal stress depletes the 1-MP isomer in favour of the thermodynamically-favoured 2-MP, thereby increasing its effectiveness as a Permian *versus* Jurassic discriminator. Furthermore, unlike many of the other parameters based on aromatic hydrocarbons (*e.g.* DNR and TNR) and hopanes (*e.g.* $C_{29}T_s$ and T_s) which demonstrate a maturity differential between Family 1 oils and Family 2 oils, the ratio 2-MP/1-MP obviously does not differentiate between Family 1 (1.08–1.68, mean = 1.38) and Family 2 crudes (1.16–1.44, mean = 1.28). However, oils from the Poolowanna Formation have significantly lower 2-MP/1-MP values (0.49–0.88, mean = 0.65) that closely match those of the Poolowanna shales (0.46–0.81, mean = 0.64).

In summary, a value of 2-MP/1-MP ≈ 1.02 (approximately 1.0) separates all the Eromanga rock extracts and oils from those of the Cooper Basin. Thus *irrespective* of source lithology (*i.e.* coal *versus* shale) and depositional environment, 2-MP/1-MP is a powerful discriminator between Cooper and Eromanga source rocks (and oils derived therefrom). This fact will be expanded upon in Chapter 3, and exploited more fully in Chapter 6 where whole-oil analyses of a larger suite of crudes (n = 62) are used to test for migration of Permian-derived hydrocarbons into the Eromanga Basin.

2.16 Secondary Migration of Cooper Basin Oils

By integrating all the chemical data hitherto assembled, it is possible to derive at a reasonable maturation level for each of the oils in this study. Estimated maturities (R_{est}) for Family 1 and Family 2 oils are provided in Table 2.12 and iterated below. By comparing R_{est} values for the oils with regional maturity maps (Figs 2.2 & 2.3) in the vicinity of each reservoir (*cf.* Section 2.7.1.3), and with due regard for the saturated hydrocarbon biomarker data assembled above, it is possible to deduce a minimum lateral migration distance for each of the oils under consideration:

	Oil type (Family)	Estimated maturity (% R_{est})	Local or near-local (< 5 km)	Short-distance 2° migration (5–8 km)	Long-distance 2° migration (≥ 10 km)
Merrimelia reservoir					
Malgoona-1A	2	0.95		x	xx
Tirrawarra reservoir					
Gidgealpa-41	2	1.00	x	xx	
Moorari-1	1	1.05	xxx		
Woolkina-1	1	1.10	xxx		
Tirrawarra-2	1	1.20	xxx		
Tirrawarra-8	1	1.15	xxx		
Tirrawarra and basal Patchawarra reservoir					
Fly Lake-8	1	1.10	xx	x	
Patchawarra reservoir					
Daralingie-18	2	0.90	x	xx	

Key: x = less likely; xx = likely; xxx = very likely

It is important to bear in mind that a major flaw with this approach may be the accuracy of the vitrinite isoreflectance maps which, in part, have been constructed using widely spaced data compounded with potentially spurious vitrinite reflectance measurements (*i.e.* vitrinite reflectance suppression: *cf.* Chapter 4). As such, any interpretation of secondary migration distances should be viewed as indicative, but not necessarily definitive. However, since 80% of the Cooper Basin oil reserves are located in the Tirrawarra Field (Tirrawarra Sandstone) alone (Gravestock *et al.*, 1998), and most of the remaining Cooper Basin oil is reservoired at Moorari/Woolkina and Fly Lake (Morton, 1998), it is evident that the bulk of the Permian reserves have been sourced from local or near-local Patchawarra rocks. Long distance migration (≥ 10 km) from a deeper, more mature source into less mature reservoirs is likely for only the Malgoona-1A (Merrimelia) crude.

2.17 THE PROBLEMATIC SOURCE AFFINITY OF THE POOLOWANNA OILS

With the exception of the API gravity data for the condensate-like Poolowanna oils (which are similar to those of the Family 1 oils, Fig. 2.7), essentially all the maturity-related biomarker data discussed above identifies the Poolowanna-hosted oils as expulsion products of source rocks in the early oil-generation window (*ca* 0.65–0.80% R_o). In contrast, all the Cooper Basin oils were unequivocably generated and expelled from their respective source rocks (both coals and shales) at maturities ≥ 0.90% and, in the case of the Family 1 oils almost certainly ≥ 1.00–1.05% R_o.

Examination of source-related biomarker parameters, such as 1-MP/9-MP (Fig. 2.12) and retene/9-MP (Fig. 2.13), reveal that the Poolowanna oils are geochemically intermediate between the Poolowanna sediments and the Cooper Basin sediments (and oils); *i.e.* the Poolowanna oils may represent mixtures of hydrocarbons derived from both basins.

Other geochemical parameters that are affected by source and facies influences, as well as maturity (*e.g.* drimane/homodrimane, T_s/T_m and $C_{29}T_s$/17α-30-norhopane) provide only an equivocal interpretation of the origin of the Poolowanna oils. For example, the T_s/T_m values of the Poolowanna oils are similar to those of the Cooper shales analysed. This may constitute further evidence that the Poolowanna oils are *partially* derived from Cooper Basin source rocks. However, the $C_{29}T_s$/17α-30-norhopane values of these oils are an excellent match with those of the Poolowanna sediments. On the other hand, the highest hopane/sterane values are obtained for the potential Eromanga source rocks. In this respect the Poolowanna oils and potential source rocks are very similar, suggesting that the former are derived from intra-Poolowanna source facies.

Even if the Poolowanna oils tested in this study were entirely derived from Poolowanna source rocks (either locally or having migrated from afar), it is unrealistic to expect a precise match for all the geochemical parameters discussed. Undoubtedly primary migration out of the source rock will favour certain molecular species over others. Furthermore, the process of petroleum formation is a geochemical and physical response to increased temperatures and pressures

acting over time (see discussions in Tissot and Welte, 1984), and as such it may not be unreasonable for more stable compounds (*e.g.* T_s) to be concentrated in the oil phase during the catalysis of organic matter and subsequent primary migration of the resultant hydrocarbons. Moreover, this may explain why ratios such as T_s/T_m are clearly accentuated in all the oils (including those from the Cooper Basin) relative to the potential source rocks tested. It must also be recognised that reservoired oil represents the integration of hydrocarbons that were not only present in source rocks as free molecules, but also the hydrocarbons which were released from kerogen during catalysis.

In summary, it is possible to argue that the Poolowanna oils tested:

1. represent early (low-maturity) expulsion products from Cooper Basin source rocks; or
2. were generated from source kitchens elsewhere in the Eromanga Basin, but not from the immediately adjacent Poolowanna source rocks in the Sturt/Tantanna area; or
3. are mixtures of locally-derived Poolowanna oil, and hydrocarbons from a more distant, intra-Eromanga source kitchen; or
4. are mixtures of Cooper Basin and Poolowanna-sourced hydrocarbons.

However, the similar maturity of the Poolowanna oils and the local intra-Poolowanna source rocks is too strong to ignore. Moreover, all these oils, with the possible exception of the Tantanna-1 crude, clearly plot in the "Jurassic field" of Figures 2.12 and 2.13 and have an obvious genetic affinity with the Poolowanna sediments. All things considered, the Poolowanna oils examined in this study appear to be Eromanga-sourced, although probably not entirely from local rocks. Other reservoirs within the Sturt Field contain oils that are apparently wholly or partly of Permian (or, in one case, pre-Permian) origin (Kagya *et al.*, 1996).

2.15 SYNOPSIS

1. Rock-Eval pyrolysis indicates that coals within the Early Permian Patchawarra Formation contain Type II organic matter and are probably better petroleum source rocks than the related shales in which the kerogen is of predominantly Type III composition. The measured vitrinite reflectances of coals and shales in the Early Permian Tirrawarra Sandstone and Patchawarra Formation ($R_o \approx 0.85$–1.20%) in the areas investigated match closely the equivalent maturities of oils and condensate-like crudes in the Merrimelia Formation, Tirrawarra Sandstone, and Patchawarra Formation ($R_c \approx 0.95$–1.10%).
2. Aromatic hydrocarbon (biomarker) parameters can be used to distinguish Cooper from Eromanga Basin-derived oils. Eromanga Basin rocks and oils are characterised by elevated levels of 1,2,5-TMN relative to 1,3,6-TMN; 1,7-DMP relative to Σ (1,3 + 3,9 + 2,10 + 3,10-DMP); 1-MP relative to 9-MP; retene relative to 9-MP (all source-related parameters); and low concentrations of 2-MP relative to 1-MP (a maturity and source-related parameter). The trimethylnaphthalene ratio (TNR) is another maturity-dependant aromatic hydrocarbon parameter which discriminates hydrocarbons reservoired in the Cooper Basin ($TNR \geq 1.0$) from those in the Poolowanna Formation ($TNR < 0.8$).
3. Many saturated hydrocarbon (biomarker) parameters also discriminate well between Cooper and Eromanga-sourced oils. These include the following ratios: drimane/homodrimane, T_s/T_m, $C_{29}T_s$/17α-30-norhopane, 17α-diahopane/17α-hopane, homodiahopanes/homohopanes and hopane/sterane. However, most of these ratios are clearly maturity-related.
4. Two families of oil are reservoired in the Cooper Basin. Family 1 oils (46–50° API) exemplified by those in the Fly Lake, Moorari, Tirrawarra and Woolkina Fields (Patchawarra Trough) were expelled from their source rocks at maturities $\geq 1.05\%$ R_o, and contain extremely high concentrations of rearranged hopanes (*e.g.* T_s, $C_{29}T_s$ and 17α-diahopane) relative to the 17α-hopanes. They have an obvious affinity with Early Permian coals, although a partial shale source cannot be ruled out. Family 2 oils (34–36° API) from the Daralingie, Gidgealpa and Malgoona Fields appear to have been generated from source rocks at marginally lower maturities (*ca* 0.95–1.00% R_o), and contain a conventional suite of hopanoid biomarkers where the 17α-hopanes predominate over the 17α-diahopanes, and 18α-neohopanes. The conventional Family 2 oils are likely to be more migrated than the condensate-like Family 1 oils. The latter appear to have been generated from local or near-local source rocks.

5. The bulk of the oil in the Poolowanna reservoirs (49–53° API) of the Sturt, Sturt East, Taloola and Tantanna Fields is derived from Jurassic (intra-Poolowanna) source rocks. However, it appears that some of the oil must have been generated from Eromanga source rocks outside the immediate Sturt/Tantanna area. Based on a variety of aromatic and saturated hydrocarbon parameters the oil at Tantanna-1 seems to be slightly more mature (*ca* 0.8% R_o) than hydrocarbons from the Sturt/Sturt East localities (0.65–0.75% R_o), and may have migrated from further afield.

CHAPTER 3

Source rock distribution in the Eromanga Basin, South Australia, and the petroleum geochemistry of its western sector

CHAPTER 3

Source rock distribution in the Eromanga Basin, South Australia, and the petroleum geochemistry of its western sector*

* Parts of this chapter have been published (Appendix 4) and prepared as technical reports as follows:

Alexander E.M., Pegum D., Tingate P., Staples C.J., Michaelsen B.H. and McKirdy D.M. (1996) Petroleum potential of the Eringa Trough in South Australia and the Northern Territory. *Australian Petroleum Production and Exploration Association Journal* 36(1), 322–349.

Michaelsen B.H. and McKirdy D.M. (1996a) Source rock and petroleum geochemistry of the Simpson Desert Basin and superjacent western Eromanga Basin: Pandieburra-1, Poonarunna-1, Putamurdie-1. Report for Department of Mines and Energy South Australia (unpublished).

Michaelsen B.H. and McKirdy D.M. (1996b) Source rock distribution and hydrocarbon geochemistry. In *The Petroleum Geology of South Australia. Vol. 2: Eromanga Basin*, ed. E.M. Alexander and J.E. Hibburt, Department of Mines and Energy South Australia. Report Book, 96/20, pp. 101–110.

Staples C.J., Michaelsen B.H. and McKirdy D.M. (1995a) Source rock and petroleum geochemistry of the Eringa Trough, Pedirka Basin. Report for Department of Mines and Energy South Australia (unpublished).

Staples C.J., Michaelsen B.H. and McKirdy D.M. (1995b) Source rock and petroleum geochemistry of the Eringa Trough, Pedirka Basin (supplementary report). Report for Department of Mines and Energy South Australia (unpublished).

3.1 SUMMARY

Ranked in order of decreasing potential as measured by Rock-Eval pyrolysis, the best petroleum source rocks in the Eromanga Basin are the coals and carbonaceous shales of the Birkhead Formation (which has its greatest hydrocarbon potential west of the Birdsville Track ridge); the organic-rich shales and siltstones of the Murta Formation (principally the Murteree Ridge area); and the coals of the Poolowanna Formation. These units display a wide range of source richness and quality, but all contain varying quantities of Type II/III (oil/gas-prone) and Type II (oil-prone) organic matter. Other units have negligible source potential.

Overall, the Birkhead Formation is demonstrated to be the most oil-prone unit in the western Eromanga Basin province. The best potential source rocks are developed at the Poonarunna-1 locality. Here hydrogen indices (HI = 288–561, mean = 426) recorded from shales with good to excellent organic richness (TOC = 1.72–19.70%, mean = 6.63%) indicate very good to excellent oil-generative potential (Type II/III to Type II kerogen). Maturity estimates derived from Rock-Eval pyrolysis (*ca* 0.7–0.85% R_o) are at variance with directly measured vitrinite reflectance which indicates a maturity of only *ca* 0.4–0.6% R_o. Biomarker evidence also suggests that petrographically measured R_o data are anomalously low at Poonarunna-1 and Putamurdie-1.

Two unusual triterpenoids, 28,30-bisnorhopane and a compound recently identified as C_{29} fernane, have been identified in Early Permian rocks (Pedirka Basin) from the Eringa Trough in the far western Eromanga province. Both compounds occur in very low concentrations, or are essentially absent in Jurassic rocks (Eromanga Basin), affording a novel means of identifying the source affinity of any oils that may be found in the region.

3.2 INTRODUCTION

By utilising PIRSA's PEPS database, and some new data from the western Eromanga Basin, this chapter reviews the distribution of petroleum source rocks of the Eromanga Basin in South Australia. To facilitate discussion of this large area, it is considered in two parts: 1) the basin east of the Birdsville Track Ridge (*i.e.* the Eromanga Basin immediately overlying the Cooper Basin and adjacent areas) which is referred to as the "eastern" sector (Fig. 3.1); and 2) the Eromanga Basin west of the Birdsville Track Ridge, which is described as the "western" sector. For the purposes of this chapter, the *western* Eromanga sector includes the Jurassic and Cretaceous strata overlying the Pedirka and Simpson Basins (Fig. 3.2). Its source rock data come mostly

from Amdel, Analabs, and University of Adelaide reports, or from well completion reports, although important new data from the Eringa Trough area (Staples *et al.* 1995; Alexander E.M. *et al.*, 1996) and from the Pandieburra-1, Poonarunna-1 and Putamurdie-1 wells (Table 3.1) were generated as part of the present study.

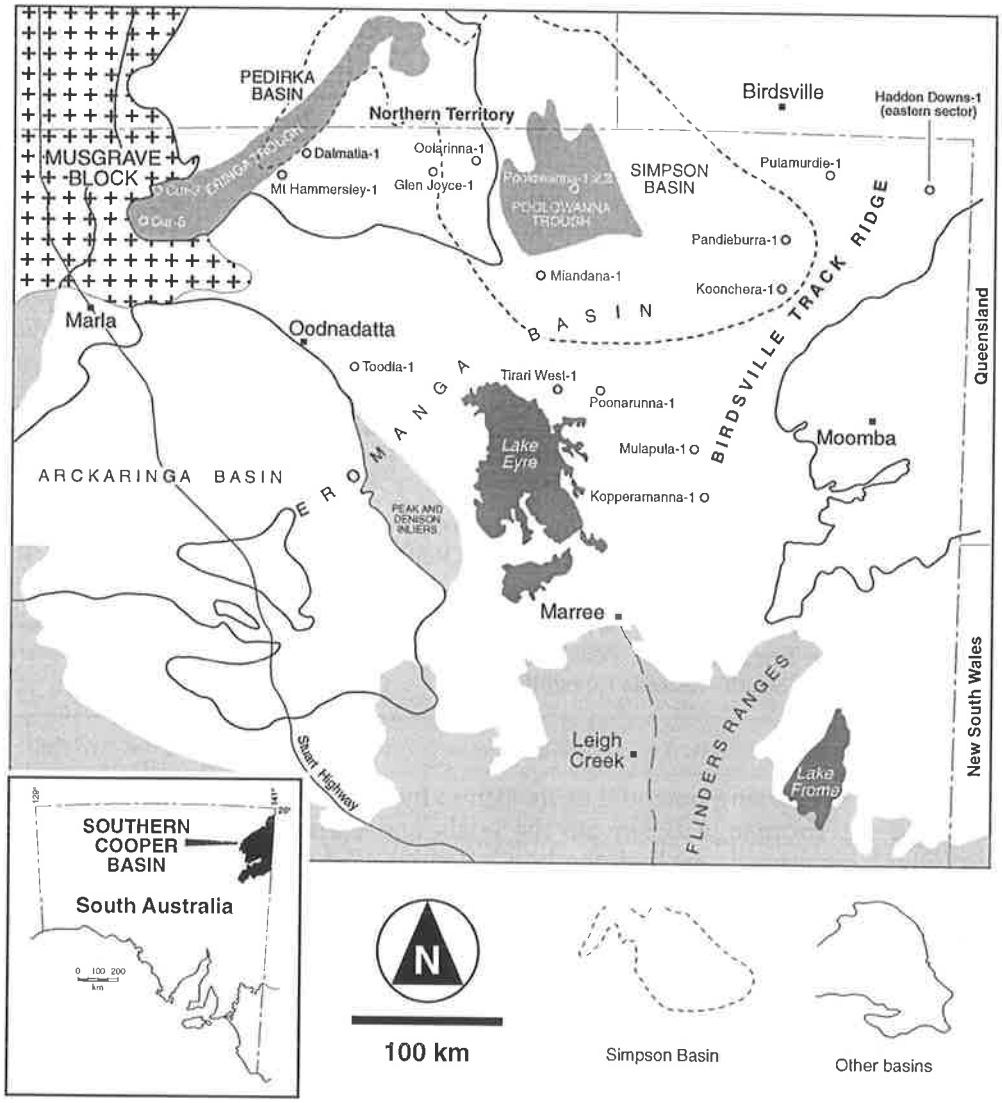


Figure 3.1 Locality map of study area, South Australia (western sector)

This chapter also explores aspects of the petroleum geochemistry of the western Eromanga Basin. These interpretations are based largely on new analytical work on core samples from the Pandieburra-1, Poonarunna-1 and Putamurdie-1 exploration wells (Michaelsen and McKirdy, 1986) augmented by existing data from Mulapula-1 (McKirdy *et al.*, 1987) and Poonarunna-1 (McKirdy and Watson, 1986). In addition, aspects of the petroleum geochemistry of the Eringa Trough area (Alexander E.M. *et al.*, 1996; Staples *et al.* 1995a,b) are revisited and discussed briefly.

Excluding further work which is the subject of Chapter 4, this chapter represents a summary of all Rock-Eval pyrolysis and GC-MS data currently available on this very large area (Fig. 3.2). The western Eromanga sector at present contributes little (if anything) to the hydrocarbon reserves of South Australia. However, its importance to South Australian oil explorers is likely to increase when oil production in the southern Cooper Basin diminishes. If high quality source rocks can be identified and geochemically characterised, our understanding of the petroleum system(s) in this area will be improved, and exploration risk reduced accordingly.

3.3 Sample selection and preparation

In total 22 core and one cuttings samples were collected from the Pandieburra-1 (5 core), Poonarunna-1 (14 core, 1 cuttings) and Putamurdie-1 (3 core) wells (Table 3.1). Wherever possible, the darkest (organic-rich) lithologies were selected. The core samples were scraped and

brushed clean to remove surficial contamination. The cuttings sample was meticulously washed and rinsed in distilled water using step-wise ultrasonification to remove drilling mud. This washed cuttings sample was then hand-picked to selectively remove sand and thereby concentrate the coaly lithology.

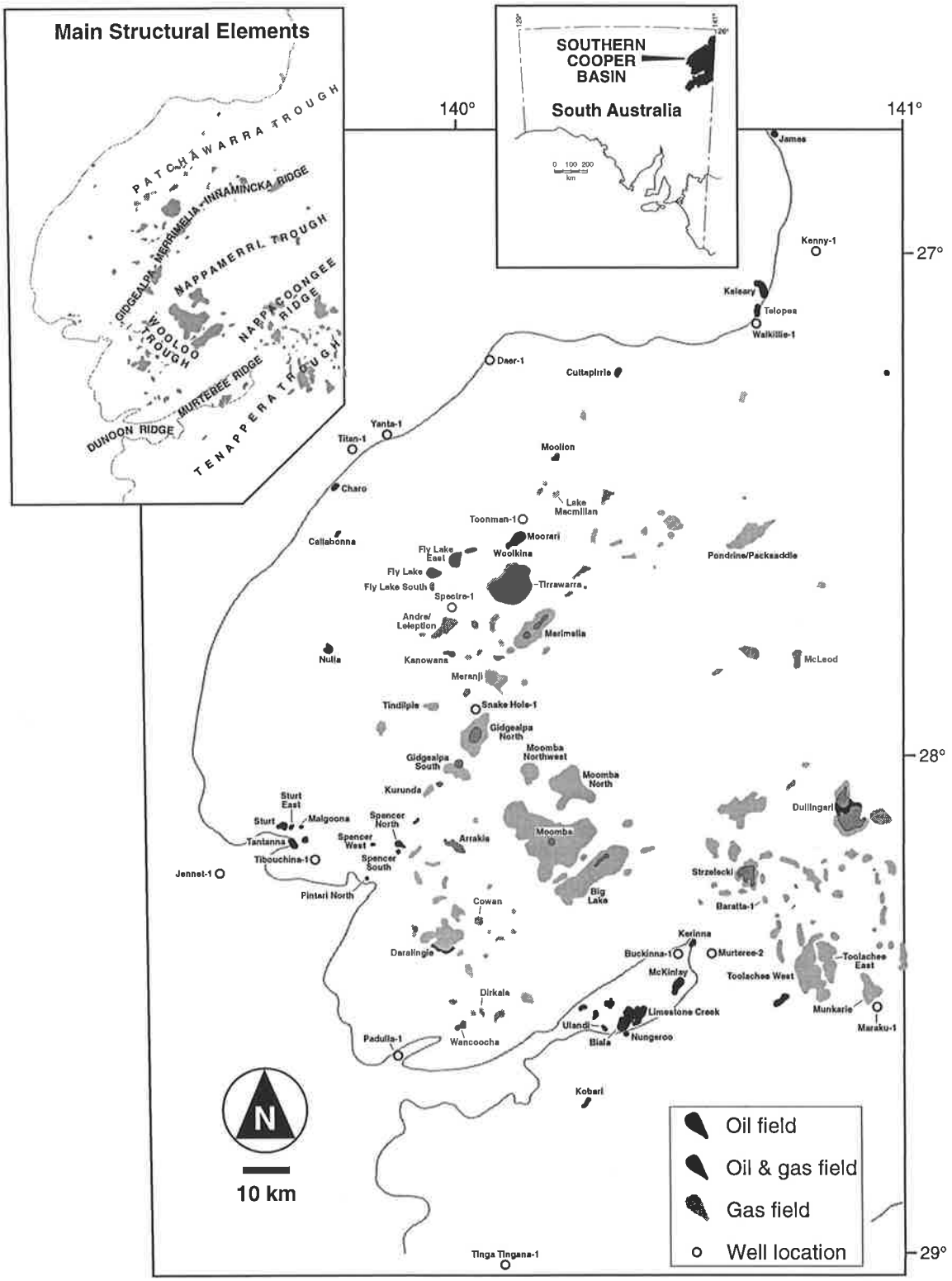


Figure 3.2 Locality map of study area, South Australia (eastern sector)

3.4 EXPERIMENTAL

3.4.1 Organic petrology and Rock-Eval pyrolysis

Sub-specimens of the 22 core samples were cut perpendicular to bedding, mounted in resin and polished for petrographic analyses (Table 3.2). A representative sub-specimen of the cuttings sample was also prepared as a polished block.

Reflectance measurements were made using a Leitz Ortholux Pol BK microscope under conditions specified by the Standards Association of Australia (1989). The means of random vitrinite (% R_r) reflectance were converted to means of maximum vitrinite reflectance (% R_o) using Kilby's (1991) formula, $R_o = 1.083 \times R_r$. All the samples, except two coals from Pandieburra-1 (6157', 6159'5") and the Poonarunna-1 (800–890') cuttings sample, were crushed to powder in a Siebtechnik mill and then analysed for total organic carbon (TOC) using a Leco WR-12 Carbon Determinator, and by Rock-Eval pyrolysis using a Girdel IFP-Fina Mark II operated in Cycle 1 mode (Table 3.3).

3.4.2 Solvent extraction and liquid chromatography

The powders of four samples from Poonarunna-1 and one sample from Putamurdie-1 were extracted in Soxhlet apparatus using an azeotropic solvent mixture (CH_2Cl_2:CH_3OH, 93:7). The extract was fractionated by liquid column chromatography on activated silica into saturated hydrocarbons, aromatic hydrocarbons and polar compounds (resins and asphaltenes) (see Table 2.4).

3.4.3 Gas chromatography-mass spectrometry of aromatic hydrocarbons

Gas chromatography-mass spectrometry (GC-MS) was undertaken using a Varian 3400 gas chromatograph interfaced to a Finnigan TSQ 70 mass spectrometer. The gas chromatograph was fitted with a 60 m x 0.25 mm i.d. fused silica column (DB-1, 0.25 μm film thickness; J & W Scientific). Helium was used as the carrier gas at an inlet pressure of approximately 23.5 psi. The oven was programmed as follows: 50° C for 2 min, 50° to 120° C at 8° C min^{-1}, 120° to 300° C at 4° C min^{-1} and then held at 300° C for 35 min. The injector was held at 60° C for 3 seconds then ramped to 300° C at 180° C min^{-1}, and held at 300° C for 5 minutes. Mass spectrometer operating parameters included an ionization voltage of 70 eV and a filament current of 200 μA. The photomultiplier voltage was set at 1100 V. Aromatic fractions in CH_2Cl_2 were injected on-column. The mass spectrometer was programmed in multiple ion detection MID mode to monitor *m/z* 128 (naphthalene), *m/z* 141 and 142 (methylnaphthalenes), *m/z* 156 (dimethylnaphthalenes), *m/z* 170 (trimethylnaphthalenes), *m/z* 178 (phenanthrene), *m/z* 192 (methylphenanthrenes), *m/z* 206 (dimethylphenanthrenes), *m/z* 219 (retene), *m/z* 231 and 245 (triaromatic steroids), and *m/z* 253 (monoaromatic steroids). A response factor of 0.69 was used to normalise the GC-MS data for phenanthrene relative to the calibrated GC response when calculating MPI. All aromatic hydrocarbon GC-MS parameters were calculated using peak areas.

3.4.4 Gas chromatography-mass spectrometry of saturated hydrocarbons

GC-MS conditions were identical to those used in the analysis of the aromatic hydrocarbons except that the photomultiplier voltage was set to 1800 V. The saturated hydrocarbon fractions were dissolved in *n*-hexane prior to injection and the mass spectrometer was programmed (MID) to monitor *inter alia m/z* 123 (sesquiterpenoids, triterpanes), *m/z* 163 (25,28,30-trisnorhopane), *m/z* 177 (demethylated hopanes), *m/z* 191 (hopanes/triterpanes), *m/z* 205 (homohopanes, methylhopanes), *m/z* 217 (steranes), *m/z* 218 (5α,14β,17β-steranes), *m/z* 231 (A-ring methylsteranes), and *m/z* 259 (diasteranes). All saturated hydrocarbon GC-MS parameters were calculated using peak areas.

3.5 SOURCE ROCK DISTRIBUTION AND MATURITY

3.5.1 Eromanga Basin

3.5.1.1 Poolowanna Formation

Western sector

The fluvial Poolowanna Formation is the basal unit of the Eromanga Basin and is its first important potential source rock. Rock-Eval data for the western sector are plotted in Figure 3.3a. As the samples analysed are predominantly coals and carbonaceous shales or siltstones, source richness is generally very high. For example, for the Poolowanna-1, -2 and -3 wells in the Poolowanna Trough, total organic carbon (TOC) ranges from 5.1 to 42.1%. Potential yield (S_1 + S_2) ranges from 11 to 160 kg hydrocarbons per tonne, indicating good to excellent source richness.

Kerogen composition for the Poolowanna samples ranges from Type III (gas-prone) to Type II (oil-prone). Although there is considerable variability, a total of 5 samples out of the 35 analysed have hydrogen indices (HI) greater than 300 (see Appendix 2 for well locations). These samples are from the Koonchera-1, Poolowanna-1 and Poolowanna-2 wells and represent intervals with good oil-generative potential. Organic petrography (Kagya, 1997) shows that in the Poolowanna

area liptinite ≥ vitrinite > inertinite. Elevated hydrogen indices (in this case characteristic of Type II kerogen) occur when the coals and shaley coals are resinite-enriched (Kagya *et al.*, 1996).

As indicated by measured vitrinite reflectance (R_o) and maturities estimated from T_{max}, the maturity of the Poolowanna Formation in the Poolowanna Trough reaches *ca* 0.9% R_o which corresponds to peak hydrocarbon generation for Type II organic matter. However, where it is intersected by Koonchera-1 on the Birdsville Track, or by Glen Joyce-1 and Miandana-1 in the Pedirka Basin, the Poolowanna Formation is only marginally mature for liquid hydrocarbon generation (0.5–0.6% R_o).

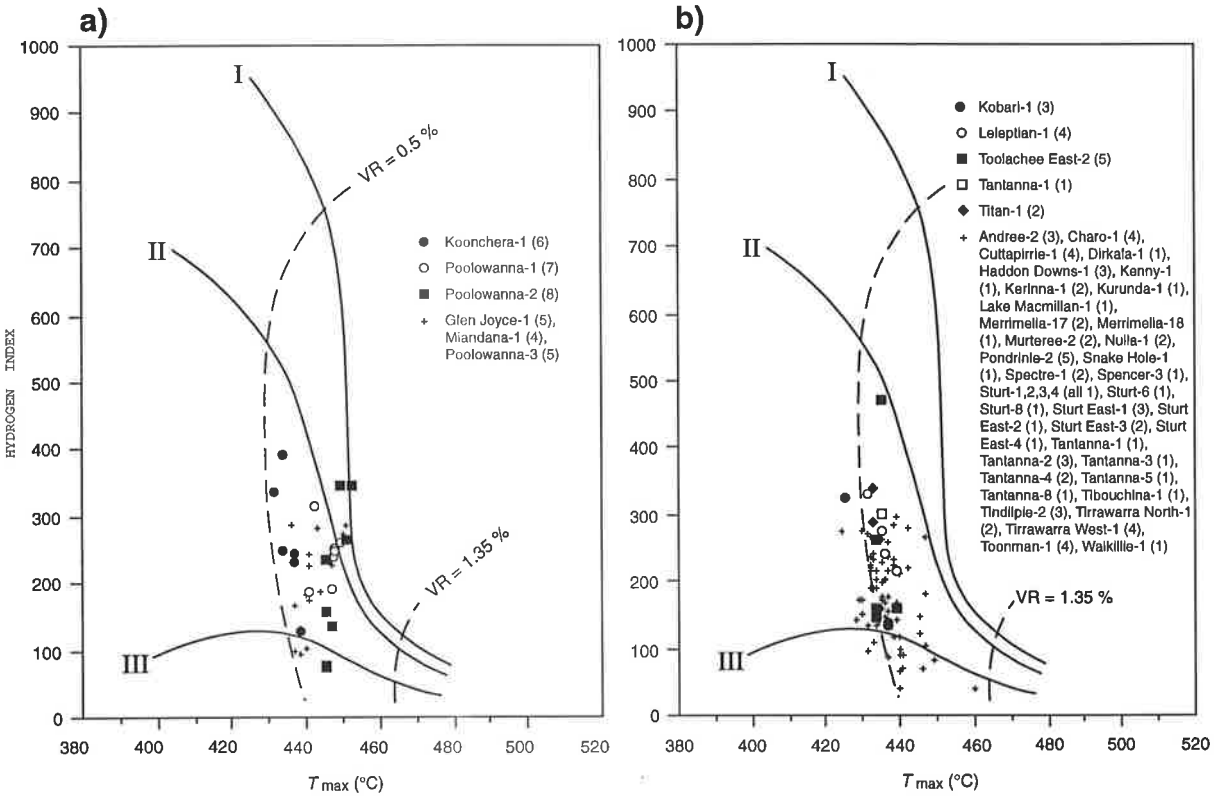


Figure 3.3 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: Poolowanna Formation, South Australia a) western sector; b) eastern sector

Eastern sector

Rock-Eval data from 44 wells (88 samples) in the Cooper sector of the Eromanga Basin are plotted in Figure 3.3b. As expected for such a large database, source richness and quality are highly variable. However, some of the best source rocks are developed at Kobari-1, Leleptian-1, Toolachee East-2, Tantanna-1 and Titan-1 (Fig. 3.3b). When considering data from only these wells, source quality ranges from fair to very good. Eight of the samples from these wells, and ten samples from other wells, have HI values greater than 250 indicating good (Type II/III kerogen) to very good oil source potential (Type II kerogen).

The organic petrography of the Poolowanna Formation in the Sturt/Tantanna area of the southwestern Patchawarra Trough is similar to that described for the Poolowanna Trough, except that in many samples inertinite is dominant over vitrinite suggesting a greater variety of sub-oxic to oxic terrestrial depositional environments (M.L.N. Kagya, University of Adelaide, pers. comm., 1996). In some samples *Botryococcus*-type telalginite is relatively abundant, and is occasionally associated with framboidal pyrite, signifying local anoxic lacustrine conditions (Kagya and McKirdy, 1996; Kagya, 1997).

The Poolowanna Formation has attained only marginal maturity (0.5–0.6% R_o) in the Sturt/Tantanna area, but is of slightly higher maturity (0.6–0.7% R_o) in the Leleptian and Toolachee East areas.

3.5.1.2 Hutton Sandstone

Source rock data for the Hutton Sandstone in the western and eastern sectors are presented in Figures 3.4a and 3.4b, repectively. Note that data from the western sector are sparse. Despite

low shale/sand ratios, some thin source beds were encountered at 1359.7 and 1362.8 m in Mulapula-1 (TOC = 1.6 and 2.3%; HI = 220 and 273; $R_o \approx 0.5\%$). These are immature and possess fair to good source source richness (TOC = 1.58 & 2.30%; $S_1 + S_2$ = 4 & 7 kg hydrocarbons per tonne) and fair to good source quality (HI = 220 and 273) for liquid hydrocarbon generation.

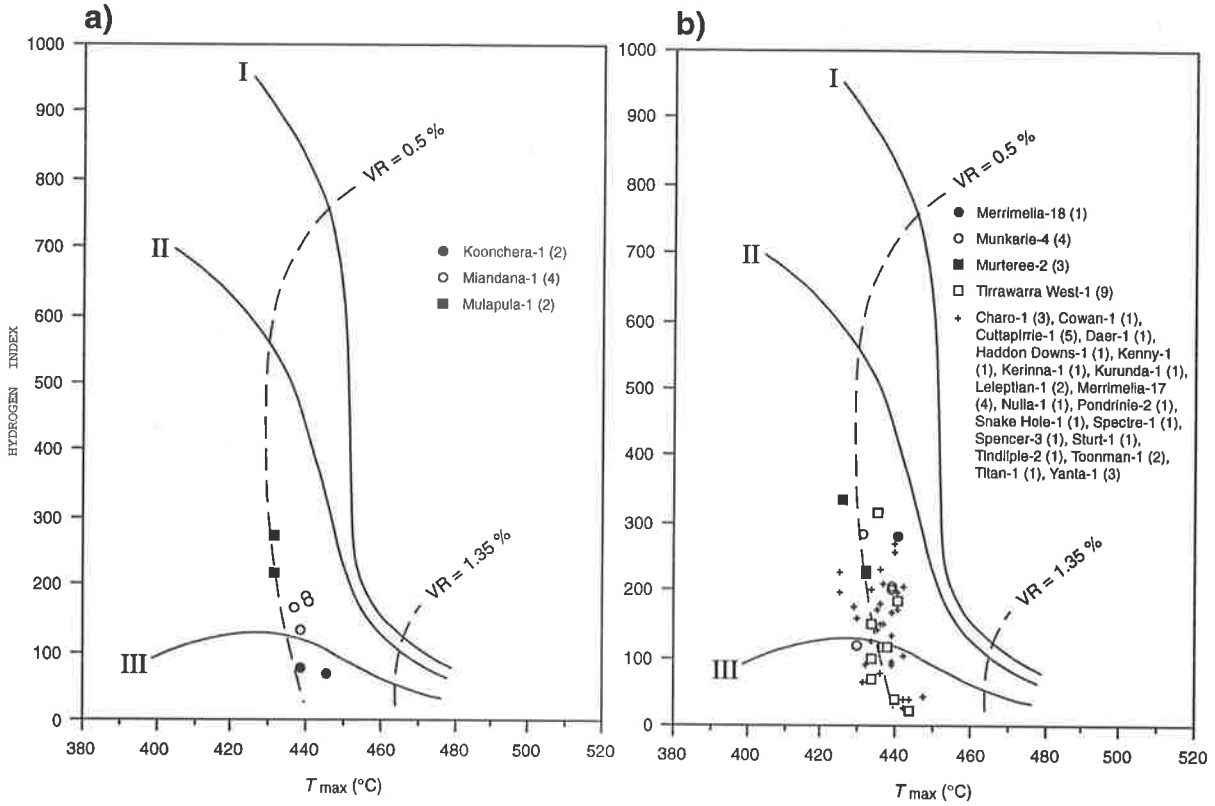


Figure 3.4 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: Hutton Sandstone a) western sector; b) eastern sector

More data are available from the eastern sector where it appears that an immature, moderately oil-prone source facies (Type II/III kerogen) is developed at Murteree-2 on the Murteree Ridge (TOC = 1.2–3.4%; HI = 229–336; $R_o \approx 0.5\%$). A single sample at Merrimelia-18 also displays good oil source potential (TOC = 16.8%; HI = 284 and is initially mature ($R_o \approx 0.65$–0.7%). The source quality of some moderately oil-prone shales at Munkarie-4 and Tirrawarra West-1 (amongst other localities) is diluted by inferior Type III kerogen in other samples from the same Hutton section.

3.5.1.3 Birkhead Formation

Figures 3.5a and 3.5b summarise the source quality and maturity of the Birkhead Formation in the western and eastern sectors, respectively.

Western sector

The Birkhead Formation is arguably the most important potential source rock unit in the western Eromanga Basin (Fig. 3.5a). Rock-Eval parameters for both the Mulapula-1 (McKirdy *et al.*, 1987: Fig. 3.6) and the older Poonarunna-1 data (McKirdy and Watson, 1986: Fig. 3.7a) data sets are broadly consistent with the newly acquired Poonarunna-1 (Michaelsen and McKirdy, 1997: Fig. 3.7b). Source richness is highly variable. In the Pandieburra-1, Poonarunna-1 and Putamurdie-1 wells, where core was selectively sampled for dark argillaceous lithologies, source richness is generally high but ranges from fair to excellent (TOC = 0.84–19.7%; S_1+S_2 = 1.43–97.64 kg hydrocarbons/tonne; Table 3.3). HI values range from 158 to 561 indicating moderately oil-prone (Type II/III) to highly oil-prone (Type II) kerogen.

The two siltstones from Pandieburra-1 have only poor to moderate organic richness (TOC = 0.84 & 1.01%; $S_1 + S_2$ = 1.43 & 1.66 kg hydrocarbons per tonne: Table 3.3a) and contain gas-prone Type III kerogen (HI = 158 and 165). Under the microscope, vitrinite and liptinite are the most abundant maceral groups, with lesser amounts of inertinite (Table 3.2). The liptinites comprise chiefly sporinite and liptodetrinite. Vitrinite reflectance (R_o = 0.54 and 0.60%) and Rock-Eval pyrolysis-derived maturity estimates (T_{max} = 437 and 438° C: Table 3.3a) concur in

suggesting that these samples are *immature* for liquid hydrocarbon generation, given their Type III kerogen composition (Fig. 3.5a).

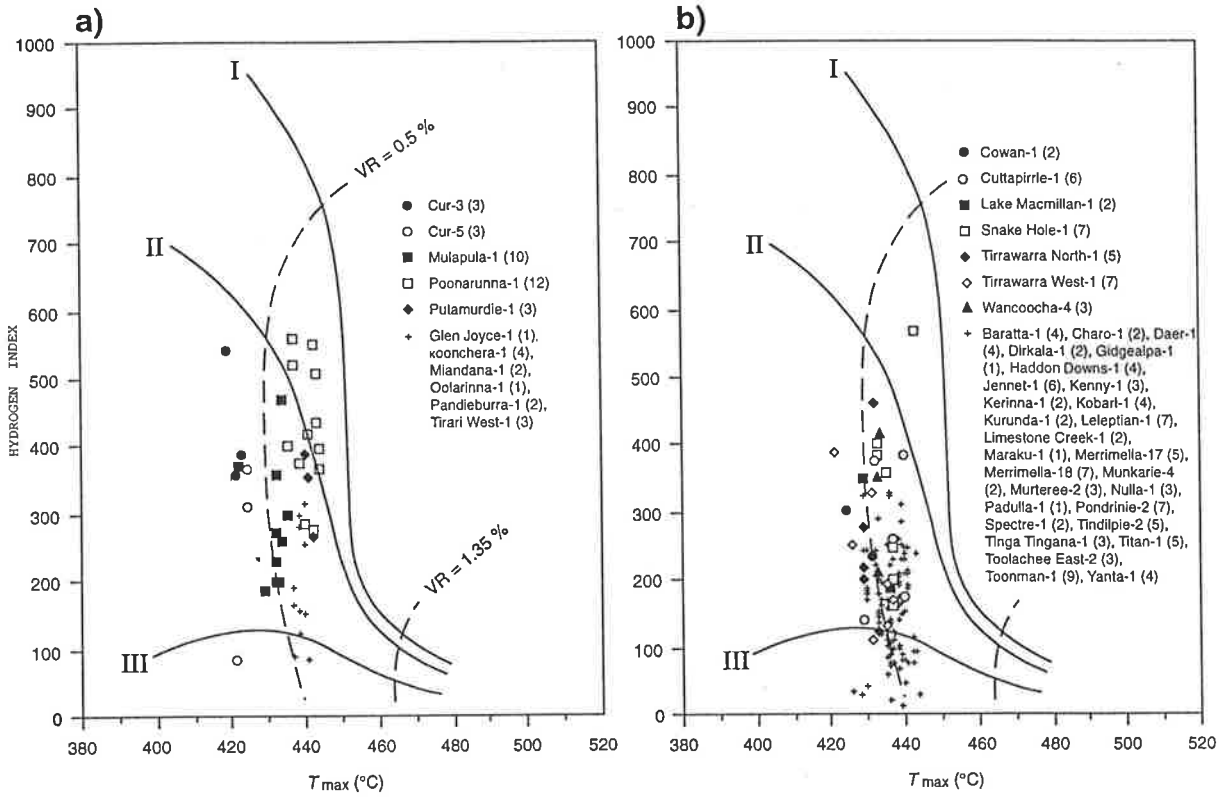


Figure 3.5 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: Birkhead Formation, South Australia a) western sector; b) eastern sector

The Birkhead samples from the Poonarunna-1 and Putamurdie-1 wells contain highly oil-prone Type II kerogen (HI = 277–553) for which Rock-Eval T_{max} values (438–444° C) suggest a maturity in the range 0.65–0.85% R_o. Organic richness for these samples ranges from moderate (*e.g.* TOC = 1.11%; $S_1 + S_2$ = 3.44 kg hydrocarbons per tonne: Putamurdie-1, 4785'1") to excellent (*e.g.* TOC = 19.70%; $S_1 + S_2$ = 98 kg hydrocarbons per tonne: Poonarunna-1, 5338'2"). There is a hint of a positive correlation between liptinite content and hydrogen index. For example, the best source rock sample (Poonarunna-1, 5209'3": HI = 553, TOC = 3.56%) from the new data set is exceptionally liptinite-rich and contains abundant cutinite with lesser amounts of sporinite, resinite and minor *Botryococcus*-type telalginite (Table 3.2). The aforementioned maturity estimates conflict with measured vitrinite reflectance (0.38–0.60% R_o), even when excluding the samples where *obvious* R_o suppression is present (see Table 3.2). Therefore, it can be concluded that R_o suppression is likely to occur throughout the sequence at the Poonarunna-1 and Putamurdie-1 localities. In such cases Rock-Eval pyrolysis-derived maturity estimates are preferred over directly measured R_o. Since Type II kerogen enters the oil window ahead of Type III kerogen (Tissot and Welte, 1984: Type II ≈ 0.5% R_o; Type III ≈ 0.7% R_o), it is highly likely that the Birkhead sequence intersected at Poonarunna-1 and Putamurdie-1 is presently an effective oil source. Furthermore, the level of maturity suggested by Rock-Eval pyrolysis indicates that the Birkhead Formation may be at the *peak* of its oil generation at the Poonarunna-1 and Putamurdie-1 localities.

The ten Mulapula-1 samples from the Birkhead Formation display source richness parameters (TOC = 0.89–21.1%; $S_1 + S_2$ = 2–85 kg hydrocarbons/tonne) that are generally lower than those of the three Poonarunna-1 samples (TOC = 2.05–15.2%; $S_1 + S_2$ = 9–87 kg hydrocarbons per tonne). Figure 3.6 summarises the Rock-Eval data from Mulapula-1. Clearly the Birkhead Formation at this locality is more oil-prone than the two thin source beds in the Hutton Sandstone (Section 3.5.1.2). However, it is worth noting that at the Pandieburra-1, Poonarunna-1 localities, the quality of source facies developed within the Namur Sandstone is, on average, similar to that of the Birkhead Formation (Figs 3.7a,b; *cf.* Table 3.3).

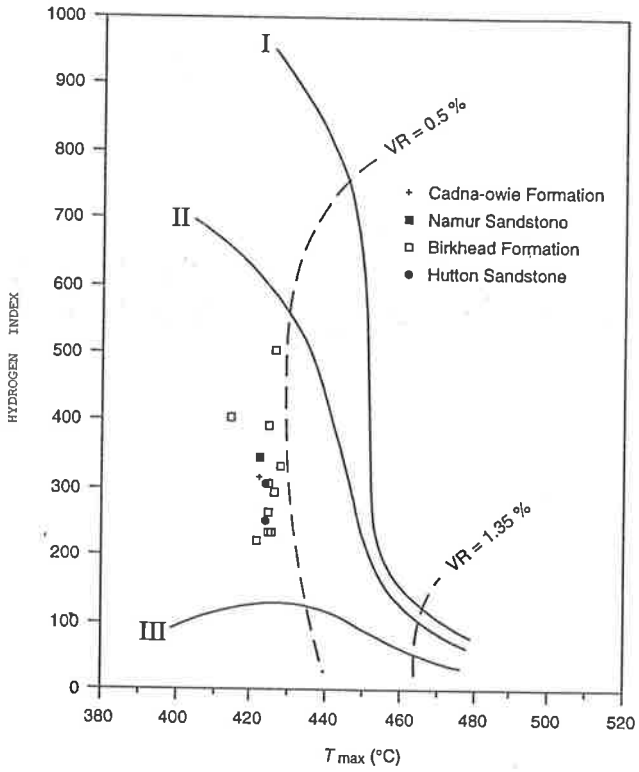


Figure 3.6 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: Mulapula-1 (data from McKirdy *et al.*, 1987)

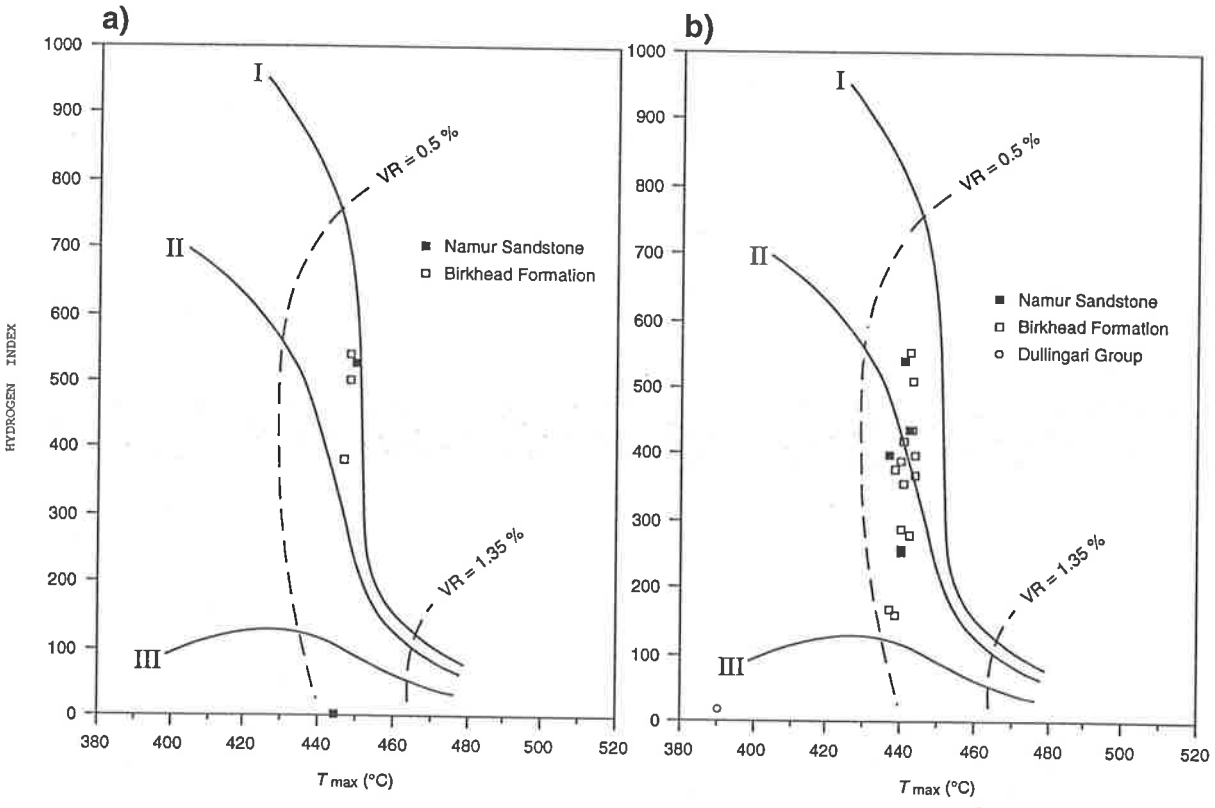


Figure 3.7 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: a) Poonarunna-1 (data from McKirdy and Watson, 1986); b) Pandieburra-1, Poonarunna-1, Putamurdie-1

The maturity of the Birkhead Formation at Mulapula-1 (≈ 0.55% R_o: Michaelsen and McKirdy, 1996a) is lower than that at Poonarunna-1 (≈ 0.65–0.85% R_o). McKirdy and Watson (1986) noted that the Birkhead facies in Poonarunna-1 is atypical because the liptinites include *lamalginite* as well as telalginite (*cf.* Table 2, sample 5256'). In the eastern Eromanga sector, lamalginite is generally absent from the Birkhead Formation (*e.g.* Cook, 1986). McKirdy and Watson (1986) concluded that the presence of lamalginite in the Birkhead Formation "may reflect the isolation of the Poonarunna-1 paludal environment from the main depocentre(s) of the Eromanga Basin during mid-Jurassic time".

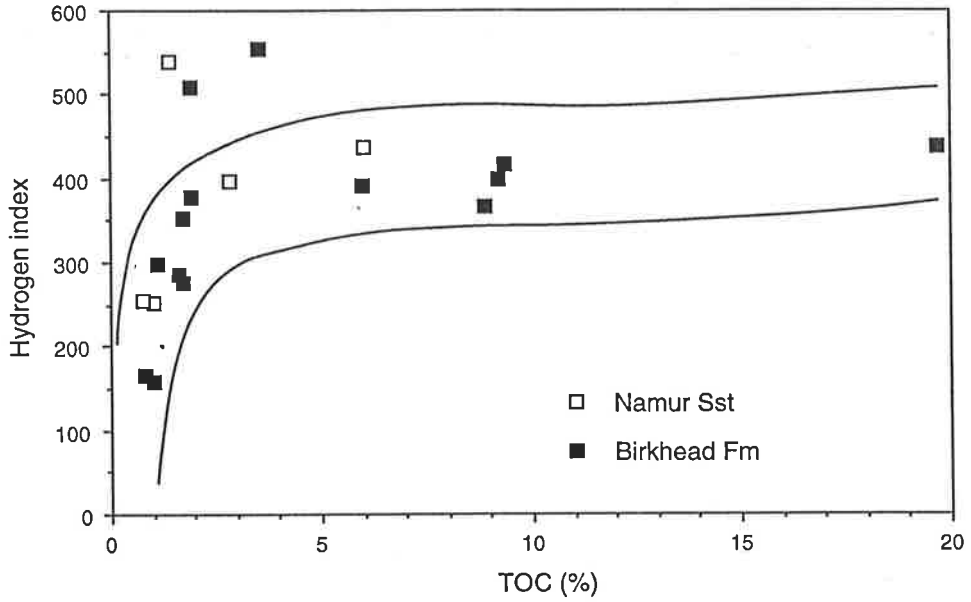


Figure 3.8 TOC *versus* HI cross-plot (Pandieburra-1, Poonarunna-1, Putamurdie-1)

Mineral matrix effect

Figure 3.8 provides an interesting perspective of the new TOC and Rock-Eval data from the Birkhead Formation (and Namur Sandstone: Michaelsen and McKirdy, 1997) described in section 3.5.1.1 and 3.5.1.2. The data are plotted as a TOC *versus* HI cross-plot and fall into one of two fields. The three exceptionally oil-prone samples (HI > 500) have relatively low TOC values of between 1.44 and 3.56%. The more conventional samples with HI values of between 158 and 438 lie along a curve which indicates that there is a broad relationship between source richness (measured by TOC) and source quality (indicated by HI). For samples with TOC values between about 0.5% and 2.5%, there is a corresponding increase in HI with increasing TOC. However, samples with TOC values greater than about 2.5% consistently have hydrogen indices of around 400.

The correlation of HI with TOC for samples containing less than 2.5% TOC can be attributed to the fact that some S_2 pyrolysate is adsorbed by the mineral components of the rock during programmed Rock-Eval pyrolysis, and remains unmeasured by the FID detector (*cf.* Orr, 1983). Therefore, Rock-Eval analysis of samples with low TOC contents provides an unduly pessimistic assessment of source rock quality as measured by hydrogen index. Similar examples of mineral matrix retention of S_2 pyrolysate (and suppression of HI) have been documented in the Eromanga Basin (*e.g.* Murta Formation: Powell *et al.*, 1989). It is conceivable that the three samples with HI values of greater than 500 would have even higher HI values, were it not for their low TOC contents and consequent retention of kerogen pyrolysate on the mineral matrix.

In an attempt to explain the exceptional preservation of oil-prone material (*i.e.* HI ≥ 500) in some samples, various saturated and aromatic hydrocarbon biomarker parameters were plotted against HI (Figures 3.9 and 3.10). With the exception of two (out of the three) ethylcholestane parameters, there is poor correlation with hydrogen index. HI appears to directly correlate with C_{29} ααα 20S/20R and C_{29} βα-diasteranes/(ααα + αββ-steranes). Both these sterane parameters are known to be maturation, as well as facies (source), dependant (Peters and Moldowan, 1993). The significance (or otherwise!) of these correlations is not apparent.

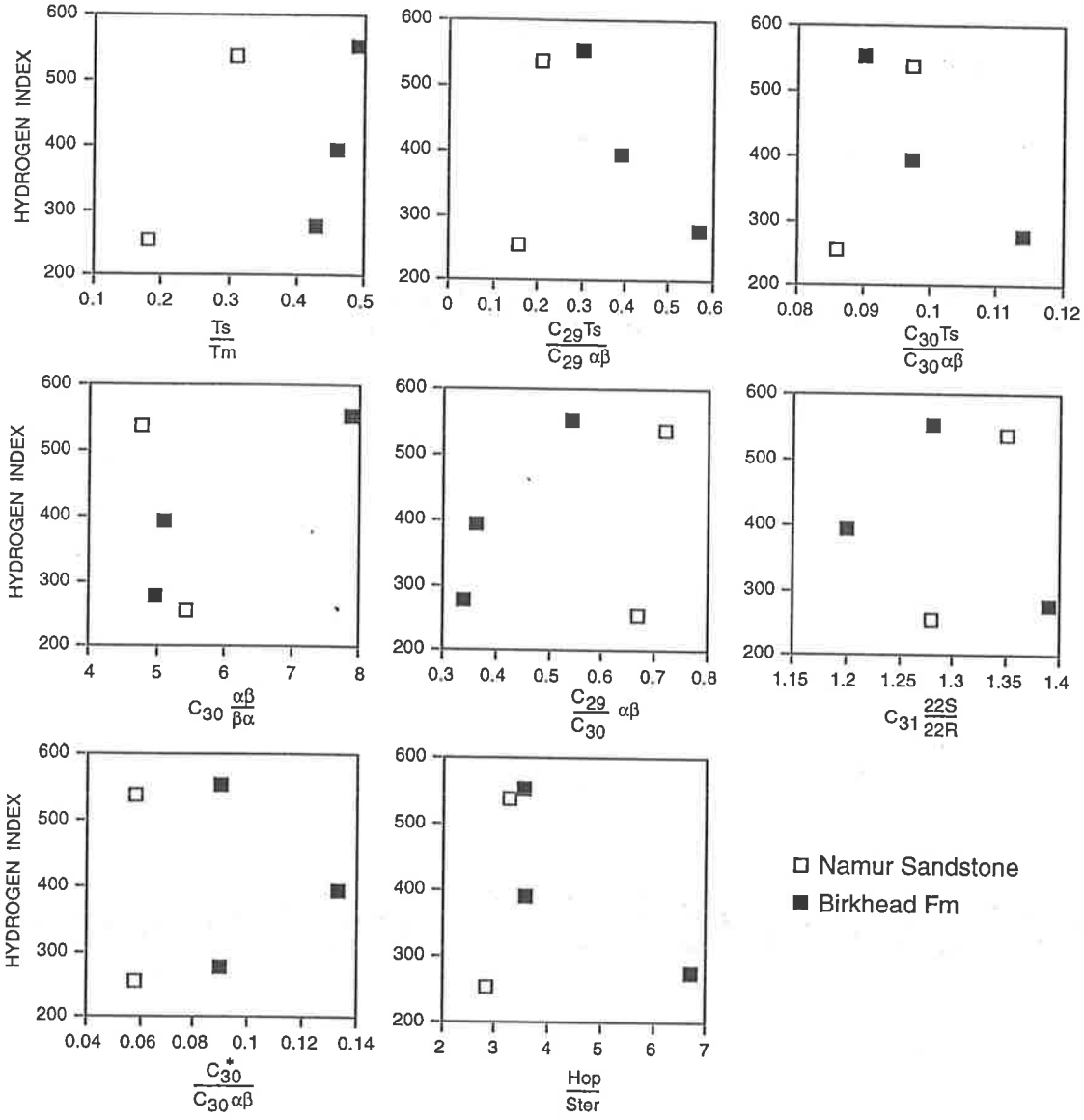


Figure 3.9 Various hopane biomarker parameters plotted against hydrogen index

The Eringa Trough of the far western Eromanga Basin

The Birkhead equivalent (*viz* the Algebuckina Sandstone), at Cur-3 and Cur-5 on the western margin of the Eringa Trough (Pedirka Basin), 500 km northwest of the Poonarunna-1 locality (Fig. 3.1), was sampled and analysed by Alexander E.M. *et al.* (1996) and Staples *et al.* (1995a). Here, coals and shales also contain high quality source facies (Type II/III and Type II kerogen) although at a lower thermal maturity (0.41–0.45% R_o: Staples *et al.*, 1995). Data from the AFMECO Cur-3 and Cur-5, Dalmatia-1 and Mt Hammersley-1 drillholes are included in Table 3.3 and graphically presented in Figure 3.11. The best quality samples from the Cur wells are telovitrinite-rich coals which contain abundant resinite and fluorinite (plant oils). As a whole, HI values (312–542) for the Birkhead Formation equivalent indicate good to excellent source potential for liquid hydrocarbons. By contrast, local potential source rocks of the underlying Purni Formation (Permian, Pedirka Basin) have significantly poorer source quality (HI = 113–359) and are submature for liquid hydrocarbon generation, although possible R_o suppression was noted in some coaly samples from the Purni Formation at Dalmatia-1 and Mt Hammersley-1 (Staples *et al.*, 1995, table 4; Alexander E.M. *et al.*, 1996, appendix 1).

Gas chromatography-mass spectrometry (GC-MS) of their saturated hydrocarbons demonstrates that the Birkhead equivalent source rocks have an enriched microbial biomarker signature (Alexander E.M. *et al.*, 1996). According to Cook (1986), hydrocarbon generation from resinite can commence as early as 0.40 to 0.45% R_o. Powell (1985) also proposed a hydrocarbon generation model wherein resinite-enriched and bacterially-modified source rocks (comprising predominantly vitrinite and inertinite) can begin generating hydrocarbons at 0.45%

R_o. Therefore, it is conceivable that the Birkhead equivalent in this area has entered the oil window. Moreover, it is entirely reasonable, indeed likely, that if the oil-prone facies of the Birkhead Formation equivalent extend basinward, they may be *effective source rocks* in zones of greater maturity within the central Eringa Trough.

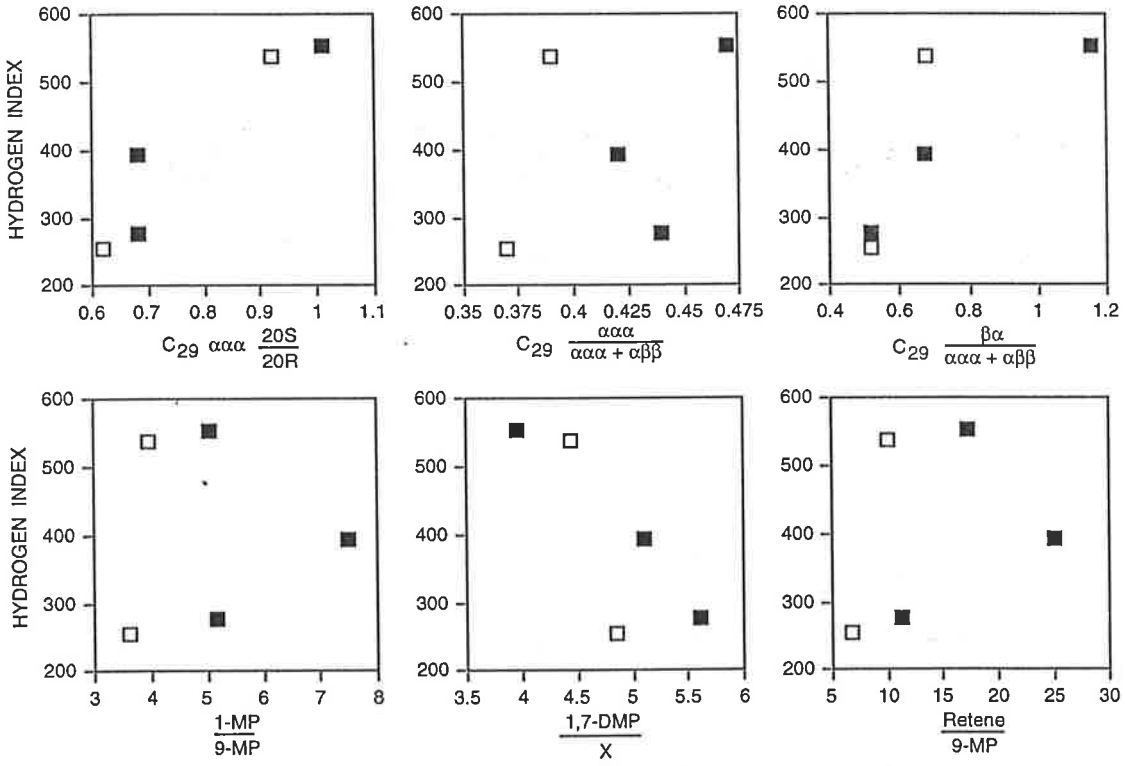


Figure 3.10 Various hopane biomarker parameters plotted against hydrogen index. Key as for Figure 3.9

It is worth noting that TOC and genetic potential are even higher in the Algebuckina Sandstone (the Birkhead equivalent) at Cur-3 and Cur-5 (TOC = 34.3–58.7%; $S_1 + S_2$ = 49–279 kg hydrocarbons/tonne) than in the Birkhead Formation at Pandieburra-1, Poonarunna-1, and Putamurdie-1. However, based on hydrogen indices, it is clear that the best petroleum source rocks identified in the entire western Eromanga Basin province are developed within the Birkhead Formation at the Poonarunna-1 locality. Furthermore, the Birkhead Formation at Poonarunna-1 appears to be the most mature source facies penetrated so far by the drill.

In summary, 30 of the 33 Birkhead Formation samples (including Birkhead equivalent) from Cur-3, Cur-5, Mulapula-1, Poonarunna-1 and Putamurdie-1 display good to excellent source quality (HI = 199–553). *The spatial distribution of these wells implies that high quality (Type II) oil source rocks are developed over wide areas of the western Eromanga Basin.* Even samples with lesser generative-potential (*i.e.* those where HI < 200) are notably better than the least oil-prone samples from other Eromanga formations.

Eastern sector

Figure 3.5b summarises the HI and T_{max} data for 135 samples from 31 well localities. Although much of the Birkhead Formation appears favourable for liquid hydrocarbon generation, its source potential is clearly less than in the western Eromanga sector. Of the 135 samples analysed, only 18 (or 13%) have hydrogen indices of 300 or greater (*i.e.* Type II/III or II kerogen). This compares to 52% of samples analysed (23 out of 44) in the western sector. High quality source facies are developed at Cuttapirrie-1, Lake Macmillan-1, Snake Hole-1, Tirrawarra North-1, Tirrawarra West-1 and Wancoocha-4. One sample from Snake Hole-1 has an exceptionally high hydrogen index (HI = 568) characteristic of very oil-prone Type II kerogen. Although these facies contain reasonably high quality source material (Type II/III kerogen), the overall generative-potential is compromised by equal amounts of inferior Type III kerogen in many of the other coals and shales.

3.5.1.4 Adori Sandstone

In both the western and eastern sectors of the Eromanga Basin, the Adori Sandstone is a poor source for liquid hydrocarbons. Only one cuttings sample (2048.3–2057.4 m) from Tindilpie-2

has any noteworthy source potential (TOC = 3.7%; HI = 449; Type II kerogen; $R_o \approx 0.6\%$). Cross-plots of Rock-Eval data for the Adori Sandstone are provided in Figures 3.12.

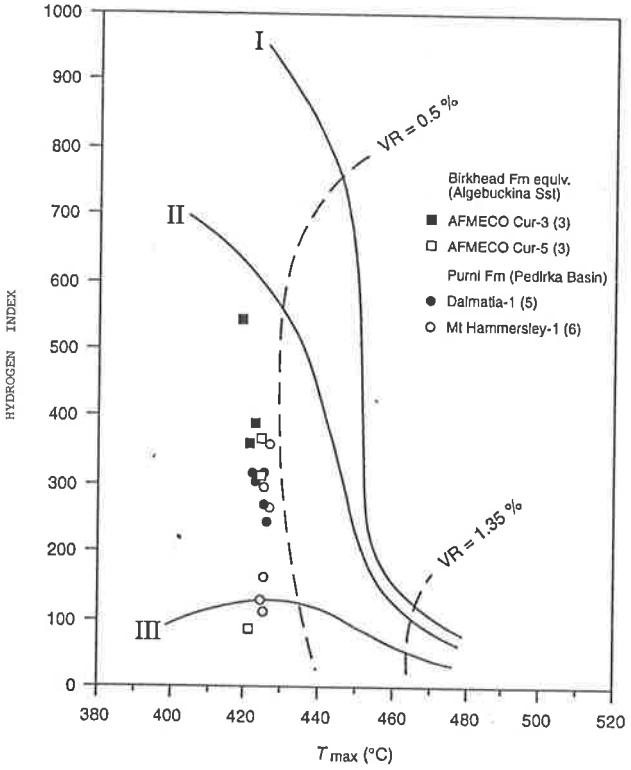


Figure 3.11 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: Eringa Trough (from Alexander E.M. *et al.*, 1996)

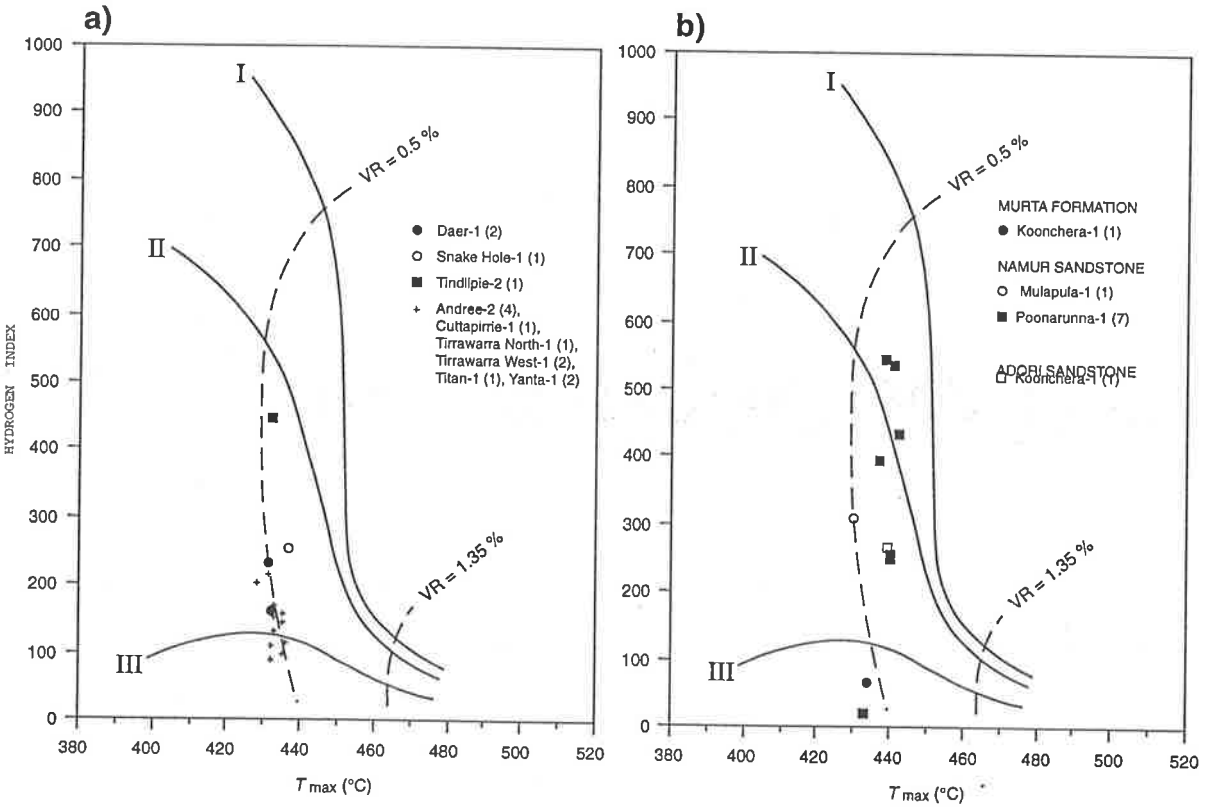


Figure 3.12 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: a) Adori Sandstone, eastern sector; b) Murta Formation/Namur Sandstone/Adori Sandstone, western sector

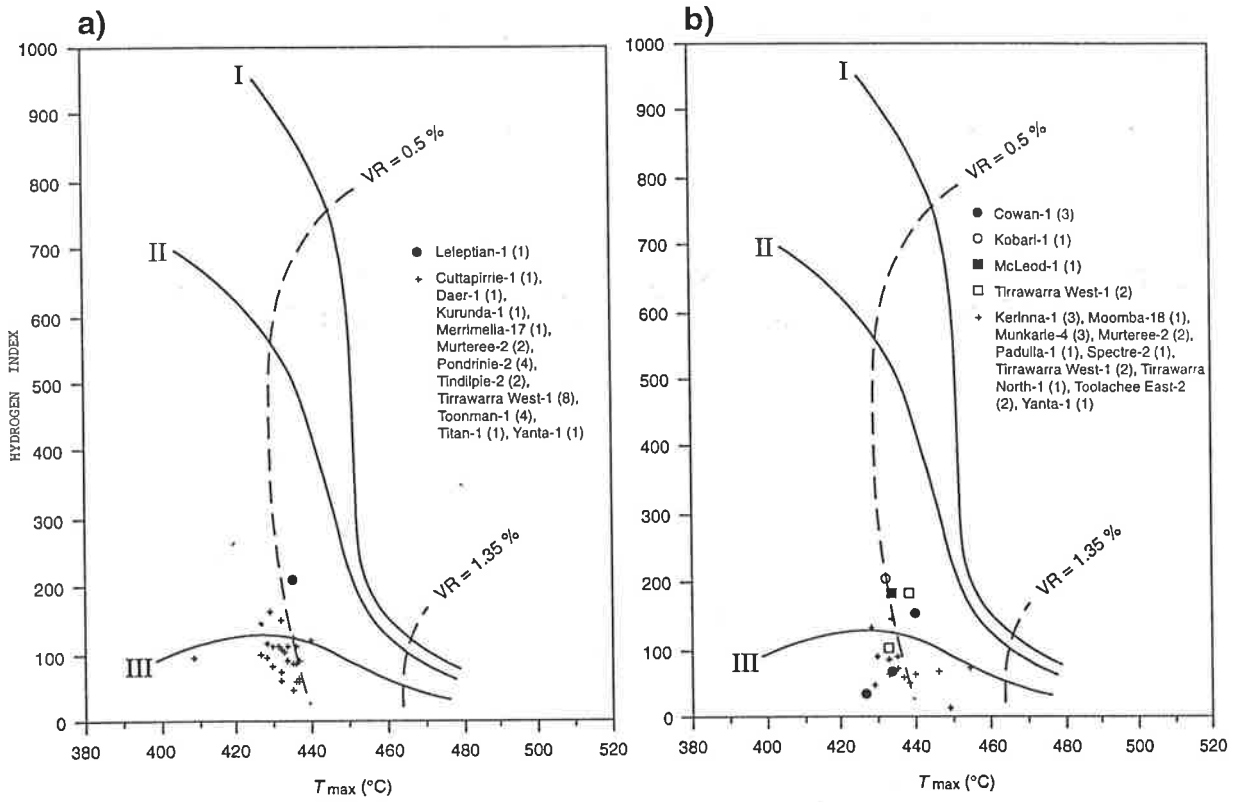


Figure 3.13 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: a) Westbourne Formation, eastern sector; b) Namur Sandstone, eastern sector

3.5.1.5 Westbourne Formation

The Westbourne Formation, which is restricted to the eastern sector of the Eromanga Basin in South Australia, has poor source potential for liquid hydrocarbons (Fig. 3.13a). Most of the 27 rock samples from 12 wells analysed by Rock-Eval pyrolysis plot beneath the Type III kerogen evolution curve, indicating very poor oil potential. Based on one cuttings sample (2020.8–2039.1 m) from Leleptian-1 (TOC = 0.77%; HI = 210; $R_o \approx 0.55\%$), the Westbourne Formation at best exhibits only minor development of a moderately oil-prone source facies.

3.5.1.6 Namur Sandstone

Rock-Eval pyrolysis data for the Namur Sandstone in the western and eastern sectors of the South Australian Eromanga Basin are presented in Figures 3.12b and 3.13b, respectively. In the western sector, based on only eight shale samples from Mulapula-1 and Poonarunna-1, the Namur Sandstone contains, on average, excellent quality Type II/III and oil-prone Type II kerogen. If one excludes an atypically poor sample from Poonarunna-1 (1523.7 m; TOC = 0.36%; HI = 22), the sample suite from Mulapula-1 and Poonarunna-1 displays fair to excellent source richness (TOC = 0.8–6.0%; $S_1 + S_2$ = 7–28 kg hydrocarbons per tonne) and good to excellent source quality (HI = 251–548; mean = 391). Dispersed organic matter in these oil-prone samples comprises mostly vitrinite with subordinate liptinite, and only minor inertinite (Michaelsen and McKirdy, 1996). However, in the exceptionally oil-prone samples with hydrogen indices above 500 (maximum HI = 548), liptinite is the dominant maceral group (*cf.* Table 3.2). The liptinite is chiefly sporinite and sporinite-derived liptodetrinite. Measured vitrinite reflectances suggest a maturity between 0.4 and 0.5% R_o, at variance with T_{max} data which indicate a significantly higher maturity (0.65–0.80% R_o). The T_{max}-derived maturity estimates are probably more accurate, since it is evident from petrographic observations that R_o suppression is likely to have lowered the measured reflectance values (Table 3.2).

Thin shale intervals of the Namur Sandstone in the eastern sector appear to have potential only for gas generation. Hydrogen indices are at best around 200, but most samples plot below the Type II evolution pathway, suggesting the presence of Type III (gas-prone) or Type IV (inert) kerogen.

3.5.1.7 McKinlay Member (basal Murta Formation)

Where developed at the base of the Murta Formation, shaley facies of the McKinlay Member appear to have generally poor source potential. Ten of the 13 samples analysed by Rock-Eval

pyrolysis plot around or below the Type III evolution curve (Fig. 3.14a) which is typical of gas-prone organic matter. Only three samples from Buckinna-1 have any liquids-generating capacity. However, this potential has been significantly downgraded with poorer quality Type III/IV organic matter in other parts of the unit.

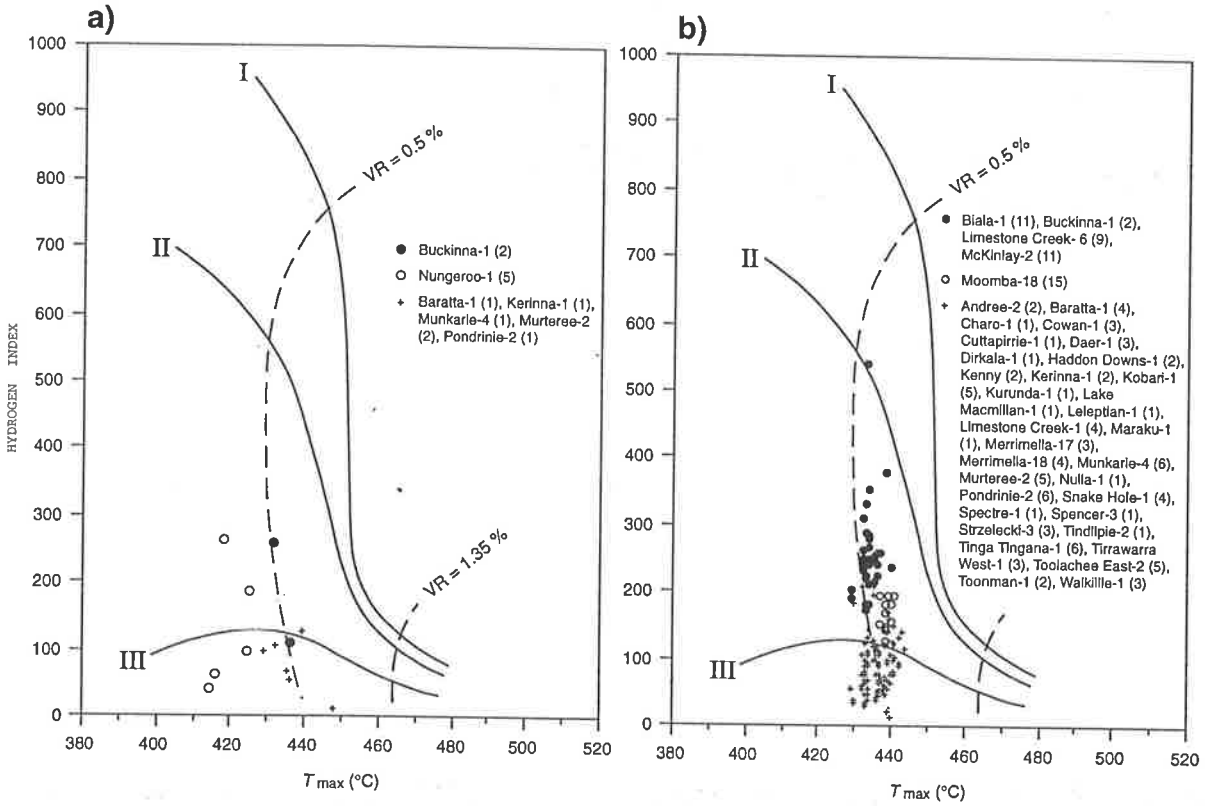


Figure 3.14 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: McKinlay Member a) eastern sector; b) Murta Formation, eastern sector

3.5.1.8 Murta Formation

The lacustrine Murta Formation is the youngest effective source rock unit in the Eromanga Basin. Its hydrocarbon geochemistry (Chapter 5) was studied in detail by Michaelsen and McKirdy (1989) and Powell *et al.* (1989) who concluded that it had potential to generate light paraffinic crude oils, even at maturity levels as low as 0.50–0.55% R_o. Rock-Eval data on 136 samples from 37 wells are summarised in Figure 3.14b. The data fall into three broad groupings, as follows:

1) Thirty-three core samples analysed from the Biala-1, Buckinna-1, Limestone Creek-6 and McKinlay-2 wells on the Murteree Ridge (see Appendix 2) have by far the best source potential (*cf.* Michaelsen and McKirdy, 1989; Chapter 5). Here TOC values in the range 0.8 to 2.6% and potential hydrocarbon yields of 3–12 kg per tonne indicate fair to good source richness. HI values between 175 and 541 are characteristic of Type II/III (oil/gas prone) to Type II (oil prone) organic matter. Optical microscopy reveals that the main macerals present are inertinite (40–80% of DOM) and liptinite (15–60% of DOM). Vitrinite is a minor component of the maceral assemblage. Many of the Murteree Ridge samples contain high concentrations of *Botryococcus*-type telalginite. A positive correlation has been observed between telalginite and elevated hydrogen indices, especially at Limestone Creek-6, where two samples which contained 25% and 26% telalginite (as a percentage of total DOM) possess HI values of 351 and 541, respectively. Intense autofluorescence of the liptinite fraction in the Murteree Ridge samples suggest it has been little altered by oxidation, probably because of relatively rapid burial (cf. Chapter 2; Michaelsen and McKirdy, 1989).

2) Data from fifteen core samples at Moomba-18 in the Nappamerri Trough form a second discrete cluster of points in Figure 3.14b. For all but one sample, TOC values range between 0.6 and 2.1% and genetic potentials are between 1 to 6 kg hydrocarbons/tonne. All but two of the 15 samples analysed have HI values between 125 and 200, and therefore contain essentially gas-prone Type III kerogen. The maceral composition of the Moomba-18 samples is broadly similar to that of the samples from the Murteree Ridge. However, the muted fluorescence of its liptinite

fraction hints that the dispersed organic matter at Moomba was subjected to enough oxidation prior to burial to result in significant loss of oil-generating potential.

3) The bulk of the remaining samples (88 from 32 wells) have HI values less than 200 and thus contain Type III to Type IV kerogen. It is possible that many of these samples have diminished source potential because they comprise cuttings which are mixtures of sandy and argillaceous lithologies. However, it is clear that the Murta Formation has poor source potential outside the Murteree Ridge, although oil-prone facies are developed in the Queensland sector (*cf.* Michaelsen and McKirdy, 1989; Powell *et al.*, 1989; Chapter 5).

The maturity of the Murta Formation along the Murteree Ridge (0.55–0.60% R_o) places it at the incipient stage of hydrocarbon generation for conventional terrestrial organic matter. Powell *et al.* (1989) provided biomarker evidence that the best Murta source facies contains abundant alkanes derived from *bacterial* precursors. Bacterial organic matter is more labile than woody (terrestrial) material. Therefore, given their current level of maturity, it is likely that the shales and siltstones of the Murta Formation along, and immediately adjacent to, the Murteree Ridge have been effective source rocks. Furthermore, Rock-Eval pyrolysis on demineralised samples from Limestone Creek-6 and Biala-1 (Powell *et al.*, 1989; fig. 4) demonstrated that Rock-Eval on powdered whole-rock samples provides an unduly pessimistic assessment of source quality in organically lean (*i.e.* TOC < 2%) rocks like the Murta Formation, due to the adsorption of hydrocarbons by the mineral matrix (*cf.* Orr, 1983). Experiments on demineralised samples (kerogens) by Powell *et al.* (1989) demonstrated that even the Murta shales from the Murteree Ridge have significantly better source potential than is indicated by conventional Rock-Eval pyrolysis. Finally, the intercalation of thin oil-prone source facies with reservoir-quality sandstones has provided a highly efficient mechanism for the drainage of hydrocarbons into carrier and reservoir lithologies.

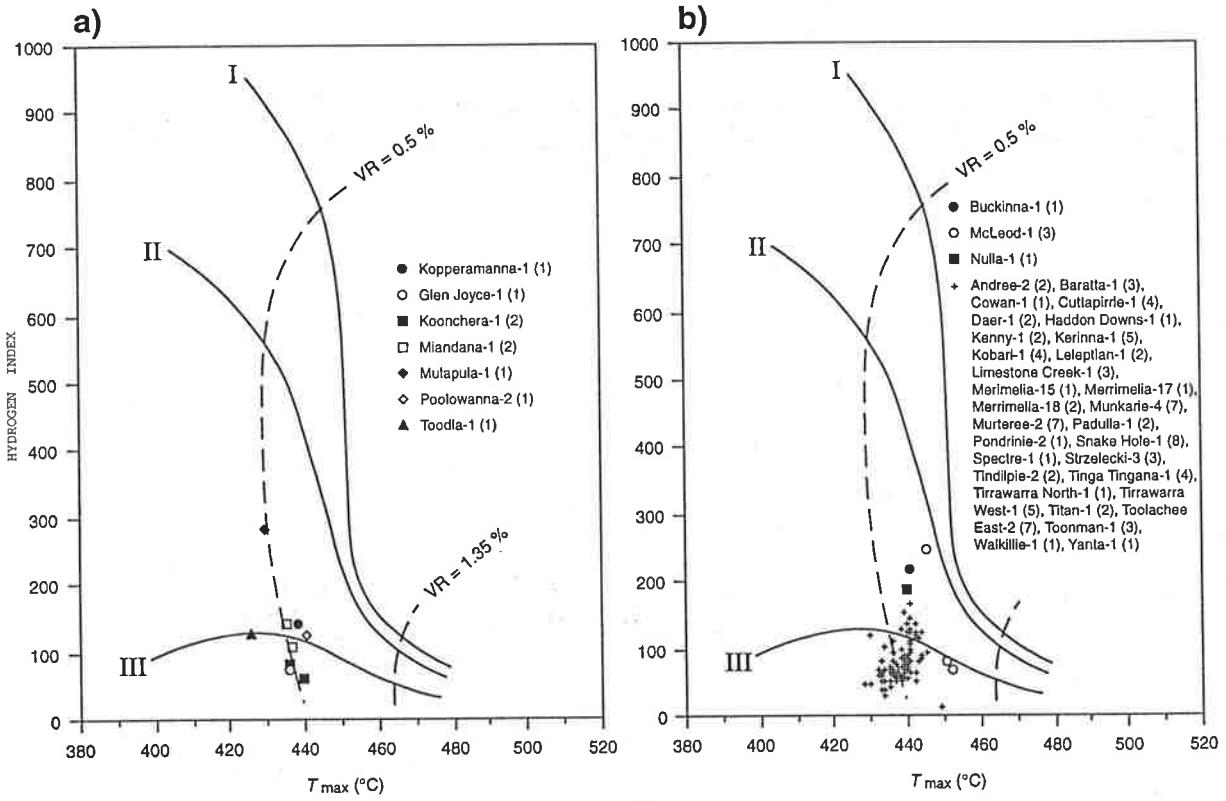


Figure 3.15 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: Cadna-owie Formation a) western sector; b) eastern sector

3.5.1.9 Cadna-owie Formation

Figures 3.15a and 3.15b summarise Rock-Eval data for the Cadna-owie Formation. In the western sector, only one sample from Mulapula-1 stands out as having any oil-source potential. Although this sample is organically lean (TOC = 0.26%), it exhibits fair to good source quality (HI = 280; Type II/III kerogen) but it is submature for liquid hydrocarbon generation ($R_o \leq$ 0.5%). The remaining samples have very poor to poor source potential for liquid hydrocarbons.

In the eastern sector, a similarly pessimistic picture emerges, except perhaps for samples from Buckinna-1, McLeod-1 and Nulla-1 (HI = 180–250).

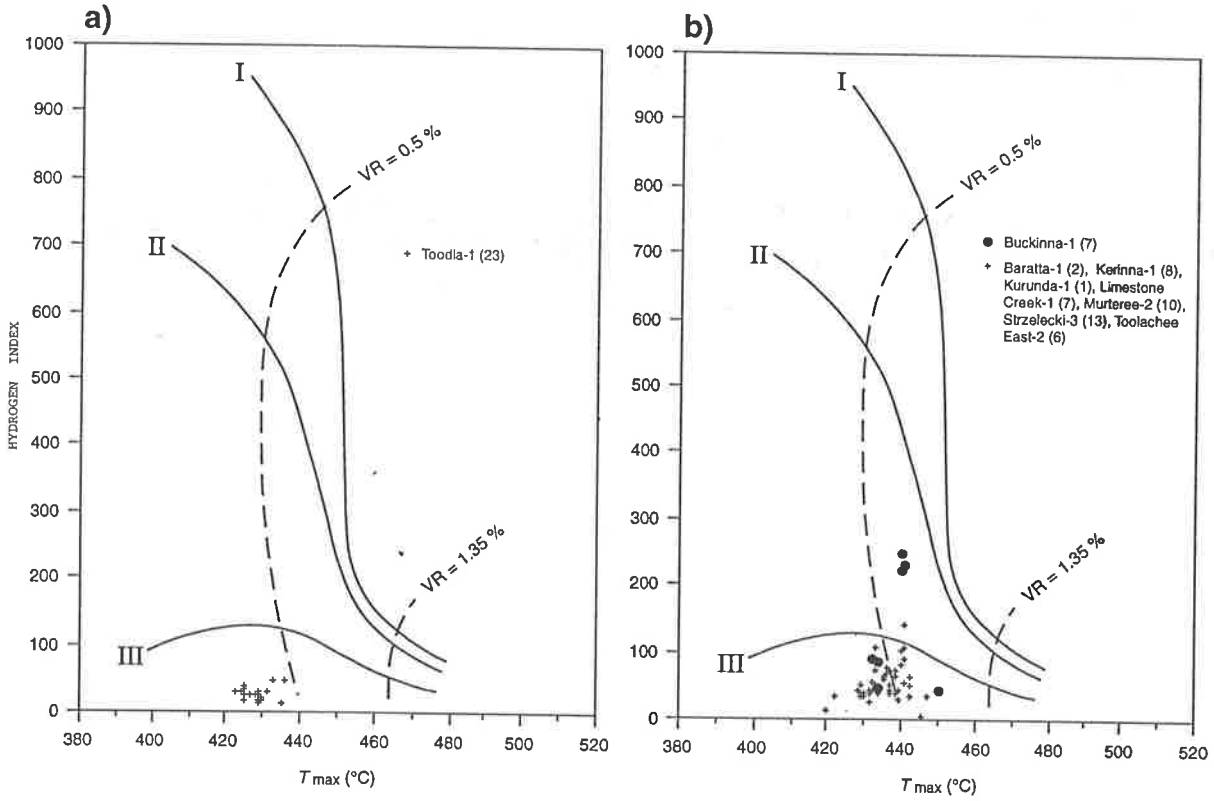


Figure 3.16 Kerogen type and maturity based on Rock-Eval T_{max} and HI data: Bulldog Shale a) western sector; b) eastern sector

3.5.1.10 Bulldog Shale

Western sector

Available data for the Bulldog Shale in the area west of the Birdsville Track Ridge are derived entirely from the Toodla-1 well. Core samples from Toodla-1 were studied intensively by McKirdy *et al.* (1986). TOC values are in the range 0.8 to 1.9% and potential yields < 1 kg hydrocarbons per tonne. Figure 3.16a demonstrates that the Bulldog Shale contains inert (Type IV) kerogen with no liquid hydrocarbon-generative potential. McKirdy *et al.* (1986) reported that the maceral assemblage is dominated by inertinite, although a minority of the samples examined contain mostly liptinite (chiefly phytoplankton and sporinite). Vitrinite is only a minor component in all samples. Suppressed fluorescence of the liptinitic fraction is evidence of partial oxidation and loss of hydrocarbon potential. The thermal immaturity of the Toodla-1 samples is evident from their low T_{max} values (423–436° C) which equate to measured vitrinite reflectances of less than 0.4% R_o.

Eastern sector

The Bulldog Shale in the eastern sector exhibits similarly poor oil-source potential (Fig. 3.16b). Notable exceptions are three samples from Buckinna-1 on the Murteree Ridge which have TOC values of 1.2–1.7% and HI values of 224–248. These samples contain Type II/III kerogen with a modest liquids-generating potential. Petrographic examination of cuttings and sidewall cores in Strzelecki-3 by McKirdy *et al.* (1986) confirmed that the Bulldog Shale contains an abundance of inertinite and subordinate vitrinite and liptinite. The present low maturity of the Bulldog Shale at such localities (< 0.45% R_o) precludes hydrocarbon generation. What appear to be unduly high T_{max} values for the Buckinna samples may be a function of organic matter type and so may not accurately represent the true thermal maturity (*cf.* McKirdy *et al.*, 1986).

3.6 Petroleum Geochemistry of the Far Western Eromanga Basin

3.6.1 Aromatic hydrocarbon biomarkers

Alexander *et al.* (1988) demonstrated that 1,2,5-trimethylnaphthalene (1,2,5-TMN), 1-methylphenanthrene, 1,7-dimethylphenanthrene (1,7-DMP) and retene are important biomarkers for the conifer family Araucariaceae (see Appendix 1a). Araucariacean biomarkers are abundant

in terrestrial rocks and oils of Jurassic age because these conifers were important members of the land plant community during that time. However, because the Araucariaceae did not appear until the Early Jurassic these aromatic compounds are found in low concentrations in rocks and oils of Permian age. Figure 3.17 is a cross-plot which incorporates two source-dependant aromatic biomarker ratios. These parameters, developed and first employed by Alexander *et al.* (1988), are powerful tools which can distinguish between Permian and Jurassic-sourced oil in the Eromanga/Cooper Basin system. Michaelsen *et al.* (1996) used them to establish a Jurassic origin for the oils reservoired in the Poolowanna Formation in the Sturt and Tantanna Fields (*cf.* Chapter 2). Moreover, Michaelsen and McKirdy (1996c) recently showed that Poolowanna source rocks and oils have aromatic biomarker signatures that are *intermediate* between those of the Cooper Basin and those higher in the stratigraphic section (*i.e.* from the Hutton Sandstone, Birkhead Formation and Namur Sandstone: Fig. 3.18). Figure 3.17 indicates that the Birkhead and Namur extracts from Poonarunna-1 and Putamurdie-1 have high 1,7-DMP/X and retene/9-MP values, characteristic of Jurassic source material. When plotted on a 2-MP/1-MP *versus* 1-MP/9-MP cross-plot (Fig. 3.18 inset) and compared to samples from the eastern Eromanga sector (where a large data set has been compiled), it is evident that these samples contain relative concentrations of araucariacean biomarkers far greater than are normally encountered in Eromanga Basin sediments. Thus, it is conceivable that oils derived from Jurassic coals and shales in the western Eromanga Basin could inherit an *atypically strong araucariacean biomarker signature*.

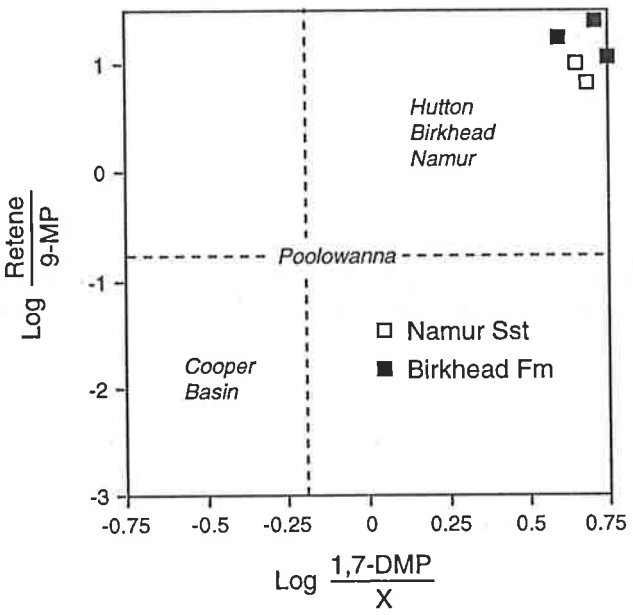


Figure 3.17 Aromatic hydrocarbon cross-plots for source rock extracts

Various maturity estimates based on aromatic hydrocarbons are presented in Table 3.5. However, due to the exceptionally high araucariacean input to these samples (*viz* 1-MP/9-MP = 3.6–7.5), all the R_c values are considered to be highly unreliable, and hence they are not considered further.

3.6.2 Saturated hydrocarbon biomarkers

If maturity estimates based on measured vitrinite reflectance (R_o) and calculated vitrinite reflectance (R_c) are unreliable, what yardstick (other than Rock-Eval pyrolysis) can one use to measure maturation in these potential source rocks?

In an attempt to address this problem, various saturated hydrocarbon biomarker parameters of the Birkhead Formation and Namur Sandstone at Poonarunna-1 and Putamurdie-1 are compared with similar data from the western Cooper Basin database (*cf.* Chapter 5; Figs 3.19 and 3.20). The western Cooper Basin study (Chapter 2) established that the concentration of rearranged hopanes relative to 17α-hopanes was a useful maturity parameter in the Cooper/Eromanga Basin system. In that study the triterpane and sterane chemistries of rocks and oils from the Cooper Basin (Patchawarra and Tirrawarra Formations) were compared with those of samples from the Poolowanna Formation. It was found that the more mature ($R_o \approx$

0.85–1.2%) Cooper Basin samples had elevated T_s/T_m, $C_{29}T_s/17\alpha$-30-norhopane and 17α-diahopane/17α-hopane ratios lighter than those of the less mature ($R_o \approx 0.6$–0.65%) Poolowanna rocks and oils. Figures 3.19a and b show the new data from the western Eromanga sector superimposed onto the fields for the Cooper Basin and the Poolowanna Formation. It appears that the Birkhead and Namur samples from Poonarunna-1 are of intermediate composition, and therefore probably of intermediate maturity (*i.e.* $R_o \approx 0.7$–0.85%). This agrees well with the maturity estimates based on Rock-Eval pyrolysis, and is further confirmation of vitrinite reflectance suppression at that locality.

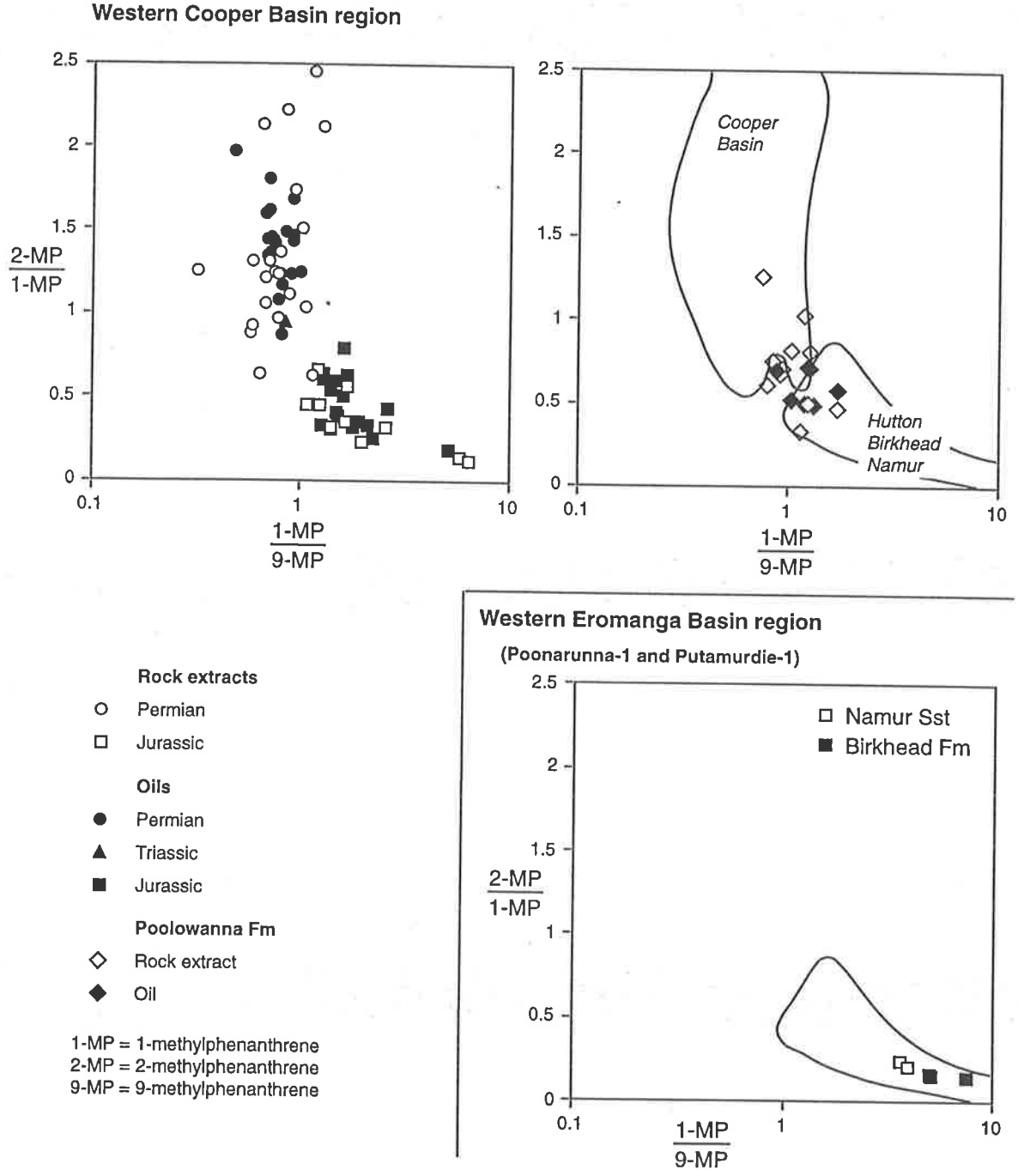


Figure 3.18 1-MP/9-MP *versus* 2-MP/1-MP for rock extracts and oils (Michaelsen and McKirdy, 1996b)

In Chapter 2 the hopane/sterane ratio was shown to be another useful maturity parameter. Cooper Basin rocks and oils have lower hopane/sterane ratios because their thermodynamically less stable 17α-hopanes converted to the 18α-neohopanes and 17α-diahopanes with increasing maturity. However, the less mature Poolowanna samples had significantly higher hopane/sterane ratios and much lower concentrations of rearranged hopanes. Again, by superimposing the Birkhead and Namur (Poonarunna-1) data onto the Cooper Basin and Poolowanna Formation fields (Fig. 3.20), it is evident that the Birkhead Formation and Namur Sandstone at

Poonarunna-1 and Putamurdie-1 have hopane/sterane ratios which are intermediate between those of the Patchawarra Formation and Tirrawarra Sandstone (Cooper Basin) and the Poolowanna Formation (Sturt/Tantanna Fields). This provides yet more evidence that directly measured reflectance of vitrinite in the Birkhead Formation and Namur Sandstone in the western Eromanga Basin (Poonarunna-1 and Putamurdie-1) is unduly low.

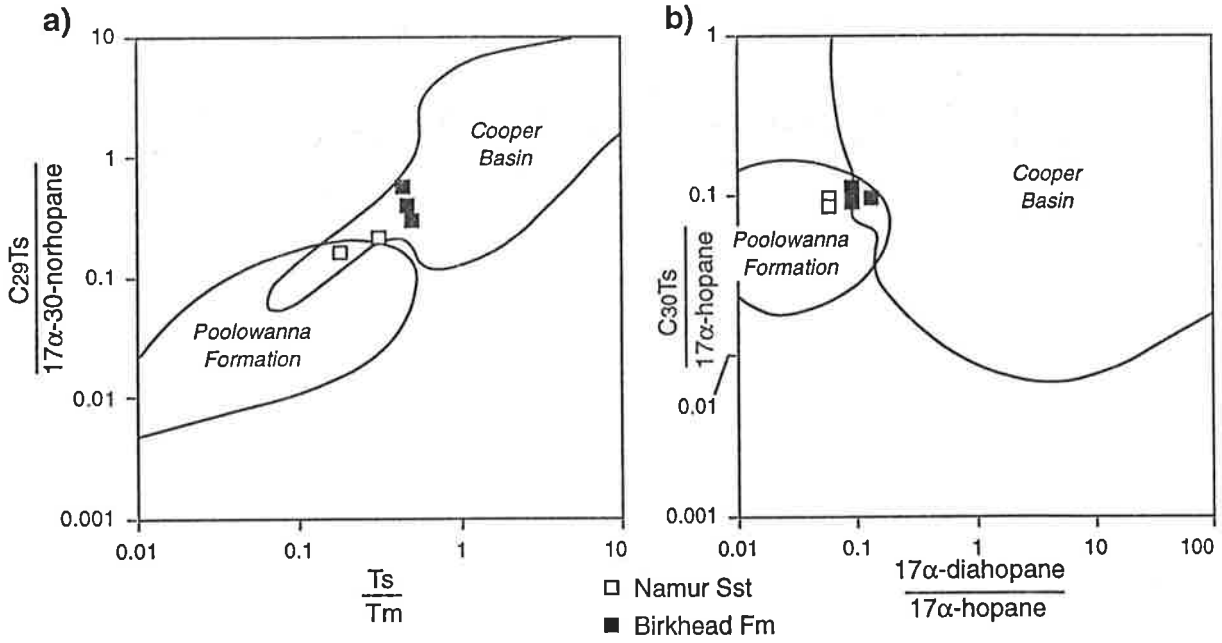


Figure 3.19 Cross-plots of various rearranged hopane parameters

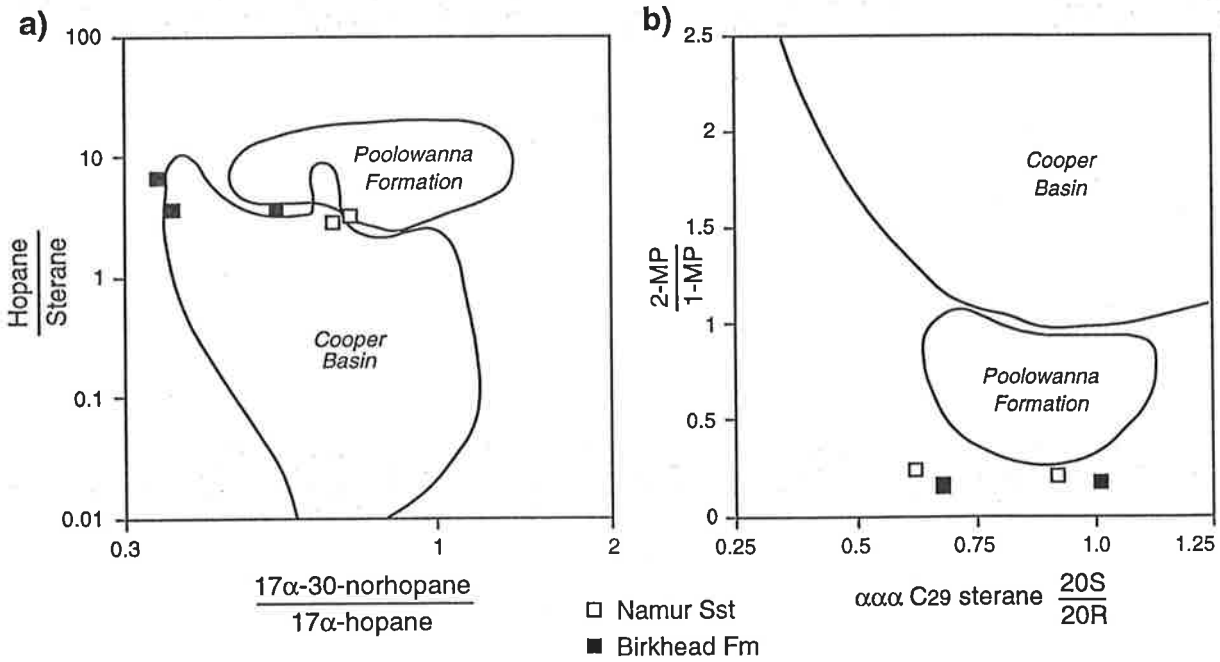


Figure 3.20 Cross-plots of various source and maturity-related biomarker parameters

3.6.3 Unusual triterpenoid biomarkers

3.6.3.1 28,30-bisnorhopane

Staples *et al.* (1995a,b) and Alexander E.M. *et al.* (1996) employed GC-MS-MS (selective reaction monitoring: SRM) to study the triterpane and sterane distributions in Permian and Jurassic rocks of the Eringa Trough area. Alexander E.M. *et al.* (1996) used the ratios 28,30-bisnorhopane/17α-hopane and retene/phenanthrene to geochemically characterise Permian and

Jurassic coals in the Eringa Trough area of the Pedirka and Eromanga Basins. Figure 3.21 summarises their data. All the Permian samples (n = 7) have lower retene/phenanthrene ratios than those of the Jurassic samples (n = 3). Indeed, retene is particularly abundant in the Birkhead equivalent coals. This is to be expected since retene originates mainly *via* the diagenetic modification of the resin acids of araucariaceaen conifers, plants that evolved during the Early Jurassic (*cf.* Chapter 1; Alexander *et al.*, 1988).

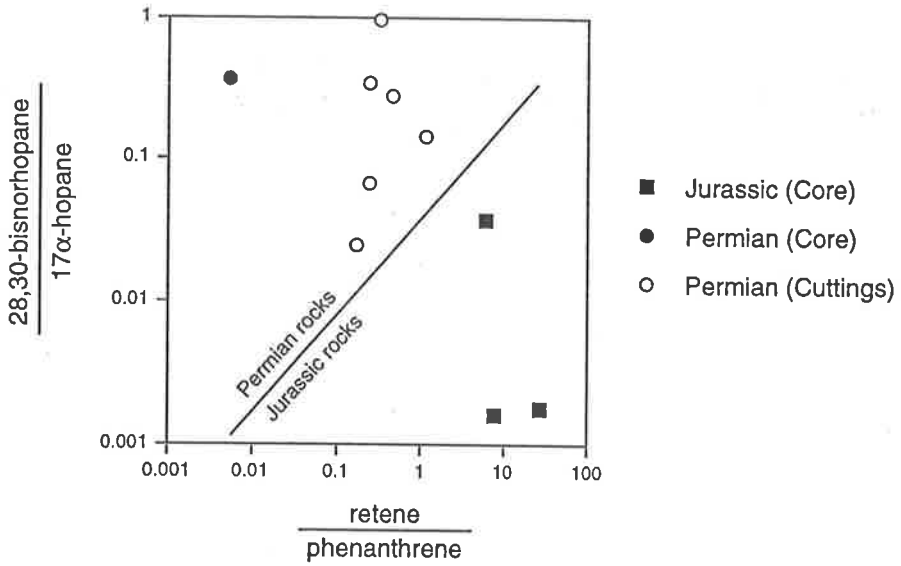


Figure 3.21 Cross-plot on logarithmic axes of retene/phenanthrene *versus* 28,30-bisnorhopane/17α-hopane for Permian (Crown Point and Purni Formations) and Jurassic (Birkhead equivalent of Algebuckina Sandstone) rock extracts, Eringa Trough (after Alexander E.M. *et al.*, 1996)

Of perhaps greater interest is the concentration of the demethylated hopane 28,30-bisnorhopane (28,30-BNH) relative to 17α-hopane. The 28,30-BNH/17α-hopane ratio is typically higher in the Permian Purni and Crown Point Formations than in the Jurassic Birkhead Formation samples. The biomarker 28,30-BNH is derived from anaerobic bacteria and is indicative of rocks deposited under suboxic and anoxic conditions (especially the latter: *cf.* Peters and Moldowan, 1993). It has been identified in rock extracts as old as Neoproterozoic (Imbus and McKirdy, 1993). However, unlike other hopanoids, it is not ubiquitous and is therefore potentially useful in oil-source correlations. In the case of the Eringa Trough, there seems to be no *a priori* reason why the concentration of 28,30-BNH in Permian coals should be higher than in Jurassic coals.

Other biomarker studies have utilised 28,30-BNH to distinguish between Cooper and Eromanga-sourced oils. Jenkins (1989) assigned source affinity on the basis of differences in the concentration of the demethylated hopanes, 25,28,30-trisnorhopane (25,28,30-TNH) and 28,30-BNH, concluding that these two compounds were essentially restricted to rocks of Jurassic age or younger, and their genetically related crude oils. However, this premise is flawed because 28,30-BNH and 25,28,30-TNH (± 25,28,30-trisnormoretane) occur in high abundance in older coal-bearing sequences, for example, in Triassic rocks of the Mungaroo Formation, Northern Carnarvon Basin, Western Australia (*cf.* Noble *et al.*, 1985; Peters and Moldowan, 1993; Michaelsen and McKirdy, 1993). The conclusions of Jenkins (1989) are at odds with the findings of Staples *et al.* (1995) and Alexander E.M. *et al.* (1996) and with the experience of other laboratories in Australia (*e.g.* Geotech Pty Ltd, AGSO: C.J. Boreham, AGSO, pers. comm., 1997).

Based on the limited number of samples from Alexander E.M. *et al.*'s (1996) Eringa Trough study, it appears that the observed variation in 28,30-BNH content could be readily exploited in future oil-source rock correlation studies of the western Eromanga Basin.

3.6.3.2 C_{29} fernane

An unusual feature of the terpane fragmentograms of the Early Permian Crown Point, Stuart Range and Purni Formation is a C_{29} triterpane (labelled X) in Alexander *et al.*'s figure 10 (Appendix 4) that elutes just prior to 17β,21β-30-norhopane. Recently, Paull *et al.* (1998) tentatively identified this compound as C_{29} fernane and demonstrated that it is a biomarker for

the fossil pteridosperm genus *Dicroidium*, seed ferns which were dominant components of the Gondwanan flora during the Triassic, and possibly also present in the Early Permian. The absence of C_{29} fernane in the Birkhead Formation coals (Alexander E.M. *et al.*, 1996, fig. 3.11), and its conspicuous presence in Permian coals (*ibid.*, fig. 10), suggests a significant pteridosperm input to the Permian rocks of the Eringa Trough. More significantly, the presence or absence of C_{29} fernane may be useful as another discriminator of Permian *versus* Jurassic source affinity.

Clearly both 28,30-bisnorhopane and C_{29} fernane have potential to be used in future oil-source correlations studies in the western Eromanga province. In the event of any new oil discoveries the western Eromanga Basin, these findings offer explorers an alternative means of distinguishing Permian and Jurassic hydrocarbons.

3.7 SYNOPSIS

1. In the western Eromanga Basin, South Australia, the best potential source rocks are developed within the Poolowanna (notably the Poolowanna Trough and the Sturt/Tantanna area of the Patchawarra Trough), Birkhead and Murta Formations (particularly the Murteree Ridge area).

2. Coals and shales of the Birkhead Formation exhibit the greatest hydrocarbon potential (maximum HI = 561). Moreover, the most oil-prone Birkhead facies (containing oil-prone Type II/II to Type II kerogen) are developed *west* of the Birdsville Track Ridge (notably at the Poonarunna-1 locality), rather than where it overlies the southern Cooper Basin. Rock-Eval pyrolysis indicates a thermal maturity of *ca* 0.7–0.85% R_o, suggesting that the Birkhead Formation in some localities may presently be close to the peak of its oil generation phase. However, this is at variance with measured vitrinite reflectance which suggests a significantly lower maturity (< 0.6% R_o).

3. Thin shale intervals developed in the Namur Sandstone at Poonarunna-1 also have considerable oil-generative potential (maximum HI = 548) and, based on Rock-Eval pyrolysis, appear to have maturities in the range 0.65–0.8% R_o. However, measured vitrinite reflectance indicate maturities not exceeding 0.5% R_o.

4. Various saturated biomarker parameters (*viz* T_s/T_m, $C_{29}T_s/17\alpha$-30-norhopane, 17α-diahopane/17α-hopane and hopane/sterane) confirm that the maturities of the Birkhead Formation and Namur Sandstone at Poonarunna-1 and Putamurdie-1 are considerably greater than indicated by measured vitrinite reflectance.

5. It is evident that either T_{max}-derived maturities or petrographically measured R_o (or both) provide erroneous maturation data. If the T_{max}-derived maturity estimates are a more accurate assessment of maturation levels, it follows that significant R_o suppression (of the order of 0.25–0.30%) occurs in both the Birkhead Formation and the Namur Sandstone at Poonarunna-1 and, in the case of the Birkhead Formation, at Putamurdie-1. This finding has important implications for the petroleum prospectivity of the western Eromanga Basin region. It opens up the area for further exploration based on plays which do not require long distance migration from Permian kitchens in the Cooper Basin.

6. The Birkhead Formation is probably even more oil-prone than indicated by conventional Rock-Eval pyrolysis. For organically lean samples (*i.e.* TOC ≤ 2.5–3%), unduly pessimistic assessment of source rock quality is attributable to adsorption of some kerogen pyrolysate by the mineral matrix during Rock-Eval analysis.

7. Exceptional concentrations of the araucariacean biomarkers 1-MP, 1,7-DMP and retene in the Birkhead Formation and Namur Sandstone at Poonarunna-1 and Putamurdie-1 render unusable maturity estimates based on aromatic hydrocarbons (*e.g.* MPI).

8. Two triterpenoid biomarkers, 28,30-bisnorhopane and the compound recently identified as the C_{29} fernane, show promise of being useful in future oil-source correlation studies. In the present study, the C_{29} fernane was only detected in pre-Jurassic rocks.

CHAPTER 4

Comparison of maturity parameters and estimation of vitrinite reflectance suppression in potential hydrocarbon source rocks from the Arckaringa, Pedirka, and western Eromanga Basins by FAMM (fluorescence alteration of multiple macerals)

CHAPTER 4

Comparison of maturity parameters and estimation of vitrinite reflectance suppression in potential hydrocarbon source rocks from the Arckaringa, Pedirka, and western Eromanga Basins by FAMM (fluorescence alteration of multiple macerals)*

* This chapter has been published as a technical report as follows:

Michaelsen B.H., Sherwood N.R., McKirdy D.M., Faiz M.M., Watson B.L. and Wythe S.R. (1997) Estimation of vitrinite reflectance suppression in potential hydrocarbon source rocks from the Arckaringa, Pedirka and western Eromanga Basins by FAMM (fluorescence alteration of multiple macerals): A pilot study. Report for Department of Mines and Energy South Australia (unpublished).

4.1 SUMMARY

FAMM (fluorescence alteration of multiple macerals) in combination with conventional vitrinite reflectance measurements, Rock-Eval-derived T_{max}, and maturity parameters derived from the aromatic fraction of rock extracts was used to demonstrate the widespread occurrence of vitrinite reflectance suppression in Permian, Triassic and Jurassic rocks from the Arckaringa and Pedirka and Eromanga Basins, respectively. The greatest vitrinite reflectance suppression occurs in Jurassic coals from the Birkhead Formation (Eromanga Basin) where suppression of up to 0.66% R_o is recorded. The significance of this finding to petroleum explorationists, especially in the western Eromanga Basin where the sedimentary succession is less deeply buried, cannot be overstated because it greatly improves the prospectivity of areas where source rocks are more shallow-lying and hitherto believed to be immature for hydrocarbon generation.

4.2 INTRODUCTION

The work outlined in this chapter was commissioned as a pilot study project by MESA to determine the extent of vitrinite reflectance (R_o) suppression in potential hydrocarbon source rocks (principally coals) from the Arckaringa, Pedirka and western Eromanga Basins in the northern petroleum province of South Australia. The work was prompted by reports of *possible* vitrinite reflectance suppression (minor) in Permian coals from the Purni Formation (Staples *et al.*, 1995a; Alexander *et al.*, 1996), and *probable* vitrinite reflectance suppression (*ca* 0.25% R_o absolute) from the Birkhead Formation (Jurassic) at Poonarunna-1 and Putamurdie-1 in the western Eromanga Basin (Chapter 3; Michaelsen and McKirdy, 1996b). However, the certainty and usefulness of these observations was limited by lack of a robust geochemical/petrographic yardstick against which to calibrate vitrinite reflectance anomalies. The putative R_o suppression reported from the Birkhead Formation at Poonarunna-1 and Putamurdie-1 was based largely on comparison of measured R_o with T_{max} (Rock-Eval). However, T_{max} is not necessarily an accurate maturity parameter (*cf.* Lo, 1993).

Maturity measurement by FAMM is a relatively new multiparameter technique which was developed by CSIRO's Division of Petroleum Resources (Wilkins *et al.*, 1992, 1995, 1997). It is designed to overcome many of the problems associated with conventional vitrinite reflectance measurements. Because the FAMM technique produces results that are independant of measured vitrinite reflectance, R_o suppression can be quantified more confidently and precisely. This chapter examines selected samples from a suite of rocks originally studied by Staples *et al.* (1995a,b), Michaelsen and McKirdy (1996b) and Ryan (1996), augmented by additional samples from the Arckaringa Basin. It represents the first study using FAMM on rocks from the northern petroleum province of South Australia. In total 23 core and cuttings samples from 11 exploration wells (Fig. 4.1) were analysed by FAMM. The resulting data were combined with conventional R_o, Rock-Eval pyrolysis and aromatic maturity parameters to test for vitrinite reflectance suppression.

4.3 SAMPLE SELECTION AND PREPARATION

With the exception of Gidgealpa-29, the target wells in this study are from the Arckaringa, Pedirka and western Eromanga Basin where the sedimentary succession is relatively shallow-lying. Twenty-three rock samples (13 core and 10 cuttings) were collected from the AFMECO Cur-3 (2 core), AFMECO Cur-5 (2 core), Comalco 1069-01 (1 cuttings), Comalco 1069-02 (1 cuttings), Comalco 1072-01 (2 cuttings), Cootanoorina-1 (1 core), Dalmatia-1 (1 cuttings), Gidgealpa-29 (2 core), Manya-2 (1 core), Mt Hammersley-1 (3 cuttings), Pandieburra-1 (2 core), Poonarunna-1 (4 core) and Toodla-1 (1 core). The lithological and stratigraphic details of these samples are provided in Table 4.1. Wherever possible, the darkest (most organic-rich) lithologies were selected. The core samples were scraped and brushed clean to remove surficial contamination. The cuttings samples were meticulously washed and rinsed in distilled water using step-wise ultrasonification to remove drilling mud. The washed cuttings were then hand-picked by selectively removing sand and thereby concentrating the coaly lithofacies.

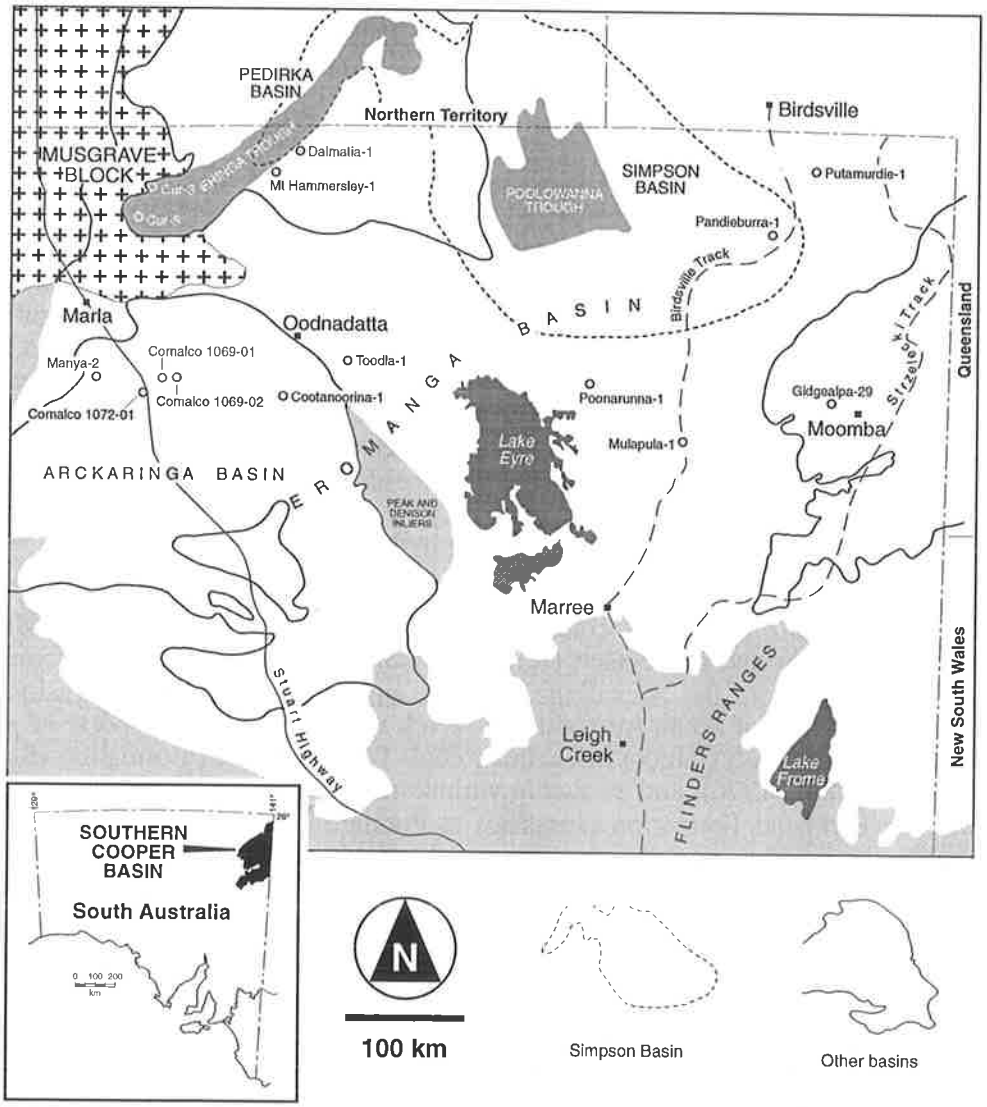


Figure 4.1 Locality map of drillholes sampled for FAMM study

4.4 EXPERIMENTAL

4.4.1 Preparation of polished blocks

The twenty-three samples were prepared as polished blocks by the University of Adelaide's lapidary (housed in the Department of Geology and Geophysics) for analysis by the author. These were made from sub-specimens of core cut perpendicular to bedding or representative (picked) cuttings, mounted in hot-setting Ciba-Geigy resin (40° C) using a 2.5 cm mould. Blocks were polished using a 1 μm diamond polishing paste (suspended in water) on a hardened silk lap. This was followed by polishing using OP-S (silica; Struers) suspension on an

OP-Chem (Struers) cloth. Maceral analyses (Table 4.2) in white and fluorescence-mode incident light were carried out at the University of Adelaide using a Leitz Ortholux II microscope.

As a check on the validity of the author's measured vitrinite reflectance data, some duplicate polished blocks of the Comalco 1069-01, 1069-02, 1072-01, and Cootanoorina-1 samples were prepared by Amdel Ltd, for analysis by Mr Brian Watson. Representative portions of each sample (crushed to -14+35 BSS mesh) were obtained with a sample splitter and then mounted in cold-setting Glasscraft resin using a 2.5 cm diameter mould. Each block was ground flat using diamond impregnated laps and carborundum paper. The surface was then polished with aluminium oxide and finally magnesium oxide.

4.4.2 Vitrinite reflectance

Reflectance measurements by the author were made using Amdel's Leitz Ortholux II Pol BK microscope and a Leitz MPV2 microphotometer under conditions specified by the Standards Association of Australia (1989). The means of random vitrinite (% R_r) reflectance were converted to means of maximum vitrinite reflectance (% R_o) using Kilby's (1991) formula, R_o = 1.083 x R_r (Table 4.3).

Reflectance measurements by Brian Watson (Table 4.3) were made using the same instrument. However, the maxima of vitrinite reflectance (R_o) was measured in accordance with the Standards Association of Australia (1989) method.

4.4.3 FAMM (fluorescence alteration of multiple macerals)

The polished blocks used for FAMM measurements were those prepared by the University of Adelaide. The sections were cleaned with ethanol to remove surficial immersion oil which was applied during the vitrinite reflectance analyses. The blocks were then repolished to ensure removal of any immersion oil which may have penetrated the section. Random vitrinite reflectance measurements (in air) on the vitrinite maceral group were measured as outlined by Standards Association of Australia (1989) with modifications based on Ting (1978). These reflectance measurements were made on the same particles of vitrinite as the FAMM analyses. The FAMM measurements were taken by staff at CSIRO's Sydney Laboratory (North Ryde) using a laser fluorescence microprobe. An Olympus BH2 microscope was used to focus the laser beam on to a 2 x 2 μm spot on the polished surface of the maceral. Each maceral was irradiated for 400 seconds and the fluorescence intensity was measured at 625 nm (orange-red) in air. Fluorescence alteration data were collected from at least ten grains which included examples of each maceral group (*viz* vitrinite, liptinite, inertinite). A reflectance fluorescence alteration diagram incorporating a set of suppression iso-correction curves is shown in Figure 4.2. The resultant data are summarised on fluorescence alteration diagrams (Fig. 4.3–4.6). Suppression corrections and FAMM equivalent R_o values are summarised in Table 4.3.

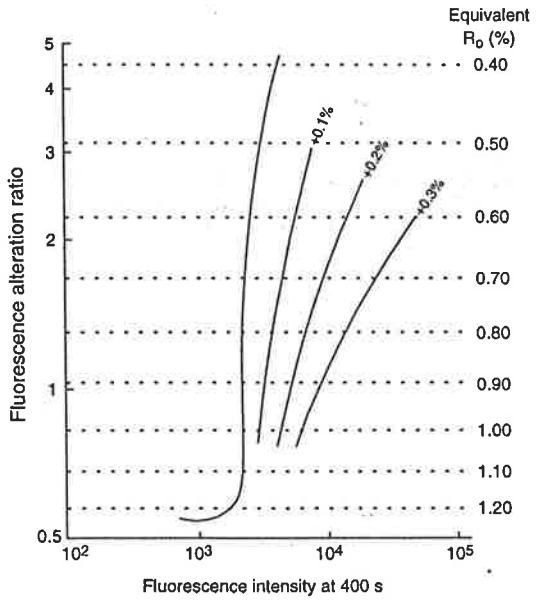


Figure 4.2 400 s fluorescence alteration diagram showing the calibration curve for orthohydrous vitrinites and suppression iso-correlation curves for the Carboniferous-Cretaceous (Sherwood *et al.*, 1997)

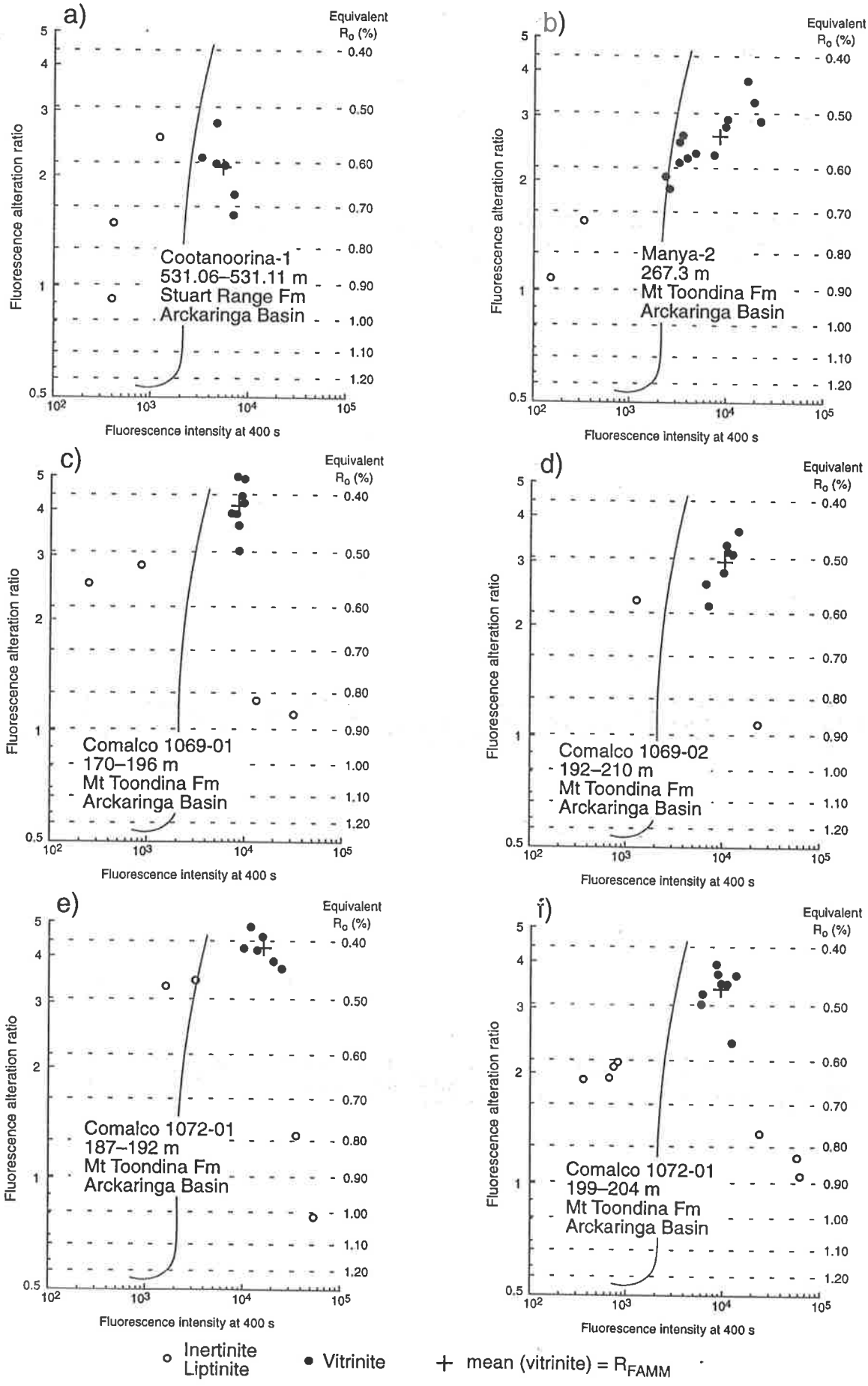


Figure 4.3 Fluorescence alteration diagrams for coals and rocks from Sturt Range (Cootanoorina-1) and Mt Toondina Formations (Manya-2, Comalco 1069-01, 1069-02 and 1072-01)

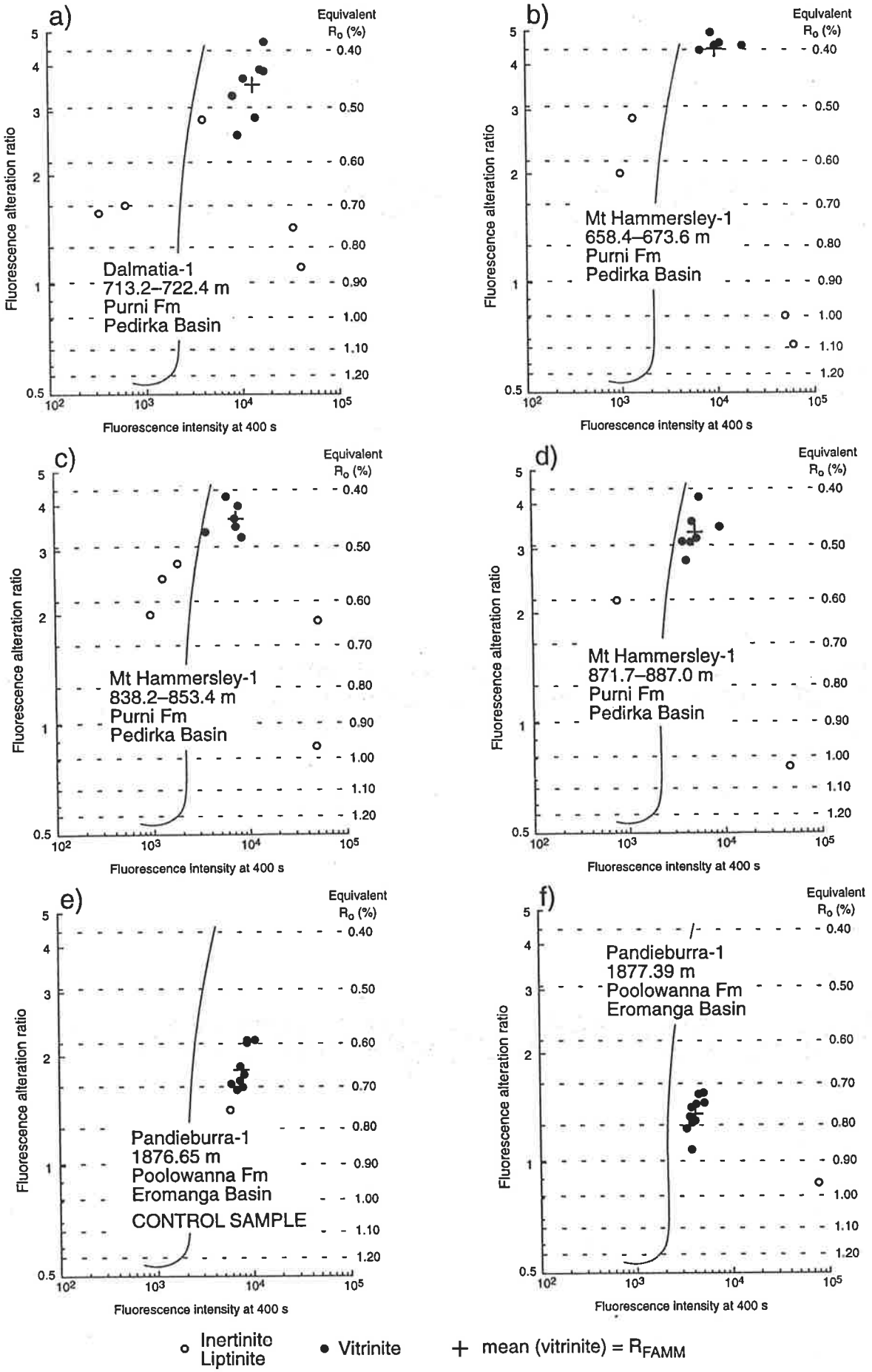


Figure 4.4 Fluorescence alteration diagram for coals and rocks from Purni (Dalmatia-1 and Mt Hammersley-1) and Poolowanna Formations (Pandieburra-1)

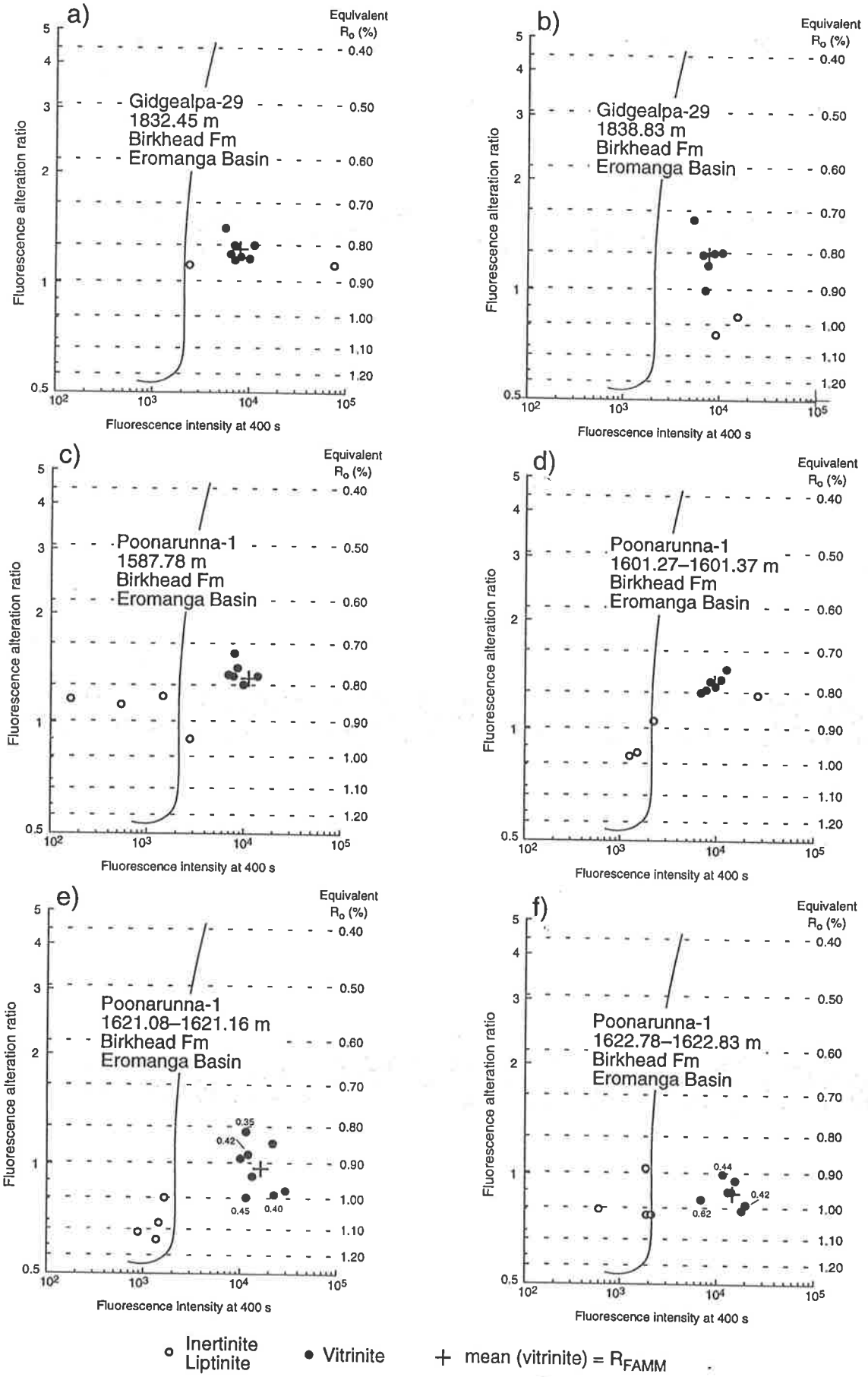


Figure 4.5 Fluorescence alteration diagram for coals and rocks from Birkhead Formation (Gidgealpa-29 and Poonarunna-1)

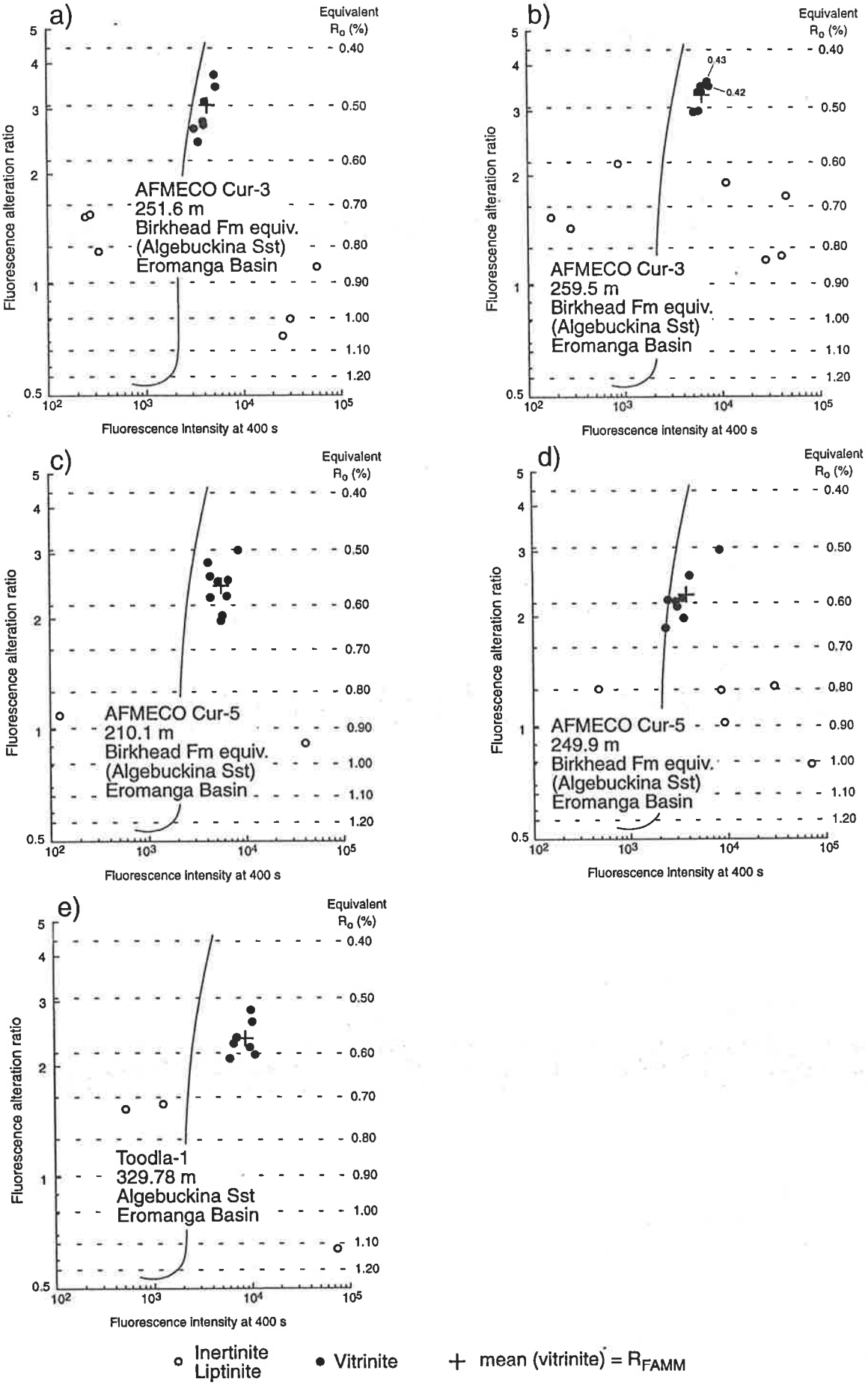


Figure 4.6 Fluorescence alteration diagram for coals and rocks from Algebuckina Sandstone (including Birkhead Formation equivalent; AFMECO Cur-3, Cur-5 and Toodla-1)

4.4.4 Geochemical analyses

4.4.4.1 Sample preparation, screening and extraction

Twenty-two of the rock samples (excluding Manya-2, 267.3 m) were crushed to powder in a Siebtechnik mill, and then analysed for total organic carbon (TOC) using a Leco WR-12 Carbon Determinator, and by Rock-Eval pyrolysis using a Girdel IFP-Fina Mark II operated in Cycle 1 mode (Table 4.4).

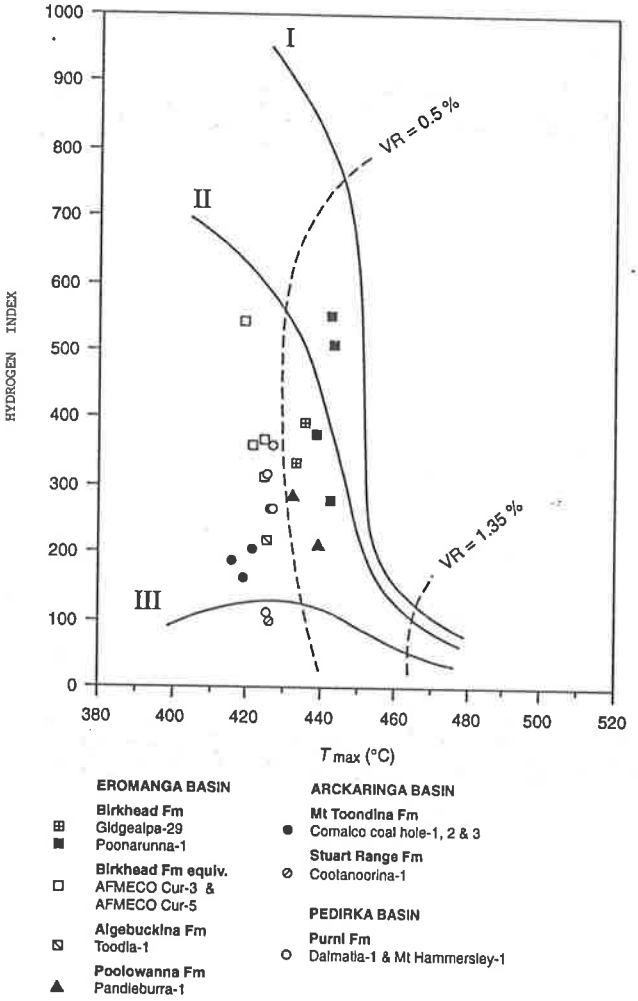


Figure 4.7 Kerogen type and maturity based on Rock-Eval T_{max} and HI data

Twenty-one of the powdered samples (excluding Manya-2, 267.3 m and Toodla-1, 329.78 m) were extracted in Soxhlet apparatus using an azeotropic solvent mixture (CH_2Cl_2:CH_3OH, 93:7). The extract was fractionated by liquid column chromatography on activated silica into saturated hydrocarbons, aromatic hydrocarbons and polar compounds (resins and asphaltenes: Table 4.5).

4.4.4.2 Gas chromatography-mass spectrometry

Gas chromatography-mass spectrometry (GC-MS) on eleven samples was undertaken using a Varian 3400 gas chromatograph interfaced to a Finnigan TSQ 70 mass spectrometer (Australian Wine Research Institute/University of Adelaide). The gas chromatograph was fitted with a 60 m x 0.25 mm i.d. fused silica column (DB-1 or DB-5, 0.25 μm film thickness; J & W Scientific). Helium was used as the carrier gas at an inlet pressure of approximately 23.5 psi. The oven was programmed as follows: 50° C for 2 min, 50° to 120° C at 8° C min^{-1}, 120° to 300° C at 4° C min^{-1} and then held at 300° C for 35 min. The injector was held at 60° C for 3 seconds then ramped to 300° C at 180° C min^{-1}, and held at 300° C for 5 minutes. Mass spectrometer operating parameters included an ionization voltage of 70 eV and a filament current of 200 μA. The photomultiplier voltage was set at 1100 V. Aromatic fractions in CH_2Cl_2 were injected on-column. The mass spectrometer was programmed (multiple ion detection: MID) to monitor *m/z* 128 (naphthalene), *m/z* 141 and 142 (methylnaphthalenes), *m/z* 156 (dimethylnaphthalenes), *m/z* 170 (trimethylnaphthalenes), *m/z* 178 (phenanthrene), *m/z* 192 (methylphenanthrenes), *m/z* 206 (dimethylphenanthrenes), *m/z* 219 (retene), *m/z* 231 and 245 (triaromatic steroids), and *m/z* 253

(monoaromatic steroids). Ten samples were analysed using a Hewlett Packard 5890 GC interfaced to a Hewlett Packard 5972 MSD mass spectrometer (Amdel Ltd, South Melbourne), programmed to detect the same ions as listed above. The temperature program of the column/oven was identical to that described above, except that the temperature of the 2 μm splitless injector was isothermal at 285° C. A response factor of 0.69 was used to normalise the GC-MS data for phenanthrene (in calculating MPI) relative to the calibrated GC response. All aromatic hydrocarbon GC-MS parameters were calculated using peak areas.

4.5 Results and discussion

4.5.1 Source potential and maturity estimated by T_{max} (Rock-Eval pyrolysis)

Kerogen type and maturity for the samples examined are illustrated in Figure 4.7.

4.5.1.1 Permian, Arckaringa Basin

Mt Toondina Formation

These coals samples have TOC values in the range from 37 to 59%. Despite their high liptinite contents (section 4.5.2.1) they are only moderately oil-prone with hydrogen indices ranging between 163 and 203 (Type III to Type III/II kerogen). T_{max} values of 416–426° C suggest a thermal maturity of around 0.4% R_o.

Stuart Range Formation

Based on Rock-Eval pyrolysis, the argillaceous siltstone from Cootanoorina-1 (531.06–531.11 m; TOC = 2.12%) is only gas-prone (HI = 100; Type III kerogen) and appears to be immature for hydrocarbon generation (T_{max} = 426° C; R_o < 0.4%).

4.5.1.2 Permian, Pedirka Basin

Purni Formation

Humic coals at Dalmatia-1 and Mt Hammersley-1 (TOC = 38.5–62.8%: Staples *et al.*, 1995) have hydrogen indices in the range 113 to 359 (Type III to II/III kerogen) indicating fair to very good source rock quality. However, they are apparently immature for hydrocarbon generation (T_{max} = 425–427° C: *ca* R_o = 0.45%).

4.5.1.3 Jurassic, Eromanga Basin

Poolowanna Formation

The control sample (see section 4.5.2.3) at 1876.65 m was chosen because it comprises entirely telocollinite (TOC = 68.0%; HI = 283; T_{max} = 432° C). The non-control sample at 1877.39 m is similar but somewhat less oil-prone (TOC = 52.0%; HI = 211; T_{max} = 439° C). Both coals contain Type II/III kerogen with good liquid hydrocarbon potential. Based on their T_{max} values these coals lie in the early oil window (*ca* R_o = 0.55–0.75%).

Birkhead Formation

Rock-Eval analyses on a Birkhead Formation coal/shale pair from Gidgealpa-29 in the southern Cooper Basin sector indicate that the Birkhead Formation at this locality is highly oil prone (coal: 59% TOC, HI = 332; shale: 2% TOC, HI = 394; Boult *et al.*, 1997) and contains Type II or II/III kerogen. Moreover, siltstones from the same formation some 200 km further west at Poonarunna-1 are exceptionally oil prone (TOC = 1.72–3.56%, HI = 277–553, Type II kerogen) and appear to have a maturity which corresponds to *ca* 0.85% R_o (T_{max} = 438–443° C).

Birkhead Formation equivalent coals from the western eromanga Basin at AFMECO Cur-3 and Cur-5 contain Type II/III (oil/gas-prone) to Type II (oil-prone) kerogen (HI = 312–542). However, they seem to be insufficiently mature (Figure 4.2) for liquid hydrocarbon generation at these two localities on the southwestern flank of the Eringa Trough (T_{max} = 419–424° C: *ca* R_o = 0.40–0.45%).

Algebuckina Sandstone

At Toodla-1 a interbedded siltstone and fine-grained sandstone from the Algebuckina Sandstone (TOC = 2.12%; HI = 219; T_{max} = 425° C) contains Type III/II kerogen which appears immature (*ca* R_o = 0.45%).

4.5.2 Measured vitrinite reflectance and petrographic observations

Vitrinite reflectance data and petrographic observations are presented in Tables 4.2 and 4.3.

4.5.2.1 Permian, Arckaringa Basin

Mt Toondina Formation

The potential source units in the Arckaringa Basin which where intersected by the Comalco coal holes are sapropelic coals which contain high concentrations of land plant spores (cannel coals) and *Botryococcus*-type telalginite (boghead or boghead-cannel coal: Table 4.2). Unlike humic coals which are deposited as peat, the three samples which represent cannel coals (Comalco 1069-01, 170–196 m; Comalco 1069-02, 192–210 m; Comalco 1072-01, 187–192 m) were deposited as detrital gyttjae towards the margins of a swamp lake(s), whereas the very algal-rich boghead-cannel coal (Comalco 1072-01, 199–204 m) was deposited nearer the centre of a lake (*cf.* Stach *et al.*, 1982). There is very good agreement between calibrated R_o (parameter **2**) and measured R_o (parameter **3**). For these cannel coals parameter **2** ranges between 0.37 and 0.44% R_o, and parameter **3** between 0.33 and 0.37% R_o. The Comalco samples comprise sapropelic coals which are non-layered and contain various proportions of detrovitrinite, sporinite, liptodetrinite and bituminite, *Botryococcus*-type telalginite and inertinite.

Another shallow sample from Manya-2 has a similarly low maturity (**2** = 0.41%). It comprises a thin coal stringer within a sandstone and the organic matter appears to be entirely bogen-structured fusinite, pyrofusinite and texto-ulminite.

Stuart Range Formation

There is a significant difference between parameters **2** (R_o = 0.49%) and **3** (R_o = 0.38%) for the Cootanoorina-1 sample, a sporinite-rich argillaceous siltstone from the Stuart Range Formation. Parameter **3** is considered more reliable because it is based on 31 reflectance measurements (rather than 11 for parameter **2**). Liptinite and inertinite dominate the maceral assemblage and there is minor vitrinite. The major liptinite is sporinite, in association with lesser quantities of *Botryococcus*-type telalginite, cutinite and liptodetrinite.

4.5.2.2 Permian, Pedirka Basin

Purni Formation

The calculated maturities of the humic coals from Mt Hammersley-1 range from 0.33 to 0.37% R_o (parameter **2**). These samples comprise vitrinite (mostly texto-ulminite and eu-ulminite) and minor inertinite and sporinite. A coaly shale from Dalmatia-1 has a similar vitrinite reflectance (**2** = 0.34% R_o). Its maceral assemblage, in order of decreasing abundance, is partly-gelified vitrinite (texto-ulminite, eu-ulminite, densinite and corpogelinite), liptinite (sporinite and resinite) and inertinite (semifusinite and fusinite).

Based on directly measured vitrinite reflectance, all the rock samples from the Arckaringa and Pedirka Basins appear to be submature for hydrocarbon generation.

4.5.2.3 Jurassic, Eromanga Basin

Poolowanna Formation

Two humic coals from the Poolowanna Formation at Pandieburra-1 were included in this study, one of which serves as a control sample. The control sample at 1876.65 m was chosen because it comprises entirely telocollinite without any apparent resinite inclusions. The two samples have vitrinite reflectance values which clearly indicate that they are mature for liquid hydrocarbon generation. The coaly shale (parameter **2** = 0.66%) from 1877.39 m depth comprises predominantly telocollinite and less common eu-ulminite. Minor resinite and sporinite are dispersed throughout the sample. As may be expected, the control sample has a similar measured vitrinite reflectance (**2** = 0.67%).

Birkhead Formation

Organically-lean siltstones from the Birkhead Formation samples at Poonarunna-1 contain DOM dominated by liptinite and vitrinite. The major liptinites are chiefly cutinite and sporinite. Vitrinite reflectance readings for the two uppermost samples from 1601.27 and 1587.78 m (**2** = 0.47% and 0.42%, respectively) are considered reliable. However, measured vitrinite reflectances for the two lowermost samples (1621.08 m and 1622.78 m) are considered unreliable because they are based on insufficient reflectance readings. At Gidgealpa-29 the calibrated R_o of the coal/shale pair suggests it is only marginally mature (**2** = 0.52–0.56%).

Humic coals from the Birkhead Formation equivalent in the AFMECO Cur-3 and Cur-5 wells are poorly layered and comprise mainly texto-ulminite and corpogelinite with abundant oil-prone resinite (± fluorinite), and lesser quantities of sporinite and cutinite. Inertinite is only a minor component. Reflectance measurements (parameter **2**) for these coals indicate a maturity in the range 0.41–0.44% R_o.

Algebuckina Sandstone
A thin (5–7 mm) coal stringer within the Algebuckina Sandstone at Toodla-1 has a measured vitrinite reflectance of only 0.35% and therefore appears to be submature for hydrocarbon generation.

4.5.3 FAMM-derived maturity

Maturities estimated by the FAMM technique are provided as parameter **4** in Table 4.3. Since parameter **4** is the FAMM equivalent *random* vitrinite reflectance, it has been converted to parameter **5** (R_{FAMM}) which is referable to the mean *maximum* vitrinite reflectance (see footnote of Table 4.3). The estimated corrections to measured vitrinite reflectance, based on the iso-correction curves in Figure 4.2, are specified as parameter 6 (Table 4.3).

4.5.3.1 Permian, Arckaringa Basin

Mt Toondina Formation
Coal samples from the Comalco drillholes have R_{FAMM} values of 0.44–0.55% indicating that they are submature to marginally mature for liquid hydrocarbon generation. In these coals maturity corrections based on FAMM range from +0.05 to +0.12% R_o (parameter **6**).

Stuart Range Formation
The siltstone from the Stuart Range Formation at Cootanoorina-1 has an R_{FAMM} value of 0.67% indicating that it is mature for liquid hydrocarbon generation. Its maturity correction based on FAMM is +0.10% R_o.

4.5.3.2 Permian, Pedirka Basin

Purni Formation
The interval between 658 m and 887 m in the Purni Formation at Mt Hammersley-1 has an R_{FAMM} maturity of 0.43–0.52% which suggests that it is submature to very marginally mature for liquid hydrocarbon generation. This interval requires only a minor FAMM correction (+0.05% R_o). A shaley coal from Dalmatia-1 has an R_{FAMM} value of 0.50% and a FAMM correction of +0.10% R_o.

4.5.3.3 Jurassic, Eromanga Basin

Poolowanna Formation
Two closely juxtaposed coals from the Poolowanna Formation at Pandieburra-1 have quite different R_{FAMM} values (control sample: 0.66%, coal at 1877.39 m, 0.77%). However, because the two samples are essentially isometamorphic, at least one (or both) of the maturity estimates must be incorrect. Maturity corrections based on FAMM (parameter **6**) are +0.10 and +0.15% R_o, respectively.

Birkhead Formation
Shales from the Birkhead Formation at Poonarunna-1 have R_{FAMM} values between 0.84 and 1.04% and their R_o corrections based on FAMM are exceptionally high (+0.25% to in excess of +0.30%). The coal and shale from Gidgealpa-29 have the same R_{FAMM} value of 0.88%, although their R_o corrections based on FAMM differ (coal, 1838.83 m, +0.20%; shale, 1832.45 m, +0.25%).

The Birkhead Formation equivalent coals from AFMECO Cur-3 (R_{FAMM} = 0.54–0.51%) and Cur-5 (R_{FAMM} = 0.63–0.65%) have only negligible or modest FAMM corrections (+0.05 to +0.08% R_o).

4.5.4 Maturity determined from aromatic hydrocarbon distributions

Maturity data based on aromatic hydrocarbon distributions are provided in Table 4.6. Calculated vitrinite reflectances maturities (R_c: parameters **1–6**) are derived from MPI, MPR, MPDF and DNR using the calibrations identified in Table 4.6. In the following discussion parameters **3** and **6** are ignored because they are only applicable to very high rank samples (> 0.9% R_o). Moreover, for every sample parameter **4** (MPR-derived) indicates a consistantly higher maturity than parameters **1**, **2** and **5**, and so it too is disregarded.

4.5.4.1 Permian, Arckaringa Basin

Mt Toondina Formation
Coals from the Comalco drillholes have anomalously high R_c values (**1** = 0.72–1.28%, **2** = 0.83–1.31%, **5** = 0.91–1.18%) which are totally at odds with the corresponding R_{FAMM} measurements (Table 4.3).

Stuart Range Formation
The silty shale from Cootanoorina-1 has calculated maturities which indicate it is marginally mature to mature for liquid hydrocarbon generation (**1** = 0.51%, **2** = 0.65%, **5** = 0.69%). These R_c values agree reasonably well with its R_{FAMM} value (0.67%: Table 4.3)

4.5.4.2 Permian, Pedirka Basin
Purni Formation
R_c values for the Purni coals over the intervals sampled in Mt Hammersley-1 (**1** = 0.49–0.61%, **2** = 0.63–0.74%, **5** = 0.55–0.69%) and Dalmatia-1 (**1** = 0.79%, **2** = 0.89%, **5** = 0.71%) display a reasonable internal consistency but are appreciably *higher* than the corresponding R_{FAMM} measurements (Table 4.3).

4.5.4.3 Jurassic, Eromanga Basin
Poolowanna Formation
As would be expected, the two Poolowanna coal samples from Pandieburra-1 have very similar R_c values (control sample: **1** = 0.55%, **2** = 0.68%, **5** = 0.66%; coal at 1877.39 m: **1** = 0.54%, **2** = 0.50%, **5** = 0.66%). In the case of the optically determined reflectance measurements, it is only the R_{FAMM} of the latter coal (*viz* 0.83%) that is aberrant, but in the opposite sense to the Permian coals of the Mt Toondina and Purni Formations.

Birkhead Formation
Siltstones from Poonarunna-1 have uniformly low R_c values (**1** = 0.37–0.42%, **2** = 0.51–0.57%, **5** = 0.24–0.28%). However, only parameters **1** and **2** are realistic. Greater maturities are recorded for the Gidgealpa coal/shale pair (coal: **1** = 0.61%, **2** = 0.74%, **5** = 0.69%; shale: **1** = 0.61%, **2** = 0.65%, **5** = 0.64%). In each case the calculated maturities of these Birkhead samples based on their aromatic hydrocarbon distributions are considerably *lower* than those suggested by their R_{FAMM} measurements (Table 4.3). However, this is not true of the Birkhead equivalent coal from 210.10 m depth in AFMECO Cur-5. Here the R_c values (**1** = 0.71%, **2** = 0.82%, **5** = 1.00%) are in fact *higher* than the R_{FAMM} value (0.65%).

4.5.5 Determination of vitrinite reflectance suppression

Vitrinite reflectance suppression (ΔR_o: Table 4.3, parameter **7**) is defined as the difference between the calibrated vitrinite reflectance in oil (R_o: Table 4.3, parameter **2**) and the FAMM equivalent maturity (R_{FAMM}, parameter **5**):

$$\Delta R_o \text{ (\% absolute)} = R_{FAMM} \text{ (\%)} - R_o \text{ (\%)}$$

The numerical data for parameter **7** (ΔR_o) are calculated using the author's vitrinite reflectance measurements, except for the Cootanoorina-1 data where the average of Watson's measurements (Table 4.3, parameter **3**) is considered more reliable. Vitrinite reflectance suppression appears to be a feature of all 23 samples.

4.5.5.1 Permian, Arckaringa Basin
Mt Toondina Formation
Vitrinite reflectance suppression in the Mt Toondina Formation coals from the Comalco drillholes varies between 0.04 and 0.18% absolute (mean = 0.09%).

Stuart Range Formation
The reflectance of vitrinite in siltstone from the Stuart Range Formation at Cootanoorinna-1 is suppressed by 0.18% absolute.

4.5.5.2 Permian, Pedirka Basin
Purni Formation
Coals from the Purni Formation at Mt Hammersley-1 exhibit vitrinite reflectance suppression of 0.06 to 0.16% absolute (mean = 0.13%). At Dalmatia-1 the suppression is 0.16% absolute.

4.5.5.3 Jurassic, Eromanga Basin
Poolowanna Formation
The coal from 1877.39 m depth in Pandieburra-1 has a vitrinite reflectance suppression of 0.17% absolute. However, 74 cm higher in the sequence, the "control" sample has a suppression of only 0.04% absolute, the lowest recorded in this study.

Birkhead Formation
Vitrinite reflectance in siltstones from the Birkhead Formation at Poonarunna-1 is suppressed by between 0.37 and 0.66% absolute (mean = 0.52%). These are by far the highest readings encountered in the study. The coal/shale pair from Gidgealpa-29 exhibits somewhat lesser but

nonetheless appreciable suppression (coal: **7** = 0.32% absolute; shale: **7** = 0.36% absolute; mean = 0.34%).

The extent of vitrinite reflectance suppression in the Birkhead equivalent coals at the AFMECO Cur-3 and Cur-5 localities is considerably more modest (Cur-3: **7** = 0.07–0.11% absolute, mean = 0.09% absolute; Cur-5: **7** = 0.21–0.24% absolute, mean = 0.09% absolute).

Algebuckina Sandstone
At the Toodla-1 locality, vitrinite reflectance in a thin (5–7 mm) coal stringer within a clean sandstone is suppressed by 0.27% absolute.

In summary, average ΔR_o values (= vitrinite reflectance suppression) for the Permian and Jurassic samples, listed in order of increasing suppression, are:

	Formation	ΔR_o (% absolute)	No. of samples
Permian			
Comalco coal holes	Mt Toondina	0.09	4
Mt Hammersley-1	Purni	0.13	3
Dalmatia-1	Purni	0.16	1
Manya-2	Mt Toondina	0.17	1
Cootanoorina-1	Stuart Range	0.29	1
Jurassic			
Pandieburra-1 (control)	Poolowanna	0.04	1
Cur-3	Birkhead equiv.	0.09	2
Pandieburra-1 (non-control)	Poolowanna	0.17	1
Cur-5	Birkhead equiv.	0.22	2
Toodla-1	Algebuckina	0.27	1
Gidgealpa-29	Birkhead	0.34	2
Poonarunna-1	Birkhead	0.50	4

The extent of suppression (ΔR_o) evident in these coals, shales and siltstones is illustrated in Figure 4.8, which also shows their adjusted (or "true") maturity in relation to the oil generation window. The relationship of (ΔR_o) to R_o and R_{FAMM} is shown in a series of cross-plots (Fig. 4.9).

4.5.6 Cause of vitrinite reflectance suppression

As discussed in Chapter 2, the aromatic hydrocarbons 1,2,5-TMN, 1-MP, 1,7-DMP and retene are diagenetic products of plant-derived acids which have been shown to be highly concentrated in araucariacean resins and exudates (*cf.* Alexander *et al.*, 1988, 1992). Therefore, a simple way of quantifying the input of plant resins to the depositional environment, and their chemical preservation (≈ impregnation of vitrinite), is to measure the concentration of these araucariacean biomarkers relative to similar (but non-biomarker compounds). This can be done by way of the following ratios: (1,2,5-TMN/1,3,6-TMN, 1-MP/9-MP, 1,7-DMP/X and retene/9-MP where X = $\sum$ 1,3-DMN + 3,10-DMN + 2,10-DMN + 2,9-DMN). The values of these ratios for the present suite of samples are given in Table 4.6 and plotted against ΔR_o in Figure 4.10.

4.5.6.1 Permian, Arckaringa Basin

Mt Toondina Formation
Coals from the Comalco drillholes have low relative concentrations of the araucariacean biomarkers (*viz* 1,2,5-TMN/1,3,6-TMN = 0.37–0.79; 1-MP/9-MP = 0.37–0.63; 1,7-DMP/X = 0.32–0.51 and retene/9-MP = 0.84–3.89.

Stuart Range Formation
These ratios are somewhat higher in the siltstone from the Stuart Range Formation at Cootanoorina-1 (1,2,5-TMN/1,3,6-TMN = 1.09, 1-MP/9-MP = 0.85), 1,7-DMP/X = 0.94 and retene/9-MP = 10.78.

4.5.6.2 Permian, Pedirka Basin

Purni Formation
The Permian coals from the Purni Formation at Mt Hammersley-1 have 1,2,5-TMN/1,3,6-TMN (0.30–0.50), 1-MP/9-MP (0.34–0.55), 1,7-DMP/X (0.38–0.65) and retene/9-MP (1.15–3.48) ratios which are broadly similar to those of the Mt Toondina Formation in the Arckaringa Basin.

The Dalmatia-1 coal also has a similar 1-MP/9-MP value (0.48), although in this case no data are available for the other ratios (Table 4.6).

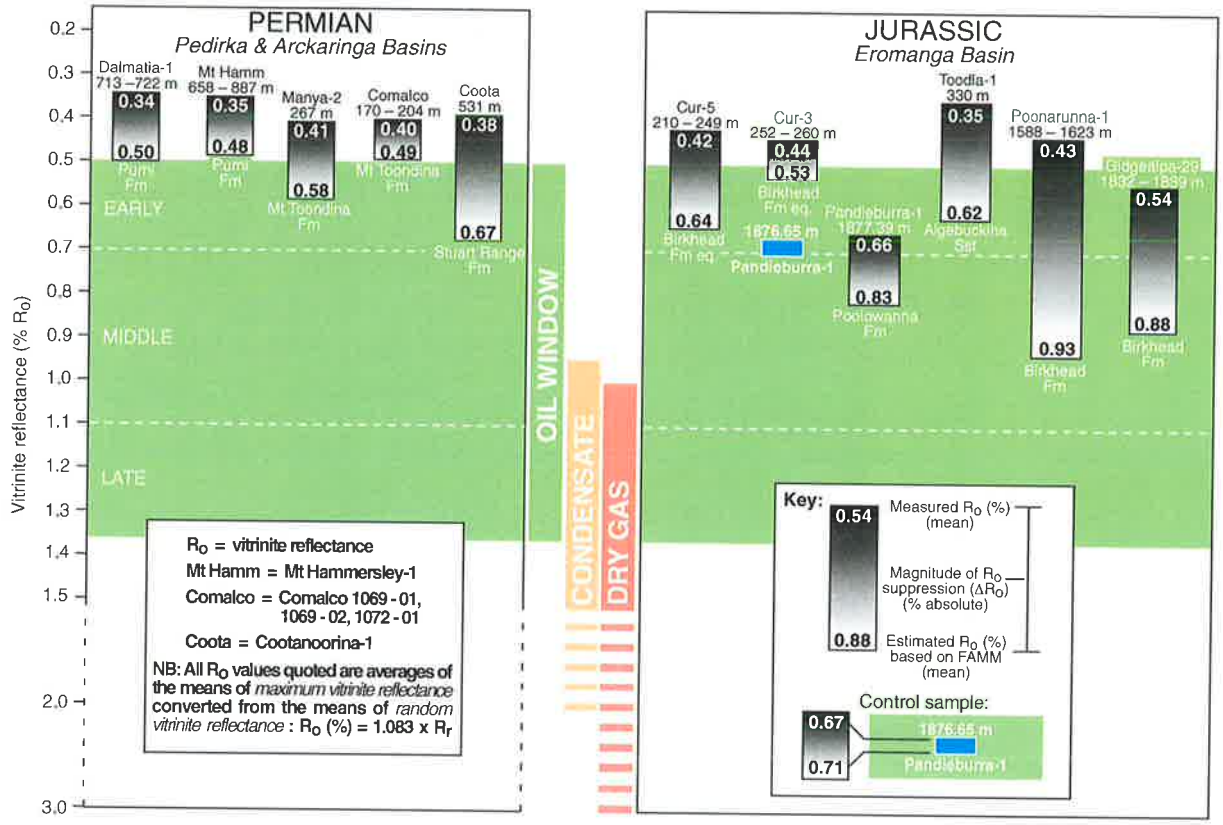


Figure 4.8 Summary of maturity of potential source rocks

4.5.6.3 Jurassic, Eromanga Basin

Poolowanna Formation

The control sample from Pandieburra-1 (coal, 1876.65 m) contains araucariacean biomarkers in much higher abundance than the samples from the Arckaringa and Pedirka Basins (1,2,5-TMN/1,3,6-TMN = 4.38; 1-MP/9-MP = 0.90; 1,7-DMP/X = 0.96). Its retene/9-MP ratio (3.90), although less than that of the Cootanoorina-1 sample (see above), is still higher than those of the other pre-Jurassic samples. The other coal from Pandieburra-1 has similar 1,2,5-TMN/1,3,6-TMN (4.67), 1-MP/9-MP (0.93) and 1,7-DMP/X (0.90) values, but a much lower retene/9-MP value (0.90).

Birkhead Formation

Siltstones from the Birkhead Formation at Poonarunna-1 have very high to extremely high relative concentrations of araucariacean resin biomarkers (1,2,5-TMN/1,3,6-TMN = 7.54–8.80, 1-MP/9-MP = 3.96–5.16, 1,7-DMP/X = 3.96–5.60, retene/9-MP = 10.66–17.34). The Gidgealpa-19 coal/shale pair also has high relative concentrations of the araucariacean biomarkers 1,2,5-TMN, 1-MP and 1,7-DMP (coal: 1,2,5-TMN/1,3,6-TMN = 2.48, 1-MP/9-MP = 1.44, 1,7-DMP/X = 9.97, retene/9-MP = 0.56; shale: 1,2,5-TMN/1,3,6-TMN = 1.87, 1-MP/9-MP = 1.68, 1,7-DMP/X = 1.64) although the relative abundance of retene is low (coal: retene/9-MP = 0.56; shale: retene/9-MP = 0.46).

The 1,2,5-TMN/1,3,6-TMN ratio (6.48) is extremely high in the Birkhead equivalent coal from AFMECO Cur-3 (259.50 m). However, a somewhat low value of 1-MP/9-MP (0.74) was obtained for the coal from AFMECO Cur-5 (210.10 m).The AMFECO Cur-3 (251.60 m) and Cur-5 (249.4 m) samples have elevated retene/9-MP values (17.72 and 39.35, respectively).

Figure 4.10 comprises four cross-plots of vitrinite reflectance suppression (ΔR_o) *versus* the aromatic hydrocarbon biomarker ratios in question. Since Araucariaceae are essentially absent from the pre-Jurassic fossil record, elevated concentrations of these compounds might be expected only in Jurassic or younger source rocks (Alexander *et al.*, 1988). Therefore, it is not surprising that of the 21 shales and coals analysed for aromatic biomarkers, those of Jurassic age (Eromanga Basin) have higher concentrations of araucariacean biomarkers than do those of

Permian age (Arckaringa and Pedirka Basins). Moreover, the data in Figure 4.10 indicate that the Jurassic samples which have have *anomalously* high araucariacean source input (based on the observed distribution of aromatic biomarkers) also exhibit the greatest vitrinite reflectance suppression. The four samples from Poonarunna-1 in which vitrinite is the most reflectance suppressed (ΔR_o = 0.37–0.66%) clearly have the strongest araucariacean input by virtue of their elevated 1,2,5-TMN/1,3,6-TMN, 1-MP/9-MP and 1,7-DMP/X ratios. There is a less clear correlation between ΔR_o and retene/9-MP, due mainly to high values of retene/9-MP in the AFMECO Cur-3 and 5 coals which have only small ΔR_o values.

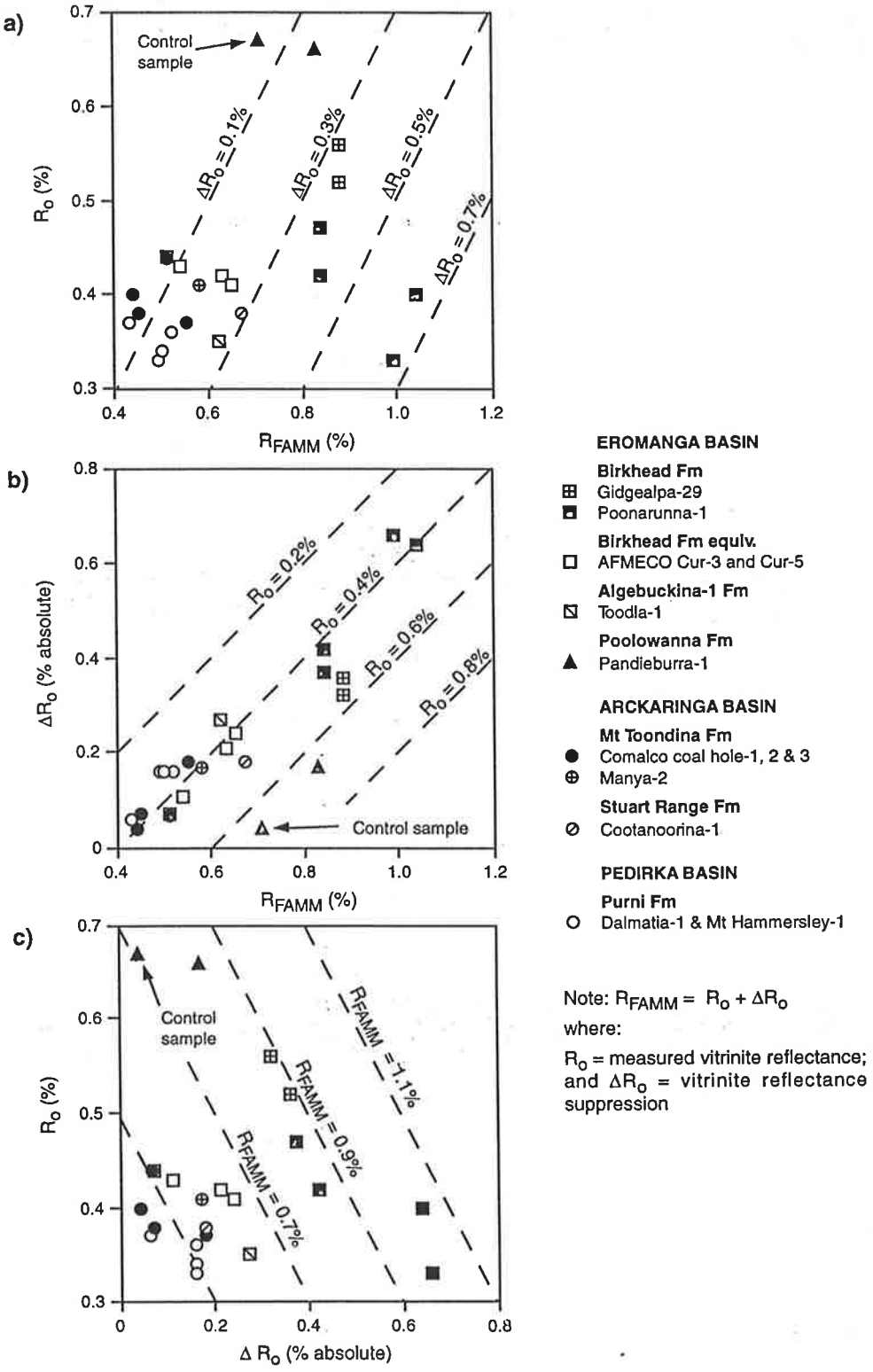


Figure 4.9 Cross-plots of R_o, ΔR_o and R_{FAMM}

It should be noted that other floral groups (*e.g.* pteridosperms) would almost certainly have contributed resinous material to the depositional environment of these Jurassic coals and siltstones. Therefore, the aromatic biomarker parameters used here probably identify only one of many possible sources for the resins. Further, the practice of using ratios (*e.g.* 1-MP/9-MP) provides no information on the *absolute* concentration of the araucariacean biomarkers in the samples. It is reasonable to assume that the absolute concentrations of the araucariacean biomarkers would correlation strongly with vitrinite reflectance suppression. The petrographic evidence shows high concentrations of fossil resin in many of the Jurassic samples (Table 4.2). However, with the exception of the Dalmatia-1 (Purni Formation) coal which contains minor resinite, coals and siltstones from the pre-Jurassic rocks examined in this study are depleted in resinite.

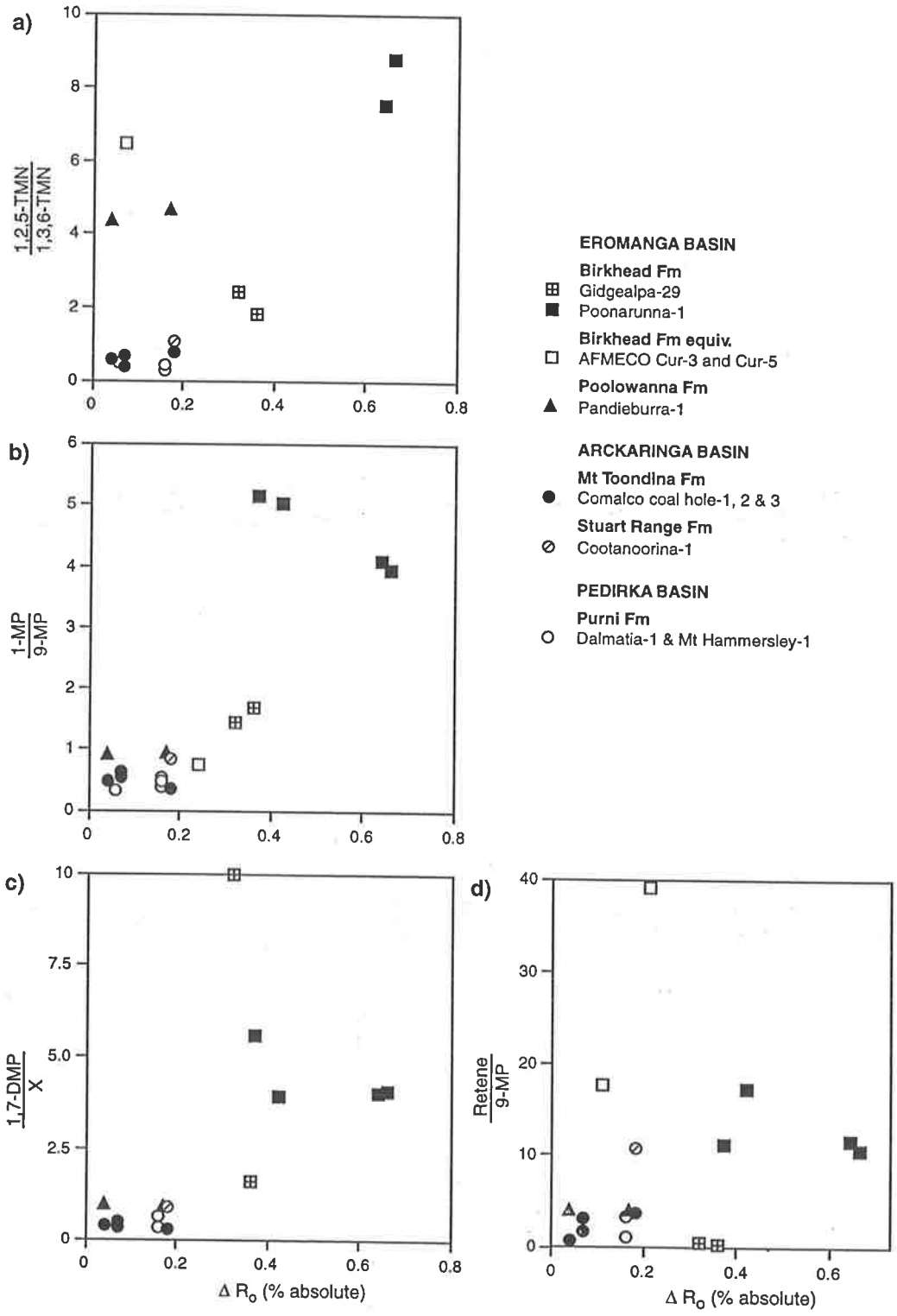


Figure 4.10 Cross-plots of small ΔR_o against various aromatic biomarker ratios

In summary, there appears to be a nexus between extreme vitrinite reflectance suppression, such as identified at Poonarunna-1, and greater than normal araucariacean resin input to the source rock depositional environment.

4.5.7 Correlation of FAMM maturity (R_{FAMM}) and vitrinite suppression (ΔR_o) with Rock-Eval parameters and MPI

Figures 4.11–4.13 are cross-plots of R_o, R_{FAMM} and ΔR_o against various source and maturity parameters (*viz* HI, MPI, and T_{max}). Examination of these graphs reveals a number of interesting and potentially useful relationships:

1. A weak inverse correlation between R_{FAMM} and MPI;
2. A strong positive correlation between R_{FAMM} and T_{max};
3. A positive correlation between ΔR_o and HI;
4. An inverse correlation between ΔR_o and MPI; and
5. A reasonably good correlation between ΔR_o and T_{max}.

Perhaps the most interesting aspect of these data is the apparently robust correlation between R_{FAMM} and T_{max} (Fig. 4.12: $R_{FAMM} = 0.02\ T_{max} - 7.85$). It is well known that the value of T_{max} is influenced not only by maturation but also by kerogen type and depositional environment. The data presented herein suggest that R_{FAMM} in the Arckaringa, Pedirka and Eromanga Basins is likewise strongly influenced by organic matter composition (*cf.* Teerman *et al.*, 1995). It is perhaps not surprising that the best source rocks are developed where vitrinite suppression is most severe, *i.e.* where impregnation of the vitrinite by oil-prone resinite is greatest.

5.5.8 Which maturity parameters are valid?

The highest R_{FAMM} values and greatest vitrinite reflectance suppressions (ΔR_o) identified in this study are those recorded for the Jurassic coals and shales of the Eromanga Basin (Figs 4.8 and 4.9). However, it is likely that some R_{FAMM} data are inacccurate. For example, the average R_{FAMM} for the two Cur-5 samples (0.64% R_o) must be erroneously high because the saturated hydrocarbon fractions of these samples contain a pseudohomologous series of 17β,21β-hopanes (Staples *et al.*, 1995a), compounds that are thermodynamically unstable and therefore absent in oils and source rocks with maturities greater than about 0.5% R_o (Tissot and Welte, 1984; Peters and Moldowan, 1993). Thus the real maturities of the Cur-5, and the Cur-3 samples, are probably around 0.47 to 0.49% R_o.

The R_{FAMM} data for two humic coals from the Poolowanna Formation at Pandieburra-1 are also problematic (Table 4.3). The control coal sample (Pandieburra-1, 1876.65 m) comprises entirely telocollinite (Table 4.2) and is therefore ideal for the petrographic measurement of vitrinite reflectance. Its measured maturity (0.67% R_o) is considered to be accurate and is consistent with that of the coal some 0.74 m deeper in Pandieburra-1 (1877.39 m; 0.66% R_o) which also comprises a high proportion of telocollinite, texto-ulminite and minor resinite and sporinite. However, FAMM-derived maturities (R_{FAMM}: parameter **5**) for the Pandieburra-1 samples are notably at variance with the calibrated vitrinite reflectance (R_o: parameter **2**). The Pandieburra-1 samples at 1876.65 m and 1877.39 m have R_{FAMM} values of 0.71% and 0.83%, respectively. Because these samples are closely juxtaposed and isometamorphic, their R_{FAMM} values cannot *both* be correct! It is interesting that the calibrated R_o values for these samples are so similar. In this case, calibrated R_o appears to be more consistent than R_{FAMM}. The ΔR_o value for the control sample (Pandieburra-1, 1876.65 m) is only 0.04% absolute which is the lowest vitrinite suppression recorded in this study (*cf.* Table 4.3). All things considered, the elevated liptinite content of the non-control sample appears to be responsible for the anomalously high R_{FAMM} value but, surprisingly, has had little or no effect on the value of measured or calibrated R_o.

It is worth noting that the original calibration of the FAMM technique excluded Jurassic samples (R.W.T. Wilkins, CSIRO, pers. comm., 1997) and was less than ideally calibrated for samples of low rank (*i.e.* < 0.5% R_o). Hence, it is probably prudent to treat all FAMM-derived maturity estimates for post-Triassic rocks cautiously (especially low rank samples) until a more appropriate calibration can be established and tested more rigorously. Moreover, many of the FAMM data are likely to be variously affected by oxidation effects, especially in the case of low

rank coals which tend to oxidise rapidly after recovery from the well site (R.W.T. Wilkins, CSIRO, pers. comm., 1997). Because oxidation causes muted fluorescence, the FAMM data will be altered. For this reason, vitrinite reflectance is likely to be a more robust technique because it responds much less rapidly to oxidation.

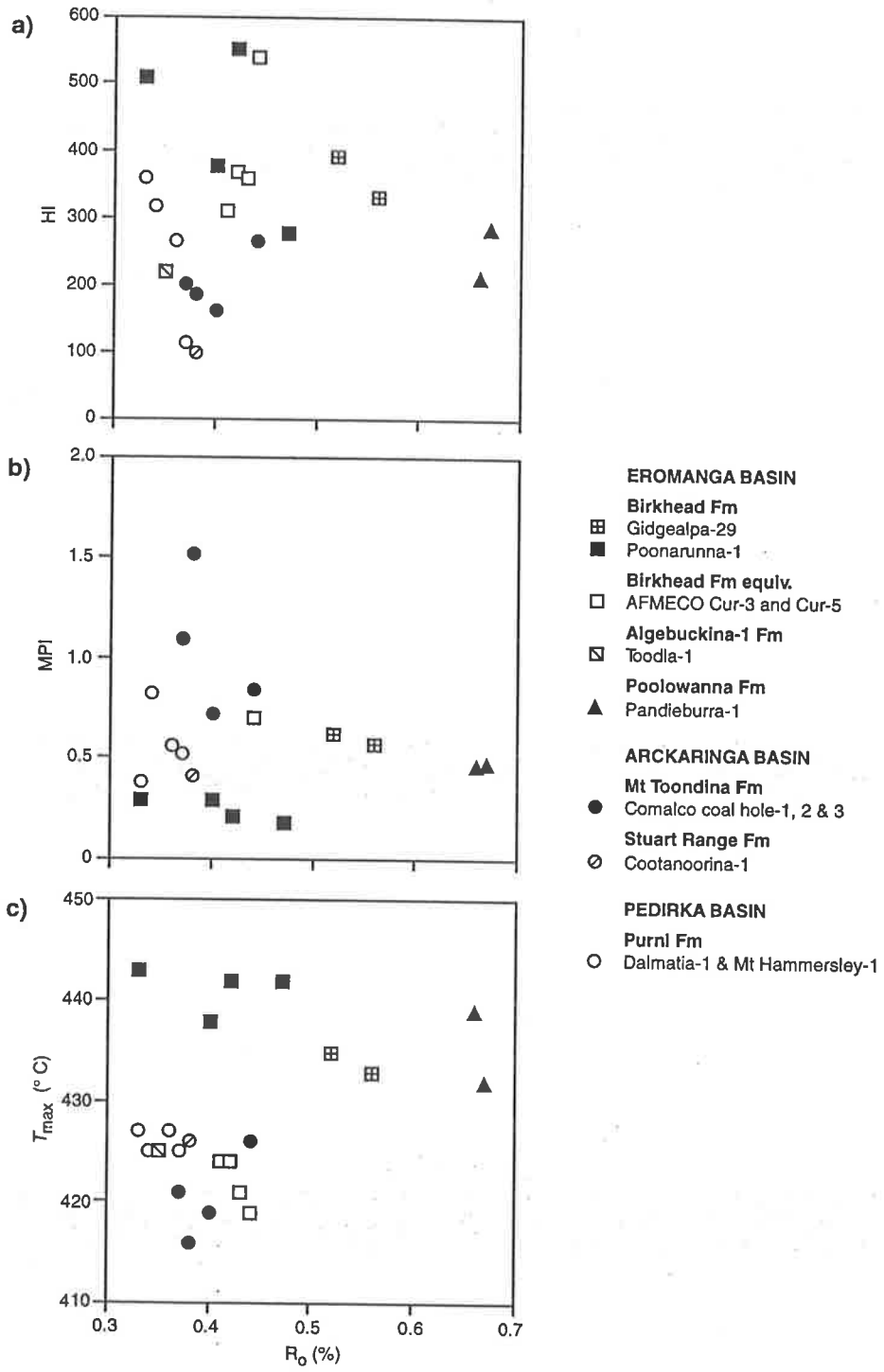


Figure 4.11 Cross-plots of R_O against various source and maturity parameters

Estimates of vitrinite reflectance suppression based on FAMM parameter **6** (Table 4.3) are consistently less than those based on parameter **7**. Predictably, samples from Gidgealpa-29 and Poonarunna-1 have the highest values for parameter **6**. It is possible that the discrepancy between FAMM parameter **6** and **7** is because the suppression iso-correction curves (Fig. 4.2) have not been calibrated to Jurassic samples.

As the discussion in Section 4.5.4 indicates, the maturity estimates derived from aromatic hydrocarbon distributions are so inconsistent that they serve to complicate the task of maturity assessment in these samples. This is largely due to the low rank of generally the samples from

AFMECO, Comalco, Dalmatia-1, Mt Hammersley-1, Manya-1 and Toodla-1 wells. However, MPI- and MPR-derived maturities (Table 6.4, parameters **1**, **2**, **4** and **5**: 0.61–0.74% R_c) for the Gidgealpa-29 coal/shale pair are in broad agreement with the maturity estimated from T_{max} (*ca* 0.65% R_o) and the directly measured vitrinite reflectance (mean = 0.54% R_o). Similarly, maturities derived from the aromatic hydrocarbon distributions (Table 6.4, parameters **1**, **2**, **4** and **5**: 0.50–0.81% R_c) of the Pandieburra-1 coals agree very broadly with the maturity estimated by T_{max} (*ca* 0.65% R_o). In both cases, the calibration of Boreham *et al.* (1988; Table 4.6, parameter **1**) is probably the best. On the other hand, the Poonarunna-1 (Birkhead) siltstones have MPI- and MPR-derived maturities (Table 4.6, parameters **1**, **2**, **4** and **5**: 0.18–0.53%) which are in rough agreement with their directly measured maturities (0.33–0.47% R_o) but at variance with their R_{FAMM} values (0.84–1.04%).

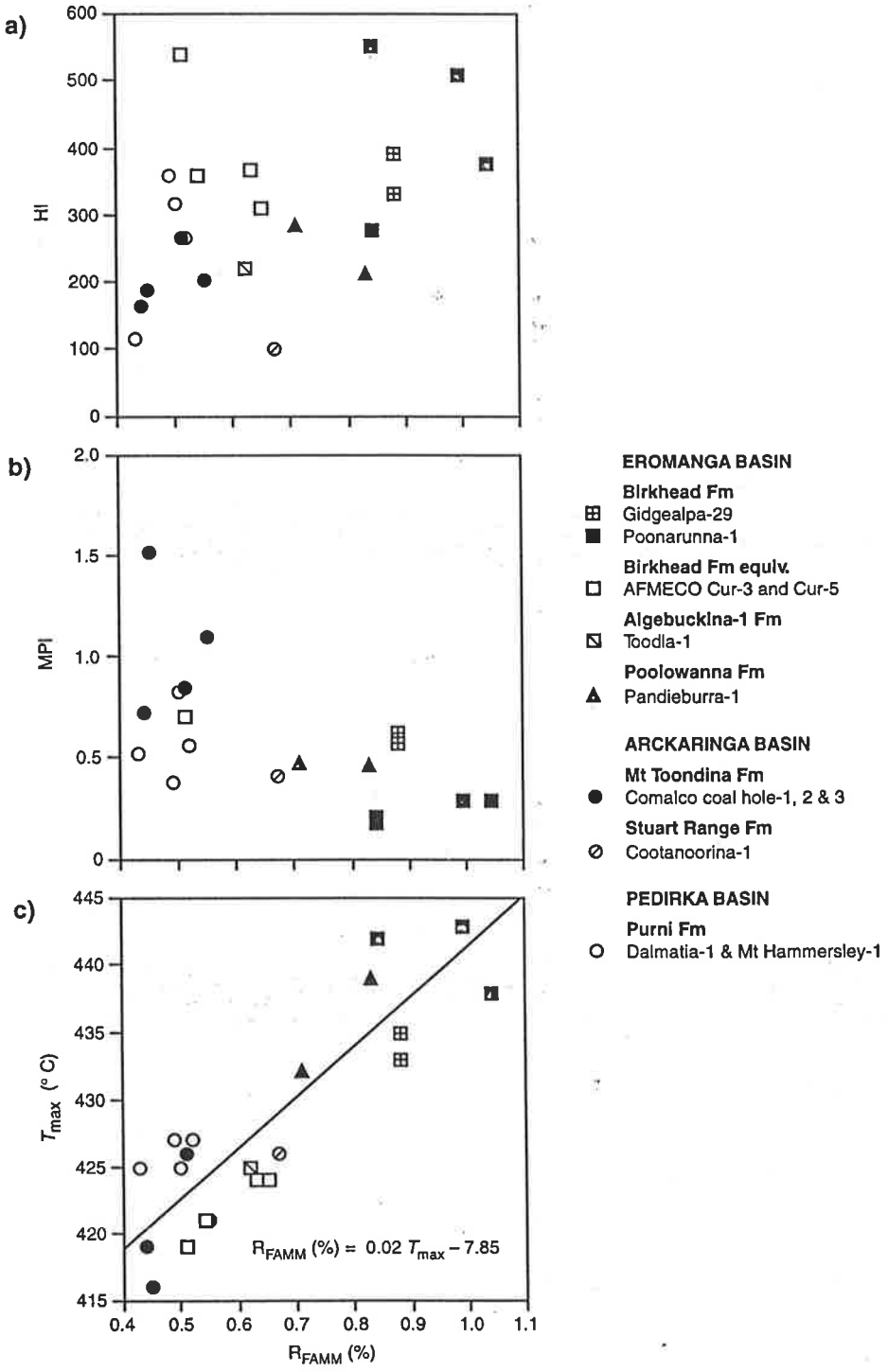


Figure 4.12 Cross-plots of R_{FAMM} against various source and maturity parameters

As a general rule, it seems that the maturity parameters derived from aromatic hydrocarbon distributions should only be used to determine source rock maturity in situations where there is clear and independent evidence (*e.g.* measured R_o or T_{max} data) of the rock having entered the oil window.

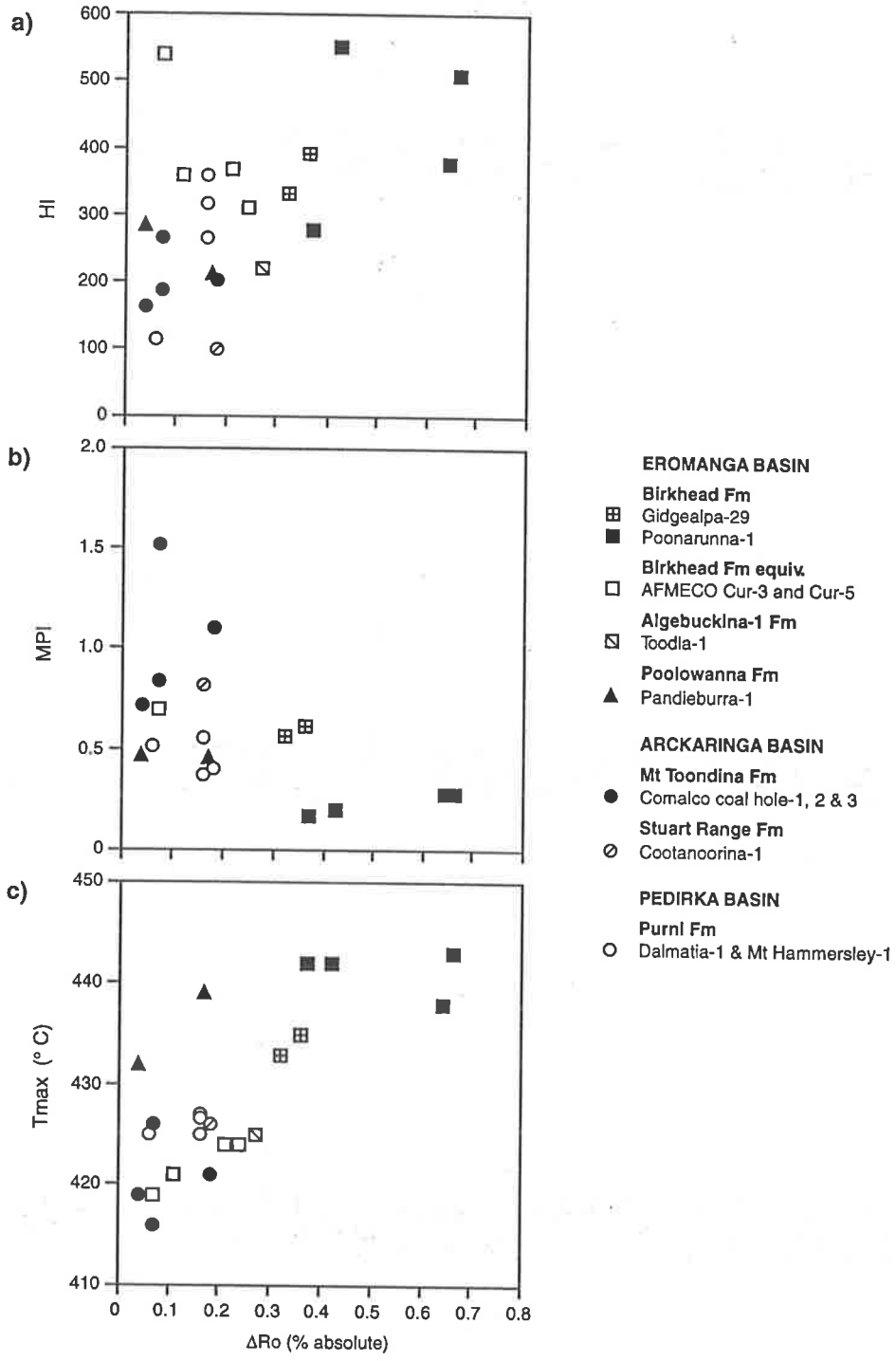


Figure 4.13 Cross-plots of ΔR_o against various source and maturity parameters

4.6 SYNOPSIS

1. Appreciable vitrinite suppression (*i.e.* $\Delta R_o \geq 0.05\%$) was found to be a feature of all but one sample (Pandieburra-1, 1876.65 m) from the suite of 23 coals, shales and siltstones analysed in this study. Therefore, the maturity of most potential source rocks in the northern petroleum provinces of South Australia appears to be significantly greater than indicated by conventional vitrinite reflectance measurements. It is likely that much of the existing vitrinite reflectance data for these basins, and in particular the Eromanga Basin (Michaelsen and McKirdy, 1996a; Chapter 3), require correction for this effect.

2. Severe vitrinite reflectance suppression (*i.e.* $\geq 0.3\%$ R_o) was noted in a number of samples from the Birkhead Formation. The most extreme vitrinite reflectance suppression occurs at Gidgealpa-29 ($\Delta R_o = 0.32–0.36\%$) and Poonarunna-1 ($\Delta R_o = 0.37–0.66\%$).
3. Rock-Eval pyrolysis-derived T_{max} appears to be a robust maturity parameter. It correlates well with maturity estimated by FAMM.
4. Detailed analysis of the extracted aromatic fractions of the shales and coals reveals a correlation between vitrinite reflectance suppression and biomarkers derived from the resins of the conifer family Araucariaceae. Enhanced concentrations of the araucariacean biomarkers 1,2,5-trimethylnaphthalene, 1-methylphenanthrene, 1,7-dimethylphenanthrene and retene occur in samples with the greatest vitrinite reflectance suppression. It therefore appears likely that the major cause of vitrinite reflectance suppression in these rock samples is impregnation of vitrinite by plant resins during early diagenesis.

CHAPTER 5

Petroleum geochemistry and organic petrology of the lacustrine Murta Formation

CHAPTER 5

Petroleum geochemistry and organic petrology of the lacustrine Murta Formation*

* Parts of this chapter have been published as follows (Appendix 4):

Michaelsen B.H. and McKirdy D.M. (1989) Organic facies and petroleum geochemistry of the lacustrine Murta Member (Mooga Formation) in the Eromanga basin, Australia. In *The Cooper and Eromanga Basins, Australia*, ed. B.J. O'Neil, Proceedings of the Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysics (SA Branches), Adelaide, pp. 541–558.

Powell T.G., Boreham C.J., McKirdy D.M., Michaelsen B.H. and Summons R.E. (1989) Petroleum geochemistry of the Murta Member, Mooga Formation and associated oils, Eromanga Basin. *Australian Petroleum Exploration Association Journal* 29(1), 114–129.

5.1 SUMMARY

The Murta Formation is a laterally extensive lacustrine unit, displaying some marine influence in its upper part, which was deposited across the southern Eromanga Basin under a moist cool temperate climatic regime during the Early Cretaceous. Source facies (dark grey to black silty shale: TOC = 0.5–2.5%) are intercalated with thin reservoir sands which have produced hydrocarbons at flow rates up to 2180 BOPD. The unit appears to be self-sourcing. Oil-source rock correlations based on alkane biomarker distributions and methylphenanthrene indices confirm that many of the oils are relatively immature (R_c = 0.54–0.61%) and largely indigenous to the Murta Formation. The gasoline-range and carbon isotopic compositions of the oils, and their high content of bacterial biomarkers (notably C_{12+} *iso-* and *anteiso*-alkanes), highlight the significant contribution of microbial biomass to their source material. This has important implications for organic petrographic studies of the Murta shale lithofacies.

Cores of carbonaceous shale and siltstone from different facies of ancient Lake Murta were sampled as follows: distal lacustrine (Moomba-18), intermediate lacustrine (Biala-1, Limestone Creek-6, McKinlay-2) and transitional to braided fluvial (Nockatunga-1, -2 and -3, Winna-1, Koora-1). Petrographic analysis in reflected light reveals that the Murta silty shales contain dispersed organic matter (DOM) of mixed algal-land plant origin, although terrestrial material is generally dominant. The main macerals are inertinite (40–80% of DOM) and liptinite (15–60% of DOM). Vitrinite is a minor component (< 10% of DOM), probably because of oxidative decay of cellulose and woody tissue by aerobic bacteria. The occurrence of *Botryococcus*-related telalginite, evidence of a freshwater lacustrine to brackish-water paralic depositional environment, is ubiquitous. Visual examination of kerogen concentrates under UV irradiation (transmitted light) reveals that the liptinitic component has been significantly modified, possibly by the action of bacteria. Much of the organic material is amorphous and sporinite/cutinite exists in various stages of degradation.

Both distal and intermediate-lacustrine organic facies are marginally mature for early-phase petroleum generation where sampled and Rock-Eval pyrolysis demonstrates that the shales contain kerogen of Type II/III composition. The intermediate shales (TOC = 1–2.5%; HI = 175–540; R_o = 0.5–0.6%) are fair to very good potential sources of liquid hydrocarbons. However, the source potential of the distal organic facies (TOC = 1–2%; HI = 125–260; R_o = 0.60–0.65%) has been downgraded by the partial oxidation of algal and land plant material prior to deposition. Within the *intermediate* lacustrine lithofacies along the Murteree Ridge there is little systematic variation in organic facies between the shales of Mount's (1982) M1–M5 subunits. Most are oil-prone, in contrast to the more gas-prone shales of the *distal* lithofacies around Moomba. The best potential source rocks, thin shale beds in the dominantly arenaceous M2 subunit are characterised by unusually high contents of well-preserved telalginite (25–26% of DOM). Shaly intervals within the *transitional* lithofacies of the upper Murta Formation at the eastern end of the NJ Ridge also contain Type II/III kerogen. Compared to their M1 equivalents in the intermediate lacustrine lithofacies, these shales display a wider range of organic richness

and quality (TOC = 0.5–1.6%; HI = 81–270) and are initially mature for oil generation (R_o = 0.5–0.6%). Source quality is better at Nockatunga than at Koora, whereas at Winna an unusual vitrinite-rich (but oil-prone) organic facies is developed. For organically lean source rocks like those of the Murta Formation (TOC < 3%), Rock-Eval data provide an unduly pessimistic assessment of kerogen quality and genetic potential because of the mineral matrix effect. Moreover, based on the FAMM study (Chapter 4), it is evident that conventionally measured maturity may well understate the true maturity of potential source rocks in the Murta Formation by as much as 0.25% R_o. The true maturity (calculated from T_{max}) of the Murta siltstones at the localities sampled along the Murteree Ridge (Biala-1, Limestone Creek-6, McKinlay-2) is likely to be in the range 0.80–0.84% R_o.

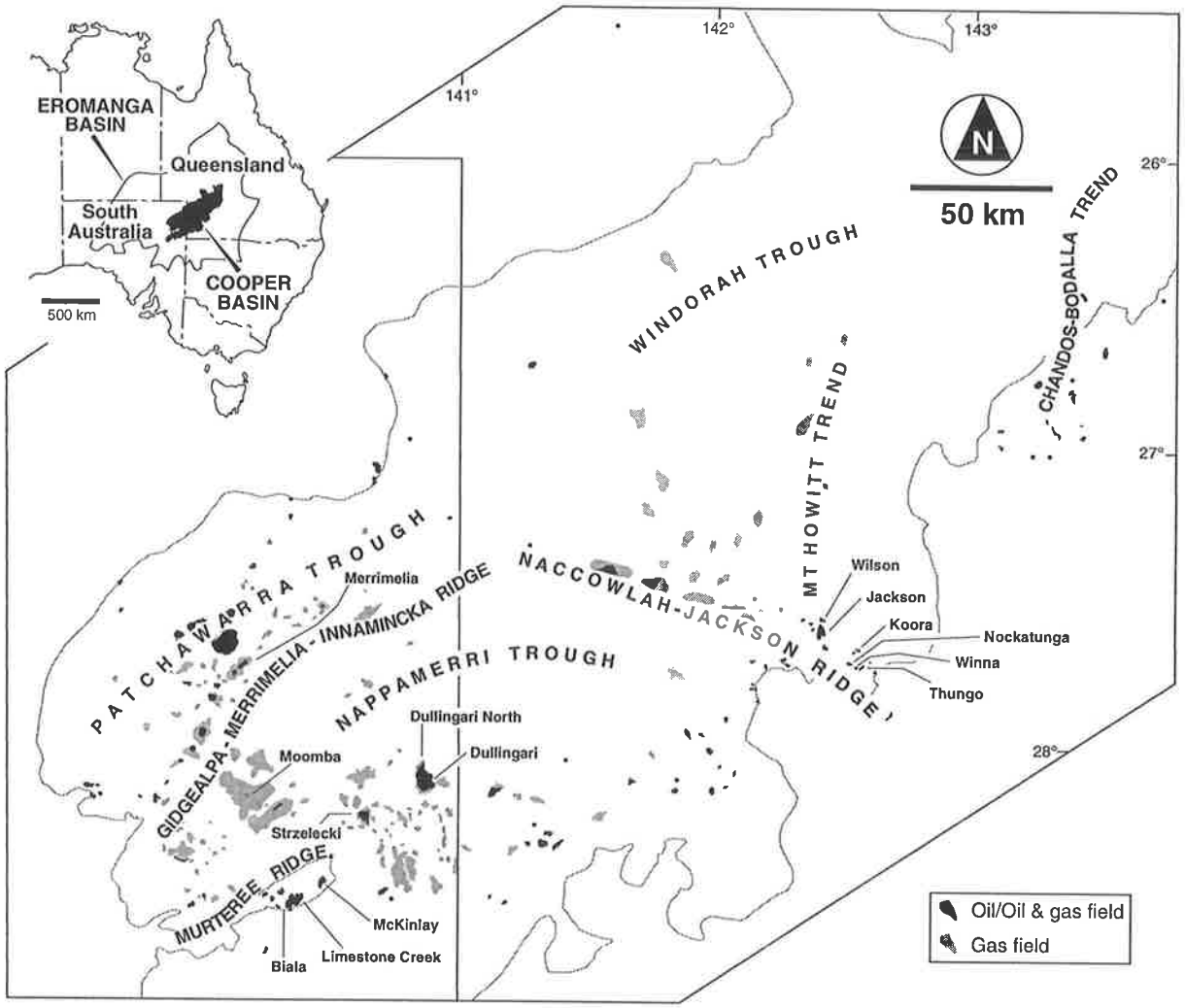


Figure 5.1 Location map of the study area, Eromanga Basin

5.2 INTRODUCTION

The Murta Formation is a laterally extensive mostly fine-grained lacustrine unit within the Early Cretaceous sequence of the southern Eromanga Basin (Mount, 1982; Ambrose *et al.*, 1986). Murta reservoir sands are host to paraffinic crude oil (Jenkins, 1982; McKirdy, 1984a,b) and production from this formation is obtained at numerous fields, including Dullingari and Merrimelia in South Australia and Jackson and Nockatunga in southwestern Queensland (Fig. 5.1).

The possibility of low-maturity source rock plays in the Eromanga Basin was first suggested by Kantsler *et al.* (1983). Subsequent geochemical studies of Eromanga Basin crude oils (*e.g.* McKirdy, 1984a,b; Vincent *et al.*, 1985; McKirdy and Morton, 1986; Jenkins, 1987; Alexander *et al.*, 1988; Powell *et al.*, 1989) have demonstrated the immaturity of Murta-hosted crude oils.

Although McKirdy (1982a,b) and Vincent *et al.* (1985) considered the oil-source potential of the Murta Formation to be fair to good on the basis of rock extract data (Fig. 5.2), the origin of its

reservoired hydrocarbons continues to be the subject of some conjecture. Mesozoic, Permian and mixed sources have been proposed (Moore *et al.*, 1986 and references cited therein).

Compelling geochemical evidence has now been assembled by Powell *et al.* (1989) to show that the Murta crudes are immature (source $R_o \approx 0.5$–0.6% at time of primary migration) and indigenous, and have not migrated from stratigraphically older sources. In the light of these findings, it is appropriate that the Murta Formation be reexamined — not only as a reservoir system but also as a low-maturity source rock play. Jenkins (1989) states that Murta-sourced crudes account for the majority of the indigenous Cretaceous and Jurassic oil, which in turn comprises 18% by volume of total mapped reserves, in the Eromanga/Cooper Basin; the remainder is of Permian origin.

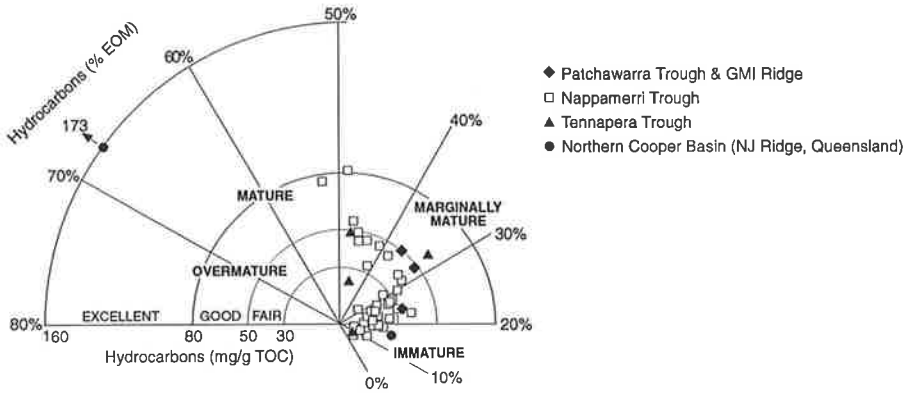


Figure 5.2 Murta Formation rock extract data (after McKirdy, 1982)

According to Boreham and Summons (1999) approximately 80% of oil reserves in the Cooper/Eromanga Basin system are reservoired in the Eromanga Basin. In 1995, some 0.76 x 10^6 kl of crude oil were produced from Eromanga reservoirs (Alexander, 1996a). Of this approximately 20.5% was produced from the Murta Formation (which includes *ca* 2.5% from the McKinlay Member), and 14% from the Namur Sandstone (Alexander 1996b). The remainder of the Eromanga production (*ca* 65.5%) derives from the Birkhead Formation, Hutton Sandstone and Poolowanna Formation.

The Murta Formation is yet another example of the increasingly diverse range of source rock types being documented in lacustrine depositional settings (Powell, 1986; Kelts, 1988). Accordingly the aims of this study were:

1. to review the distinctive geochemistry of Murta-hosted hydrocarbons, highlighting in particular their mixed bacterial-land plant source affinity;
2. to define the principal organic facies of the Murta Formation within the southern sector of the Eromanga Basin in South Australia (Murteree Ridge and Moomba areas) and Queensland (eastern NJ Ridge); and
3. to assess the petroleum-generative potential of these organic facies at their present low maturation levels.

Core samples were used for petrographic and geochemical (Rock-Eval pyrolysis) analysis, thereby avoiding the problems associated with cuttings, *viz* contamination by cavings from overlying strata and the mixing of thinly interbedded coarse-grained (reservoir) and fine-grained (source) lithologies.

5.3 STRATIGRAPHY AND DEPOSITIONAL ENVIRONMENT

The Murta Member was recognised as a Neocomian low-energy lacustrine facies of the late Jurassic–Early Cretaceous Mooga Formation by Nugent (1969). Gravestock *et al.* (1995) subsequently elevated it to Formation status. Its interbedded sandstone, siltstone and silty carbonaceous shale together comprise a laterally extensive, mostly fine-grained unit which contrasts with the medium to coarse grained graided fluvial sediments of the underlying Namur Sandstone. Mount *et al.* (1992) loosely defined the McKinlay Member as the silty sandstone transition between the Namur Sandstone and the overlying Murta Member. The McKinlay Member is now formally defined as the basal unit of the Murta Formation (Gravestock *et al.*,

1995. The upper and lower boundaries of the McKinlay Member intertongue Murta Formation and Namur Sandstone respectively (Alexander and Sansome, 1996).
Mount (1981) has defined a type section for the Murta Formation at Dullingari North-1, whereas Dullingari-9 was proposed as a 'reference section' by Ambrose *et al.* (1982; Fig. 5.3). To remain consistent with the most recent workers and published literature (*viz* Zoellner, 1988, and Michaelsen and McKirdy, 1989; Powell *et al.*, 1989) and to avoid confusion, only the five-fold stratigraphic subdivision based on the Dullingari North-1 type section is used herein (Fig. 5.4).

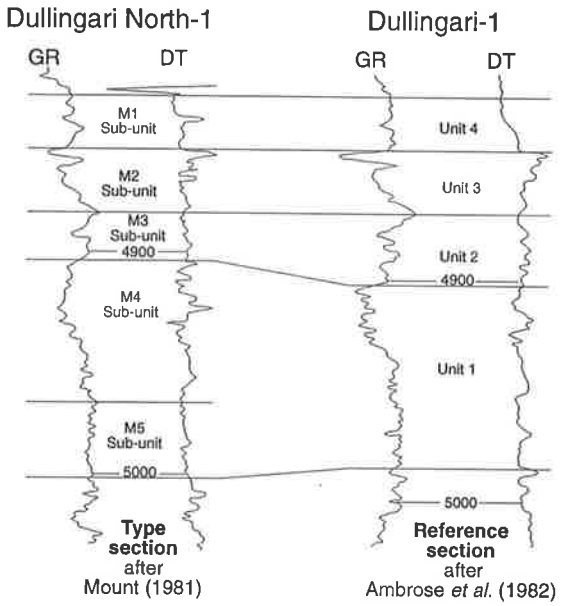


Figure 5.3 Type and reference sections of the Murta Formation. Depths in feet

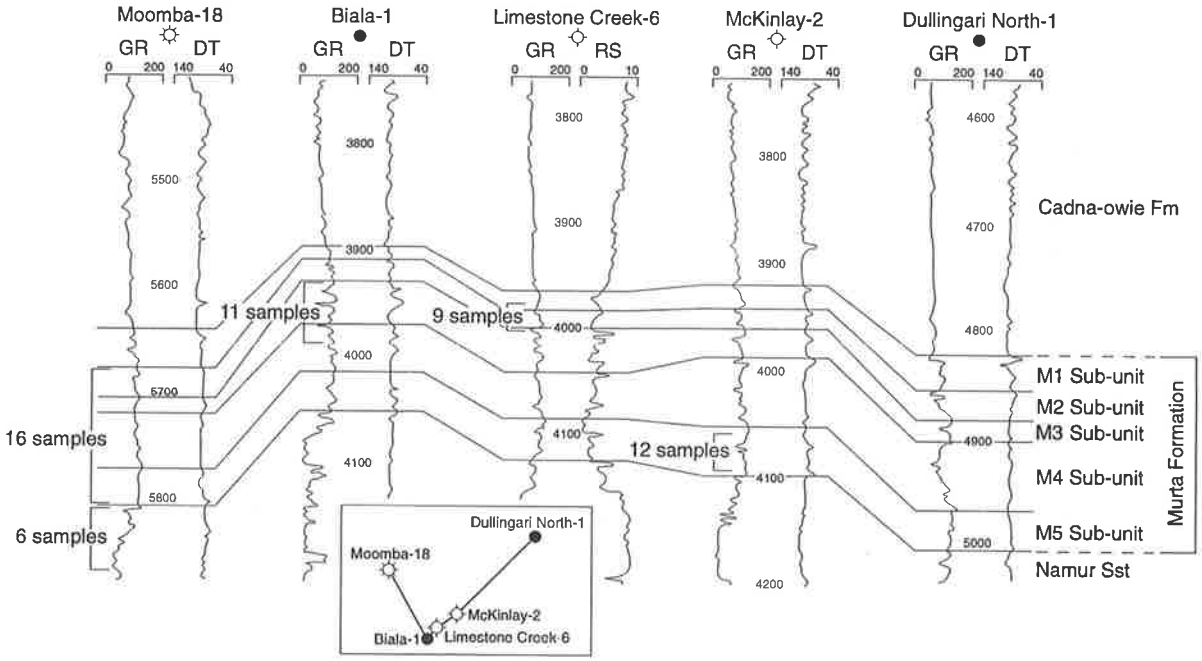


Figure 5.4 Stratigraphic correlation, Moomba-18 to Dullingari North-1. Depths in feet

For detailed lithofacies descriptions of the M1–M5 subunits the reader is referred to Mount (1982). Each subunit includes intervals of dark carbonaceous siltstone and/or silty shale which are the product of open-water lacustrine sedimentation. Lake Murta was envisaged by Mount (1982, p. 356) to be "a large and shallow inland lake characterised by very gentle bottom slopes and clear quiet waters, and surrounded in the hinterland by braided-fluvial plains....Sediment-laden river-waters passed into the lake as clastic-charged underflows, episodic density currents, that built a series of overlapping 'sub-lacustrine turbidite fans' on the lake floor".

Ambrose *et al.* (1982, 1986) suggested that the Namur braided-fluvial regime supplied coarser-grained sediment to the lake predominantly from the northeast, and proposed a depositional model in which the following lithofacies were differentiated: braided-fluvial, transitional to braided fluvial, proximal lacustrine, intermediate lacustrine and distal lacustrine. However, there is evidence that Murta sediments along the Murteree Ridge have a southern provenance. No distal lacustrine mudrocks are evident here, the formation consisting of subaqueous silts and fine sands interbedded with shoreface sands (Gravestock and Alexander, 1986). This observation is accommodated better by the palaeogeographic model of Mount (1982). So too are the sedimentological and geochemical data assembled by Zoellner (1988) and Powell *et al.* (1989) which suggest a brackish to marine environment for the upper part of the Murta sequence (M3 through M1 subunits). The eastern marine barrier thrown up by the first global rise of sea level in the Early Cretaceous, and which led to flooding of the Namur fluvial plains in the southern Eromanga Basin (Mount, 1982), was eventually breached by a large estuarine channel that fed marine sands into Lake Murta, at first probably by underflow (Zoellner, 1988). The regional southwesterly decrease in thickness and sand content of the Murta Formation may be consistent with a diminishing marine influence.

Seismic sequence analysis reveals that the Murta Formation is a shallowing-upwards and basinward-prograding sequence (Lemon, 1989). The Murta passes disconformably into the overlying Cadna-owie Formation, a coarsening-upwards paralic or restricted marine sedimentary package which exhibits a well developed regressive character. The concept of a Neocomian marine influence in northeastern South Australia is reinforced by the identification of tidal deposits and tempestites within the Cadna-owie Formation as far southwest as the northern Flinders Ranges (Lemon, 1989; Alley and Lemon, 1988).

According to the 'sublacustrine turbidite fan' model of Mount (1982) the Murta Formation comprises dark carbonaceous, pelagic siltstones, representing periods of settling of suspended fines and autochthonous algal organic matter, intercalated with terrestrial siliciclastics (carrying allochthonous organic matter) that were deposited as turbidite sheets. The palynoflora of the Murta Formation indicates the type of vegetation which grew in the vicinity of Lake Murta. According to Price (1983) the drier slopes of the hinterland were covered by open gymnosperm forest (including *Classopollis*-producing conifers) with a tree fern/pteridosperm understorey and a ground cover of ferns. Lycopods, ferns and equisetalean (reed-like) plants populated low-lying swamps. Oxygenated surface waters of the oligotrophic lake supported planktonic algae (including *Botryococcus*, Leiosphaeridiae and a probable dinoflagellate). A palaeolatitude of 65–70° south and a humid, cool temperate climate with marked seasonality is indicated for the Eromanga Basin during the Neocomian (Frakes and Francis, 1988).

The laminated, non-bioturbated character of its carbonaceous siltstone suggests that stable anoxic conditions existed at the lake floor during accumulation of the basal M5 subunit. Intensely bioturbated turbidite sediments are common thoughout the rest of the Murta sequence (M4 through M1: Ambrose *et al.*, 1986, fig. 3). Whether or not the benthic environment remained anoxic during deposition of the intercalated black silts, or merely sub-oxic (0.1–0.5 ‰ dissolved O_2: Demaison *et al.*, 1983), is debatable. Horizontal worm burrows (feeding trails) in black organic-rich muds of the lower M2 subunit at Dullingari-5 (Mount, 1982) are consistent with sub-oxic bottom waters. Intermittent density underflows would have temporarily increased the degree of oxygenation of the lake bottom, allowing more intense bioturbation of the newly deposited turbidite silts and sands, as well as the immediately underlying lacustrine muds.

Evidence of soft-sediment deformation is ubiquitous within the Murta sequence. The types of sedimentary structures present in the Murta sedimentary pile (*viz* load casts, penecontemporaneous microfaulting, slump folds; Michaelsen and McKirdy, 1989, fig. 5) are characteristic of rapid deposition which is essential for the optimum preservation of autochthonous organic matter (Ibach, 1982; Demaison *et al.*, 1983). When settling through an oxygenated water column, such planktonic material is more susceptible to bacterial degradation than is terrestrially-derived plant detritus.

5.4 RESERVOIR AND SOURCE ROCK LITHOFACIES

Ambrose *et al.* (1986) conclude that the more distal the Murta facies, the greater its shale content and hydrocarbon source potential but the lesser its overall prospectivity due to a lack of reservoir sands. Mount [1982: citing McIntyre (1980)] emphasises that concentrations of liptinite-rich dispersed organic matter (DOM) exceed 2.8% in the offshore deeper water,

argillaceous M1, M3 and M5 subunits at Dullingari North-1. Sporinite and alginite are the dominant liptinite macerals, the latter comprising up to 25% of the total DOM in some shaly bands.

In contrast, the proximal lacustrine facies (*e.g.* at Jackson-1) is characterised by the highest sand/shale ratios. Alginite-rich source rocks have not yet been identified in the basal M5 equivalent here, although DOM levels as high as 3–3.5% occur in silty shales of the upper Murta Formation. Vitrinite is dominant over liptinite and inertinite (Ambrose *et al.*, 1986). Nevertheless, the prospectivity of this facies is highly regarded — a legacy of reservoir quality delta-front sands. The prolific M2 reservoirs of the Dullingari Field are sub-lacustrine fan deposits and an overlying thin shoreline sand which underwent considerable low-energy winnowing during a stillstand of the lake (Mount, 1982).

5.5 SAMPLING PROCEDURES

An assessment and comparison is made of the hydrocarbon-source potential of the intermediate-proximal (Napacoongee-Murteree Block) and distal shale facies (Moomba Block) within South Australia. Dark shale laminae were selectively sampled in an attempt to optimise the shale/sand ratios in the core material analysed. This is desirable because DOM is concentrated within fine-grained sediments. Also, argillaceous rocks are less likely to be contaminated or stained by migrated hydrocarbons.

Cores from three wells, Biala-1, Limestone Creek-6 and McKinlay-2, collectively provide coverage of nearly the entire Murta sequence in the Murteree Ridge region. Within the Nappamerri Trough, Moomba-18 cored the lower M2 to M5 Murta subunits (Fig. 5.5). No core was available from the M1 subunit in this area. A series of 54 samples were taken from the cored Murta sections in these wells, including six from the subjacent Namur Sandstone in Moomba-18. These samples from South Australia were supplemented with 33 samples of the upper Murta and base Cadna-owie from four wells in Queensland, Queensland: Koora-1 (3 samples, M1–M2; 7 samples near base Cadna-owie), Nockatunga-1 (9 samples, M1–M2), Nockatunga-2 (4 samples, M1–M2), Nockatunga-3 (7 samples, M1–M2) and Winna-1 (3 samples, M2–M3).

5.6 ANALYTICAL TECHNIQUES AND PETROGRAPHIC ANALYSES

The petrographic techniques employed in this study were maceral analysis of *in situ* dispersed organic matter, the determination of maceral reflectance (incident light), and kerogen examination in transmitted light. Geochemical analyses included Rock-Eval pyrolysis of whole-rock samples and capillary gas chromatography (GC) of some whole oils.

5.6.1 Petrographic analyses

Blocks of core were cut perpendicular to bedding, mounted in hot-setting Araldite resin and polished for petrographic analysis. These polished sections were examined using oil immersion lenses. Kerogen concentrates (sieved and unsieved) were prepared as strewn mounts in Eukitt medium.

Although point-counting methods can be efficiently used for maceral analysis of coals, Cook (1986) has recognised that this procedure is invalid for DOM where the concentration of individual macerals generally is too low to permit a precise estimation of their abundance. The lithological heterogeneity of the Murta Formation further compounds the problem of estimating maceral abundance. The inclusion, in the optical counting field, of organically barren lithologies results in the under-estimation of DOM in the richer argillaceous laminae, and also gives rise to misleading maceral associations. To overcome these difficulties, a method was devised to semiquantitatively estimate DOM composition with the aid of a series of charts, especially designed for lithologically inhomogeneous sediments (Michaelsen, 1986). The terminology used herein to describe dispersed organic matter is that defined by the Standards Association of Australia (1986).

Reflectance measurements were made using a Leitz Ortholux II Pol BK microscope at AMDEL's Frewville laboratories under the conditions outlined in Standards Association of Australia (1981).

5.6.2 Photography

A Leitz Ortholux II microscope and a Wild Photoautomat MPS Spot camera were used to photograph the dispersed organic matter. A K 510 barrier filter and exciter filters BG 12 and BG 38 were employed for fluorescence-mode photography. The kerogen strewn slides were

examined and photographed using a palynological microscope fitted with a fluorescence light source.

5.6.3 Rock-Eval pyrolysis

The aforementioned potential source rock samples (48 from South Australia, and 33 from Queensland) were analysed for total organic carbon (TOC) and by Rock-Eval pyrolysis. The resulting data were interpreted in accordance with well established guidelines (Peters, 1986) to obtain information on source richness, kerogen type and thermal maturity. Estimates of maturity derived from hydrogen index *versus* T_{max} cross-plots are particularly useful where the DOM is lean in vitrinite phytoclasts, as is the case for much of the Murta Formation.

5.7 PETROLEUM GEOCHEMISTRY

Oils produced from Cretaceous units within the Eromanga Basin (Namur Sandstone, Murta Formation, and Cadna-owie Formation) are typically light (45° API gravity), non-waxy (pour point ≤ 0° C), low sulphur (< 0.05%), paraffinic crudes (Vincent *et al.*, 1985; Moore, 1986). Oils with higher wax contents (pour point = 9–18° C) do occur in Murta and Namur reservoirs, notably at Talgeberry-1 (Murta), Winna-1 (Murta), Sigma-1 (Namur, Murta), Strzelecki-4 (Namur), McKinlay-1 (Namur), Biala-1 (Namur, Murta) and Limestone Creek-1, -3 (Namur, Murta) (Fig. 5.5). Gasoline-range hydrocarbons (C_5–C_{10}) comprise 30–60% by weight of the oils. The lower gasoline yields, and concommitantly higher pour points, possibly reflect loss of light ends as a result of *in situ* washing by meteoric waters. This alteration process has been more widespread (and more aggressive) in Jurassic oil reservoirs (McKirdy, 1985; Heath *et al.*, 1989; Boreham and Hill, 1998; Boreham and Summons, 1999). Water washing may also account for the very low gas/oil ratios of the Cretaceous oil accumulations (*e.g.* Dullingari, GOR = 120–187 SCF/STB: Mount, 1981, 1982).

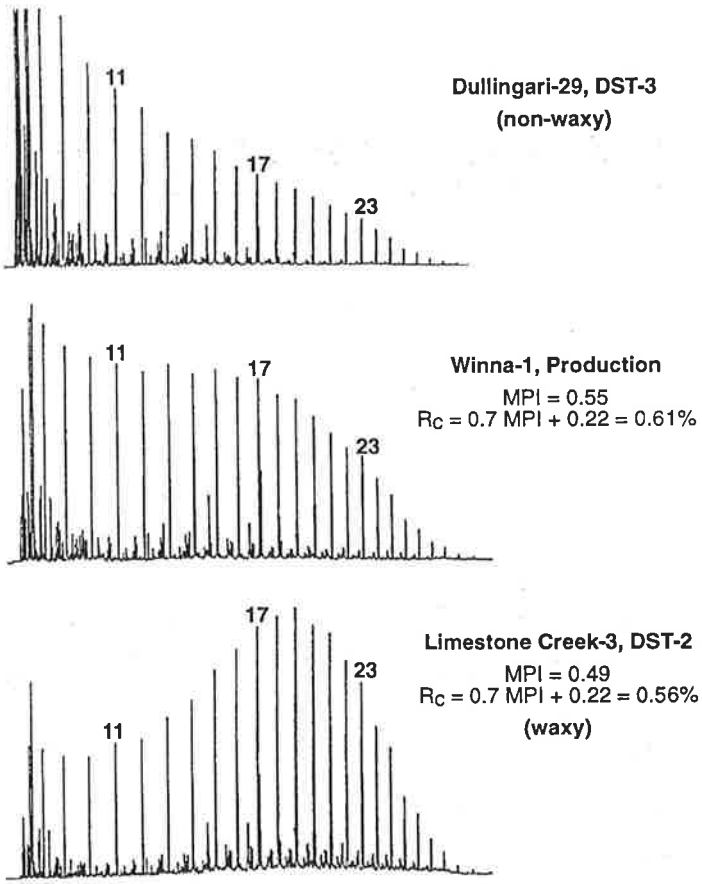


Figure 5.5 Whole-oil chromatograms of selected Murta Formation oils: a) Dullingari-29, DST 3; b) Winna-1, Production Test; c) Limestone Creek-3, DST 2

These Cretaceous oils are notable for their high pristane/phytane ratios (Pr/Ph = 5–9), although the waxy Murta/Namur crudes from fields along the Murteree Ridge have somewhat lower ratios (Pr/Ph = 3–4; Fig. 5.5). Paraffinic oils from Jurassic and Permian reservoirs throughout the Eromanga/Cooper Basin have pristane/phytane values mostly in the range 3 to 5, consistent

with their predominantly terrestrial origin. Another feature of the Cretaceous oils is their relative immaturity. Maturation indicators obtained from GC-MS analysis of their biomarker alkanes (*e.g.* C_{29} ααα-sterane 20*S*/20*R* and C_{30} βα-hopane/αβ-hopane ratios) and triaromatic hydrocarbons (*e.g.* methylphenanthrene index, MPI: Table 5.1) demonstrate a striking maturity differential between the Cadna-owie/Murta/Namur oils and those in stratigraphically older reservoirs:

Reservoir age	MPI	R_c (%)	C_{29} ααα $\frac{20S\dagger}{20R}$	C_{30} $\frac{\beta\alpha\ddagger}{\alpha\beta}$
Cretaceous*	0.45–0.56	0.54–0.61	0.53 – 0.82	0.16 – 0.23
Jurassic	0.60–0.81	0.64–1.04	0.82 – 1.16	0.09 – 0.17
Triassic/Permian	1.04–1.26	0.95–1.10	0.98 – 1.14	0.02

* excludes Murta oils from Merrimelia field
†Ratio of 20*S* to 20*R* epimer of 5α,14α,17α-24-ethylcholestane
‡Ratio of 17β-hopane (moretane) to 17α-hopane

The MPI values reveal that the Murta/Namur oils migrated from their source rocks at the very threshold of the conventional oil window (calculated vitrinite reflectance, R_c = 0.54–0.61%). Among the few exceptions are the Merrimelia-6, 15 (Murta) oils for which higher source maturities are indicated (R_c = 0.73–0.84%).

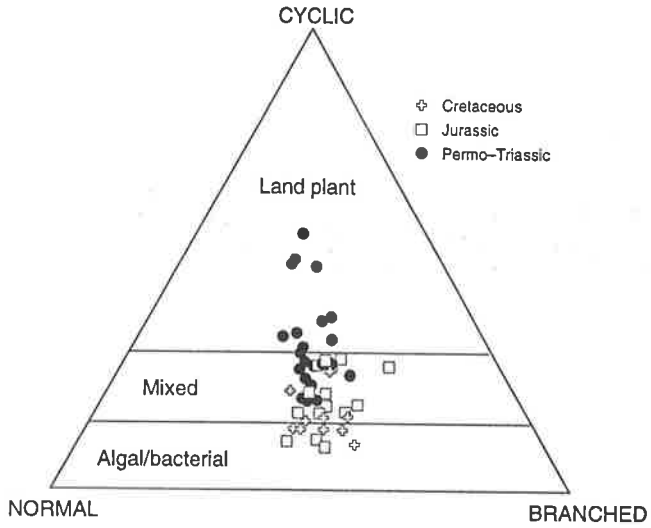


Figure 5.6 Source affinity of Cooper Basin and Eromanga Basin oils based on C_5 to C_7 alkane disributions (Michaelsen and McKirdy, 1989)

Oils of Permian and Jurassic origin, by and large, may be distinguished using two of the aromatic biomarker parameters proposed by Alexander *et al.* (1988), *viz* 1,2,5-TMN/1,3,6-TMN and 1-MP/9-MP ratios (Table 5.1). These oils were expelled from their respective source rocks at maturation levels (R_c = 0.64–1.04%, Jurassic; R_c = 0.95–1.10%, Permian) more in keeping with accepted models of hydrocarbon generation for terrestrial organic matter (Powell, 1987).

The maturation contrast between oils in Cretaceous, Jurassic and Permian reservoirs is paralleled (at some localities) by maturation-dependent differences in the molecular and isotopic compositions of natural gas (Vincent *et al.*, 1985). Gas in the Murta Formation at Dullingari North-1 clearly is less mature than gases in the underlying Permian reservoirs (Table 5.2).

By any account, therefore, the Murta/Namur oils are unusual. Kantsler *et al.* (1983, p. 90) were among the first to recognise the key role played by bacteria in their origin: *"Murta Member oils are geochemically distinct from oils in stratigraphically lower reservoirs and are believed to have been sourced from initially mature source rocks rich in bacterially-degraded (terrestrial) organic matter"*. A major contribution by bacterial remains to the source material of the Cretaceous (and, to a lesser degree, Jurassic) oils is evident from their C_5–C_7 alkanes (Fig. 5.6); the carbon isotopic composition of their C_{12+} hydrocarbons (Fig. 5.7); and their high concentrations of *iso*- and *anteiso*-alkanes relative to normal alkanes (Powell *et al.*, 1989). A

marked dominance of C_{29} steranes and diasteranes over C_{27} and C_{28} isomers indicates that land plants (rather than aquatic algae) were the major contributing eukaryotic precursor organisms (Vincent *et al.*, 1985; Powell *et al.*, 1989).

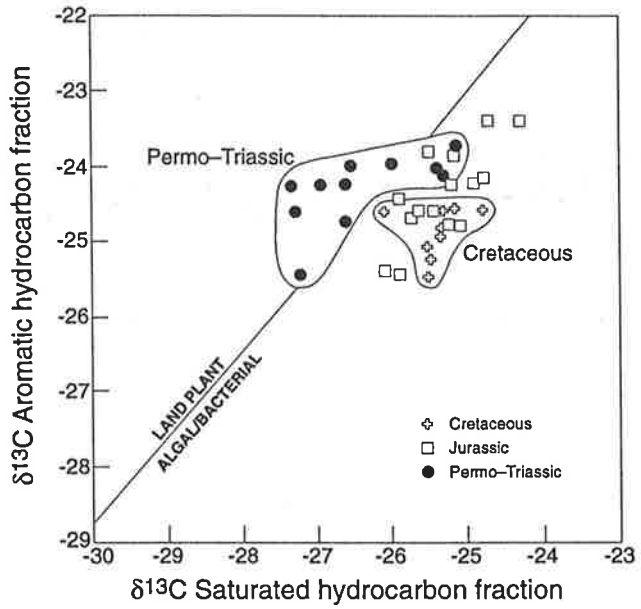


Figure 5.7 Carbon isotopic composition plot (after Sofer, 1984) of Cooper Basin and Eromanga Basin oils (Michaelsen and McKirdy, 1989)

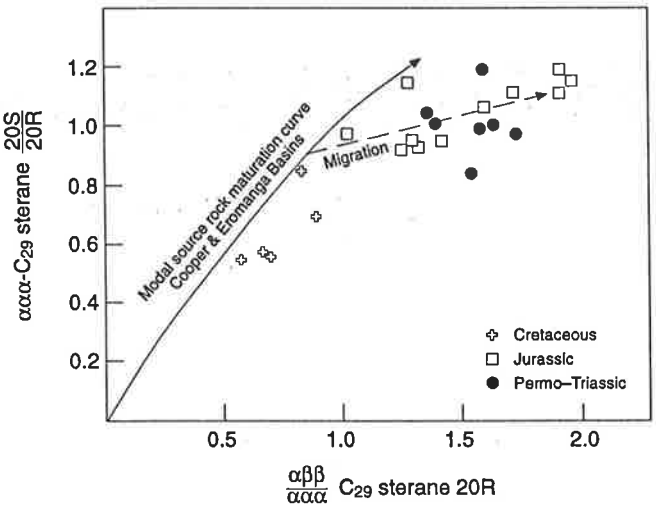


Figure 5.8 C_{29} sterane maturity and migration plot (after Seifert and Moldowan, 1981) of Cooper Basin and Eromanga Basin oils (Michaelsen and McKirdy, 1989)

Under appropriate freshwater lacustrine conditions aerobic bacteria are capable of upgrading the oil-source potential of woody-herbaceous material by preferentially degrading cellulose and lignin (Powell, 1986, 1987), and simultaneously contributing lipid-rich bacterial biomass to the residual organic matter (Lijmbach, 1975). Moreover, certain *aerobic* bacteria are known to contain high concentrations of discrete pristane (relative to phytane: Han *et al.*, 1968), and this may explain the elevated Pr/Ph ratios of many Murta oils.

Finally, the sterane isomeric ratios plotted in Fig. 5.8 indicate that Cretaceous oils are not only less mature than Jurassic and Permian crudes, but also less migrated. Short migration distances are implied and this is entirely consistent with the thinly intercalated source and carrier/reservoir beds that characterise the Murta Formation. This situation is optimal for efficient drainage of the *first-formed* petroleum hydrocarbons from the silty Murta source rock at a vitrinite $R_o \approx 0.5\%$. Although bacteria also contribute significantly to the source material of Jurassic oils, in this case primary migration occurred at higher maturation levels ($R_o > 0.6\%$) permitting generation of

waxy hydrocarbons from the leaf cuticle (cutinite) and cork tissue (suberinite) that are among the principal liptinites of the Birkhead coals and DOM (Cook, 1986).

5.8 ORGANIC FACIES

The geochemical character of Murta-hosted crudes demonstrates that they have been derived from bacterially-modified terrestrial organic matter, probably of Jurassic or younger age. Moreover, the relative immaturity of many of these oils ($R_o \approx 0.5$–0.6% at time of primary migration) corresponds closely to the measured vitrinite reflectance of the Murta sequence, implying essentially *in situ* generation. Petrographic and geochemical studies of core samples of the Murta Formation have provided additional evidence which supports a genetic relationship between certain Murta organic facies and these unusual oils.

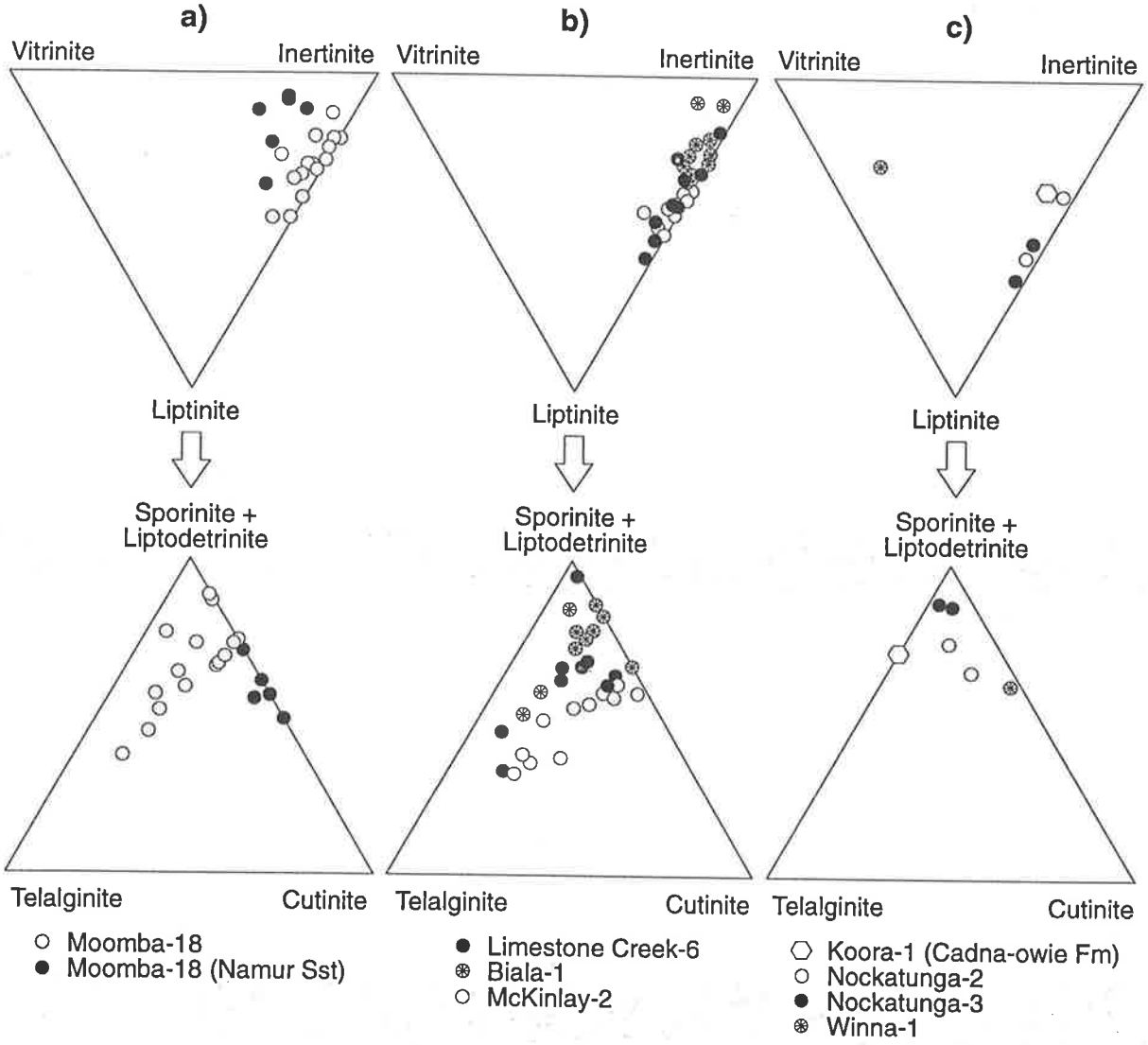


Figure 5.9 Maceral abundances in a) Namur Sandstone and distal lacustrine lithofacies of the Murta Formation at Moomba-18; b) intermediate lacustrine lithofacies of the Murta Formation at Biala-1, Limestone Creek-6 and McKinlay-2; c) transitional lithofacies of Murta Formation at Nockatunga-2, Nockatunga-3 and Winna-1. Data on basal Cadna-owie Formation at Koora-1 included for comparison (Michaelsen and McKirdy, 1989)

An organic facies is a mappable sedimentary rock unit identified soley by its dispersed organic matter (Jones and Demaison, 1980). Organic facies may be characterised by the relative abundance of the maceral groups (*viz* inertinite, vitrinite and liptinite) and their component macerals (Standards Association of Australia, 1986). These maceral associations are normally heterogeneous and controlled by the precursor flora, the provenance of the organic matter (whether allochthonous or autochthonous) and the nature of the depositional milieu (as defined by pH, Eh, and level of microbiological activity: Stach *et al.*, 1982). Consequently, the type and distribution of its organic facies has a significant bearing on the petroleum-generative potential of a sedimentary sequence (McKirdy *et al.*, 1984, 1986b; Demaison *et al.*, 1983; Thomas *et al.*, 1985).

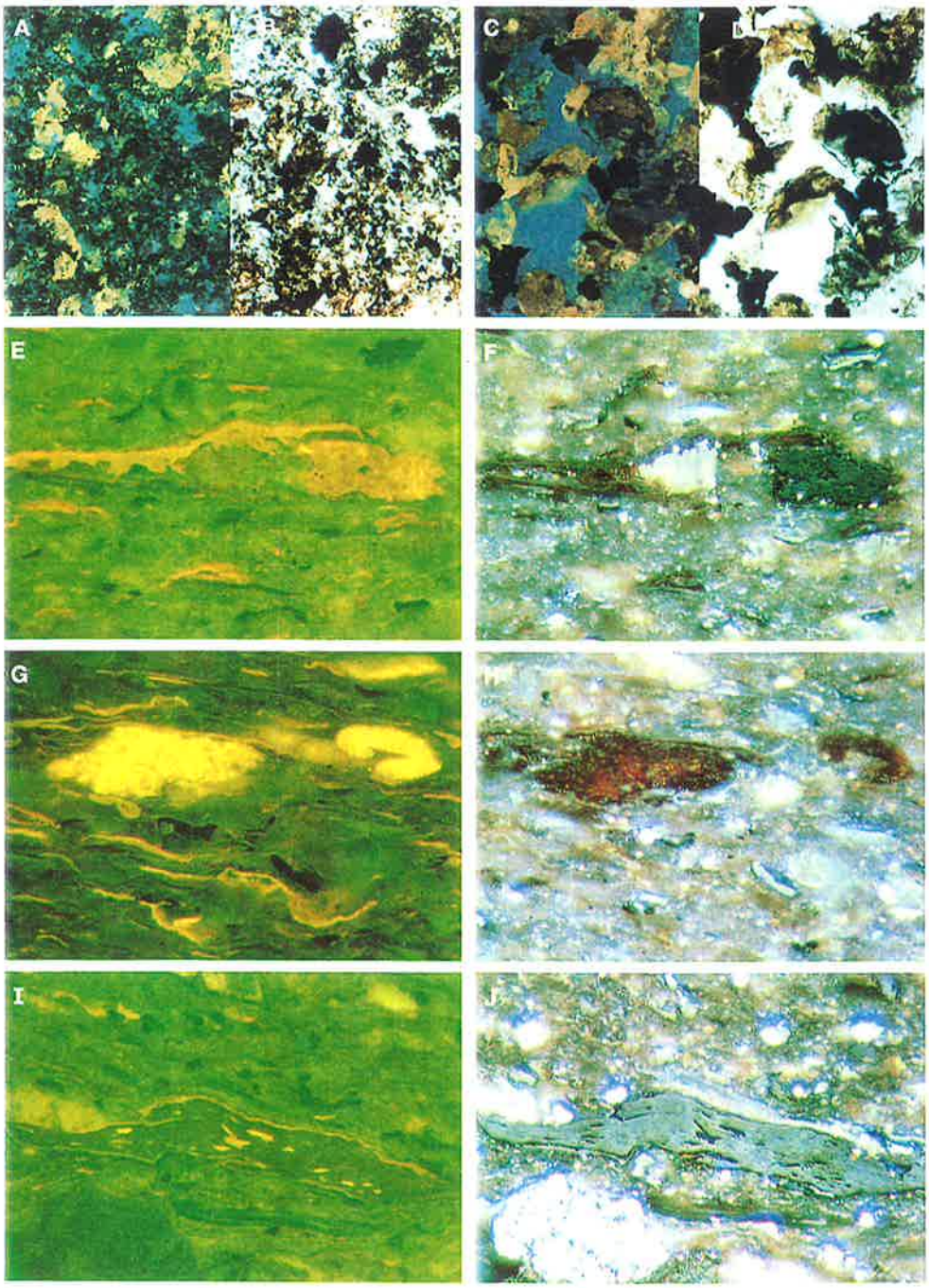


Plate 5.1 Selection of photomicrographs of organic-rich facies in the Murta Formation and Namur Sandstone, South Australia. All polished sections are oblique to bedding, field width 0.23 mm.

a) Kerogen concentrate (unsieved) from the Murta Formation shale siltstone (Limestone Creek-6, M2 sub-unit) showing both structured and amorphous material some of which fluoresces. Fluorescence-mode
b) As for a, but in polarised transmitted light
c) Sieved (> 0.02 mm) fraction of kerogen concentrate in a) & b) examined in transmitted light showing structured liptinitic and woody material. Fluorescence-mode
d) As for c, but in polarised transmitted light
e) DOM in Murta Formation distal lithofacies (Moomba-18, M2 sub-unit). *Botryococcus*-type telalginite, cutinite, sporinite and liptodetrinite. Fluorescence-mode. Liptinites possess orange fluorescence and inertinite is black. Fluorescence-mode
f) As for e, but in reflected white light
g) DOM in Murta Formation, intermediate lithofacies (Limestone Creek-6, M2 sub-unit). *Botryococcus*-type telalginite (yellow) and abundant sporinite and liptodetrinite. Fluorescence-mode
h) As for g, but in reflected white light
i) DOM in shale from Namur Sandstone (Moomba-18, 1777.5 m). Relatively intact vitrinite phytoclast enveloped by cutinite (orange) with resinite inclusions (yellow). Fluorescence-mode
j) As for I, but in reflected white light

5.8.1 Nappacoongee-Murteree and Moomba Blocks, South Australia

5.8.1.1 Murta Formation

The highly comminuted state of much of the dispersed organic matter preserved in carbonaceous siltstones and silty shales of the Murta Formation suggests extensive transportation and possible reworking from pre-existing sediments prior to its final deposition and burial.

The proportions of the three maceral groups are remarkably similar within the distal (Fig. 5.9a) and intermediate (Fig. 5.9b) lacustrine facies. The main macerals present are inertinite (40–80% of DOM) and liptinite (15–60% of DOM). Inertinite represents oxidised humic material (Stach *et al.*, 1982) and commonly, in the Murta Formation, exhibits dark grey to black corrosion rims. Inertodetrinite (all inertinite between 2 and 30 μm in maximum length; Standards Association of Australia, 1986) is by far the dominant maceral, whereas semifusinite and micrinite are subordinate.

Vitrinite is formed during diagenesis by the humification of cellulose and lignin (Dow, 1977; Stach *et al.*, 1982). It is a minor component here (< 12% of DOM: Figs 5.9a and 5.9b), probably because of oxidative decay of precursor woody tissue by aerobic bacteria. Individual sub-macerals are difficult to distinguish because of their highly fragmented nature. Vitrinite phytoclasts rarely exceed 30 μm in size. Pale oxidation haloes were noted in some samples. This feature is consistent with extensive transportation distances from source to site of deposition and preferential attack by fungi and aerobic bacteria (Powell, 1985). Weak auto-fluorescence in other samples indicates the presence of lipid-rich bacterial remains within the host vitrinite (Taylor *et al.*, 1988) or, alternatively, the generation of petroleum from, or its absorption by, the vitrinite itself.

The liptinites (in decreasing order of abundance) are sporinite and liptodetrinite, *Botryococcus*-type telalginite and cutinite (Figs 5.9a and 5.9b). Bituminite is very rare or absent. Examination of some complementary kerogen slides in transmitted light suggests that most of the ambiguous material classified as liptodetrinite is, in fact, sporinite in a poorer state of preservation. Comparison of the sieved (20 μm diameter) and unsieved fractions from identical samples reveals significant concentrations of structureless, somewhat fluorescing organic matter (Plate 5.1). In the whole rock sample, this amorphous component is intimately associated with the mineral matrix. Although likely to constitute at least 15–20% of the total DOM assemblage in most samples, it is difficult to identify during routine examination of polished blocks in normal incident light. Its presence is interpreted as further evidence of extensive bacterial degradation prior to preservation. Approximately equal proportions of intact gymnospermous pollen (*e.g. Classopollis*), and tree fern spores (notably *Cyathidites* and *Osmundacidites*) dominate a subordinate algal component. Price (1983) has also recognised bryophyte and lycopod spores within Murta sediments at Dullingari.

Alginite derived from *Botryococcus*-related micro-algae was identified in all five subunits within both sequences although it is restricted to isolated shale beds. The modern colonial Chlorophyceaean alga, *Botryococcus braunii* Kützing, has been the subject of many phytochemical investigations. Extant green algae of this genus are planktonic, found in freshwater or brackish environments and are prolific producers of lipids rich in C_{25}–C_{34} paraffinic hydrocarbons (Maxwell *et al.*, 1968; Largeau *et al.*, 1980; Metzger *et al.*, 1985a,1985b; McKirdy *et al.*, 1986a). The bulk of these hydrocarbons are synthesised and stored in the outer cell wall where they impart buoyancy to the living alga. A resistant polymer which is a potential precursor of highly oil-prone kerogen has also been identified in the cell wall of this alga (Berkaloff *et al.*, 1983; Largeau *et al.*, 1984).

At Moomba-18 within the Nappamerri Trough (Fig. 5.1; Table 5.3) argillaceous intervals of the Murta Formation typically display poor to fair source richness for hydrocarbons (TOC = 0.8–1.8%; $S_1 + S_2$ = 1–4 kg hydrocarbons/tonne). Hydrogen indices in the range HI = 125–200 and T_{max} values of 434–441° C suggest that these *distal* shales contain Type III kerogen at a present maturation level of R_o = 0.6–0.65% (Fig. 5.10a). Vitrinite reflectance data are sparse for core samples of the Murta Formation in Moomba-18 (R_o = 0.61%, n = 10), although a statistically reliable set of telovitrinite reflectance readings from the top of the underlying Namur Sandstone (R_o = 0.62%, n = 70) confirms the foregoing assessment of maturity. Kerogen composition tends to Type II/III in the richer Murta samples, as illustrated by an M3 shale (TOC = 2.05%; $S_1 + S_2$ = 5.6 kg hydrocarbons/tonne; HI = 260) in which liptinite (mostly sporinite and liptodetrinite) comprises 46% of the DOM. Similar organic matter in leaner M4 and M5 shales (TOC = 1.4–1.7%) gives appreciably lower hydrogen indices (HI =

156–196), a clear indication that the latter parameter is subject to a mineral matrix effect (as recognised by Powell *et al.*, 1989). Kerogen pyrolysis yield (S_2 peak) is commonly suppressed in siliciclastic rocks containing less than 3% TOC (Espitalié *et al.*, 1980; Orr, 1983).

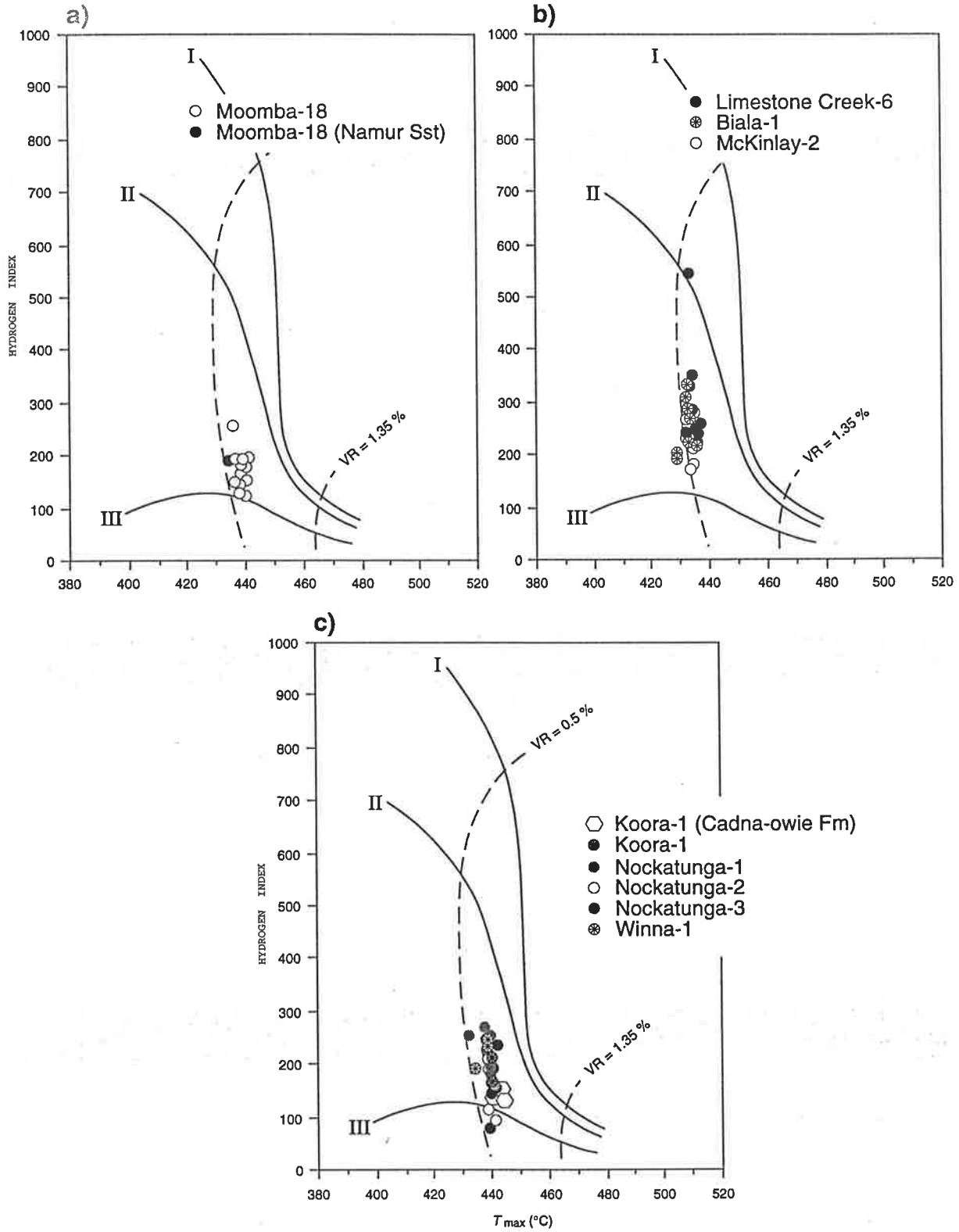


Figure 5.10 Kerogen type and maturity based on Rock-Eval T_{max} and HI data for a) the Murta Formation and Namur Sandstone at Moomba-18; b) the Murta Formation at Biala-1, Limestone Creek-6 and McKinlay-2; c) transitional lithofacies of Murta Formation at Nockatunga-1, Nockatunga-2, Nockatunga-3, Koora-1 and Winna-1. Data on basal Cadna-owie Formation at Koora included for comparison

Along the Murteree Ridge shale intervals within the Murta Formation contain kerogen of Type II/III or II composition and display improved organic richness and source quality (TOC = 1–2.5%; $S_1 + S_2$ = 3–12 kg hydrocarbons/tonne; HI = 175–540). Although only marginally

mature (R_o = 0.5–0.6%), these *intermediate* lacustrine shales are fair to very good sources of oil (Fig. 5.10b).

Optical microscopy has revealed high percentages of unoxidised algal material within many core samples of the *intermediate* facies, in particular shales from the M2 subunit. This probably reflects more rapid deposition in a less distal lacustrine setting, leaving less time for inorganic and bacterial oxidation. A positive correlation between liptinite/*Botryococcus*-derived telalginite content (as % of total DOM) and HI is particularly evident in shales at Limestone Creek-6. Two samples that contain the greatest proportion of liptinite (52–58% of total DOM) and telalginite (25–26% of total DOM) possess hydrogen indices (HI = 353 and 541) which are the highest values obtained in this study. These samples have excellent oil source potential. At McKinlay-2 (M5 subunit) and Biala-1 (M3–M4 subunits) the fluorescence of liptinite (particularly telalginite) is slightly less intense than at Limestone Creek-6 (M1–M3 subunits), and a positive correlation between alginite concentration and elevated hydrogen indices is not as obvious.

The fluorescence colour and intensity of telalginite range from moderate orange to moderate yellow at Moomba-18 through moderate yellow at McKinlay-2 and Biala-1, to intense yellow at Limestone Creek-6 (Table 5.4; Plate 5.1). Telalginite phyterals at Moomba-18 are typically less than 52 μm in maximum dimension, but at Limestone Creek-6 exceed 115 μm in diameter. The size of natural algal colonies varies with age (Burns, 1982). However, it has been demonstrated that laboratory cultures of *B. braunii* grown in a CO_2-enriched atmosphere require less time to increase their biomass than similar cultures under normal conditions (Metzger *et al.*, 1985b; Wolf *et al.*, 1985). After a critical period, disintegration occurs resulting in increased colony numbers. Hence, the smaller telalginite dimensions observed within the distal facies and some zones of the intermediate lacustrine sequence may be attributed to the physiological state of the alga, and/or a depressed or fluctuating nutrient supply within the oligotrophic lake.

Similarly, other liptinites within the Nappamerri Trough (*e.g.* sporinite and liptodetrinite) also display a change in fluorescence intensity and colour (from moderate/intense orange to dull yellow) compared to their equivalents along the Murteree Ridge (intense orange to medium yellow). The characteristics of all liptinites (but notably telalginite) in white incident light also differ — along the Murteree Ridge they are typically brown whereas at Moomba they assume a grey colour. A summary of liptinite characteristics for the Murta Formation, based on observations on a representative set of samples, is presented in Table 5.4.

The reduced fluorescence intensity of liptinite at the Moomba locality may be attributed to either or both of two phenomena:

1. Generation of hydrocarbons associated with an *Inkohlungsprung* (coalification jump: Stach *et al.*, 1982); and/or
2. Oxidation during sedimentation and/or early diagenesis (McKirdy *et al.*, 1986b).

According to Cook (1986) hydrocarbon generation from telalginite does not occur before a thermal maturity corresponding to 0.7% R_o. Therefore, partial oxidation of the telalginite and other liptinites during transportation and settling through an oxic water column is likely to be the major reason for the poorer source quality of the distal facies and its concominant depressed liptinite fluorescence.

Despite the total shale content of the M2 subunit being less than in the more argillaceous M1, M3 and M5 subunits (Figs 5.3 and 5.4), isolated shaly intervals within the M2 subunit from the intermediate lacustrine facies (and to a lesser extent, the distal facies) are significantly richer in better quality oil-prone organic matter than are their counterparts within the other subunits (Table 5.3).

5.8.1.2 Namur Sandstone

By way of contrast, the Namur Sandstone (based on six samples from Moomba-18) contains relatively well preserved DOM with a higher proportion of vitrinite (13–27%), and a different suite of liptinites (cutinite > sporinite > liptodetrinite > resinite; Fig. 5.9a). Bituminite is normally an insignificant component and *Botryococcus* is notably absent in most samples. Two types of vitrinite are recognised: detrovitrinite is slightly duller and has a grainy texture, whereas telovitrinite is typically enveloped by cutinite. Individual phytoclasts (particularly telovitrinite) are aligned parallel with the bedding laminae and are often greater than 1 mm in length and up to 30 μm in width (Plate 5.1).

The intact nature of much of liptinitic and humic material within the Namur Sandstone suggests that transportation distances from source to site of deposition were relatively short. These data are consistent with deposition in a swamp or some other low energy environment peripheral to the Murta lacustrine system. One shale sample from the Namur Sandstone displays very good organic richness (TOC = 3.50%; $S_1 + S_2$ = 7.4 kg hydrocarbons/tonne) and moderate source quality (HI = 185).

Although the total shale volume is subordinate in the M2 subunit, and almost insignificant in the case of the Namur Sandstone, the data presented herein demonstrate that isolated thin shale laminae occuring within dominantly arenaceous lithofacies are often significantly richer in hydrogen rich oil-prone organic matter than more massive shales (*e.g.* M5 subunit, McKinlay-2). Dominantly sandy intervals containing only minor shale are commonly deposited more rapidly than more argillaceous units, thereby reducing the likelihood of source quality degradation by aerobic bacteria.

5.8.2 Nockatunga area, Queensland

5.8.2.1 Murta Formation

The Murta Formation at the eastern end of the NJ Ridge (Queensland) lies within the transitional lithofacies of Ambrose *et al.* (1986). Selected shale/siltstone samples from the upper Murta Formation (M1 equivalent at Nockatunga-2 and 3) contain high concentrations of inertinite, and a liptinite assemblage (39–64% of DOM) dominated by sporinite and liptodetrinite (Fig. 5.9c). The contents of vitrinite (2–8% of DOM) and telalginite (1–7% of DOM) are both uniformly low.

Carbonaceous shale (TOC = 1.33%) from 1016.3 m depth in Winna-1 is tentatively assigned to the M2 or M3 subunit. Its DOM is atypical in that it contains a substantially higher proportion of relatively well preserved vitrinite (56% of DOM: Fig. 5.10b). Further work is required to determine the distribution and palaeoenvironmental significance of this novel organic facies, and its possible relationship with Zoellner's (1988) postulated marine incursion.

The organic richness and hydrocarbon genetic potential of argillaceous Murta sediments in the Nockatunga/Winna/Koora area (Fig. 5.1) extend to lower values than elsewhere (TOC = 0.54–1.59%; $S_1 + S_2$ = 0.5–6.5 kg hydrocarbons/tonne). Likewise source quality tends to be poorer, as reflected by hydrogen indices in the range HI = 81–270 (Fig. 5.1c). The aforementioned mineral matrix effect has obscured the true quality of the better potential source beds. Kerogens isolated from five Murta shales (TOC = 0.9–1.5%) have atomic H/C values in the range 0.91–1.30, and hydrogen indices (HI = 320–400) that are appreciably higher than those measured from the corresponding whole-rock samples (Powell *et al.*, 1989).

5.8.2.2 Cadna-owie Formation

Silty shales (TOC=0.88–1.18%) from the base of the Cadna-owie Formation in Koora-1 (968.7–974.5 m depth) make an interesting comparison with the underlying Murta Formation (M1 subunit: 984.1 – 987.0 m) in the same well. DOM in the one sample of Cadna-owie Formation examined petrographically is inertinite-rich and vitrinite-poor (Fig. 5.9c). This DOM is distinguished from that in the Murta Formation only by its higher telalginite content (10% of DOM) which is, perhaps, surprising for a marginal *marine* unit.

Rock-Eval data on the Cadna-owie shales ($S_1 + S_2$ = 1.2–1.9 kg hydrocarbons/tonne; HI = 118–156; T_{max} = 443–444° C) suggest that they contain initially mature ($R_o \approx 0.6\%$) gas-prone Type III kerogen (Fig. 5.16). The subjacent Murta Formation is slightly more organic-rich (TOC = 0.95–1.49%; $S_1 + S_2$ = 2.3–5.0 kg hydrocarbons/tonne) and contains better quality Type II/III kerogen (HI = 168212: Fig. 5.10c) Again, low TOC values (< 3%) and the likelihood of a mineral matrix effect during Rock-Eval pyrolysis make this assessment of Cadna-owie source quality unduly pessimistic. Indeed, kerogen isolated from the same shale for which DOM data are available shows it to be oil and gas-prone (atomic H/C = 1.04; HI = 347, *cf.* whole-rock HI = 156: Powell *et al.*, 1989).

5.9 PETROLEUM-GENERATIVE POTENTIAL

The hydrocarbon source potential of the Murta Formation may be assessed by collating the available sedimentological, petrographic, pyrolysis and vitrinite reflectance data.

A primary control on organic facies (and hence petroleum-generative potential) is the oxicity of the depositional environment within the overall Murta lacustrine setting. Carbonaceous siltstones and shales from three broad lithofacies associations have been examined. Characterised by

proximity to the source areas of clastic sediment and listed in order of increasing frequency and intensity of exposure of the *benthic* environment to oxygenated water, these associations are: distal lacustrine, intermediate lacustrine, and transitional to braided fluvial.

For each of the M2–M5 subunits in South Australia a consistent pattern emerges whereby kerogen quality (HI) and/or organic richness (TOC, $S_1 + S_2$) is greater in the *intermediate* than in the distal lithofacies. Potential source rocks in the distal lithofacies are generally leaner (TOC < 1.75%) and of poorer quality (HI < 200), reflecting partial oxidation of algal and land plant material as it settles slowly through the oxic epilimniom. Even within the *M5 subunit*, which hitherto has been regarded as distal throughout the southern Eromanga Basin, the same compositional difference exists between the Moomba area (distal) and the Murteree Ridge (intermediate).

Within the *M1 subunit* a simliar but less marked difference in organic richness and overall kerogen quality is evident between the *intermediate* lithofacies (at Limestone Creek) and the *transitional* lithofacies (at Nockatunga and Koora). Although carbonaceous siltstones are predominantly oil-prone in both areas, more than one-third of the M1 samples analysed from PL 33 are essentially gas-prone (TOC < 1.25%; $S_1 + S_2 < 2$ kg hydrocarbons/tonne; HI < 175). In this case, sporinite content proves to be an effective discriminator of depositional environment. Sporinite in the M1 subunit is both more abundant and much better preserved at Nockatunga (19–37% of DOM; 66 – 82 of sporinite and liptodetrinite) than at Limestone Creek (4–7% of DOM; 22–37% of sporinite and liptodetrinite).

Where, then, are the best potential source rocks developed within the stratigraphic and palaeogeographic framework of ancient Lake Murta? Within the intermediate lacustrine lithofacies association along the Murteree Ridge at Biala, Limestone Creek and McKinlay carbonaceous siltstones are, with few exceptions, oil-prone (HI > 200) throughout the entire Murta sequence. However, the best quality source beds (TOC = 2%; $S_1 + S_2$ = 8–12 kg hydrocarbons/tonne; HI = 350–540) are located in the *M2 subunit*. They contain liptinite-rich organic matter (kerogen atomic H/C = 1.0) in which well preserved, *Botryococcus*-related telalginite is unusually abundant (25–26% of DOM). Similar telalginite-rich sediments (15–22% of DOM) occur within the *M5 subunit*, but here total organic carbon contents are lower (TOC ≤ 2%) and both hydrogen index (HI = 175–245) and genetic potential ($S_1 + S_2$ = 3–5 kg hydrocarbons/tonne) have been suppressed by the mineral matrix effect. Kerogen isolation from one of these siltstones (HI = 185) has an atomic H/C value of 0.95 and is clearly oil-prone.

Oil-prone source beds (TOC = 0.9–1.6%; $S_1 + S_2$ = 2–6.5 kg hydrocarbons/tonne) within the transitional lacustrine lithofacies of the upper Murta Formation at Nockatunga (M1) and Winna (M2/M3?) appear to be of a different character in that the liptinite component of their organic matter (30–64% of DOM) is predominantly intact sporinite. The Winna source facies is further distinguished by its uncommonly high vitrinite content (56% of DOM). In both cases, source quality (fair to good) is better than indicated by Rock-Eval pyrolysis of whole-rock samples: hydrogen indices as high as HI = 400 have been measured from kerogen concentrates.

Although the distal lacustrine sequence at Moomba generally lacks high-grade source rocks, fair oil generative potential is displayed by selected silty shales from the M2 and M4 subunits (TOC = 1.4–2.0%; $S_1 + S_2$ = 3–6 kg hydrocarbons/tonne; HI = 180–260). Their source potential has been downgraded by partial oxidation of the liptinitic fraction.

The contribution of bacterial biomass to potential source rocks in the Murta Formation is difficult to identify and quantify using the techniques employed in this study. Clues to its presence are provided by:

1. the highly comminuted state of the dispersed organic matter;
2. a significant proportion (15–20% or more) of fluorescent amorphous material in slides of unsieved kerogen (Plate 5.1);
3. sporinite and liptodetrinite in various stages of (bacterial?) degradation; and
4. the very low abundance of vitrinite in the terrestrial component of the DOM.

Furthermore, the same bacterial biomarkers that characterise the Murta oils are also found in Murta source rock extracts (Powell *et al.*, 1989).

5.10 MATURITY SUPPRESSION IN THE MURTA FORMATION?

In the foregoing discussion, the maturity of potential Murta source rocks is conventionally assessed using directly measured vitrinite reflecance (R_o) and/or Rock-Eval-derived T_{max}. However, the implications of the FAMM study described in Chapter 4 (based on Permian and Jurassic shales and coals) is that vitrinite reflectance suppression is likely to be widespread throughout the Cooper/Eromanga sequence. It is therefore reasonable to expect that vitrinite reflectance suppression may also be important in the Murta Formation.

Although FAMM data were not obtained from samples of the Murta Formation, it is possible to estimate the likely true maturity (or at least a more accurate maturity) from the available Rock-Eval data. As shown in Chapter 4, the relationship between maturity determined by FAMM and T_{max} (Rock-Eval pyrolysis), is R_{FAMM} (%) = $0.02T_{max}$ – 7.85. When applied to Rock-Eval data on core samples in siltstones of the Murta Formation, from the Biala-1, Limestone Creek-1, McKinlay-2 and Moomba-18 wells, the equivalent unsuppressed vitrinite reflectance (R_{FAMM}) over the intervals indicated is shown to be as follows:

Locality	Depth interval (m)	Average T_{max} (° C)	n	Estimated R_{FAMM} (%)
Biala-1	1199.97–1215.52	432	10	0.80
Limestone Creek-6	1211.91–1219.99	434	9	0.84
McKinlay-2	1237.74–1247.85	433	11	0.82
Moomba-18	1732.00–1768.37	438	16	0.91

Of course, these calculated values should ultimately be tested directly by FAMM. However, the data measured by conventional means may well underestimate the maturity of the Murta Formation by as much as *ca* 0.25% R_o. Whereas directly-measured R_o and T_{max} place the Murta Formation along the Murteree Ridge (where the most oil-prone source facies are developed, *cf.* Chapter 3) in the early oil window (*ca* 0.5–0.6% R_o), the calculated R_{FAMM} values indicate a more likely maturity of around 0.82% R_o, approaching the peak of oil generation from Type II or II/III kerogen.

Despite very close similarities between biomarker contents of Murta siltstones and oils (*cf.* Powell *et al.*, 1989), and their matching maturities based on MPI and other criteria (*e.g.* sterane isomers: Powell *et al.*, 1989), the proposition that the Murta Formation has generated significant quantities of oil appears to contradict recent kinetic studies on petroleum generation. These indicate that potential Murta source rocks generate oil at significantly greater maturities (*i.e.* ≥ 0.8% R_o: Boreham and Hill, 1998). This conundrum can be resolved if one accepts that the "conventional" maturation level(s) of the Murta siltstones are unduly low, and that their calculated R_{FAMM} maturities are more accurate.

5.11 SYNOPSIS

1. Key aspects of the geochemistry of paraffinic crude oils reservoired within lacustrine sands of the Neocomian Murta Formation (notably their C_5–C_7 alkane distributions; carbon isotopic compositions of C_{12+} saturate and aromatic hydrocarbons; and high concentrations of bacterial biomarkers, including *iso*- and *anteiso*-alkanes) are a direct reflection of their derivation from terrestrial organic matter enriched in the remains of bacteria and other micro-organisms.
2. Oil maturity measurements based on sterane isomer ratios and triaromatic hydrocarbon distributions point to the likelihood of their origin from source beds within the Murta Formation itself, at vitrinite reflectances in the range R_o = 0.5–0.6%.
3. Organic petrography, in combination with Rock-Eval pyrolysis, is capable of discriminating between source and non-source facies within carbonaceous siltstones and shales of the Murta Formation. Three discrete organic facies have been defined and these correspond to the generalised distal, intermediate and transitional lacustrine lithofacies of Ambrose *et al.* (1986).
4. Petrographic observations support the notion that the heterolithic Murta Formation was deposited in a fresh to brackish aquatic environment. Dispersed organic matter within all organic facies is dominated by highly comminuted land plant detritus including oxidised humic material (inertinite), fern spores and saccate gymnosperm-derived pollen. Liptinite

is the dominant maceral group along the Murteree Ridge where telalginite originating from *Botryoccocus*-type algae, usually a minor component, is particularly abundant. Examination of kerogen in transmitted light reveals the presence of a significant amount of amorphous material (15–20% of total kerogen).

5. Within the *distal* lacustrine sequence (Moomba, Nappamerri Trough), organic matter of both algal and terrestrial affinity has been oxidised prior to burial thereby reducing its petroleum-generative potential. Here the fluorescence colours of the liptinites (notably telalginite) are typically reduced to a medium orange/yellow. This predominantly gas-prone organic facies contains shale/siltstone intervals that display depressed organic richness and source quality (TOC = 1–2%; potential yield = 1–6 kg hydrocarbons/tonne; Type III kerogen).

6. By way of contrast, along the Murteree Ridge (*intermediate* lacustrine facies), oil-prone Murta shales display a superior oil source-potential (TOC = 1–2.5%; potential yield = 3–12 kg hydrocarbons/tonne; Type II/III kerogen). Throughout this facies, the primary coloration and fluorescence characteristics of the liptinites have been preserved implying more rapid deposition and burial of the organic matter. The best oil-prone shales (HI = 350–540), in which *Botryococcus* comprises up to 26% of the DOM, occur as isolated laminae in the otherwise sandy M2 subunit (notably at Limestone Creek).

7. Potential for significant liquid hydrocarbon generation from Type II/III kerogen also exists within silty shales (TOC = 0.9–1.6%; HI = 168–212; $S_1 + S_2$ = 2–6.5 kg hydrocarbons/tonne) of the *transitional* lacustrine sequence in the Nockatunga area (Queensland). The DOM assemblage at here (M1 subunit) is similar to those of the distal and intermediate lacustrine facies (*i.e.* inertinite > liptinite > vitrinite), except that its liptinite is predominantly intact sporinite and telalginite is less abundant. At Winna an oil-prone vitrinite-rich organic facies is developed within the M2/M3 subunit.

8. Conventionally measured and calculated maturities for the Murta siltstones are likely to be erroneously low. Calculated maturities derived from T_{max} indicate that the oil-prone source facies developed along the Murteree Ridge has a maturation level (calculated $R_{FAMM} \geq 0.80\%$) which exceeds directly measured vitrinite reflectance by as much as 0.25% R_o absolute.

CHAPTER 6

Eromanga oil pools as products of multiple source rocks and in-reservoir mixing: Evidence from aromatic hydrocarbon signatures

CHAPTER 6

Eromanga oil pools as products of multiple source rocks and in-reservoir mixing: Evidence from aromatic hydrocarbon signatures*

* Parts of this chapter have been published as follows (Appendix 4):

Boult P.J., Ryan M.J., Michaelsen B.H., McKirdy D.M., Tingate P.R., Lanzilli E. and Kagya M.L.N. (1997) The Birkhead Hutton (!) petroleum system of the Gidgealpa area, Eromanga Basin, Australia. In *Petroleum Systems of SE Asia and Australasia Conference*, ed. J.V.C. Howes and R.A. Noble. Indonesian Petroleum Association, Jakarta, Indonesia, pp. 213–235.

Boult P.J., Lanzilli E., Michaelsen B.H., McKirdy D.M. and Ryan M.J. (1998) A new model for the Hutton/Birkhead reservoir/seal couplet and the associated Birkhead-Hutton(!) Petroleum System. *Australian Petroleum Production and Exploration Association Journal* 38(1) 724–744.

Michaelsen B.H. and McKirdy D.M. (1999) Aromatic hydrocarbon signatures of oils from the Cooper and Eromanga Basins, central Australia: Evidence of multiple sources and in-reservoir mixing. *19th International Meeting on Organic Geochemistry, Abstracts*. European Association of Organic Geochemists, Istanbul, Turkey, pp. 645–646.

Michaelsen B.H. and McKirdy D.M. (2000) Migration and mixing of oils in the Cooper/Eromanga Basin. In *Australian Organic Geochemistry Conference, Book of Abstracts*. Australian Institute of Marine Science, Townsville, Queensland.

Michaelsen B.H. and McKirdy D.M. (2001) Migration and mixing of oils in the Cooper and Eromanga Basins, central Australia. *In Eastern Australasian Basins Symposium, A Refocused Energy Perspective for the Future* (ed. K.C. Hill and T. Bernecker), Petroleum Exploration Society of Australia, Special Publication, pp. 289–300.

6.1 SUMMARY

The aromatic hydrocarbon contents of 62 oils from South Australia and Queensland were screened using whole-oil GC-MS in order to more fully characterise each Permian (Cooper Basin) family (*cf.* Chapter 2), and to distinguish them from oils of Jurassic (intra-Eromanga) origin. A novel combination of aromatic source and maturity parameters has enabled the recognition of multiple petroleum systems; instances of migration from Permian kitchens into Jurassic reservoirs; and Eromanga traps which have received charges from both Permian and Jurassic source rocks.

6.2 INTRODUCTION

This survey of aromatic hydrocarbon distributions in a large suite of oils from the Cooper and Eromanga Basins was prompted by the discovery of two families of oil in Early Permian reservoirs (Chapter 2). Family 1 oils, such as those in the Fly Lake, Tirrawarra, Moorari and Woolkina Fields of the Patchawarra Trough, are exceptionally mature (MPI-derived $R_c \approx$ 1.05–1.2%; TNR > 1). They also display unusual molecular characteristics based on their saturated hydrocarbon biomarkers, namely: rearranged hopanes >> 17α-hopanes; steranes >> hopanes. Matching rearranged hopane distributions in coals of the Patchawarra Formation are evidence that these high-maturity oils were derived from coals, rather than shales which have more conventional hopane distributions (McKirdy *et al.*, 1997). The latter are a feature of Family 2 Permian oils in fields such as Daralingie, Gidgealpa, Malgoona and Sturt (MPI-derived R_c = 0.93–0.99%; rearranged hopanes < 17α-hopanes ; steranes < hopanes).

This chapter describes the results of whole-oil GC and GC-MS analyses used to screen the isoprenoid and aromatic hydrocarbon contents of 62 oil samples from South Australia (n = 44) and Queensland (n = 18). The purpose of the work was to test whether aromatic hydrocarbon signatures can be used to quantify the relative volumes of high-maturity oil which may have migrated from the Cooper Basin into the overlying Eromanga Basin.

The objectives of a recent study by Boreham and Summons (1999) were similar. They used a broad suite of analyses including GC (n-alkanes), GC-MS (saturated and aromatic hydrocarbons) and carbon isotopic composition of bulk aromatic and saturated hydrocarbon

fractions. However, pivotal to their study were interpretations based on compound-specific isotopic analyses of *n*-alkanes. The work outlined in this chapter (Section 6.4.6, summarised by Michaelsen and McKirdy, 1999) presents an alternative (more rapid and less expensive) method of semi-quantitatively estimating the relative contribution of Permian and Jurassic source input to an oil accumulation.

Whole-oil analyses are rapid and relatively inexpensive because they do not require time-consuming preliminary fractionation of the oil sample. A secondary aim of this work was to test whether whole-oil GC-MS using the Hewlett-Packard instrument (described below) is sufficiently sensitive and reliable to become a routine analytical tool for the oil exploration industry.

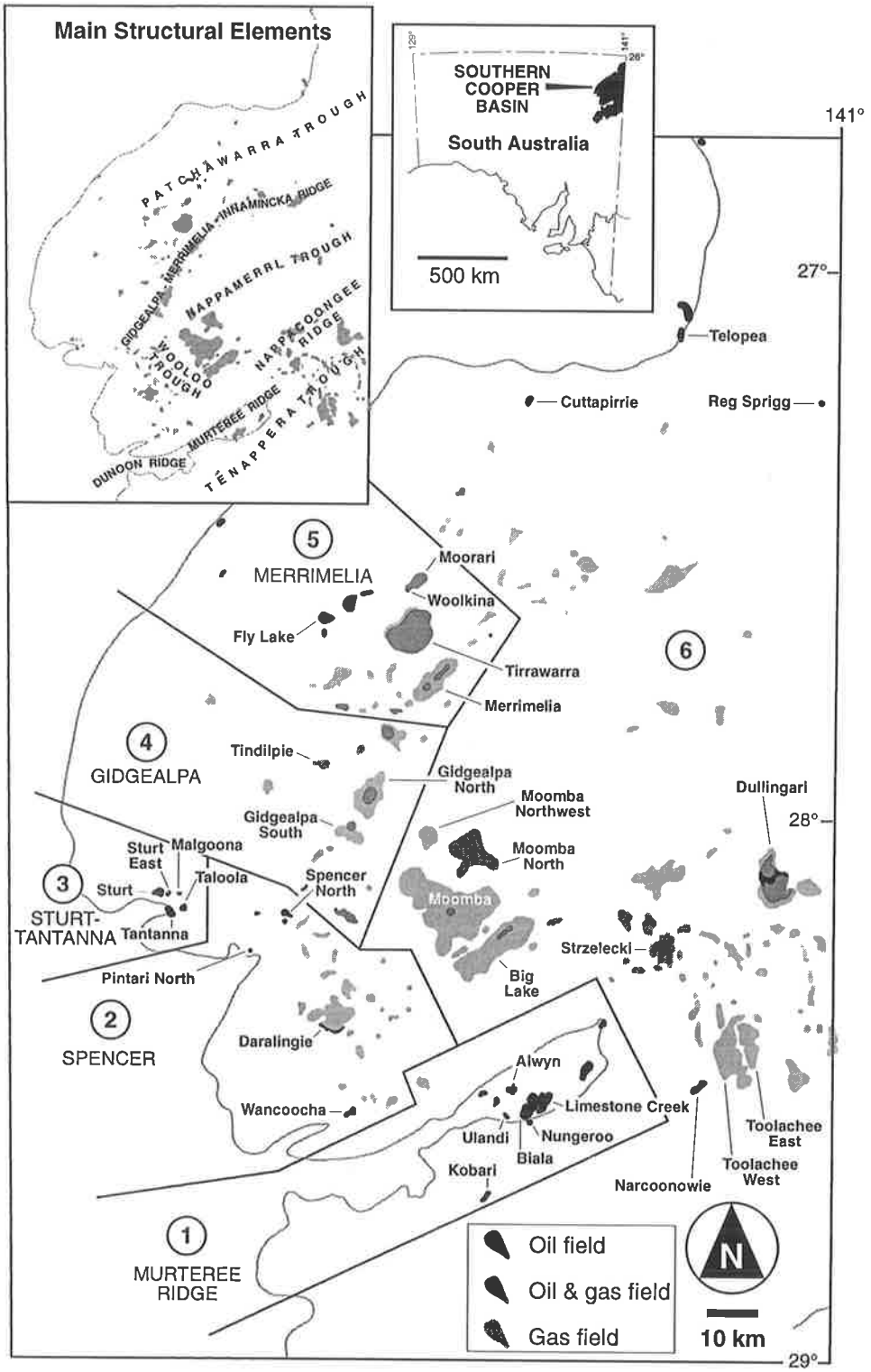


Figure 6.1 Study area in South Australia with respect to the oil and gas fields of the southern Cooper Basin. (Generalised structural-stratigraphic cross-sections for selected fields in areas 1–5 are represented in Figure 6.14)

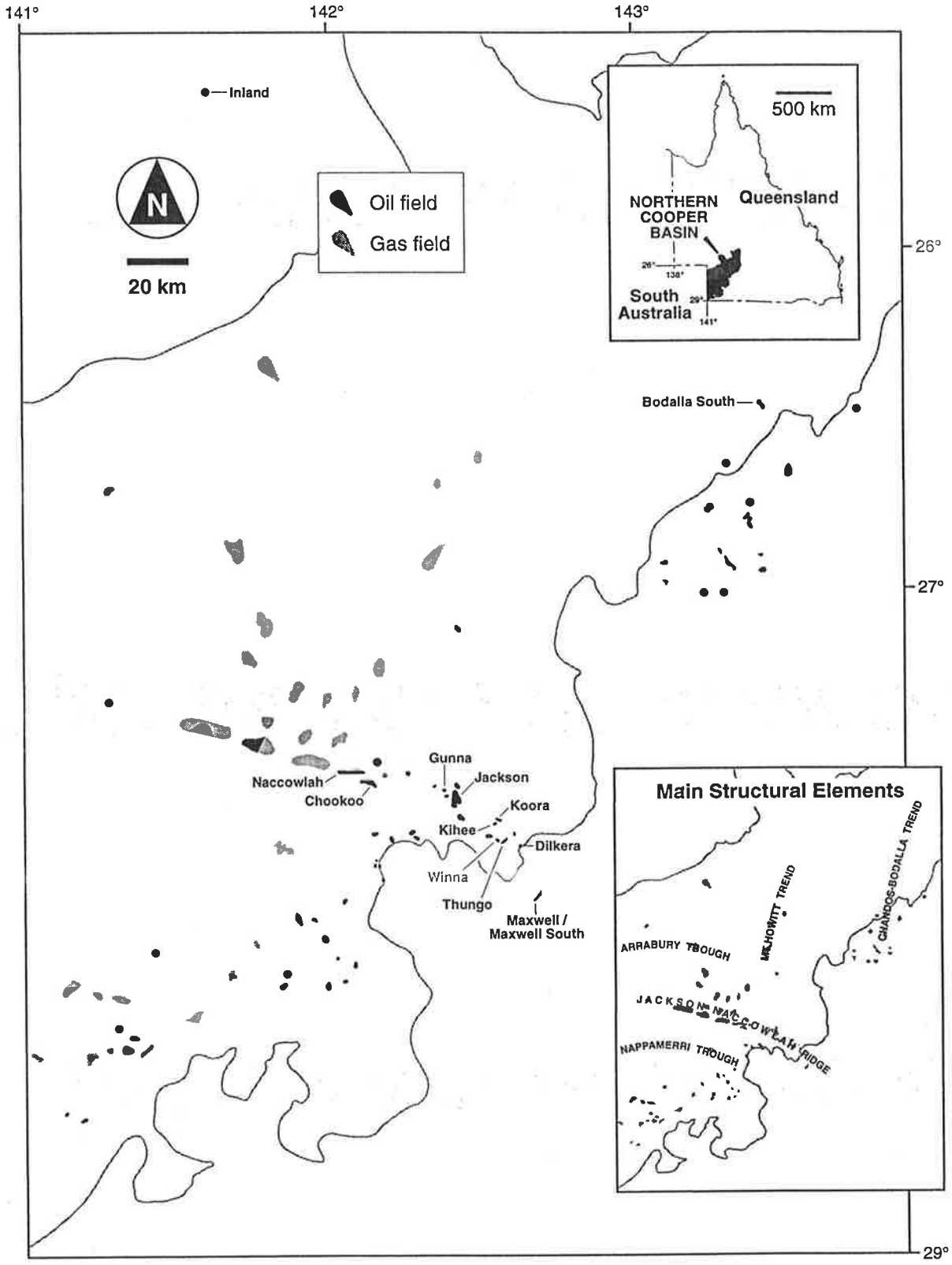


Figure 6.2 Study area in Queensland with respect to the oil and gas fields of the northern Cooper Basin

6.3 EXPERIMENTAL

6.3.1 Gas chromatography

Gas chromatography of whole oils was conducted on a Hewlett-Packard 6890 Series GC fitted with a split/splitless injector (T = 295° C; split ratio = 1:200), a HP-5 capillary column (30 m length, 0.25 mm internal diameter, 0.25 μm film thickness) and a FID.

Helium was used as the carrier gas at an average velocity of 19 cm s^{-1} (inlet pressure *ca* 11.3 psi). The FID was serviced by H_2 (30 ml min^{-1}), N_2 (make-up gas: 30 ml min^{-1}) and zero grade air (295 ml min^{-1}). To resolve the gasoline-range hydrocarbons the oven was cryogenically cooled using liquid nitrogen. The temperature programme (courtesy Xinke Yu, University of Adelaide) of the oven was as follows: –60° C for 2 min, –60° to 10° C at 20°/min, 10° to 20° C at 10°/min, 20° to 40° C at 20°/min, 40° to 240° C at 5.5°/min, 240° to 310° C at 6°/min and finally held at 310° C for 60 to 70 min. Data were collected using a Hewlett-Packard Vectra XA (166 MHz) computer running *ChemStation* software under a *Windows 95* operating system.

Typically 0.3 µl of oil was injected. Waxy oils required preheating prior to injection and the syringe was also heated to ensure maximum transfer of the sample into the injector. To prevent cross-contamination between injections, the syringe was disassembled and exhaustively cleaned with solvents after each analysis. Blank analyses were made periodically to check the system.

6.3.2 Gas chromatography-mass spectrometry

For GC-MS analyses the same Hewlett-Packard GC was fitted with a HP-5MS capillary column (same specifications as above) and reconfigured to interface with a Hewlett Packard 5973 Mass Selective Detector. The oven temperature programme was similar to that used for GC, except that the oven was not cryogenically cooled. Rather, the oils were injected at an oven temperature of 60° C and held at that temperature for 11.136 min. This procedure ensured that compounds with boiling points above 60° C had retention times which matched those obtained by GC analysis, thus allowing for easy cross-referencing between data sets.

The MS was operated in SIM mode and programmed for the following ions: *m/z* 128.1 (naphthalene), *m/z* 132.1 (tetramethyltetralins), *m/z* 142.1 (methylnaphthalenes), *m/z* 146.1 (pentamethyltetralin), *m/z* 156.2 (dimethylnaphthalenes), *m/z* 170.2 (trimethylnaphthalenes), *m/z* 178.2 (phenanthrene), *m/z* 184.2 (tetramethylnaphthalenes), *m/z* 192.2 (methylphenanthrenes), *m/z* 198.2 (pentamethylnaphthalenes and methyldibenzothiothenes), *m/z* 206.2 (dimethylphenanthrenes) and *m/z* 219.2 (retene). However, for the purpose of this thesis, the alkyltetralin, dibenzothiothene, and tetra- and pentamethylnaphthalene data were not interpreted. The dwell time of each ion monitored was 12 ms resulting in 3.04 cycles s^{-1}. The GC-MS transfer line, MS quadrupole and ion source temperatures were 310°, 106° and 230° C respectively, and the electon multiplier voltage was typically *ca* 1176 mV. Blank analyses were run between oil samples to ensure that the injector and column were clean.

6.4 Results and Discussion

Table 6.1 presents important source and maturity ratios based on isoprenoid and aromatic hydrocarbons in the South Australian and Queensland oils. All the parameters calculated were from integrated peak areas. GC traces and selected GC-MS fragmentograms for the oil samples are provided in Figures 6.3–6.13.

6.4.1 *n*-Alkane distribution

6.4.1.1 Cooper Basin

South Australia

The different chemistry of the Cooper Basin Family 1 and 2 oils is clearly evident from their disparate whole-oil chromatograms (Fig. 6.3). Family 1 oils have an *n*-alkane profile with a maximum around *n*-C_7, whereas in Family 2 oils the *n*-alkanes are skewed towards higher carbon numbers (maximum in the range *n*-C_{13} to *n*-C_{23}) and, in the case of the Daralingie-18 (Patchawarra) crude, exhibit some bimodality. High proportions of waxy hydrocarbons (*n*-C_{20+}) in Cooper Basin Family 2 oils such as Daralingie-18 (Patchawarra) and Malgoona-1A (Merrimelia), and also Sturt-6 are consistent with land plant-derived source material (Lijmbach, 1975; Tissot and Welte, 1984). A high proportion of gasoline-range hydrocarbons in Family 1 oils is consistent with generation at high maturity (advanced catagenesis: *cf.* Tissot and Welte, 1984), or derivation from bacterial/algal organic matter (Lijmbach, 1975). Burns *et al.* (1987) studied the *n*-alkane distibutions of oils from the coal-bearing Gippsland Basin, southeast Australia, and found that high maturity, condensate-like oils (*viz* ≥ 1.1–1.15% R_c; API ≥ 46°) were heavily depleted in high carbon number (waxy) *n*-alkanes. Such oils from the Kingfish, Emperor and Batfish Fields (Burns *et al.*, 1987, fig. 2) have unimodal *n*-alkane profiles maximising at *n*-C_9 or less which are virtually identical to those of the Cooper Basin Family 1 oils. Thus, the *n*-alkane profiles of the Family 1 oils provide further evidence that they have been generated from their source rocks at maturities of 1.1% R_o or greater. This is in contrast to the situation for the Cooper Basin Family 2 oils which are more like Gippsland Basin crudes (from

the Wirrah, Tuna, Flounder and Fortesque Fields) which were expelled from their source rocks at maturities less than 1.1% R_o (Burns *et al.*, 1987, fig. 2) and consequently have lower API gravities (31–41°). Given the similarity of the biomarker compositions of Family 1 oils with those of mature ($R_o \approx$ 1.1–1.2%) Cooper Basin coals (Chapter 2), it seems unlikely that the *n*-alkane profiles exhibited by the oils are anything other than an indication of their advanced thermal maturity.

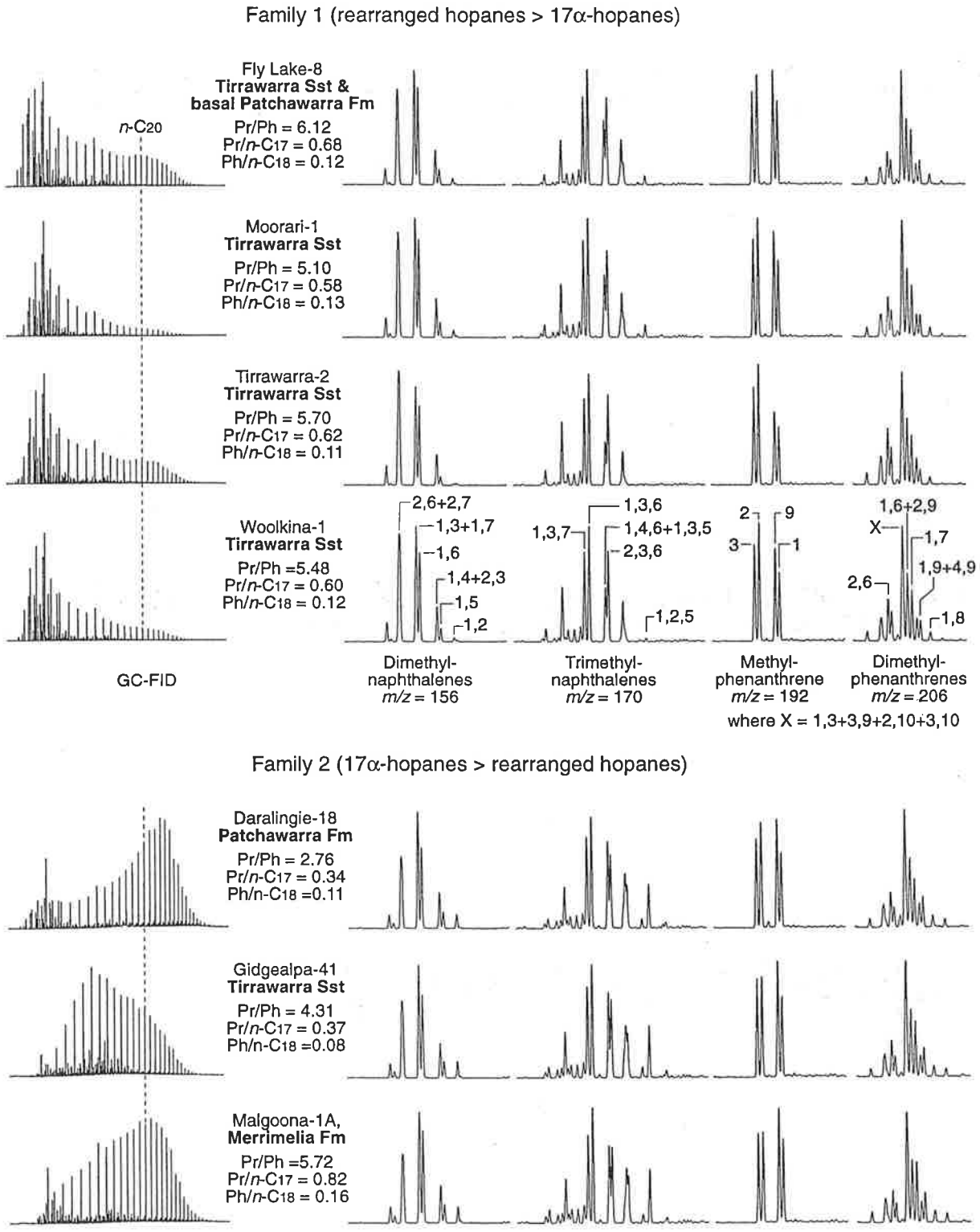


Figure 6.3 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in production oils from the Cooper Basin, South Australia

Other Cooper Basin oils from Gidgealpa-17 (Patchawarra; Fig. 6.4), Merrimelia-7 (Nappamerri; Fig. 6.10), Telopea-2 (Nappamerri; Fig. 6.6) and Wancoocha-3 (Patchawarra; Fig. 6.8) have *n*-alkane profiles which are clearly more similar to those of Family 2. However, the *n*-alkane

profile of the crude from Reg Sprigg-1 (DST-1, Nappamerri; Fig. 6.6) is similar to those of Family 1, suggesting that this oil migrated from its source rock at a maturity ≥ 1.1% R_o. The Patchawarra oil from Wancoocha-3 (Fig. 6.8) is interesting because it exhibits pronounced bimodality with maxima at *n*-C_5 and *n*-C_{23}. This feature could indicate mixing of Family 1 and Family 2 oils.

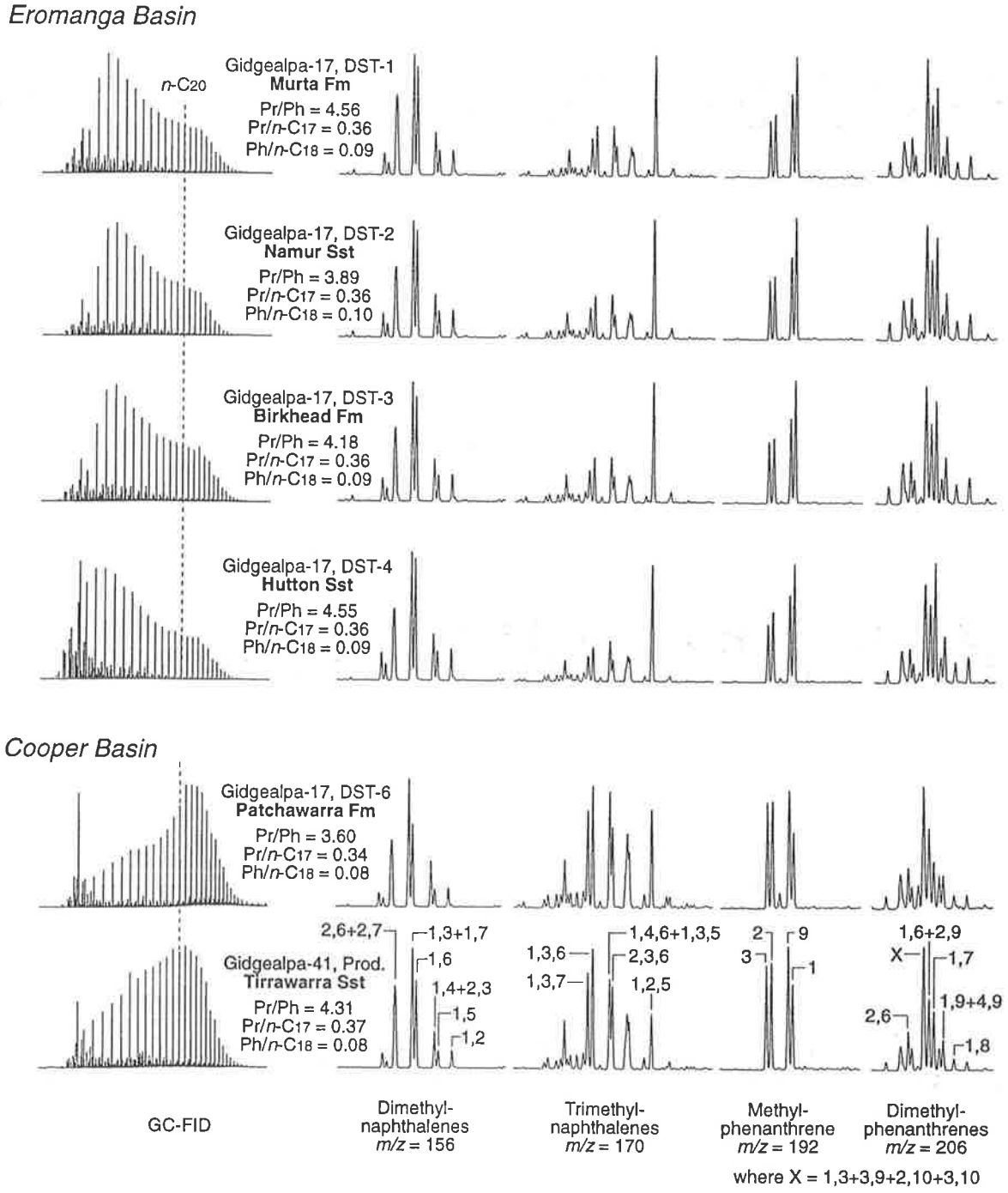


Figure 6.4 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalisecl) showing kcy aromatic hydrocarbon compounds in DST and production oils from the Gidgealpa Field, South Australia

6.4.1.2 Eromanga Basin

South Australia

There are few Eromanga oils in South Australia which have *n*-alkane profiles similar to those of the Family 1 Cooper Basin oils (Figs 6.4–6.10). However, oils from Cuttapirie-1 (Poolowanna; Fig. 6.6), Moorari-4 (Birkhead; Fig. 6.6), Dullingari-29 (Murta; Fig. 6.8), Merrimelia-8 (Namur; Fig. 6.10) and Merrimelia-10 (Hutton; Fig. 6.10) are very light oils with GC-FID profiles more akin to those of Cooper Basin Family 1 crudes.

The remainder of the Eromanga oils have greater (but highly varied) proportions of waxy *n*-alkanes and are therefore more similar to Cooper Basin Family 2 oils. However, *n*-alkane profiles of oils within fields with multiple pay zones show considerable variability between Eromanga and Cooper Basin reservoirs. For example, the GC traces of the oils from stacked reservoirs within the Eromanga sequence of the Gidgealpa Field are distinctly different from those in the underlying Tirrawarra and Patchawarra Formations (Fig. 6.4). Likewise, the Merrimelia-7 (Nappamerri) oil from the Cooper Basin is much waxier than the Merrimelia oils from the overlying Hutton Sandstone, Namur Sandstone and Murta Formations (Fig. 6.10).

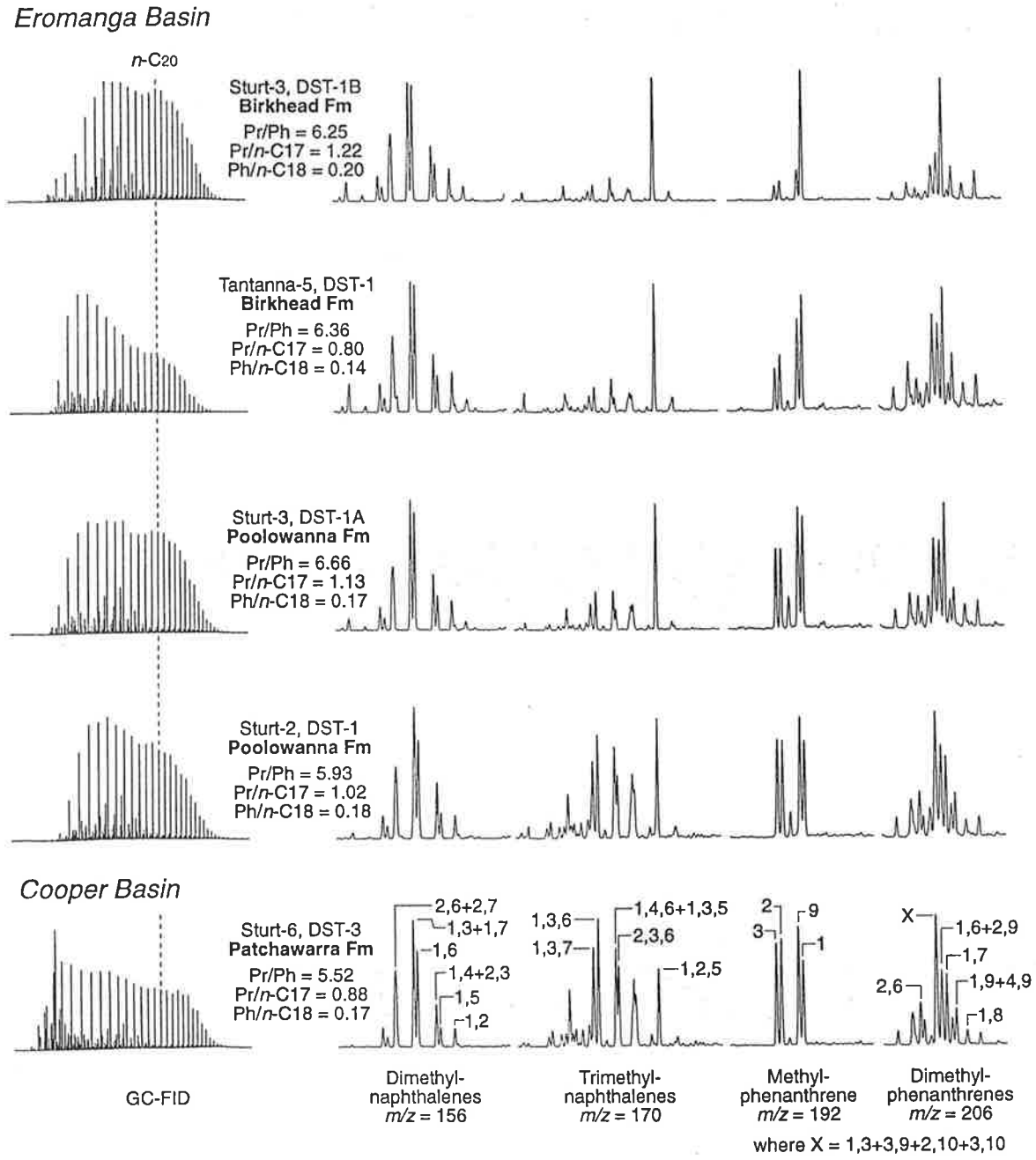


Figure 6.5 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in DST oils from the Sturt and Tantanna Fields, South Australia

With the exception of the Kobari-1 oil, hydrocarbons from the Namur Sandstone and Murta Formation in the Murteree Ridge area are very waxy (Fig. 6.7). Based on their *n*-alkane profiles, these oils are similar to Patchawarra-reservoired oil at Daralingie-18 (Family 2), down-dip in the Nappamerri Trough. Murteree Ridge oils are also similar to nearby oil from Spencer-5 and Strzelecki-6 (Birkhead and Hutton reservoirs, respectively; Fig. 6.8). Based on these similarities it is conceivable that Permian-derived hydrocarbons have migrated from a deeper Wooloo or Nappamerri Trough (Permian) source kitchen into the reservoirs of the Murteree Ridge area and

the nearby Eromanga reservoirs at Spencer-5 and Strzelecki-6 (Fig. 6.14). It is interesting that the GC-FID profiles of the oils from Namur reservoirs higher in the Eromanga sequence at Spencer-5 and Strzelecki-6 are clearly bimodal (Fig. 6.8). The compositions of these two Namur oils are such as to indicate a mixed source: possibly a hydrocarbon charge from the Cooper Basin which supplied most of the lower-carbon-number (gasoline-range) *n*-alkanes; and a separate charge(s) from a more local (Eromanga) source kitchen(s) which supplied waxy *n*-alkanes (or *vice versa*).

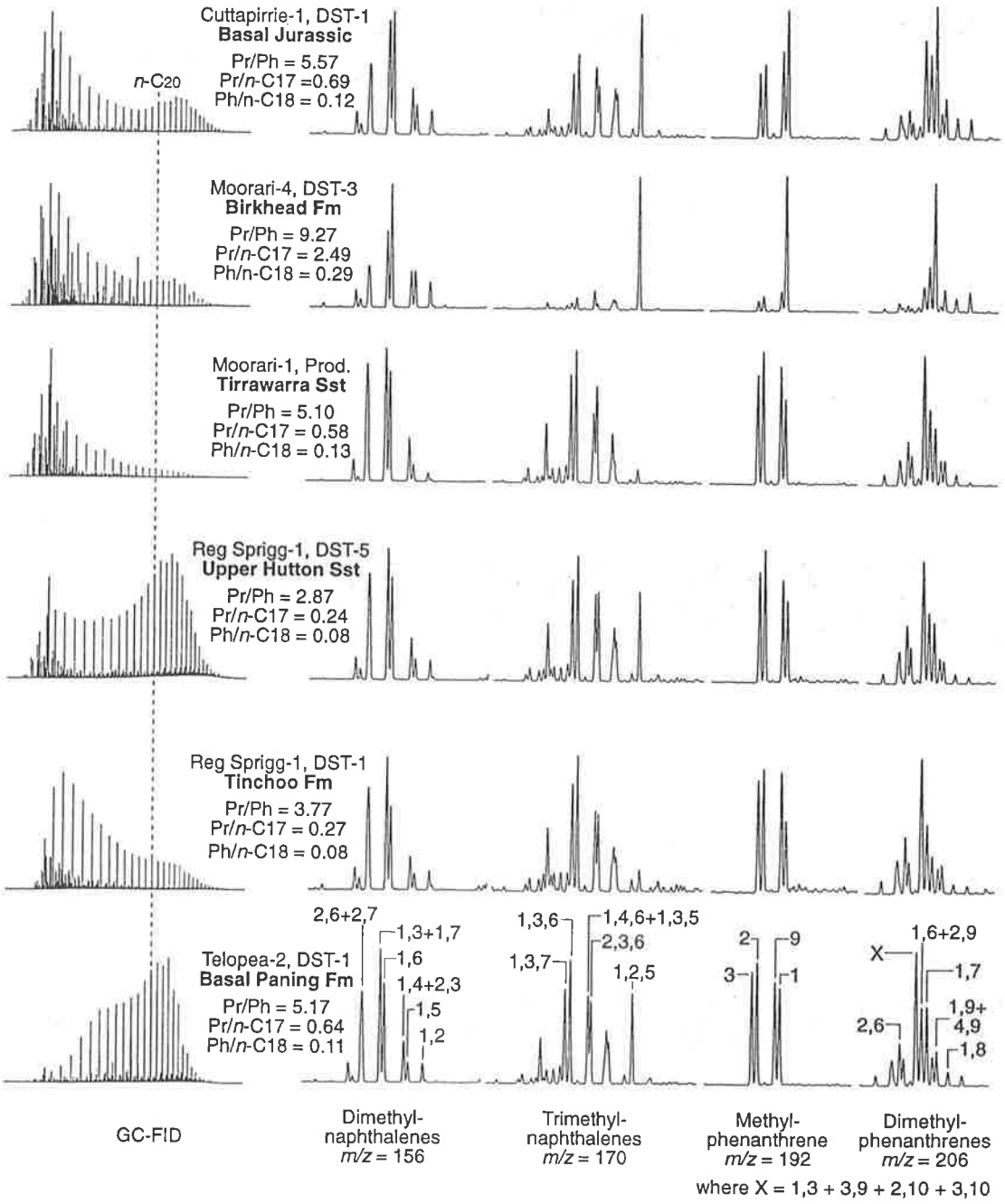


Figure 6.6 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in DST and production oils from the Patchawarra Trough, South Australia

It would be naïve to believe that robust oil–oil correlations can be undertaken using GC analyses alone. However, based solely on *n*-alkane distributions there is little evidence for migration of large quantities of (unaltered) Family 1 oil from the Cooper Basin into the superjacent Eromanga succession. Notwithstanding, in many fields with stacked reservoirs, such as Gidgealpa (Fig. 6.4) and Merrimelia (Fig. 6.10), the oils in Eromanga reservoirs are richer in light ends than are oils in the underlying Cooper Basin reservoirs (Fig. 6.14). In these cases, the Eromanga oils may represent lighter ("front end") components that have been stripped from

Cooper Basin-derived oils (Family 2) *via* water washing during secondary migration (*cf.* Boreham and Hill, 1998; Boreham and Summons, 1999). It is interesting that oils in the stacked reservoirs of the Sturt Field (Fig. 6.14) do not show a significant increase in API gravity with higher stratigraphic level and therefore it is less plausible that these oils contain proportionately large quantities of light (< n-C_{13}) hydrocarbons derived from Cooper Basin source rocks (Fig. 6.5). However, pronounced bimodality in the n-alkane profiles of oils from the Poolowanna and Birkhead Formations at Sturt-3 suggests that these oils may be derived from the mixing of two (or more) separate hydrocarbon charges.

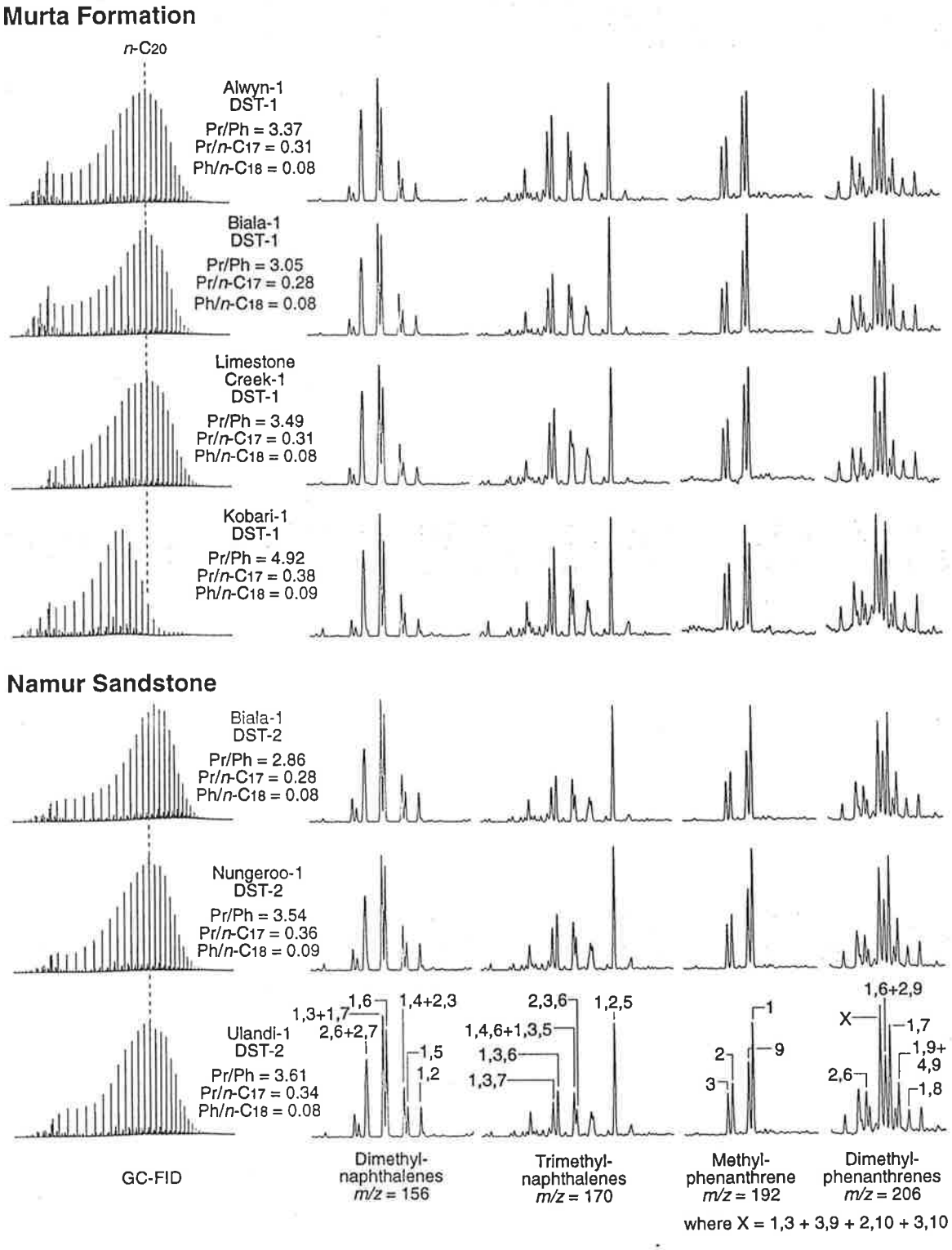


Figure 6.7 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in DST oils from the Murteree Ridge, South Australia

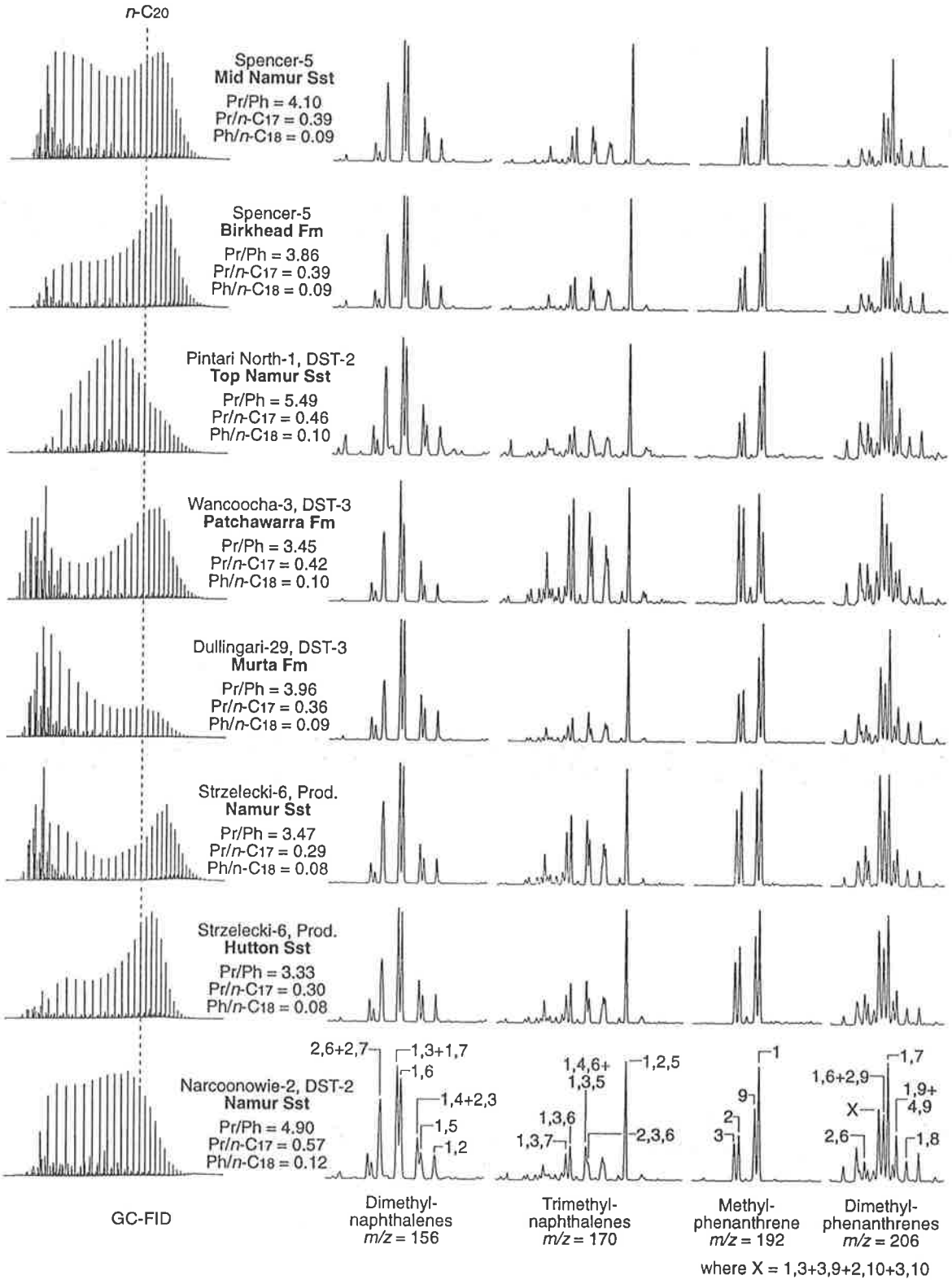


Figure 6.8 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in miscellaneous oils from the southern Cooper Basin, South Australia

Queensland

Naccowlah-Jackson Ridge

The *n*-alkane profiles of the Naccowlah South-1 and the Chookoo-1 oils (both Hutton) from the northwestern end of the NJ Ridge (Fig. 6.11) are very similar to those of the Cooper Basin Family 1 oils. It is therefore reasonable to infer that these oils may have been derived from very mature (? Cooper Basin) source rocks. All the other oils from the NJ Ridge (Table 6.1) contain proportionally greater quantities of waxy hydrocarbons derived from land plant material. The bimodality of several of the GC traces may indicate that some of these oils are mixtures of two

(or more) hydrocarbon charges. Arguably, bimodality is most obvious in the Jackson-3 (Westbourne), Gunna-1 (Murta), Jackson-2 (Hutton) and especially the Gunna-1 (Birkhead/Hutton) crudes. Indeed, the Jackson-1 (Murta) oil has a trimodal *n*-alkane distribution. This evidence suggests likely mixed sources for these hydrocarbon accumulations. The oils from the southeastern end of the NJ Ridge are also bimodal (Fig. 6.12), indicating derivation from source rocks containing various mixtures of algal/bacterial and land plant organic matter; or, alternatively, multiple oil charges from source rocks at different levels of organic maturation.

Inland and Bodalla South Fields

There is a distinct similarity between the *n*-alkane profiles of the Cooper Basin Family 1 oils and those of the Hutton and Namur oils at Inland-1. The latter have *n*-alkane maxima at *n*-C_8, whereas the Family 1 oils have maxima at *n*-C_6 or *n*-C_7. It is therefore conceivable that the Inland-1 oils have an affinity (not supported by the aromatic hydrocarbon data) with the super mature Permian oils of the Cooper Basin. Oil from the Hutton Sandstone at Bodalla South-1 has a unimodal *n*-alkane profile very similar to that of a typical Cooper Basin Family 2 oil, notably the Tirrawarra oil at Gidgealpa-41 (Fig. 6.3). Unlike most, if not all, of the Eromanga-reservoired oils from the NJ Ridge, the oils from Inland-1 and Bodalla South-1 do not display bimodal *n*-alkane profiles. This possibly means that they do not represent mixtures of different hydrocarbon charges.

6.4.2 Pristane/phytane ratio

The Pr/Ph ratios of crude oils vary considerably between reservoir formations; and between the South Australian and Queensland sectors of the study area within the same formations (notably the Birkhead and Murta; Tables 6.1 and 6.2; *cf.* Chapter 5).

6.4.2.1 Cooper Basin

South Australia

The Cooper Basin Family 1 oils (*cf.* Chapter 2; Table 6.3, mean Pr/Ph = 5.6) have significantly higher Pr/Ph values than do those of Family 2 (mean Pr/Ph = 4.3). This is evidence for Family 1 oils being derived from terrestrial plant remains deposited in a relatively oxic peat swamp environment (Powell and McKirdy, 1975; Lijmbach, 1975; Tissot and Welte, 1984). This corroborates the evidence based on polycyclic alkane biomarkers (Chapter 2) that Family 1 oils are derived from coals rather than shales. The Pr/Ph ratios of Family 2 oils are consistent with their derivation from non-marine shaley lithofacies, with only a minor contribution (if any) from coals. The Patchawarra crudes from Gidgealpa-17 and Wancoocha-3 have Pr/Ph ratios (3.6 and 3.5 respectively) which suggest a clastic source rock. By contrast, the Patchawarra crude from Sturt-6 has a Pr/Ph ratio (5.5) which indicates a likely coaly source facies.

6.4.2.2 Eromanga Basin

South Australia

Oils recovered from reservoirs in the Eromanga Basin display an even broader range of Pr/Ph values. It is interesting to note that the formations which are host to oils with relatively low Pr/Ph ratios (*viz* Hutton, mean Pr/Ph = 3.7; Namur, mean Pr/Ph = 4.3; Murta, mean Pr/Ph = 4.0), happen to lack thick paludal facies, whereas formations which have significant coal measures contain oils with high Pr/Ph ratios (*viz* Poolowanna, mean Pr/Ph = 6.1; and Birkhead mean Pr/Ph = 5.9) Formations. This is evidence that the Poolowanna and Birkhead Formations may have been at least partly self-sourcing.

On the other hand, it is possible that elevated Pr/Ph ratios in some of the Eromanga oils may signal alteration during secondary migration. It is entirely reasonable for the Pr/Ph ratio to be enhanced in some of the Eromanga oils if, indeed, they are products of long-distance secondary migration from Permian hydrocarbon kitchens. This is because pristane, being of lower molecular weight than phytane, is less likely to be retained in the residual crude left in the carrier beds along the migration pathway. Indeed, based on a suite of oils (n = 162) from the Cooper/Eromanga Basin, Boreham and Summons (1999) argued that elevated Pr/Ph ratios (> 4.5), when associated with lighter oils, indicate alteration by migration fractionation. At Gidgealpa (Fig. 6.4), only two of the four Eromanga oils have Pr/Ph values greater than 4.5 and although the Eromanga oils are obviously lighter than the two Cooper Basin oils, it is not possible to infer that the Eromanga oils (partially) represent the light fractionated products of Permian oil.

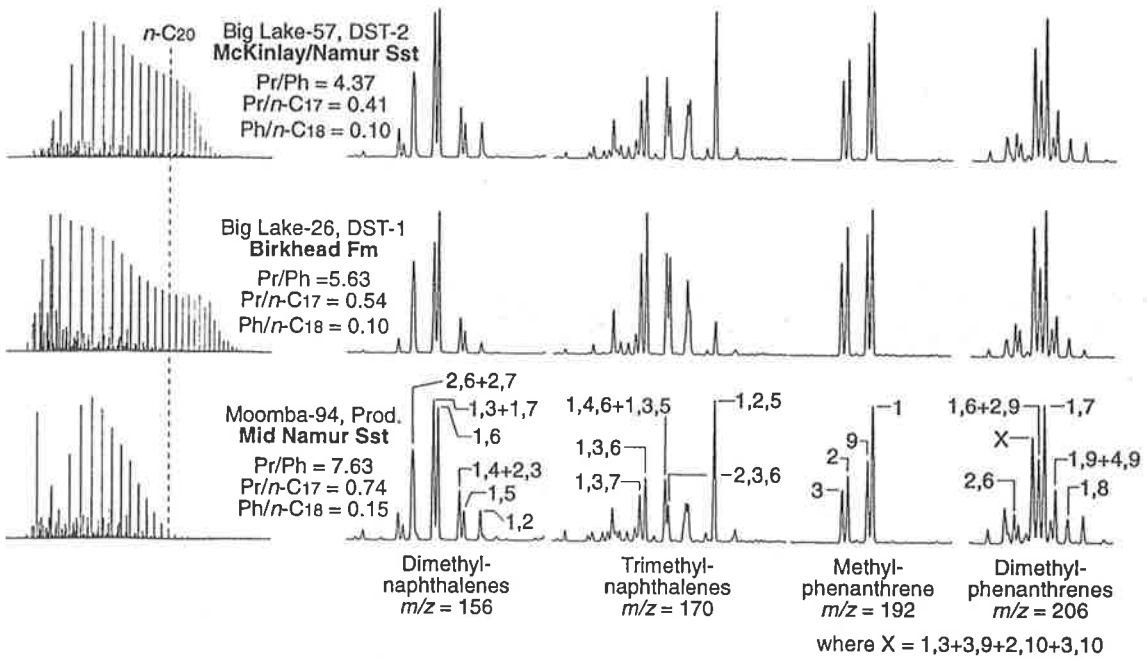


Figure 6.9 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in DST and production oils from the Moomba and Big Lake Fields, South Australia

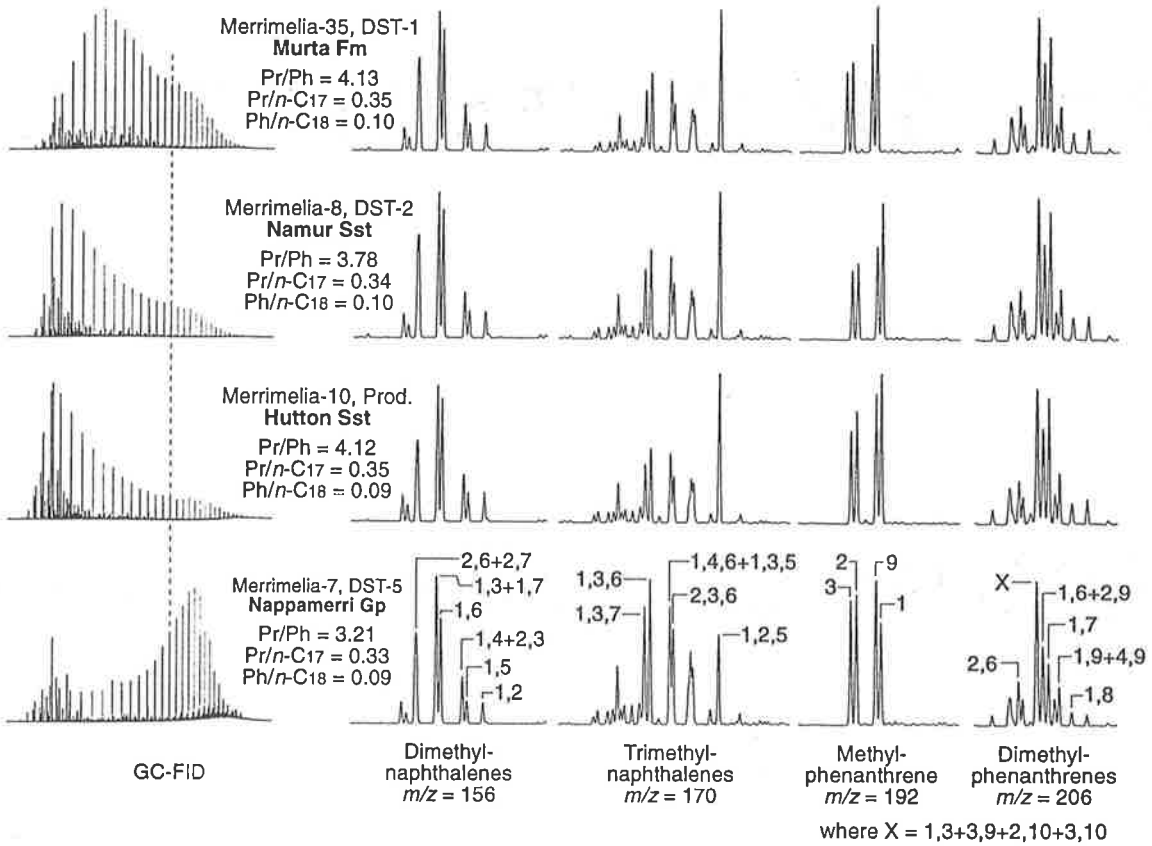


Figure 6.10 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in DST and production oils from the Merrimelia Field, South Australia

Very high Pr/Ph values for Birkhead oils recovered from Moorari-4 (9.27), Tantanna-5 (6.36), 36), Sturt-3 (6.25) and Big Lake-26 (5.63), as well as Hutton oils from Moomba-94 (7.63) and Pintari North-1 (5.49), and Poolowanna crude from Sturt-3 (6.66), Sturt-2 (5.95) and Cuttapirrie-1 (5.57) indicate that these hydrocarbon accumulations were clearly sourced from coaly organic matter.

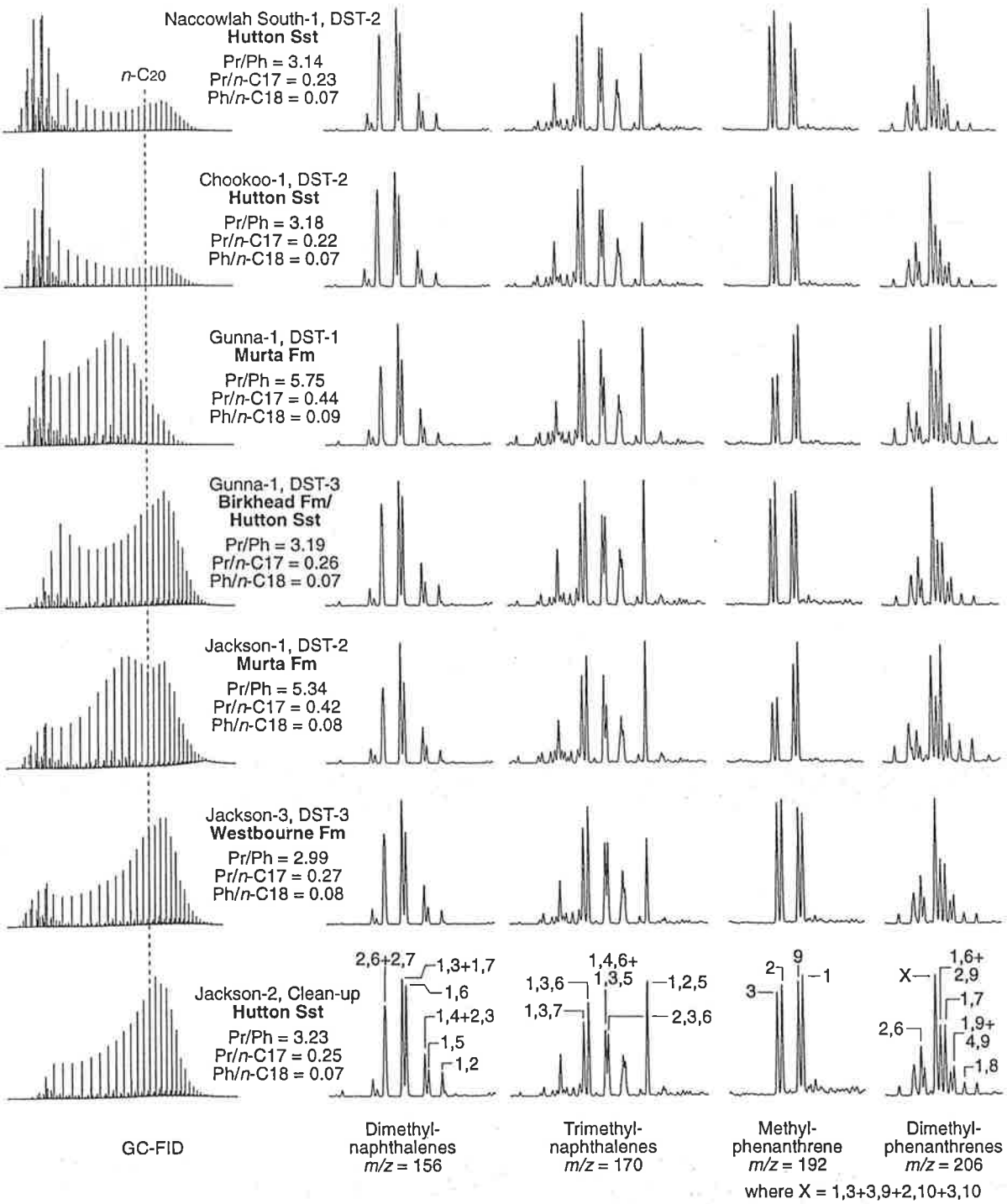


Figure 6.11 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in miscellaneous oils from the Naccowlah-Jackson Ridge (northwest), Queensland

Queensland

The entire Queensland sample suite comprises oils from intra-Eromanga reservoirs (Tables 6.1 and 6.2). Notwithstanding that oils from the Birkhead Formation, Westbourne Formation and Namur Sandstone are poorly represented, it is clear that the mean Pr/Ph values within a given formation are generally the same in Queensland and South Australia. Obvious exceptions are the Birkhead oils (Pr/Ph higher in South Australia) and Murta oils (Pr/Ph higher in Queensland) (Table 6.2). There is evidence that the Murta may be slightly coaly (vitrinite-rich) along the NJ Ridge (*cf.* Chapter 5) and therefore it could be expected that any oils of *in situ* derivation would have somewhat higher Pr/Ph values.

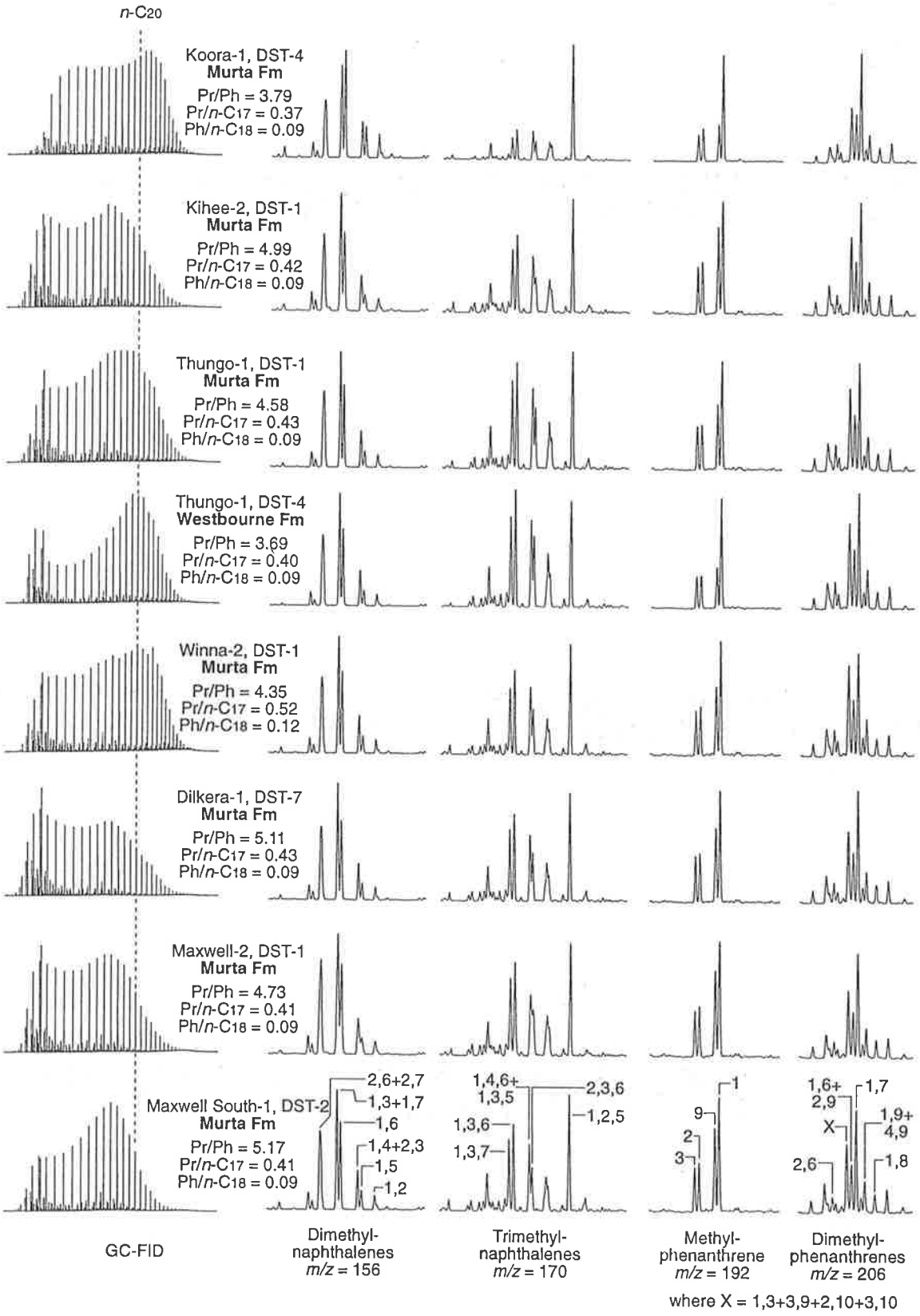


Figure 6.12 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in miscellaneous oils from the Naccowlah-Jackson Ridge (southeast), Queensland

More interesting is the distibution of Pr/Ph ratios within stacked reservoirs (Table 6.2). The Pr/Ph ratio shows a systematic increase with higher stratigraphic level (Table 6.2). In the Jackson Field where three oils were analysed, there is overall increase in Pr/Ph ratio upwards through the stratigraphic section from the lowermost Birkhead (3.2) and Westbourne (3.0) Formations, to the upper Murta (5.3) Formation. There is also an increase in Pr/Ph ratio with stratigraphic height at Gunna, Inland and Thungo. The consistency of the data is strong evidence that the Queensland oils are either fractionation products, and/or mixtures of multiple hydrocarbon charges.

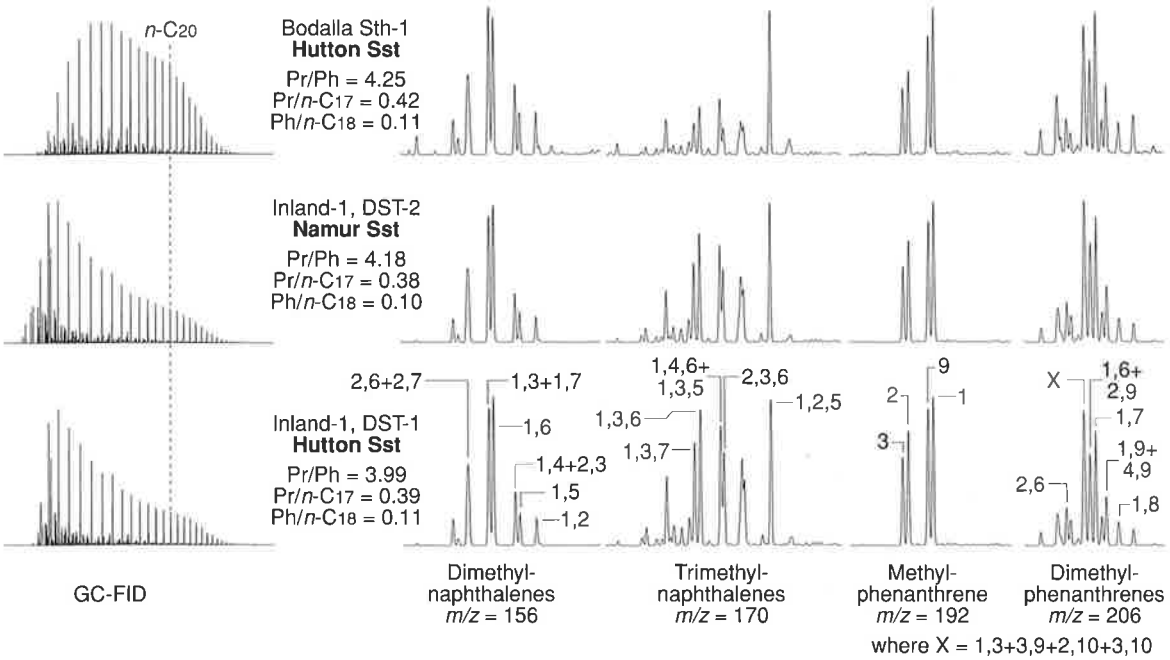


Figure 6.13 Whole oil-GC traces and selected partial GC-MS fragmentograms (height normalised) showing key aromatic hydrocarbon compounds in miscellaneous oils from the northern Cooper Basin, Queensland

6.4.3 Pristane/*n*-C_{17} and phytane/*n*-C_{18} ratios

6.4.3.1 Cooper Basin

South Australia

The mean values of Pr/*n*-C_{17} and Ph/*n*-C_{18} in the oils from each formation and, where applicable from stacked reservoirs, are also summarised in Table 6.2. The Pr/*n*-C_{17} ratio shows considerable stratigraphic variability. Within the Cooper Basin oil suite Pr/*n*-C_{17} ratios for oils belonging to Family 1 (mean = 0.62) are higher than those for Family 2 (mean = 0.53). This observation is at variance with previous observations on the relative maturity of the Family 1 and Family 2 oils since it is well documented that the Pr/*n*-C_{17} ratio decreases with increased maturity (Connan and Cassou, 1980) and therefore higher values might be expected for the Family 2 oils. However, the oxicity of the depositional environment is also known to affect the Pr/*n*-C_{17} ratio in source rocks. Rocks deposited under more oxidising conditions (*i.e.* coal-forming peat swamps) are known to have higher Pr/*n*-C_{17} ratios than non-marine (*e.g.* lacustrine) siltstones and shales (Lijmbach, 1975; Connan and Cassou, 1980). Therefore, higher values of Pr/*n*-C_{17} are to be expected in oils derived from coals rather than clastic rocks. Thus, the Pr/*n*-C_{17} values for Family 1 oils are entirely consistent with their derivation from coals. Moreover, the higher Pr/*n*-C_{17} values for Family 1 oils may signal that petroleum expulsion from their respective source rocks was *more efficient* than in the case of Family 2 crudes (Mackenzie *et al.*, 1983; Leythaeuser *et al.*, 1984; Leythaeuser and Schwarzkopf, 1985). Of course numerous factors control the ultimate size of an oil field. However, this proposition appears to be reasonable since the fields from which the Family 1 oils were collected comprise the overwhelming majority of the Cooper Basin oil reserves. Indeed, more than 80% of the entire Cooper Basin oil reserves are trapped in the Tirrawarra Field alone (Gravestock *et al.*, 1998). The smaller fields from which the Family 2 oils were collected (Daralingie, Gidgealpa, Malgoona) may have been charged from source rocks where expulsion of hydrocarbons was only minimal, resulting in the observed lower Pr/*n*-C_{17} values of these oils.

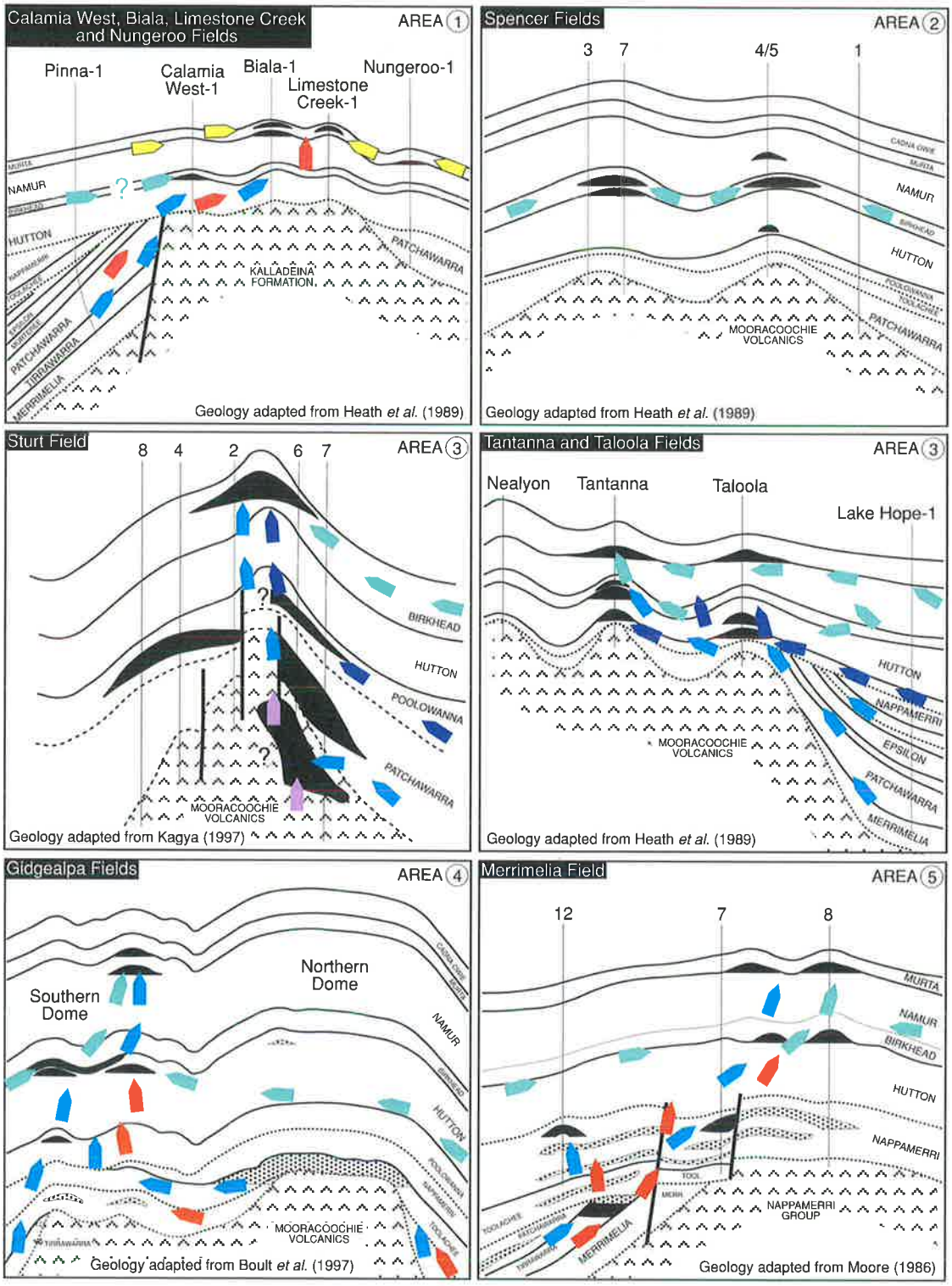


Figure 6.14 Generalised structural-stratigraphic cross-sections of selected fields from areas 1–5 (*cf.* Fig. 6.1). "Petroleum Supersystem" nomenclature after Bradshaw *et al.* (1994). Variable horizontal and vertical scales

6.4.3.2 Eromanga Basin

South Australia

A feature of the Eromanga oils is that there is a contrast between the high Pr/*n*-C_{17} values of crudes from the coaly Poolowanna (mean = 0.94) and Birkhead (mean = 0.97) Formations, and those of the oils in the Hutton Sandstone (mean = 0.31), Namur Sandstone (mean = 0.41) and Murta Formation (mean = 0.35) which have considerably lower values. Such higher values would be expected if, as discussed above, the Poolowanna and Birkhead Formations have been self-sourcing. Pr/*n*-C_{17} data from the Sturt Field is potentially interesting because there is a systematic increase in this parameter through the section (Patchawarra: Pr/*n*-C_{17} = 0.88, Poolowanna: Pr/*n*-C_{17} = 1.07, and Birkhead: Pr/*n*-C_{17} = 1.22). This might indicate fractionation of Permian-derived hydrocarbons as they migrated up-section through the Eromanga sequence, or differential co-mingling of Permian-derived hydrocarbons with indigenous Eromanga oil (*i.e.* Permian-derived hydrocarbons mixing with lesser qualtities of Jurassic oil in the Poolowanna Formation, and proportionally more Jurassic oil in the Birkhead Formation). Alternatively, the decrease in Pr/*n*-C_{17} up section in the Sturt Field probably reflects an increase in the maturity of these oils (*cf.* Table 6.3, section 6.4.5). By contrast, values for the Pr/*n*-C_{17} ratio are remarkably uniform in all the Cooper and Eromanga reservoirs at Gidgealpa and Merrimelia. This may indicate that the Eromanga reservoirs at these localities have not received large amounts of hydrocarbons derived from the Cooper Basin.

Average Ph/*n*-C_{18} values are less than or equal to 0.16 in all cases. The highest values are recorded in the Merrimelia, Poolowanna and Birkhead Formations. This observation is also consistent with these oils being derived from coaly organic matter.

Queensland

Ph/*n*-C_{17} values are more uniform in the Queensland oils: averages for the Hutton (0.30), Birkhead (0.26), Westbourne (0.34) and Namur (0.38) crudes are only slightly less than that for the Murta oils which have the highest value (0.43) consistent with their slightly elevated average Pr/Ph ratio (Table 6.2). Average Ph/*n*-C_{18} ratios for oils from Jurassic/Cretaceous units in Queensland are very similar, ranging from 0.07 to 0.10. However, because of the small sample numbers, notably from the Birkhead Formation, the Ph/*n*-C_{17} and Ph/*n*-C_{18} data are of limited usefulness.

6.4.4 Araucariacean biomarkers

As discussed in previous chapters, aromatic biomarkers of the conifer family Araucariaceae are age-specific (Jurassic and younger) and important components of the southern hemisphere molecular fossil record. Figures 6.15 and 6.16 are logarithmic cross-plots that display the araucariacean biomarker parameters developed by Alexander *et al.* (1988, 1992) as measured in the present suite of oils (Table 6.1).

6.4.4.1 Methylphenanthrenes and trimethylnaphthalenes

South Australia

Cooper Basin Family 1 oils contain the lowest concentrations of 1,2,5-TMN relative to 1,3,6-TMN (0.03–0.10) in the study. The Gidgeapla-41 crude, the only Tirrawarra oil not included in Family 1, has a significantly higher 1,2,5-TMN/1,3,6-TMN ratio (0.45) which falls into the range for the Family 2 oils (0.39–1.09). It is difficult to explain the contrast in 1,2,5-TMN/1,3,6-TMN between Families 1 and 2 in terms of source input. It is probably related to the different thermodynamic stabilities (heats of formation) of 1,2,5-TMN and 1,3,6-TMN. The empirical evidence suggests that 1,2,5-TMN is less stable than 1,3,6-TMN, and hence 1,2,5-TMN/1,3,6-TMN ratios are lower in the more mature Family 1 oils. The 1-MP/9-MP ratios of Family 1 and Family 2 oils are similar, suggesting that this parameter is thermodynamically more robust.

Other samples which plot in the "Permian" field include oils from Triassic reservoirs at Merrimelia-7, Reg Sprigg-1 and Telopea-2 (Figs 6.6 and 6.10). Oils in Mesozoic reservoirs at Big Lake-26 (Birkhead), Reg Sprigg-1 (Hutton), Sturt-2 (Poolowanna) and Kobari-1 (Murta) plot within or close to the "Permian" field, suggesting that they are wholly or partly derived from pre-Jurassic source rocks. The remaining oils from the Eromanga Basin plot clearly within or close to the "Jurassic" field, implying that they do not contain any appreciable contribution from source rocks in the Cooper Basin. Of all the Eromange oils, those in the Murta Formation have the least typical "Jurassic" signatures, whereas the Birkhead crudes at Moorari-4 and Sturt-3 have Jurassic end-member chemistries (1,2,5-TMN/1,3,6-TMN = 11.88 and 7.65, respectively; 1-MP/9-MP = 6.54 and 4.02, respectively: Figs 6.5 and 6.6). Palynological evidence (Alexander

et al., 1988) suggests that the Birkhead Formation was laid down at a time when the Araucariaceae were at their most dominant on the botanical landscape. However, the Murta Formation was deposited during the Early Cretaceous when araucariacean conifers had already declined in importance. Hence, the subtle geochemical contrast between oils in the Birkhead and Murta Formations is entirely consistent with the palynological record. Oil accumulations along the Murteree Ridge (Fig. 6.7) and adjacent areas have chemistries consistent with an intra-Murta origin (*cf.* Chapter 5).

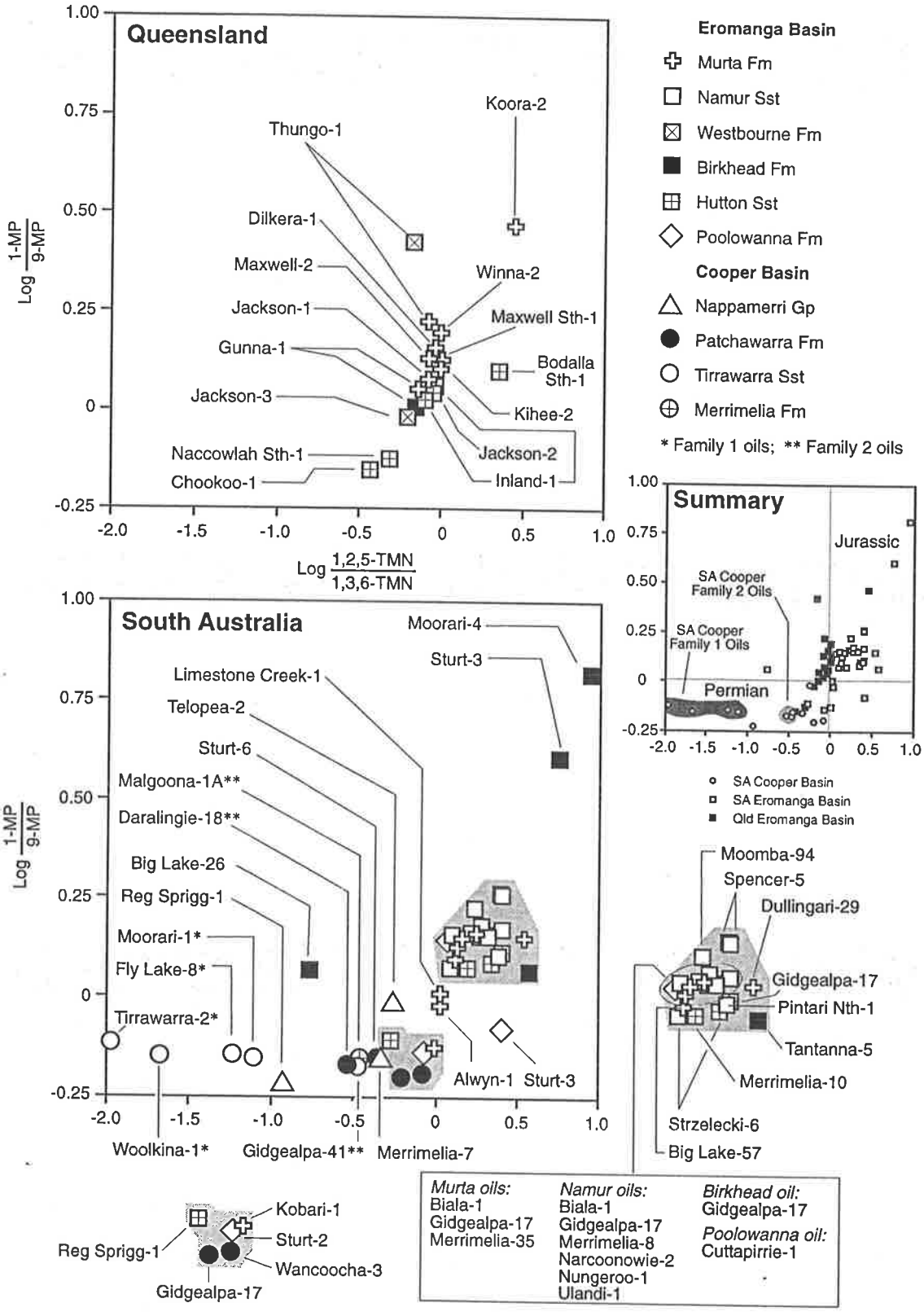


Figure 6.15 Aromatic source parameters: log (1,2,5-TMN/1,3,6-TMN) *versus* log (1-MP/9-MP)

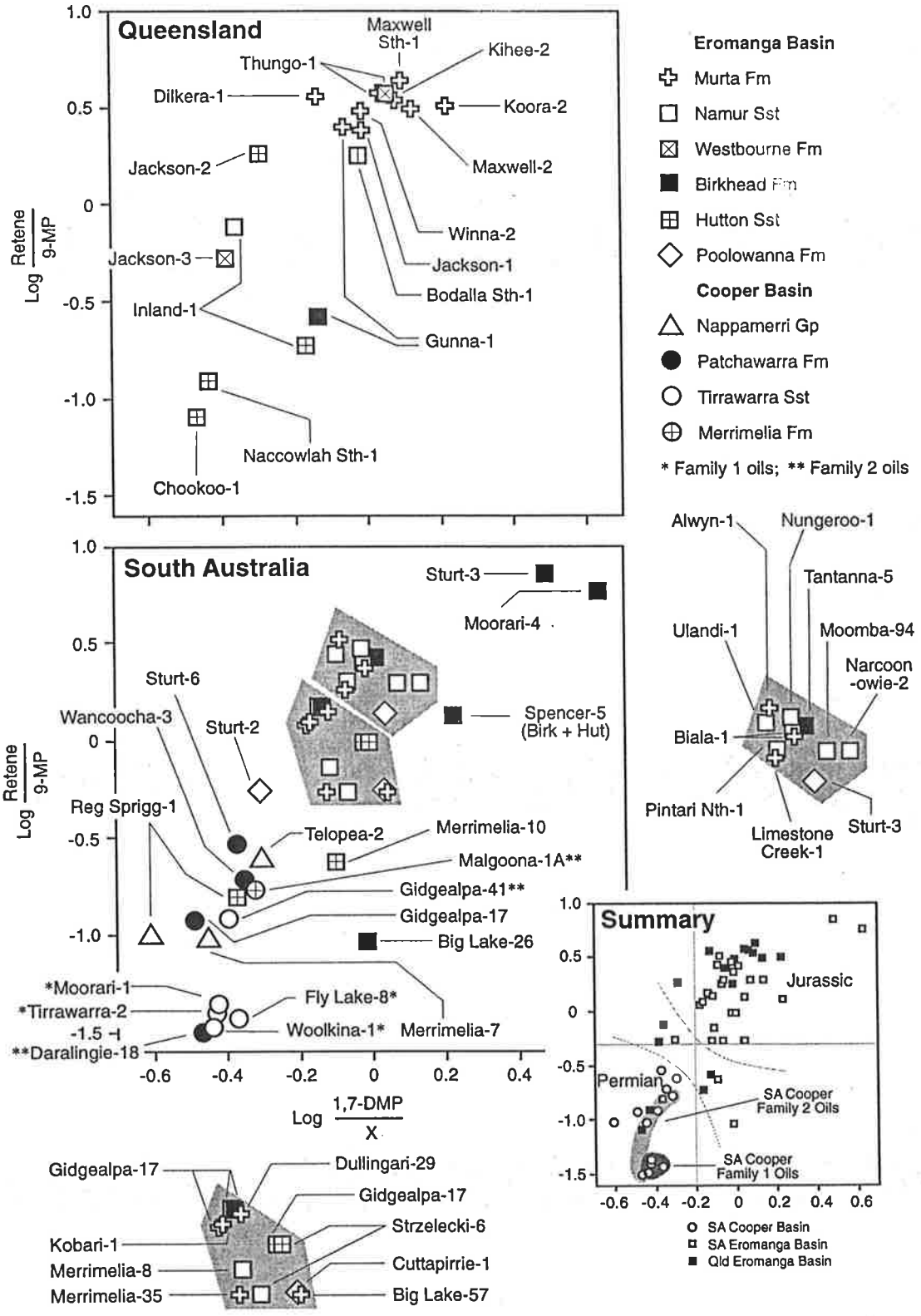


Figure 6.16 Aromatic source parameters: log (1,7-DMP/X) *versus* log (retene/9-MP)

Notwithstanding the similarity of their *n*-alkane profiles (Section 6.4.1.2), the wide disparity in the respective 1,2,5-TMN/1,3,6-TMN and 1-MP/9-MP ratios of the Tirrawarra and Birkhead crudes at Moorari demonstrates the integrity of the Triassic regional seal at this locality. These two oils are clearly part of different petroleum systems which are physically separated by the Nappamerri Group. Likewise at Gidgealpa-17, the Hutton, Birkhead, Namur and Murta-hosted oils are indicated to be of Jurassic origin and clearly distinct from the deeper Patchawarra (Gidgealpa-41) and Tirrawarra (Gidgealpa-17) crudes (*cf.* Boult *et al.*, 1997, 1998; Fig. 6.4).

Queensland

The Queensland oils are all from Eromanga reservoirs (Figs 6.11–6.13). In Figure 6.15 most of the Murta crudes plot in a tight cluster (1,2,5-TMN/1,3,6-TMN = 0.96–1.36; 1-MP/9-MP = 1.13–1.67), the exception being oil from Koora-2 which has a "Jurassic" end-member chemistry similar to that of Birkhead oil at Sturt-3. Two oils, Chookoo-1 and Naccowlah South-1 (both Hutton) have very convincing Permian source affinities because they plot well inside the "Permian" field and adjacent to the Cooper Basin Family 2 oils. Thus, they appear to be entirely of intra-Cooper Basin origin. The saturated hydrocarbon contents of oils from these two fields (and others along the NJ Ridge) were analysed and described by Vincent *et al.* (1985) who on the basis of sterane isomerisation data (*ibid.*, fig. 14) recognised that the Chookoo and Naccowlah South oils had *migrated furthest from source to reservoir*, when compared to other oils in the area. This reinforces the aforementioned observation that the two oils in question are derived from deep Permian source rocks. The Nappamerri Group which acts as a seal for the Cooper Basin elsewhere, is thin to absent above reverse faults which are present in the Chookoo/Naccowlah South area (Vincent *et al.*, 1985). Such faults may have acted as conduits for hydrocarbon migration between the Cooper and Eromanga Basins. In summary, the Queensland Eromanga oils are similar to those from South Australia in terms of their 1-MP/9-MP ratios, but intermediate between the South Australian Cooper and Eromanga oils on the basis of their 1,2,5-TMN/1,3,6-TMN values. Thus, Eromanga oil trapped in fields along the NJ Ridge appear to have considerable affinity with the Cooper Basin. This important observation will be amplified later in this chapter.

6.4.4.2 Dimethylphenanthrenes and retene

In Figure 6.16 the relative concentration of 1,7-DMP/X (where X = Σ 1,3-DMN + 3,10-DMN + 2,10-DMN + 2,9-DMN) is plotted against retene/9-MP. These data reveal a similar scenario to that described above.

South Australia

Values of 1,7-DMP/X (0.36–0.43) and retene/9-MP (0.03–0.04) for Family 1 oils plot tightly in the "Permian" field along with a Patchawarra (Family 2) oil from Daralingie-18 (1,7-DMP/X = 0.34; retene/9-MP = 0.03). However, other Family 2 oils have higher retene/9-MP (0.12–0.29) values, but similar 1,7-DMP/X (0.32–0.48) values. If one accepts that the Daralingie-18 oil is an anomalous outlier, it is difficult to explain the discrepancy between Family 1 and Family 2 as measured by retene/9-MP. Based on source input, there appears to be no *a priori* reason why Family 1 oils should have lower retene/9-MP values unless a thermodynamic disequilibrium exists between retene and 9-MP which causes a lowering of the ratio if retene is more readily depleted during intermediate to advanced catagenesis.

The Big Lake-26 (Birkhead; Fig. 6.9), Merrimelia-10 (Hutton; Fig. 6.10) and Sturt-2 (Poolowanna; Fig. 6.5) oils may represent mixtures of Cooper-derived and Eromanga-derived hydrocarbons. The Big Lake-26 sample is particularly interesting because a stratigraphically higher oil from the same area (Big Lake-57, Murta) appears to have a stronger Jurassic source affinity. It seems therefore that the hydrocarbon architecture of the Big Lake Field has been complicated by oil mixing during secondary migration. Based on a study of penta- and tetramethyltetralin distributions, Alexander *et al.* (1996) reported similar heterogeneities in the Big Lake Field concluding that Big Lake-55 (DST-1, Namur) oil was derived from source rocks of Jurassic age, but that the stratigraphically lower Big Lake-36 (DST-2, Hutton) and Big Lake-37 (DST-1, Birkhead) oils were derived from Cooper Basin source rocks.

The Birkhead-reservoired crudes at Moorari-4 (1,7-DMP = 4.26; retene/9-MP = 5.72) and Sturt-3 (1,7-DMP/X = 3.03; retene/9-MP = 7.03) again show an end-member araucariacean signature. Eromanga-hosted oils from Gidgealpa-17 have higher 1,7-DMP/X and retene/9-MP ratios than do the Gidgealpa-17 (Patchawarra) and Gidgealpa-41 (Tirrawarra) crudes, and plot well within the Jurassic field of Figure 6.16. In so doing, they corroborate the inference based on their 1,2,5-TMN/1,3,6-TMN and 1-MP/9-MP signatures (Fig. 6.15) that the Hutton, Birkhead, Namur and Murta oils at Gidgealpa are all of intra-Eromanga origin.

Gidgealpa Field

The subtle chemical distinction between 1) the Hutton oil, and 2) the Birkhead, Namur and Murta oils evident in the bottom inset of Figure 6.16 possibly reflects two separate oil charges. A double pulse of hydrocarbon migration into the Gidgealpa southern dome was argued by Boult *et al.* (1998) who recently developed a new model for the Hutton/Birkhead resevoir/seal

couplet and associated Birkhead/Hutton petroleum system, with particular reference to the Gidgealpa area.

Based on the data of Ryan (1996), these workers highlighted significant differences in the saturated biomarker chemistry of the Birkhead and Hutton oils at Gidgealpa-17. The Birkhead oil (DST-3) contains a conventional suite of hopanoids (Boult *et al.* 1998, fig. 17; C_{27} 17β,21α-22,29,30-trisnorhopane << $T_s \leq T_m$, 22*S* > 22*R* C_{31} 17α-homohopane). By contrast, the Hutton crude (DST-4) represents a non-conventional oil and contains C_{31} and C_{32} 17β,21β-hopanes and a predominance of 22*R* over 22*S* C_{31} 17α-homohopane which is uncharacteristic of an oil, but more typical of a low rank sediment (R_o < 0.5%; Tissot and Welte, 1984). In particular, 22*R* 17α-homohopane is the predominant isomer in low rank coals. Furthermore, in the Hutton oil, C_{27} moretane (17β,17α-22,29,30-trisnorhopane) predominates over T_s and is almost in equal abundance to T_m. In the Gippsland Basin, Philp and Gilbert (1982) likewise discovered 17β,21β-hopanes in a terrestrially-sourced oil and assumed leaching or "solubilisation" of the 22*R* C_{31} homohopane and the 17β,21β-hopanes from an immature coaly facies. A similar scenario can explain the occurrence of the unusual hopanes in the Hutton oil at Gidgealpa-17. Elevated concentrations of araucariacean biomarkers and the occurrence of these thermally unstable biomarkers in the live oil indicates that it is implausible for the live oil to have migrated into the Gidgealpa southern dome from what would almost certainly be hotter Permian rocks directly below. The lack of the thermally unstable biomarkers within the oil (Gidgealpa-17, DST-3) saturating the (intra-Birkhead) seal indicates that it is more representative of a palaeo-oil that leaked upward from within the Birkhead/Hutton palaeo-reservoir (see discussion in Boult *et al.*, 1998).

A double pulse of migration is also supported by maturation modelling within the Gidgealpa drainage area (Boult *et al.*, 1997) which indicates that the Birkhead Formation in the Nappamerri Trough expelled the majority of its oil (first pulse: palaeo-oil) between 90 and 70 Ma. Then at *ca* 70 Ma, the Birkhead Formation in the Patchawarra Trough entered the oil window and possibly contributed hydrocarbons which were trapped in the Gidgealpa southern dome and represented by the DST-3 sample. A recent (*ca* 1 Ma) and significant increase in geothermal gradient for the Cooper/Eromanga region has been inferred (Pitt, 1986; Gleadow, 1988; Boult *et al.*, 1997). It is reasonable that this heating event initiated the second pulse of oil represented by DST-4. However, since the Birkhead Formation in the Nappamerri Trough has a present-day maturity of ≥ 0.9% R_o (Fig. 6.18) and is therefore mature to post-mature for oil generation, much of the second charge probably originated from the Birkhead source rocks (*ca* R_o = 0.6–0.65%) in the Patchawarra Trough. Boult *et al.* (1998) argued that the second oil charge derived from the Birkhead Formation ($R_o \approx$ 0.6–0.65%) in the Tindilpie area where oil-prone coaly source rocks (*cf.* Chapter 3; Michaelsen and McKirdy, 1996) are developed as thick coal pods associated with major flooding surfaces (Boult *et al.*, 1998, fig. 10). This charge was stratigraphically focussed southward into the Gidgealpa southern dome along palaeo-ridges developed at the unconformity between the Hutton Sandstone and Birkhead Formation. Boult *et al.* (1998, fig. 11) depicts a possible migration pathway from the Tindilpie area to the Gidgealpa southern dome which passes through the 0.5% vitrinite (R_o) contour line. It is postulated that the 17β,21β-hopanes and the 22*R* C_{31} homohopane, present in the Gidgealpa-17 (DST-4: Hutton) live oil, were leached from sub-mature coals ($R_o \leq$ 0.5%) along this route. Boult *et al.* (1998, fig. 18) used 2D seismic lines and isochron mapping of the Hutton/Birkhead disconformity to identify incised erosional channels extending northward of the Tindilpie area where the maturity of the Birkhead Formation places it in the early oil window (R_o = 0.6–0.65%).

In summary, the saturated and aromatic biomarker evidence indicates that the Hutton and Birkhead oil pools at Gidgealpa-17 were sourced from *separate* oil charges derived from Birkhead formation coals.

Queensland

The relative disposition of the Queensland oils in the 1,7-DMP/X *versus* retene/9-MP cross-plot (Fig. 6.16) is similar to that in Figure 6.15. The Hutton crudes at Chookoo-1 and Naccowlah South-1 clearly plot in the "Permian" field. The oils from Gunna-1 (Birkhead), Inland-1 (Hutton, Namur), and Jackson-3 (Westbourne) plot in the transitional zone between "Permian" and "Jurassic". Although they are reservoired in the Eromanga succession, these four oils apparently have some Permian source affinity (*i.e.* they are mixtures of Cooper- and Eromanga-derived hydrocarbons). It is particularly significant that the Inland Field is located well beyond the "zero edge" of the Cooper Basin (Figure 6.2) and yet its Hutton and Namur oils appear to be

mixtures of Permian and Jurassic-sourced hydrocarbons. On the other hand, the 1,7-DMP/X and retene/9-MP ratios of all the Murta oils in Queensland suggest that they are of intra-Eromanga origin.

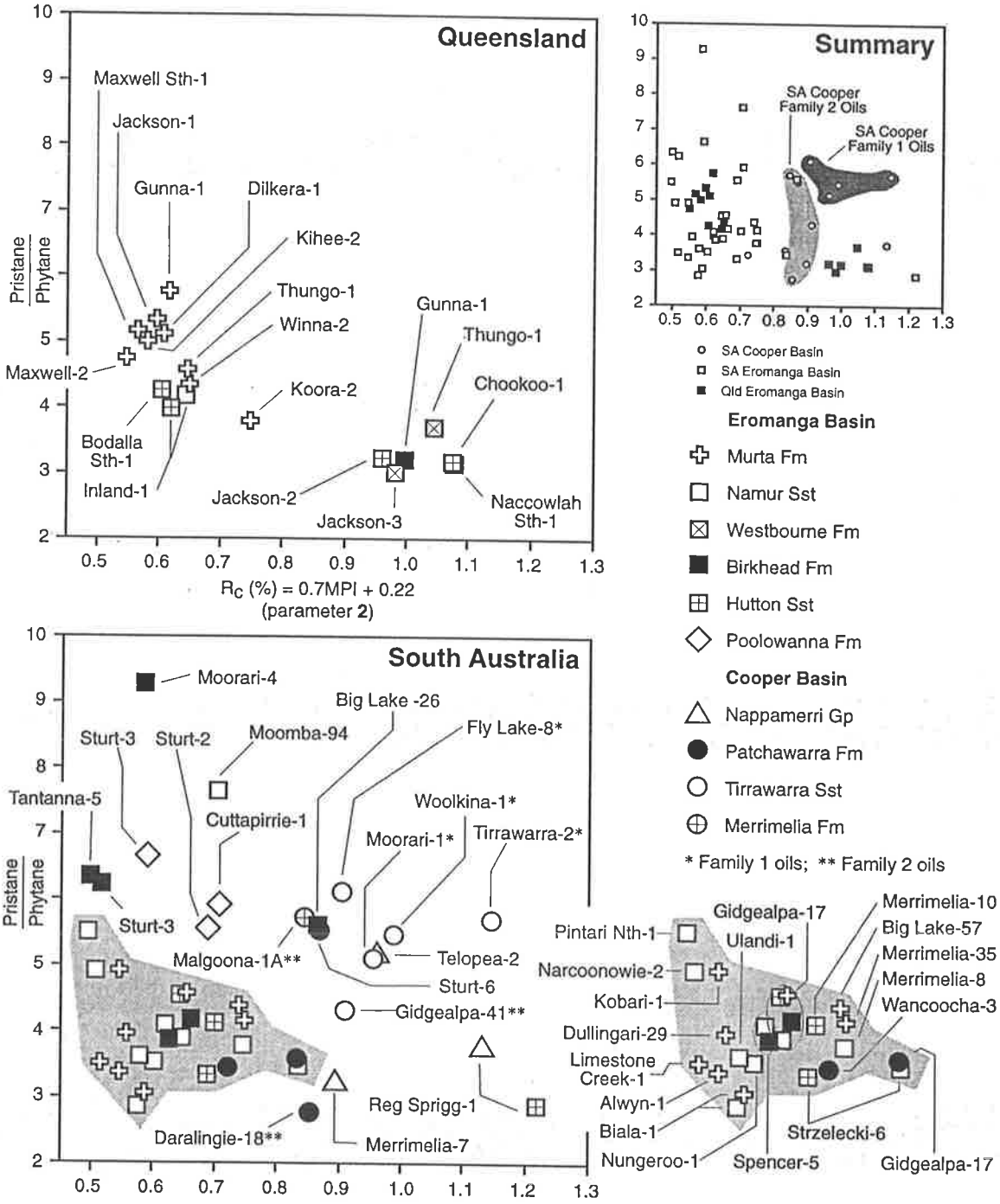


Figure 6.17 Calculated vitrinite reflectance (parameter **2**) *versus* pristane/phytane

6.4.5 Which maturity parameter to use?

6.4.5.1 Methylphenanthrene ratio and methylphenanthrene index

Methylphenanthrene ratios, methylphenanthrene indices and calculated vitrinite reflectances for each of the 62 oils are provided in Table 6.1 and summarised in Table 6.3. The methylphenanthrene index has been computed in two ways: the first (MPI) according to the defined formula (see footnote Table 6.1), and the second (MPI_n) by the same formula except that 1-MP was assumed to equal 9-MP in abundance. The latter measurement was used only for oils in which 1-MP/9-MP > 1.5. This situation is commonly the case in Jurassic oils where biomarkers derived from Araucariaceae are present. Examples are the Eromanga oils at Gidgealpa-17 (Fig. 6.4) and the Birkhead oils at Sturt-3 and Moorari-4 (Figs 6.5 and 6.6); several oils from the Murteree Ridge area and southern Cooper Basin (Figs 6.7 and 6.8); and

oils from the southeastern end of the NJ Ridge in Queensland (Fig. 6.12). Samples which contain exceptionally high concentrations of araucariacean resin biomarkers, such as Moorari-4 (Birkhead) and Sturt-3 (Birkhead), have very low MPI values (0.2 and 0.24, respectively) which translate to unrealistically low R_c values of 0.36 and 0.39% using the formula of Boreham *et al.* (1988), or 0.52 and 0.54% using Radke and Welte's (1983) formula. However, by substituting the conventionally-derived MPI with MPI_n more realistic maturities are obtained [R_c = 0.58% (Moorari-4) and 0.52% (Sturt-3) using the formula of Boreham *et al.* (1988); R_c = 0.71% (Moorari-4) and 0.65% (Sturt-3) using Radke and Welte's (1983) formula]. Inspection of the data in Table 6.1 shows that using MPI_n raises the estimated maturity (R_c) by an average of 0.06% (parameter **2**) and 0.05% (parameter **4**) in Jurassic samples. It is difficult to decide whether Radke and Welte's (1983) calibration or that of Boreham *et al.* (1988) provides a more accurate maturity. Certainly, the calibration of Boreham *et al.* (1988) gives an unduly low R_c if MPI is used without normalising 1-MP to 9-MP. Therefore, in the case of Jurassic oils where 1-MP/9-MP > 1, the discussion which follows is based entirely on MPI_n-derived R_c (*i.e.* Table 6.1: parameters **2** and **4**). For such oils, it is possible that the true maturity is somewhere in the range between R_c estimated by parameters **2** and **4**. Regardless of which calibration is used, it is the *contrast* in maturity between the Cooper Basin oils and most of the Eromanga oils that is the principal feature of the data.

Table 6.1 also provides maturity estimates based on the methylphenanthrene ratio (MPR). Anomalously low MPR-derived R_c values (Table 6.1: parameter **5**) for the Birkhead oils at Moorari-4 and Sturt-3 emphasise the problem of accurate maturity determination using aromatic hydrocarbons when araucariacean biomarkers are present in oils. Nevertheless, the other data appear to be sensible, there being a maturity contrast between the Cooper and the remaining Eromanga oils based on parameter **5**, consistent with the maturities derived from MPI and MPI_n (parameters **1–4**). Some of these data are summarised in Figures 6.17, 6.18 and 6.19 which are cross-plots of R_c (parameter **2**) *versus* Pr/Ph, R_c (parameter **4**) *versus* Pr/Ph, and parameter **4** *versus* parameter **5**, respectively. It is interesting that the least mature oil (Moorari-4, Birkhead) has by far the highest Pr/Ph ratio (9.27). The low maturity Sturt-3 (Birkhead) crude also has a very high Pr/Ph value of 6.25. Clearly the resinite-enriched coals from which these oils were derived, were deposited under highly oxidising conditions. However, overall there appears to be poor correlation between Pr/Ph values and maturities estimated from MPI (Figs 6.17 and 6.18).

South Australia

Cooper Basin Family 1 oils have R_c values (**2** = 0.91–1.14%; **4** = 0.99–1.19%; **5** = 1.04–1.25%) consistent with those determined from chromatographically-fractionated aromatic samples (Chapter 2). On average these maturities are marginally greater than those for Family 2 oils (**2** = 0.72–0.91%; **4** = 0.83–0.99%; **5** = 1.03–1.10%). Thus, Family 1 and Family 2 oils cannot be clearly distinguished on the basis of MPI or MPI_n-derived R_c. Other samples with very high maturities include those from the Nappamerri Group at Merrimelia-7 (**2** = 0.89%; **4** = 0.98%; **5** = 1.04%), Reg Sprigg-1 (**2** = 1.13%; **4** = 1.18%; **5** = 1.17%) and Telopea-2 (**2** = 0.96%; **4** = 1.04%; **5** = 1.04%).

The Hutton oil at Reg Sprigg-1 has an almost identical maturity (**2** = 1.22%; **4** = 1.26%; **5** = 1.15%) to the Nappamerri crude at the same locality. Because both oils appear to have migrated from deeper (more mature) source rocks, the Nappamerri Group evidently has poor sealing efficiency at this locality.

The Birkhead oil at Big Lake-26 (**2** = 0.87%; **4** = 0.95%; **5** = 0.90%) has a maturity similar to that of the Permian Family 2 oils, which is further evidence of its partial derivation from the Cooper Basin. The Strzelecki-6 (Namur) crude (**2** = 0.84%; **4** = 0.93%; **5** = 0.85%) likewise may be partly derived from more mature Cooper Basin source rocks. The remaining Eromanga oils have maturities expected of *in situ* expulsion products. Moreover, they exhibit a maturation gradient whereby the least mature oils occur in the stratigraphically highest reservoirs and the maturity increases with increasing stratigraphic depth of the reservoir (Table 6.3; *cf.* Chapter 5, Table 5.1).

For the purposes of further discussion, only parameter **2** will be considered. Within the Murta data set, 5 out of 8 oils (63%) have maturities ≤ 0.59% R_c. The Namur suite has 4 out of 10 oils (40%) with similar low maturities; and if the problematic Moorari-4 and Sturt-3 data are excluded, 1 out of 4 (25%) of the Birkhead oils, and 1 out of 3 (33%) of the Poolowanna oils have maturities of less than 0.59% R_c. In the case of the Murta Formation, those oils with higher

maturities (Gidgealpa-17: 2 = 0.66%; Merrimelia-35: 2 = 0.75%; Big Lake-57: 2 = 0.74%) are *all from fields containing stacked reservoirs*. In fact, the Eromanga oil pools in the Gidgealpa Field are remarkable in that they have nearly identical R_c values (Hutton: 2 = 0.65%; Birkhead: 2 = 0.66%; Namur: 2 = 0.65%; Murta: 2 = 0.66%) indicating a common intra-Eromanga (but non-Murta) source. In contrast, oils in reservoirs of the Merrimelia Field are of less uniform but significantly higher maturity (Nappamerri: 2 = 0.89%; Hutton: 2 = 0.70%; Namur: 2 = 0.75%; Murta: 2 = 0.75%) implying partial derivation from the Cooper Basin.

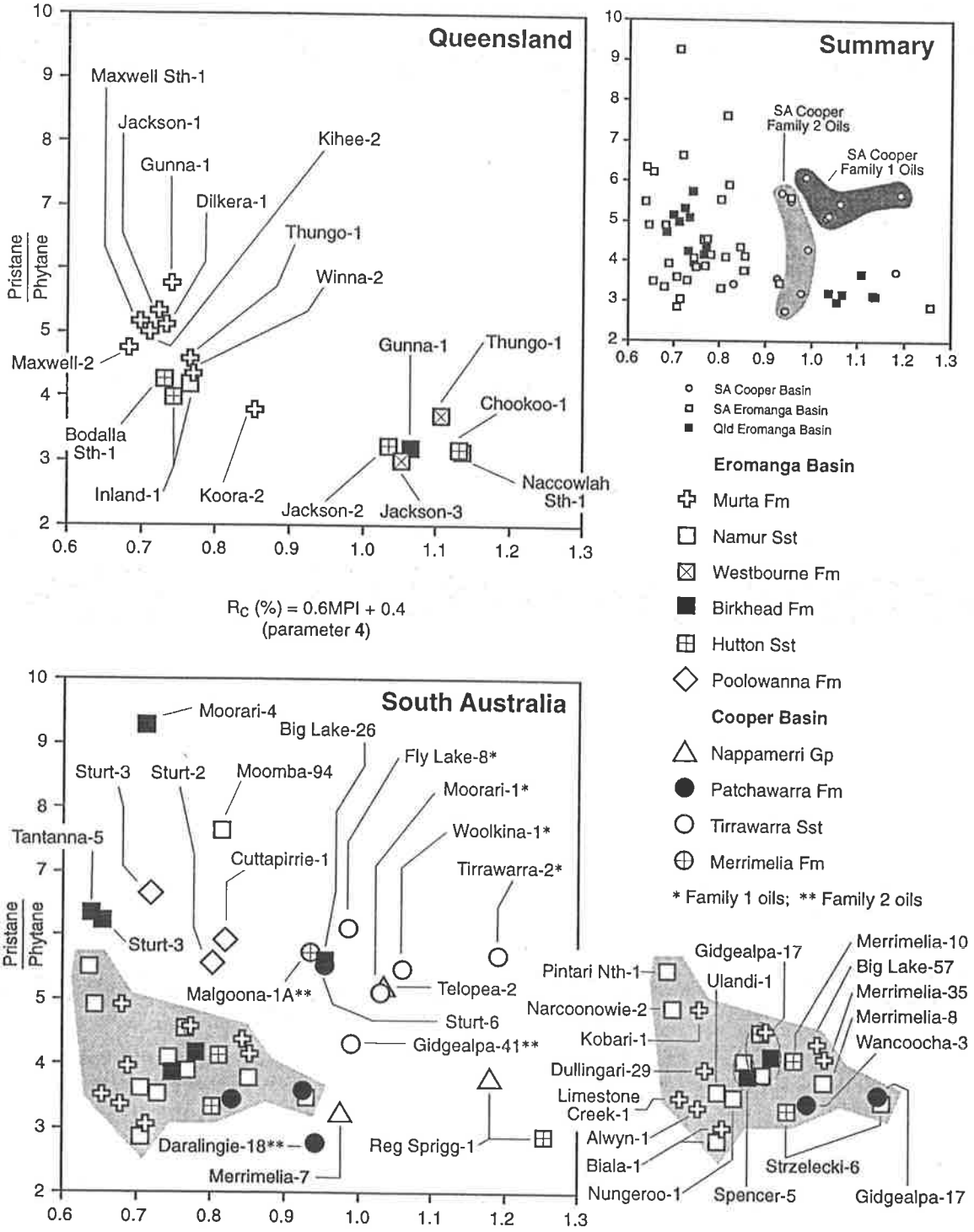


Figure 6.18 Calculated vitrinite reflectance (parameter 4) *versus* pristane/phytane

The Big Lake-57 (Murta) oil is also of similarly high maturity (2 = 0.74%). This oil is highly unlikely to be entirely of intra-Eromanga origin, especially since the Birkhead oil at Big Lake-26 (2 = 0.87%), is without doubt of mixed Permian/Jurassic origin (as discussed above). The lower maturity of the Murta oil suggests a greater source contribution from the Eromanga Basin.

In summary, although the many Murta-reservoired oils with R_c values in the range 0.5–0.6% (parameter **2**) appear to be of intra-Murta origin (*cf.* Chapter 5), there are other Murta oils which have migrated from deeper source rocks in the Eromanga Basin (*e.g.* Gidgealpa Field), or represent mixtures of Cooper and Eromanga-derived oils (*e.g.* those in the Merrimelia and Big Lake Fields).

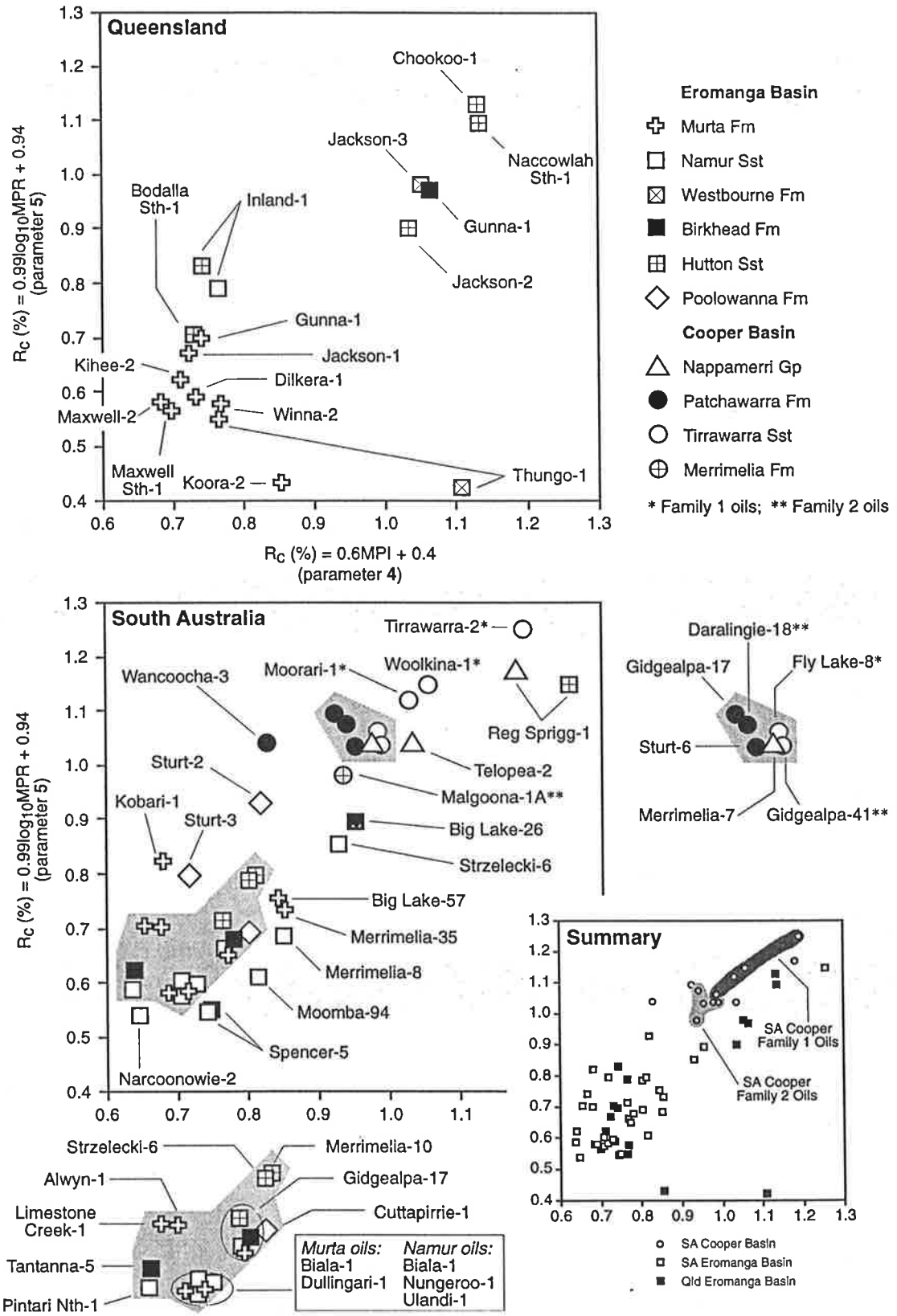


Figure 6.19 Calculated vitrinite reflectance: MPI-derived *versus* MPR-derived

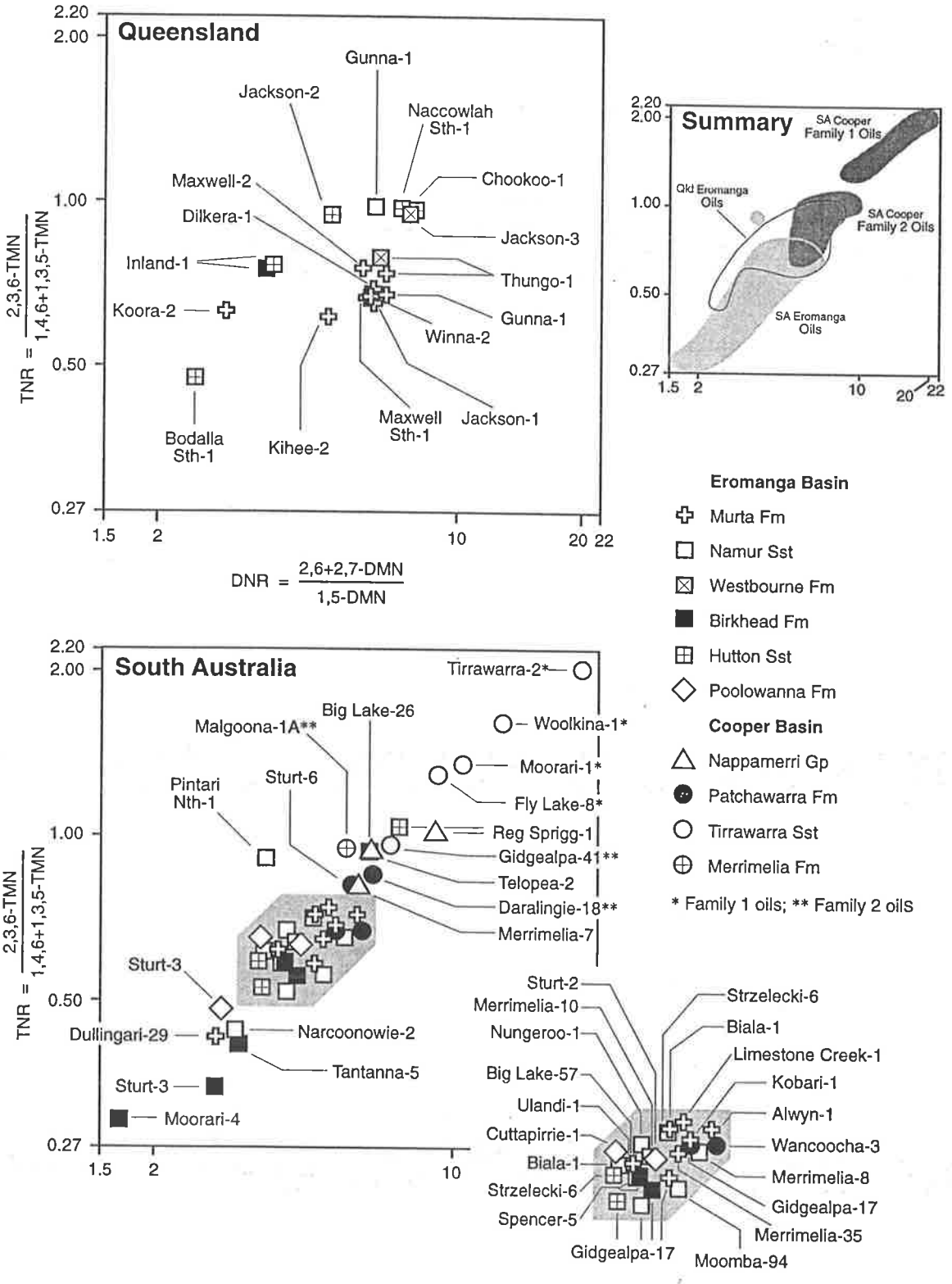


Figure 6.20 Aromatic maturity parameters: DNR *versus* TNR

Queensland

Naccowlah-Jackson Ridge

The methylphenanthrene-derived maturities of Eromanga oils are generally greater along the NJ Ridge than in South Australia (Tables 6.1 and 6.3). With the exception of the Koora-2 crude (2 = 0.75%), all the Murta-reservoired oils have relatively low maturities (2 = 0.55–0.65%). Three of these oils (Maxwell-2, Maxwell South-1, Kihee-2) have R_c values less than 0.59% similar to indigenous Murta crudes in South Australia. It is interesting to note that the two least mature oils come from the southeastern extremity of the NJ Ridge beyond the local Cooper Basin "zero edge". Conversely, the most mature oils are from the Hutton Sandstone (mean 2 = 0.87%), Birkhead Formation (2 = 1.00%) and Westbourne Formation (mean 2 = 1.02%) at Chookoo-1

and Naccowlah South-1. These have R_c values more typical of Cooper Basin oils in South Australia. However, their high maturities are at variance with the thermal rank of the local potential source rocks (Chapter 5; Powell *et al.*, 1989); and, as discussed above, their muted "araucariacean signature" implies that at least part of their charge originated in the Cooper Basin. Hutton oils from Chookoo-1 and Naccowlah-1 have identical high R_c values (**2** = 1.08%). MPR-derived maturities (parameter **5**) are also very high for the Chookoo-1 (**5** = 1.13%) and Naccowlah South-1 (**5** = 1.09%) oils (Fig. 6.14). These two oils appear to have been sourced entirely from the Cooper Basin.

Calculated maturities of oils from the central NJ Ridge at Jackson-2 (Hutton: **2** = 0.96%, **5** = 0.90%), Gunna-1 (Birkhead; **2** = 1.00%, **5** = 0.90%) and Jackson-3 (Westbourne: **2** = 0.98%, **5** = 0.98%) are also high, but less so than those of the very mature Chookoo-1 and Naccowlah South-1 oils. The remaining oils from this area have lower, more conventional "Eromanga-type" maturities. The Jackson-1 (Murta) crude was generated from a relatively low maturity source rock (**2** = 0.60%, **5** = 0.67%). Obviously the oils in the stacked reservoirs at Jackson were expelled from their respective source rocks at different maturity levels. It is unlikely that low-rank Eromanga source rocks were the sole contributors of the hydrocarbons to the Hutton and Westbourne oil pools. A contribution from the Cooper Basin is highly likely. Indeed, the Hutton and Westbourne oils at Jackson contain lower concentrations of araucariacean biomarkers signalling a clear Permian source contribution (Figs 6.15 and 6.16).

Inland and Bodalla South Fields

Modest calculated maturities are recorded for crudes from the Hutton (**2** = 0.62%, **5** = 0.83%) and Namur (**2** = 0.65%, **5** = 0.79%) reservoirs at Inland-1. Nonetheless, based on their retene/9-MP and 1,7-DMP/X values, the Inland-1 oils appear to be partly derived from the Cooper Basin. It is *possible* that Permian hydrocarbons which invaded the Eromanga reservoirs at Inland-1 were early expulsion products (*i.e.* $R_c \leq 0.65\%$). However, this interpretation is at variance with the observed *n*-alkane distributions (Section 6.4.1.2) for the Inland-1 oils, and is different from, for example, that of the Westbourne crude at Jackson-3 where the Permian contribution to the final Eromanga-hosted oil accumulation was obviously a hydrocarbon charge of elevated maturity ($R_c \geq 0.95\%$).

There is no clear evidence of low-maturity Permian oil in the Jurassic/Cretaceous succession where it directly overlies the Cooper Basin. However, it is possible that the chemistries of any such early expulsion products of Permian source rocks which migrated into the overlying Eromanga Basin were later obscured by a subsequent charge with a high-maturity Permian signature. The Inland oil accumulations are positioned well to the north of the Cooper Basin margin (*ca* 60 km). Therefore, extensive lateral migration from source kitchen to trap must be invoked if the Inland oils do indeed contain Permian-derived hydrocarbons.

Further west, on the other side of the Cooper Basin, the Bodalla South-1 (Hutton) oil has a relatively low calculated maturity (**2** = 0.61%, **5** = 0.70%) consistent with its expulsion early in the oil generation window from a Jurassic source.

6.4.5.2 Dimethylnaphthalene and trimethylnaphthalene ratios

South Australia

Figure 6.20 is a cross-plot of the conventional maturity parameters DNR and TNR. Unlike the the maturation parameters discussed above, which are based on phenanthrene and various of its methylated isomers, the alkylnaphthalene data highlight a clear distinction between Cooper Basin Family 1 and Family 2 oils. Family 1 oils have DNR values ranging from 9 to 20, whilst TNR values fall between 1.3 and 2.0. The data confirm that Family 1 oils were indeed generated at higher maturities than Family 2 oils. The fact that MPR and MPI_n-derived maturity data do not clearly distinguish between these two groups of Permian oils (Fig. 6.19) suggests that the alkylphenanthrene-derived parameters are not sufficiently responsive above a critical maturity of *ca* 1.0% R_o to be particularly useful here.

Other South Australian oils shown to have high maturities in Figure 6.20 include those from Reg Sprigg-1 (Nappamerri and Hutton), Telopea-2 (Nappamerri), Big Lake-26 (Birkhead) and Merrimelia-7 (Nappamerri). This is consistent with maturity estimates based on MPI_n and MPR. The Reg Sprigg and Telopea crudes are very mature Cooper Basin oils which have permeated, and migrated vertically beyond, the Nappamerri Formation which is, as previously mentioned, an inefficient seal in this part of the northeastern Patchawarra Trough (Fig. 6.1). By virtue of their DNR and TNR values, the Reg Sprigg-1 and Telopea-2 oils are more akin to

Family 2 oils from the Cooper Basin. This observation is partly at odds with the MPR- and MPI-derived maturities of the Reg Sprigg-1 oils which indicate that they have a close affinity with the Cooper Basin Family 1 oils (Fig. 6.17–6.19).

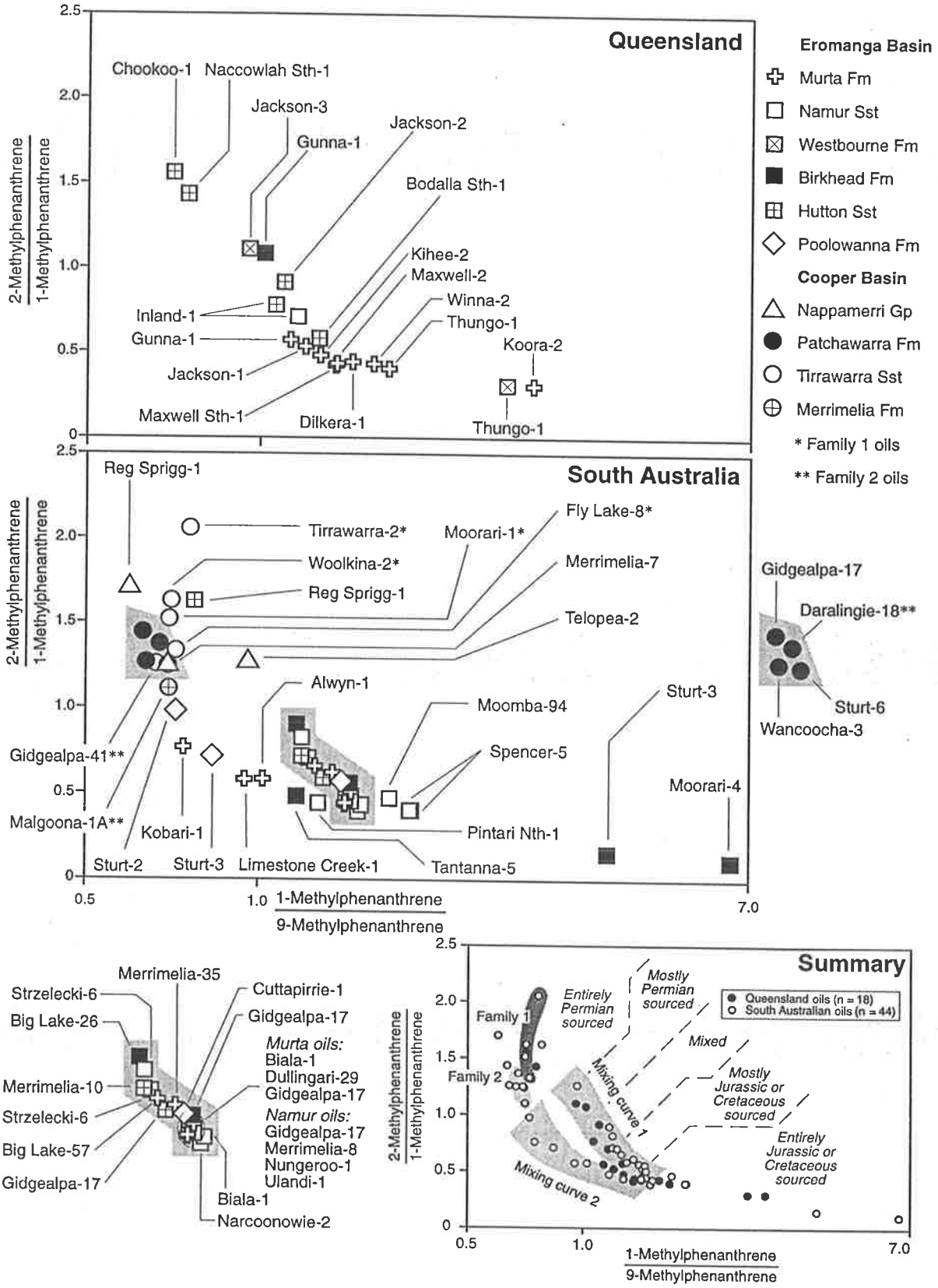


Figure 6.21 Aromatic source and maturity parameters

Of particular interest are the oils that have very low DNR and TNR values. Once again the Birkhead oils at Moorari-4 (DNR = 1.69; TNR = 0.30) and Sturt-3 (DNR = 4.02; TNR = 0.59) have unusual end-member chemistries, yet none of the compounds used in the calculation of DNR and TNR are araucariacean resin markers. Notwithstanding the absurdly low maturity

values obtained for these oils using MPI (parameter **1**) and MPR (parameter **5**), it is unlikely that their exceptionally low DNR and TNR values also are unrealistic. Rather, the data presented in Figure 6.15 suggest that the Moorari-4[1] and Sturt-3 samples have maturities even lower than those of the Dullingari-29 (Murta: **2** = 0.56%, **5** =0.58%), Narcoonowie-2 (Namur: **2** = 0.51%, **5** = 0.54%), Sturt-3 (Poolowanna: **2** = 0.59%, **5** = 0.80%) and Tantanna-5 (**2** = 0.50%, **5** = 0.62%) oils. Cook (1986) raised the prospect of resinite-enriched source rocks yielding hydrocarbons at maturity levels as low as 0.4% R_o (*i.e.* pre-conventional oil window). Thus it seems that the Birkhead crudes at Moorari-4 and Sturt-3 *may indeed* have been generated at such low levels of thermal alteration (*viz* incipient catagenesis).

Queensland

According to the DNR and TNR data (Fig. 6.20), several Queensland oils are also high maturity crudes, *viz* Chookoo-1 (Hutton), Naccowlah South-1 (Hutton), Jackson-3 (Westbourne), Jackson-2 (Hutton), and Gunna-1 (Birkhead). This is consistent with their maturity parameters based on methylphenanthrenes (Figs 6.17–6.19).

6.4.6 Mixing of Cooper and Eromanga Basin oils

Eromanga reservoirs along the NJ Ridge in Queensland have received various hydrocarbon charges from the Cooper Basin, and the resulting oils can be classified accordingly:

1. Oils in the Hutton Sandstone at Chookoo-1 and Naccowlah South-1 (northwest NJ Ridge) appear to be derived entirely from a Permian source kitchen. These hydrocarbons must have breached the top Cooper Basin regional seal (Nappamerri Group) *en route* to their respective Eromanga reservoirs.
2. The Hutton oil at Jackson-2, the Birkhead oil at Gunna-1, and the Westbourne oil at Jackson-3 (central NJ Ridge) represent Permian hydrocarbons which have also breached the Cooper Basin regional seal and invaded these Jurassic reservoirs to comingle with indigenous Eromanga oil.
3. The Murta oils from Koora-2, Winna-2 and Thungo-1, and the Westbourne crude from Thungo-1 (southeast NJ Ridge) are wholly Jurassic/Cretaceous in origin. Evidently the Cooper Basin hydrocarbons entered the Eromanga Basin in the Chookoo/Naccowlah South area and migrated in a southeasterly direction along the NJ Ridge. This is consistent with the migration paths postulated by Vincent *et al.* (1985, fig. 5) for the Late Jurassic–Early Cretaceous section in this area. It also agrees with the migration fairways inferred by Boreham and Summons (1999, fig. 20).

These findings may be conveniently summarised by incorporating what are arguably the two most responsive aromatic parameters, 2-MP/1-MP (MPR) and 1-MP/9-MP, into a novel cross-plot (Fig. 6.21, see summary inset; *cf.* Fig. 3.21). The latter is one of the source-related parameters developed by Alexander *et al.* (1988), whereas 2-MP/1-MP was developed by Radke and Welte (1983) as a maturity parameter (based largely on northern hemisphere rock and oil samples). In the Cooper/Eromanga Basin, MPR is doubly effective: it continues to operate as a maturity parameter by virtue of the fact that 2-MP is the more stable of the two isomers in question (*i.e.* more mature Cooper Basin source rocks and oils have higher concentrations of this isomer than do less mature Eromanga source rocks and oils). However, its effectiveness in source rocks and oils of the Eromanga Basin is enhanced by the specific input of the araucariacean biomarker, 1-methylphenanthrene, making it sensitive to both source and maturity.

In the source affinity cross-plots previously discussed (*e.g.* Figs 6.15 and 6.16), the data are somewhat scattered and there are no clearly defined trends. However, in Figure 6.21 the *Queensland data define a sinusoidal curve*. Cooper Basin-sourced oils have low 1-MP/9-MP values and plot to the left (notably Chookoo and Naccowlah South). Conversely, Murta oils from Koora-2, Thungo-1, Winna-2, Dilkera-1, Maxwell-2, Maxwell South-1, and probably also the Westbourne crude at Thungo, appear to have been sourced predominantly (or entirely) from within the Eromanga Basin. On Figure 6.21, at approximately the position of the Maxwell-2 (Murta) data point, there is an inflexion in the curve and its gradient changes abruptly. This method of presenting source and maturity data reveals a *mixing curve which allows the*

[1] Boreham and Summons (1998, p. 142) also recognised the Moorari-4 (Birkhead) oil as the least mature in the Cooper/Eromanga Basin. They used it to define a maturity threshold of 0.65% R_o, below which they claimed no expulsion from a source rock can occur. However, Boreham and Summons (1999, appendix 2) provide a maturity of 0.54% R_c for the same oil. Apparently both values were calculated using Radke and Welte's (1983) formula: R_c (%) = 0.6 MPI + 0.4.

proportion of Cooper and Eromanga-derived hydrocarbons to be estimated semi-quantitatively. In the summary inset of Figure 6.21, the South Australian and Queensland data sets are combined. Most of the South Australian oils plot along the mixing trend defined by the Queensland oils ("mixing curve 1"). However, some South Australian samples define a second mixing trend ("mixing curve 2"). "Mixing curve 1" may be subdivided into five segments which identify the oils within them as "entirely Permian-sourced", "mostly Permian-sourced", "mixed", "mostly Jurassic/Cretaceous-sourced", and "entirely Jurassic/Cretaceous-sourced" (*cf.* Table 6.4).

The reason for the existence of two divergent mixing curves is intriguing and is analysed more fully in Chapter 7. "Mixing curve 1" apparently represents comingling of Eromanga-derived crude with Family 1 (Patchawarra-derived) ± Family 2 oil, whereas "mixing curve 2" may reflect comingling of Eromanga oil with less mature Patchawarra-derived Family 2 crude and/or oil derived from another source rock unit such as the Toolachee Formation. Unfortunately, oils from the Toolachee Formation were unavailable for this study. A recommendation that arises from this work is that future geochemical studies in the Eromanga Basin should include where possible rock samples and oils from the Toolachee Formation. Geochemical studies based on compound-specific (chiefly *n*-alkane) isotope data at the Australian Geological Survey Organisation (Canberra) indicate that the Toolachee source rocks have also contributed to the hydrocarbon reserves of the Cooper Basin (C.J. Boreham, AGSO, pers. comm., 1998).

It is significant that the South Australia oils on "mixing curve 2" are from the southwestern margin of the Cooper Basin (Figure 6.1, areas 1–3), where oils from Permian reservoirs are known to be of Family 2 composition (*e.g.* Daralinge-18, Patchawarra; Malgoona-1A, Merrimelia) or probable Family 2 composition (*e.g.* Sturt-6, Patchawarra; Wancoocha-3, Patchawarra). Conversely, the South Australian oils that plot along "mixing curve 1" are from areas 4–6 (Figure 6.1), where Family 1 oils occur (*viz* area 5) or where the Patchawarra Formation is presently mature or post-mature for liquid hydrocarbon generation (*cf.* Figure 2.2). The Queensland crudes from Eromanga reservoirs which plot along "mixing curve 1" also appear to be the products of mixing of Family 1 oil with indigenous Jurassic/Cretaceous oil. These matters are analysed more fully in Chapter 7.

The novel cross-plot in Figure 6.21 will not replace the classic araucariacean biomarker plots (*e.g.* Figs 6.15 and 6.16). However, as another way of presenting aromatic hydrocarbon data, it does provide a convenient means of semiquantitatively estimating the relative proportions of Permian and Jurassic/Cretaceous-derived hydrocarbons within oil pools of the Cooper/Eromanga Basin province.

6.5 SYNOPSIS

1. *n*-Alkane distributions characteristic of very high maturity oils (*viz* Cooper Basin Family 1) occur in only a small proportion of the Eromanga-hosted oils tested by GC.
2. GC-MS analysis of whole-oil samples is capable of yielding reliable and reproducible information on aromatic hydrocarbons (*e.g.* alkylnaphthalenes, alkylphenanthrenes and retene).
3. The aromatic biomarker signatures of their oils suggest that significant volumes of high-maturity oil have not migrated from the Cooper Basin into the overlying Eromanga Basin. For example, the stacked reservoirs of the Tirrawarra Sandstone and Birkhead Formation at Moorari contain oils with quite distinct chemistries. The Tirrawarra oil is of high maturity and pre-araucariacean (*i.e.* pre-Jurassic) in its source affinity, whereas the Birkhead-reservoired oil is an archetypical Eromanga-sourced oil. The Moorari-4 (DST-3, Birkhead) oil contains the highest concentrations of araucariacean biomarkers encountered in this study.
4. The best criteria to distinguish Cooper Basin Family 1 and Family 2 oils using aromatic hydrocarbons are the conventional maturity parameters, DNR and TNR. These same ratios confirm that Eromanga oils in Queensland have a greater affinity with the Cooper Basin than do those in South Australia.
5. Permian Family 1 oils are restricted to a small area (Fly Lake-Tirrawarra-Moorari-Woolkina) within the Patchawarra Trough, Cooper Basin, whereas Permian Family 2 oils seem to have a wider geographic distribution. However, other oils (*e.g.* Reg Sprigg, Hutton) in the Patchawarra Trough also have very high maturities similar to those of Family 1 oils.

6. The stacked Eromanga reservoirs (Hutton, Birkhead, Namur, Murta) of the Gidgealpa Field were charged by Jurassic (probably Birkhead) source rocks. However, oils from stacked reservoirs at Merrimelia and Big Lake appear to be partly derived from the Cooper Basin.

7. In the Sturt and Tantanna Fields, located adjacent to the Cooper Basin "zero edge" in the southwest Patchawarra Trough, Permian oil may have invaded the Poolowanna and Birkhead reservoirs and comingled with indigenous Eromanga oil.

8. The Eromanga oil fields of the NJ Ridge (Queensland) have variable inputs from the Cooper Basin. The Hutton-reservoired oils at the northwest end of the NJ Ridge (Chookoo and Naccowlah South) appear to be derived entirely from a Permian source kitchen. In the central part of the trend, oils at Jackson (Hutton and Westbourne) and Gunna (Birkhead) appear to be of mixed Cooper/Eromanga origin, whereas at its southeast end (*e.g.* Koora, Winna, Thungo and Maxwell) oils in the Murta and Westbourne reservoirs are wholly Jurassic/Cretaceous in origin.

9. It appears that Permian oil breached the Cooper Basin seal in the Chookoo/Naccowlah South area and then migrated in a southeasterly direction. For whatever reason Permian oil failed to reach the Eromanga reservoirs at the southeast end of the NJ Ridge which remain charged with indigenous Jurassic oil.

10. A novel cross-plot of 1-MP/9-MP *versus* 2-MP/1-MP has been developed which allows for a semiquantitative estimate of the relative contributions of Cooper and Eromanga-sourced hydrocarbons to the Jurassic and Cretaceous reservoirs of the Eromanga Basin.

CHAPTER 7

Regional analysis of oil migration and mixing

CHAPTER 7

Regional analysis of oil migration and mixing

* Parts of this chapter have been published as follows (Appendix 4):

Michaelsen B.H. and McKirdy D.M. (2000) Migration and mixing of oils in the Cooper/Eromanga Basin. In *Australian Organic Geochemistry Conference, Book of Abstracts*. Australian Institute of Marine Science, Townsville, Queensland.

Michaelsen B.H. and McKirdy D.M. (2001) Migration and mixing of oils in the Cooper and Eromanga Basins, central Australia. *In Eastern Australasian Basins Symposium, A Refocused Energy Perspective for the Future* (ed. K.C. Hill and T. Bernecker), Petroleum Exploration Society of Australia, Special Publication, pp. 289–300.

7.1 SUMMARY

This chapter presents additional data on the migration of Permian and Jurassic/Cretaceous hydrocarbons and their interpretation based on the mixing curves described in Chapter 6. Aromatic hydrocarbon data for a suite of potential source rocks and oils, originally collated by Michaelsen *et al.* (1995d) and Boreham and Summons (1999, appendix 2) are described. Boreham and Summons' (1999) oils are exclusively from the Eromanga Basin, and in the Queensland sector are mostly located above the margins of the Cooper Basin, notably in the Bodalla South and Inland areas. Although the mixing curves in Chapter 6 were defined using both 1-MP/9-MP and 2-MP/1-MP ratios, it is possible to provisionally estimate the degree of mixing of Permian and Jurassic/Cretaceous hydrocarbons in many of these oil pools by plotting their 1-MP/9-MP (or alternatively 2-MP/1-MP) ratios onto the mixing curves. Such oils in the Bodalla South area of the northeastern Cooper Basin have varied source affinity. Thus, for example, those in the Poolowanna Formation at Bargie-1 and Black Stump-1 are sourced entirely or predominantly from the Cooper Basin, whereas oils in the Birkhead Formation at Talgeberry-1 and the Murta Formation at Utopia-1 are derived from Jurassic/Cretaceous source rocks.

In the northwestern Cooper Basin area, a Jurassic (Birkhead Formation) source kitchen is inferred in the Haddon Syncline/Morney Anticline area. Jurassic hydrocarbons from this area have mixed in varying amounts with Permian oil derived from the Windorah Trough to the south. Consequently, the Murta Formation oil pool at Morney-1 (closest to the Haddon Syncline) has a 75% Jurassic/25% Permian source affinity. By contrast, the Cadna-owie Formation oil at Cuddapan-1 (furthest from the Morney Syncline) has a 25% Jurassic/75% Permian affinity.

Areas in South Australia where Family 1 oils have most obviously invaded the Eromanga Basin (and mixed with Jurassic/Cretaceous hydrocarbons) overlie thermally mature to overmature regions of the Cooper Basin (*viz* northern Patchawarra Trough and southwestern Nappamerri Trough) where Family 1 oils are known or are inferred. However, there is no evidence that Family 1 oils have migrated beyond the western "zero edge" of the Cooper Basin. As such the Birkhead Formation oils near the western margin of the Cooper Basin at Charo-1 and Callabonna-1 do not have a Cooper-sourced component.

7.2 DETAILED INTERPRETATION OF OIL MIXING CURVES

To facilitate more detailed interpretation of the mixing curves based on the parameters 1-MP/9-MP and 2-MP/1-MP, a number of computer-generated or "synthetic" mixing curves were constructed based on the hypothetical mixing of end-member oils (Figs 7.1 and 7.2). These curves were drafted using the methylphenanthrene isomer ratios without consideration for the quantitative abundance of each individual isomer. An additional oil sample recovered from the Murta Formation at Garanjanie-1 (Section 1.4), in the vicinity of the southwestern margin of the Cooper Basin, was analysed by the author for Gray's (1998) thesis and is incorporated in the discussion here. This oil was analysed by GC-MS using the methodology outlined in Section 6.3.2 and therefore the derived data are exactly comparable to the analyses of the 62 oils in

Table 6.1. For the purpose of this discussion, the relevant details of the Murta Formation oil at Garanjanie-1 are as follows:

Well	Sample type/ID	Unit	R_c **1** (%)	R_c **3** (%)	1-MP / 9-MP	2-MP / 1-MP	Interpreted age of source rock
Garanjanie-1	DST-1	Murta Fm	0.53	0.67	0.70	0.63	Permian

Refer to Table 6.1 for definitions of **1** and **3**

Similar to oils reservoired in the Cooper Basin which are derived from Permian source rocks, the Eromanga (Murta Formation) oil at Garanjanie is characterised by low levels of the araucariacean biomarkers 1,2,5-trimethylnaphthalene, 1-methylphenanthrene, 1,7-dimethylphenanthrene and retene (Gray, 1998).

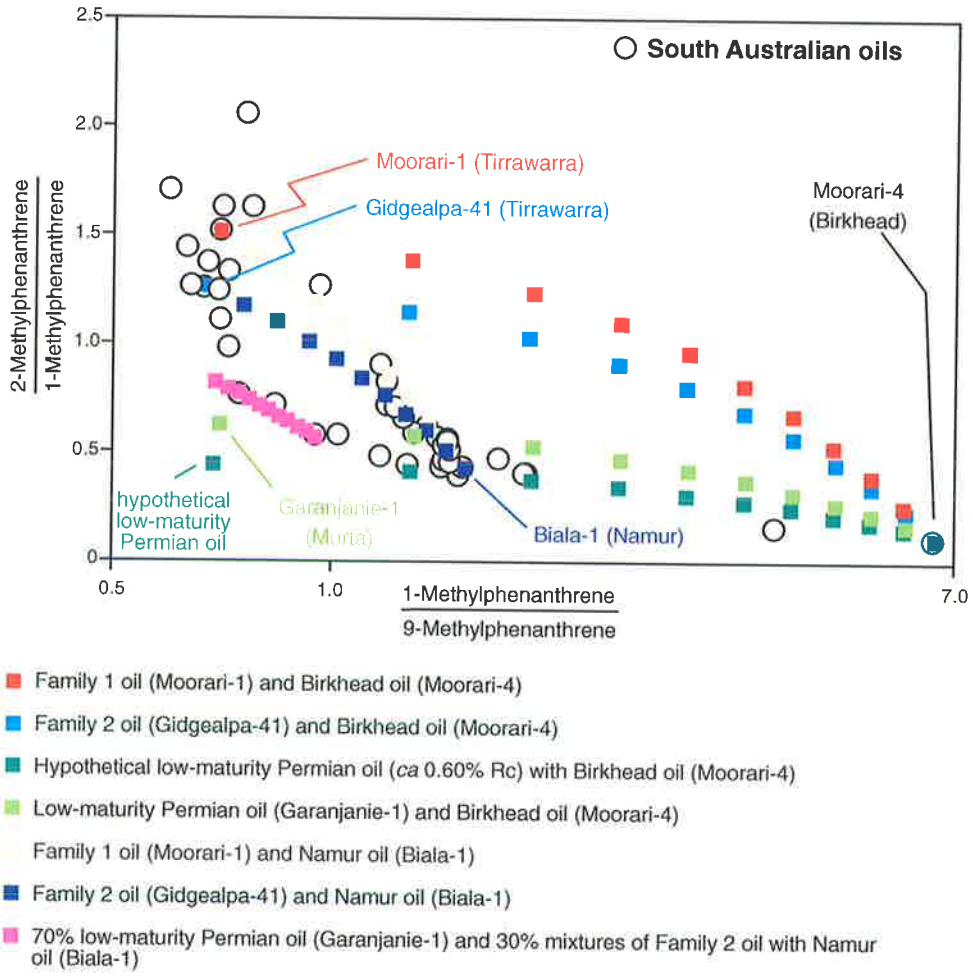


Figure 7.1 Cross-plot of 1-MP/9-MP *versus* 2-MP/1-MP: Comparison of oils (unspecified stratigraphy) from South Australia with computer-generated mixing curves for hypothetical and actual crudes as indicated

7.2.1 South Australia

Seven synthetic mixing curves (Fig. 7.1) were constructed based on South Australian oils which represent mixing of:

1. a typical Family 1 oil (Moorari-1: Tirrawarra Sandstone) and Birkhead oil (Moorari-4);
2. a typical Family 2 oil (Gidgealpa-41: Tirrawarra Sandstone) and Birkhead oil (Moorari-4);
3. a hypothetical low-maturity Permian oil (**3** = 0.55–0.60% R_c) and Birkhead oil (Moorari-4);
4. a low-maturity Permian oil (Garanjanie-1: Murta Formation) and Birkhead oil (Moorari-4);

5. a typical Family 1 oil (Moorari-1: Tirrawarra Sandstone) and a typical oil from the Murteree Ridge (Biala-1: Namur Sandstone) of inferred Jurassic/Cretaceous source affinity;
6. a typical Family 2 oil (Gidgealpa-41: Tirrawarra Sandstone) and a typical oil from the Murteree Ridge (Biala-1: Namur Sandstone) of inferred Jurassic/Cretaceous source affinity; and
7. 70% low-maturity Permian oil (Garanjanie-1: Murta Formation) and 30% mixtures of Family 2 oil (Gidgealpa-41) with Namur Sandstone oil (Biala-1).

The above curves are underlain by the actual data for the South Australian oils (Fig. 7.1). It is evident that the mixing of archetypical Birkhead oil from Moorari-4 with Family 1 or Family 2 crude cannot explain the composition of any of the South Australian oils. This is significant because Boreham and Summons (1999) believed the Birkhead crude at Moorari-4 to be one of the few pure or near-pure Jurassic oils in the Eromanga Basin (see Section 7.5). Implicit in their argument for diminished Jurassic/Cretaceous source contributions to the Eromanga oil accumulations was that oils similar to the Birkhead crude at Moorari-4 had mixed with Permian hydrocarbons, a proposition not supported here. On the other hand, it is possible to argue that the composition of some other Eromanga oils is a consequence of the mixing of the Moorari-4 (Birkhead) crude with hypothetical low-maturity (*ca* 0.55–0.60% R_c) Permian oil (see discussion below). Such oils include the Birkhead oils from Sturt-3, Spencer-5 and Tantanna-5 oils, and Namur oils from Biala-1 and Narcoonowie-2. However, the argument that these oils are mixing products is not favoured since it is obvious that their compositions are similar to potential source rocks of Jurassic age (Fig. 7.3). As such the indigenously-sourced Jurassic Birkhead oil from Moorari-4 is best viewed as being geochemically atypical.

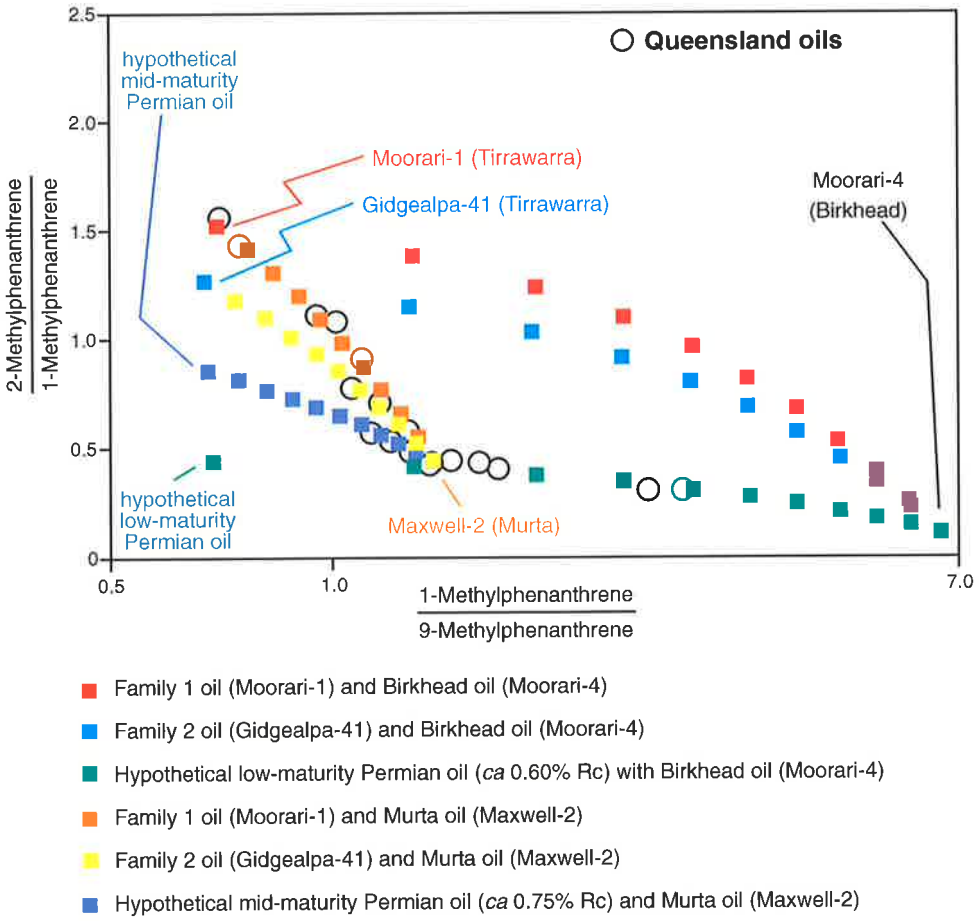


Figure 7.2 Cross-plot of 1-MP/9-MP *versus* 2-MP/1-MP: Comparison of oils (unspecified stratigraphy) from Queensland with computer-generated mixing curves for hypothetical and actual crudes as indicated

The compositions of the South Australian oils on "mixing curve 1" can be explained by invoking mixing of Jurassic oil with either Cooper Basin Family 1 or Family 2 crudes where the

Permian component of the mixture is less than *ca* 40%. Beyond this point, the input of Family 1 crude becomes increasingly significant and predominates over the input of Family 2 oil (Fig. 7.4). This makes geological sense since a Permian oil-prone source rock can be expected to expel Family 2 oil below *ca* 1% R_o, followed by Family 1 oil above 1.0% R_o. Given that both the Patchawarra and Toolachee Formations probably have been effective source rocks, it is conceivable that where the Toolachee Formation may be at a maturity of say 0.90–0.95% R_o, and consequently expelling Family 2 oils, the underlying Patchawarra Formation will be at a higher maturity of say 1.00–1.10% R_o and expelling Family 1 oil. Both the Patchawarra and Toolachee-sourced oils could migrate into the Eromanga Basin to mix with Jurassic/Cretaceous oil in the same reservoir. Obviously such a scenario will complicate the interpretation of both the computer-generated mixing curves and their relationship with the actual oil data.

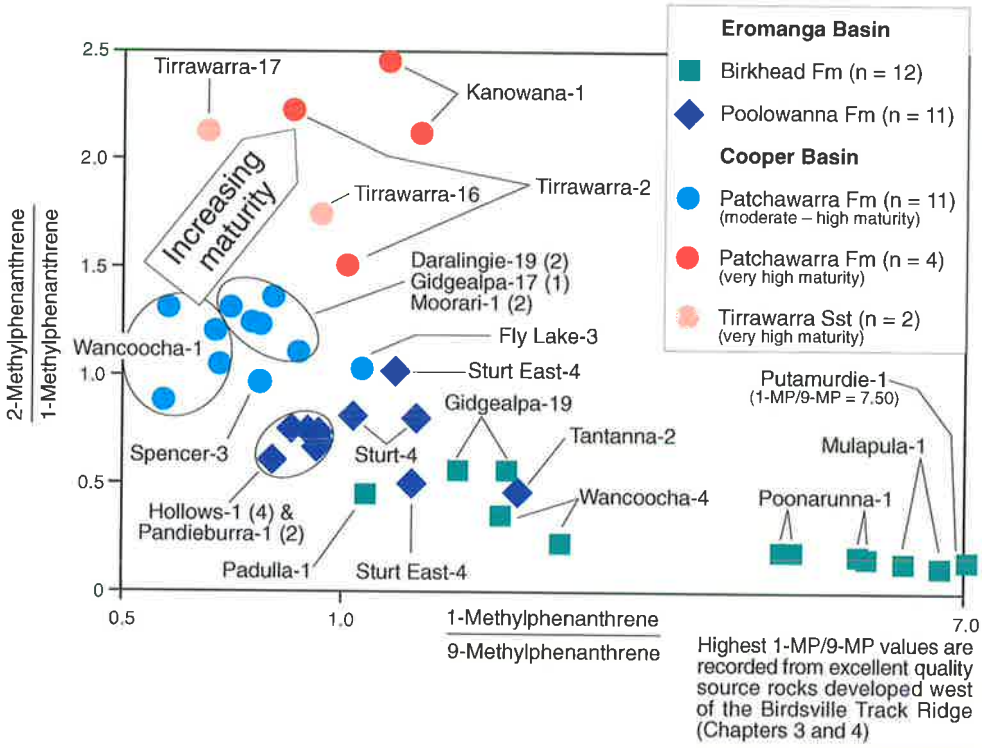


Figure 7.3 Cross-plot of 1-MP/9-MP *versus* 2-MP/1-MP based on GC-MS analyses of the aromatic hydrocarbon fraction of rock extracts by various laboratories between 1986 and 1997 (Adelaide University: 26; Amdel Ltd: 7; Analabs: 7). Data sources: Chapters 2, 3 and 4, and other data compiled by Michaelsen *et al.* (1995)

The compositions of several oils which plot on "mixing curve 2" can be mimicked by mingling a high proportion (70%: Fig. 7.1, dark pink points) of low-maturity oil, similar in composition and maturity (**3** = 0.67%) to the Murta crude from Garanjanie-1, with lesser amounts of indigenous Eromanga crude (*e.g.* at Biala-1) and more conventional (Family 2) Cooper Basin oil from the Patchawarra Formation (at Gidgealpa-41). For example, the composition of the Murta crude at Kobari can be explained by invoking a 70% contribution from a Permian-sourced, low-maturity Garanjanie-like oil, a 24% contribution from Family 2 crude, and 6% from an oil similar to the Namur crude at Biala-1.

However, it is evident from the detailed analysis of the mixing curves in Figure 7.4 that the methylphenanthrene distribution of oils from Tantanna-5 (Birkhead Formation) and Pintari North-1 (Namur Sandstone) cannot be explained simply by the mixing of Garanjanie-1 (Murta Formation) and Biala-1 (Namur Sandstone) crude alone. It is necessary to invoke a very low-maturity (*ca* 0.55–0.65% R_c) hypothetical Permian oil, which for convenience is here referred to as "Family 3" and is nominally assigned a 1-MP/9-MP value of 0.69, and a 2-MP/1-MP value of 0.43, considered reasonable for such a crude. Therefore, if the (reasonable) assumption is made that oils which plot on "mixing curve 2" are derived from the blending of three components, *viz* hypothetical Family 3 oil, Family 2 crude (in this case represented by the Tirrawarra Sandstone oil from Gidgealpa-41), and Eromanga crude (in this case represented by

Namur Sandstone oil from Biala-1) (Fig. 7.1), the composition of the oils which define "mixing curve 2" can be explained as follows:

	Family 3 oil (hypothetical oil of low rank)	Family 2 oil (*viz* Gidgealpa-41: Patchawarra Fm)	Total Permian oil (Family 3 + 2)	Total Jurassic/ Cretaceous oil (*viz* Namur Sst from Biala-1)
	(%)	(%)	(%)	(%)
Sturt-2 (Poolowanna Fm)	28	66	94 (95)	6 (5)
Kobari-1 (Murta Fm)	52.5	39	91.5 (90)	8.5 (10)
Sturt-3 (Poolowanna Fm)	47	35	82 (80)	18 (20)
Limestone Creek-1 (Murta Fm)	50	18	68 (70)	32 (30)
Alwyn-1 (Murta Fm)	42	17.5	59.5 (60)	40.5 (40)
Tantanna-5 (Birkhead Fm)	36.5	6	42.5 40)	57.5 (60)
Pintari North-1 (Namur Sst)	26.5	2	28.5 (30)	71.5 (70)

Rounded figures are in parenthesis

Some of the oils which define "mixing curve 1" can be adequately explained by the mixing of indigenous Eromanga crude (*e.g.* Namur Sandstone oil from Biala-1) with Family 1 oil (Moorari-1: Tirrawarra Sandstone) and include the Gidgealpa-17 (Murta Formation), Cuttapirie-1 (Poolowanna Formation) Merrimelia-35 (Murta Formation), Strzelecki-6 (Namur Sandstone) and Big Lake-26 (Birkhead Formation) oil (Figure 7.4: mixing regime A).

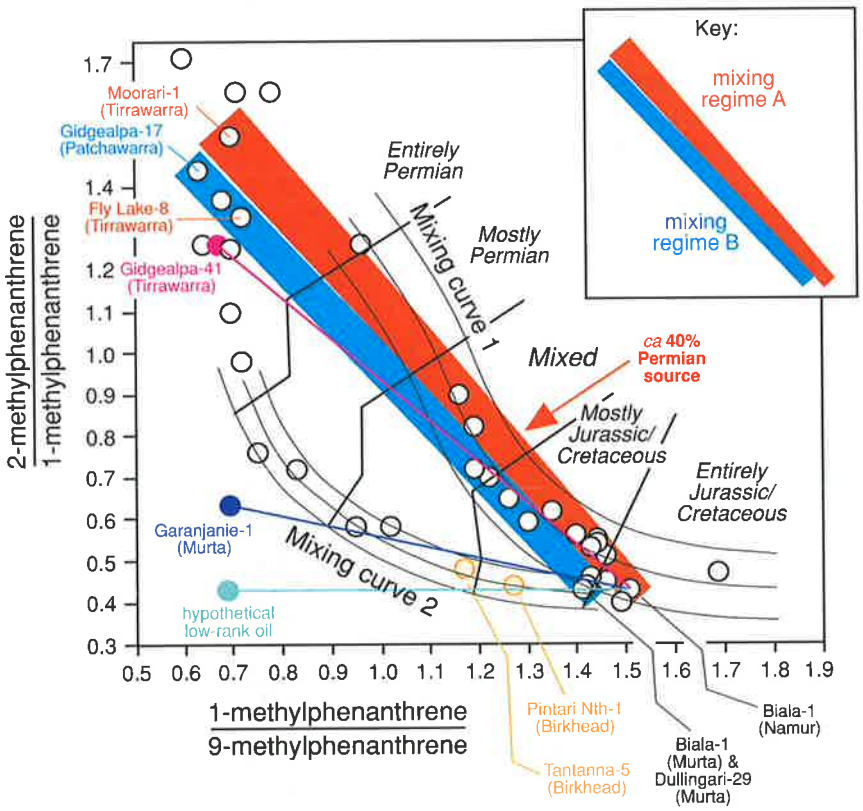


Figure 7.4 Detailed examination of oil "mixing curve 1" and "mixing curve 2" for oils from South Australia (notc the linear horizontal axis)

However, Eromanga oils from Gidgealpa-17 (Hutton Sandstone), Merrimelia-35 (Hutton Sandstone), Big Lake-57 (Murta Formation), and Strzelecki-6 (Hutton Sandstone) appear to be products of the mixing of Jurassic/Cretaceous oil (similar in composition to Murta Formation oil from Biala-1 or Dullingari-29) with various amounts of Family 2 (*e.g.* Patchawarra

Formation crude from Gidgealpa-17) or Family 1 oil (*e.g.* Tirrawarra Sandstone crude from Fly Lake-8 (Fig. 7.4: mixing regime B). However, for the purposes of estimating the proportion of Permian *versus* Jurassic/Cretaceous hydrocarbons in an oil sample, it is unnecessary to subdivide "mixing curve 1" for the South Australian data.

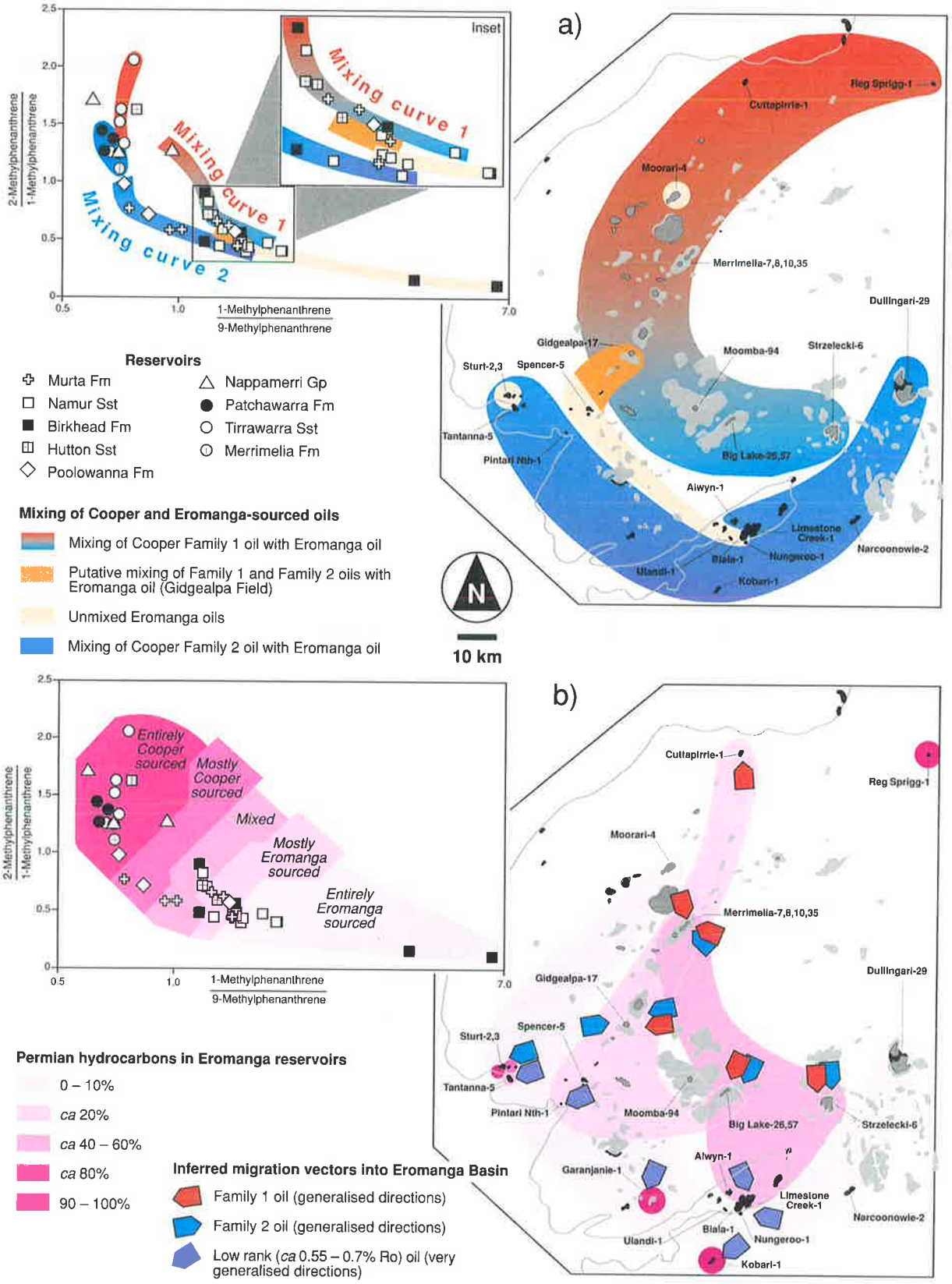


Figure 7.5 a) Distribution of Eromanga Basin oils in South Australia based on "mixing curve 1" and "mixing curve 2"; b) Summary of degree of mixing of Permian and Jurassic/Cretaceous oils

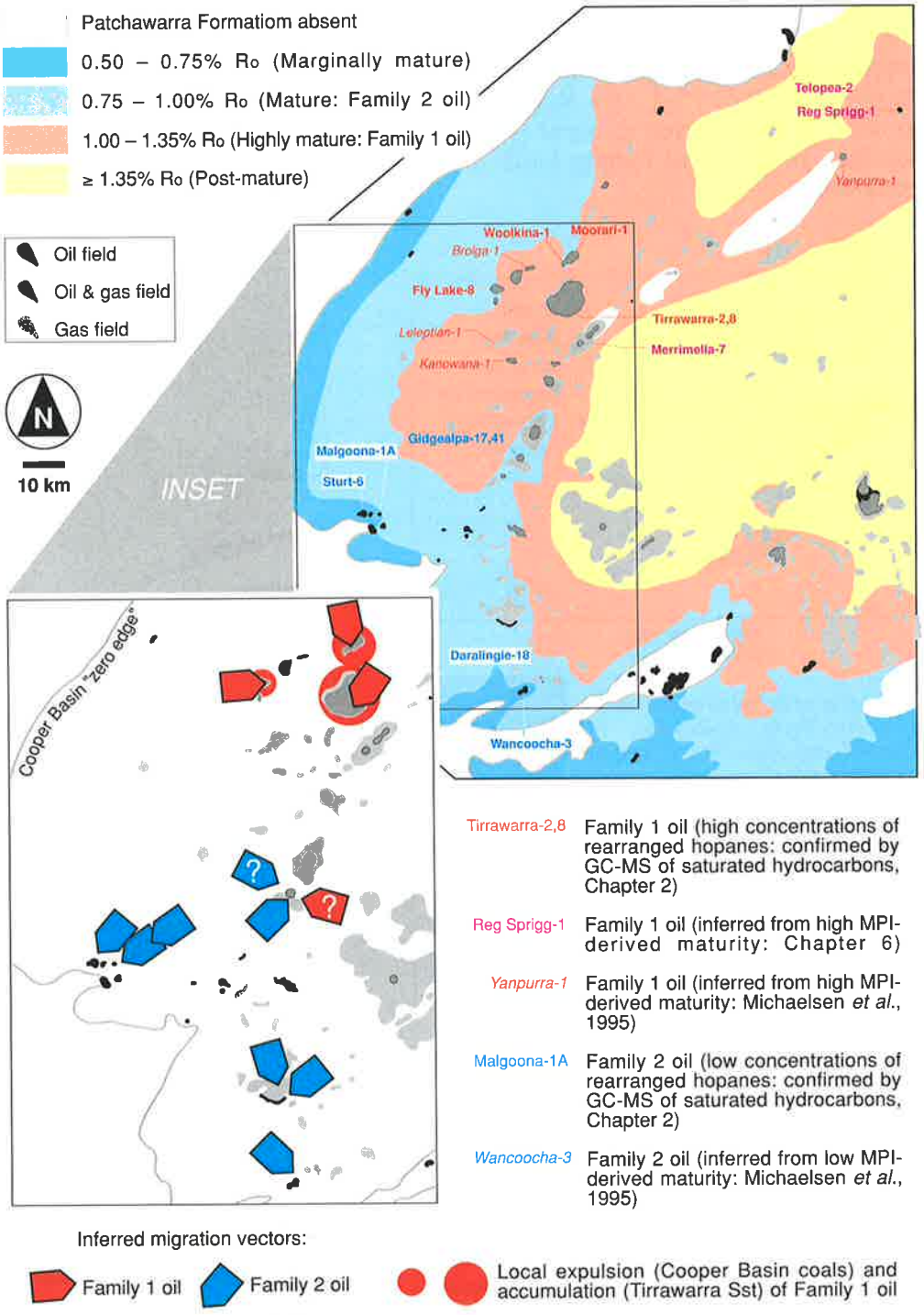


Figure 7.6 Maturity of base Patchawarra Formation with respect to distribution of Family 1 and Family 2 oils. Inset: Inferred intra-Cooper Basin migration vectors for Family 1 and family 2 oils (*cf.* Chapters 2 and 6)

In the South Australian sector, the oil pools which define "mixing curve 2", *viz* the Poolowanna Formation oils from Sturt-2 and 3, the Birkhead Formation oil from Tantanna-5, and the Murta Formation oil from Limestone Creek-1 (Murta Formation), Alwyn-1 (Murta Formation), Kobari-1 (Murta Formation), Sturt-2 and 3 (Poolowanna Formation) are geographically restricted to the southern margin of the Cooper Basin as shown in Figure 7.5a. This is a significant observation because in this area the Patchawarra Formation is only moderately mature for liquid hydrocarbon generation (0.5–0.75% R_o: Fig. 7.6), consistent with the proposition that predominantly low-maturity oils of local Cooper Basin-derivation have mixed with Jurassic/Cretaceous oil. Detailed examination of Figure 7.5 shows that "mixing curve 2" could be extended to the right to include oils from Narcoonowie-2 (Namur Sandstone) and Dullingari-29 (Murta Formation). If so this would indicate that these oil pools are subtly tainted with Permian hydrocarbons, although from a practical point of view, they can be assumed to be

wholly Eromanga-sourced as previously argued (Chapter 6). On the other hand, Eromanga oils on "mixing curve 1" are confined to the northern Patchawarra Trough and the southern margin of the Nappamerri Trough (Fig. 7.5a) where the Patchawarra Formation is in the main to late oil-generation window (0.75–1.35% R_o) and juxtaposed over areas where Family 1 crudes are known to occur or are inferred to occur (Fig. 7.6). These observations argue against the long-range secondary migration of Family 1 oils towards (or beyond) the southwesterly margin of the Cooper Basin.

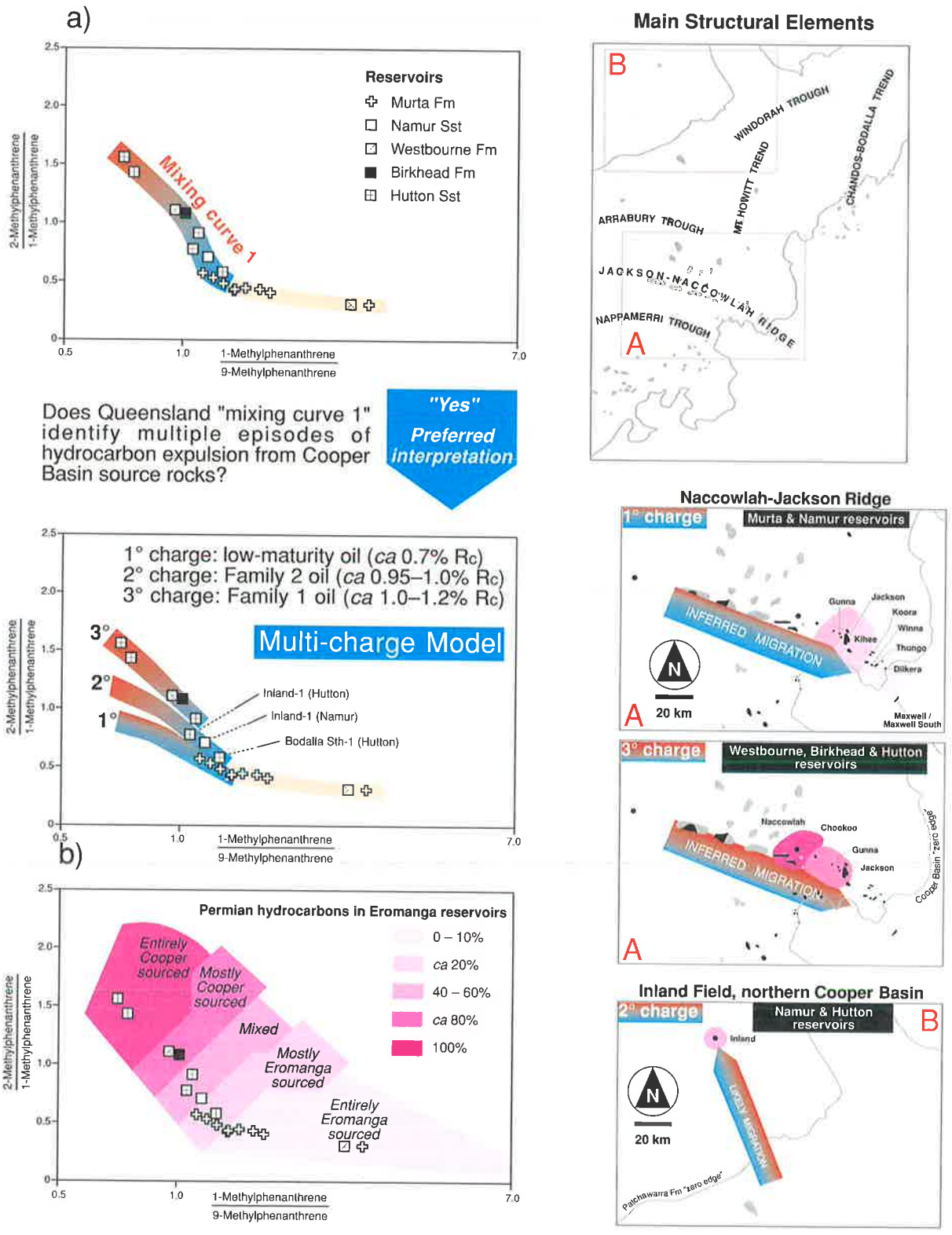


Figure 7.7 a) Reinterpretation of "mixing curve 1" in Queensland; b) Summary of degree of mixing of Permian and Jurassic/Cretaceous oils

7.2.2 Queensland

Because no oils from the Cooper Basin in Queensland were available for this study, the representative Family 1 (Tirrawarra Sandstone oil from Moorari-1) and Family 2 (Tirrawarra Sandstone oil from Gidgealpa-41) crudes were used in the construction of two synthetic mixing curves in Figure 7.2. The Birkhead Formation oil from Moorari-4 was also reused as it compositionally represents an end-member Jurassic oil of the type not yet discovered in Queensland. Three additional synthetic mixing curves were constructed based on mixing of a representative Eromanga oil (Murta Formation: Maxwell-2) with

1) a typical Family 1 oil (Moorari-1: Tirrawarra Sandstone),
2) a typical Family 2 oil (Gidgealpa-41: Tirrawarra Sandstone) and
3) a hypothetical medium-maturity (**3** $\approx$ 0.75% R_c) Cooper Basin (Permian) oil.

The six curves were underlain by the actual data for the Queensland oils (Fig. 7.2). Inspection of Figures 7.2 and 7.7 indicate that "mixing curve 1" can be represented by a composite of three subsidiary curves. As such, the following observations can be made:

1. The methylphenanthrene distribution of Murta Formation oils from Kihee-2, Jackson-1 and Gunna-1 (on the NJ Ridge) can be explained by the theoretical mixing of a hypothetical middle-rank (*ca* 0.75% R_c) Cooper Basin (Permian) oil and a representative Eromanga oil. In Figure 7.7 this subsidiary curve is labelled "1°".
2. Oils from areas other than the NJ Ridge at Bodalla South-1 (Hutton Sandstone) and Inland-1 (Hutton and Namur Sandstones) can be explained by the mixing of representative Family 2 oil and representative Eromanga oil. In Figure 7.7 this subsidiary curve is labelled "2°".
3. Oils from various units at Jackson-1, Jackson-2, Gunna-1, Jackson-3 (on the NJ Ridge) are inferred to be mixing products of Family 1 oil and representative Eromanga oil. In Figure 7.7 this subsidiary curve is labelled "3°".

The recognition of 1°, 2° and 3° subsidiary curves within "mixing curve 1" for the Queensland data provides a clue to the timing of trap formation and possibly the diagenetic alteration of migration conduits within the Eromanga Basin. The following scenario is envisaged:

The Permian hydrocarbon component of oils on the 1° curve was probably generated during the first expulsion event (*ca* 250 Ma: Fig. 1.15). These crudes may have resided in the Cooper Basin during the early phase of Eromanga Basin deposition. However, upon the laying down of the upper units of the Eromanga Basin, these Permian hydrocarbons were remobilised into Eromanga Basin aquifers and comingled with indigenous Eromanga crude formed during the second (*ca* 105 Ma: Fig. 1.15) expulsion event. The resultant mixed oils were trapped in reservoirs in the southeast extension of the NJ Ridge (*e.g.* at Jackson; see migration cartoon in Figure 7.7).

The absence of oils from the 2° curve along the NJ Ridge suggests a fundamental change in the drainage architecture in the central NJ Ridge where Permian hydrocarbons had previously invaded the Jurassic sequence. Alternatively hydrocarbon migration may have been blocked by diagenetic alteration of carrier sandstones or the occlusion of migration conduits along and through fault zones. Permian hydrocarbons which migrated into the Eromanga Basin around Naccowlah South and in the Jackson-Dilkera area may have used high-angle reverse faults (Vincent *et al.*, 1985) and/or normal faults (Stanmore, 1989) as conduits. However, this is unlikely to have occurred further southeast (around Dilkera) where it would appear that faulting is less intense or possibly absent. Significantly, the Murta oil at Dilkera is interpreted to be sourced entirely from the Eromanga Basin (Chapter 6). Williams and Moriarty (1986, p. 384) highlight that the Hutton oil pool at Naccowlah South is the only reservoir in the area to be filled to structural spill-point, and suggest that this fact constitutes "a compelling argument that much of the oil had migrated prior to the major phase of folding in the Tertiary" which is consistent with the conclusions of Deighton and Hill (1998), *i.e.* that most of the oil commenced secondary migration during the 105 and 90 Ma expulsion events (Fig. 1.15).

Obviously any diagenetic event which potentially affected fluid flow in the basins must have taken place between the cessation of deposition of the uppermost Eromanga Basin source/reservoir unit (age of top Murta Formation is 135 Ma) and the second (*ca* 105 Ma) or third (*ca* 90 Ma) expulsion event. Rezaee *et al.* (1997) provide evidence of major sandstone cementation (linked with basinwide tectonism) at *ca* 100 Ma for the Tirrawarra Sandstone in the

Moorari/Fly Lake area of South Australia. This event is well timed to have *obstructed* fluid flow (carrying hydrocarbons from the 90 Ma expulsion event) in the Permian and Jurassic/Cretaceous sandstones.

The third (*ca* 95 Ma) and fourth (*ca* 20–0 Ma) expulsion events in the Cooper Basin produced very mature oils which reinvaded the NJ Ridge (see migration cartoon in Figure 7.7). Oil pools which define the 3° curve are from this area. Implicit in the thermal and subsidence modelling of Deighton and Hill (1998) is that the hydrocarbon expulsion potential of source rocks in the Nappamerri Trough (specifically in South Australia) was exhausted before the end of the second expulsion event which immediately preceded Rezaee *et al.*'s (1997) 100 Ma diagenesis phase. If this is true for the Nappamerri Trough in Queensland, the mature (Family 1) Cooper Basin oil which has infiltrated the Gunna-1 (Birkhead Formation) and Jackson-3 (Westbourne Formation) reservoirs will have been sourced from the Arrabury or Windorah Troughs to the north. It is assumed that the direction of secondary migration of hydrocarbons along the NJ Ridge in the vicinity of the Naccowlah South, Gunna and Jackson Fields has remained much the same since the onset of Eromanga Basin deposition. This proposition is reasonable given that the major structural features of the basins have persisted throughout the history of the Cooper Basin (Section 1.2.1).

7.3 OTHER AROMATIC HYDROCARBON DATA

7.3.1 Aromatic hydrocarbons in rock extracts: Implications for palaeogeographic reconstruction and stratigraphic correlation

7.3.1.1 Birkhead Formation

In Chapter 3 it was asserted that the best source facies of the Birkhead Formation are developed west of the Birdsville Track Ridge. It was further postulated that source quality is directly related to the input of land-plant resins, notably those derived from araucariacean conifers. In Figure 7.3 the ratio 1-MP/9-MP is plotted against 2-MP/1-MP for the aromatic fractions of 40 rock extracts using data from Chapters 2, 3 and 4 augmented with data compiled by Michaelsen *et al.* (1995d) from various Amdel Ltd, Analabs Pty Ltd and University of Adelaide reports to industry. The data of Michaelsen *et al.* (1995d) and seven additional extract samples from the NJ Ridge in Queensland which were analysed by Alexander *et al.* (1988) are listed below:

Well	Depth	Sample type/ID	Formation	R_c **1** (%)	R_c **3** (%)	1-MP / 9-MP	2-MP / 1-MP	Reference
South Australia								
Mulapula-1	4022'11"	Core	Birkhead	-	-	5.78	0.14	McKirdy & Cox, 1987a
Mulapula-1	4023'9"	Core	Birkhead	-	-	6.47	0.12	McKirdy & Cox, 1987a
Padulla-1	4562'	SWC-5	Birkhead	0.44	0.59	1.07	0.45	Hartung-Kagi, 1987
Wancoocha-4	5133'3"	Core 1	Birkhead	0.42	0.57	1.64	0.35	Tybor, 1986b
Wancoocha-4	5136'10"	Core 1	Birkhead	0.47	0.61	1.98	0.23	Tybor, 1986b
Hollows-1	6202'	SWC-20	Poolowanna	0.66	0.78	0.93	0.70	Watson, 1994
Hollows-1	6203'	SWC-18	Poolowanna	0.67	0.78	0.85	0.75	Watson, 1994
Hollows-1	6203'6"	SWC-17	Poolowanna	0.58	0.71	0.92	0.67	Watson, 1994
Hollows-1	6205'	SWC-14	Poolowanna	0.58	0.71	0.80	0.61	Watson, 1994
Spencer-3	5992'	SWC-6	Patchawarra	0.70	0.81	0.77	0.97	McKirdy, 1986
Wancoocha-1	6160'0"	Core 2	Patchawarra	0.55	0.68	0.68	1.05	Tybor, 1986b
Wancoocha-1	6172'6"	Core 2	Patchawarra	0.43	0.58	0.57	0.88	Tybor, 1986b
Wancoocha-1	6178'10"	Core 2	Patchawarra	0.44	0.59	0.58	1.31	Tybor, 1986b
Wancoocha-1	6210'5"	Core 2	Patchawarra	0.53	0.66	0.67	1.21	Tybor, 1986b
Queensland								
Thargomindah-2	1253 m		Westbourne	0.38	0.54	7.8	-	Alexander *et al.*, 1988
Arrabury-1	1958 m		Birkhead	0.42	0.57	3.7	-	Alexander *et al.*, 1988
Arrabury-1	2010 m		Birkhead	0.47	0.61	3.3		Alexander *et al.*, 1988
Challum-1	1836 m		Birkhead	0.59	0.72	2.7	-	Alexander *et al.*, 1988
Chookoo-1	1669 m		Birkhead	0.73	0.84	1.1	-	Alexander *et al.*, 1988
Naccowlah East-1	1702 m		Birkhead	0.48	0.62	3.2	-	Alexander *et al.*, 1988
Pepita-1	1791 m		Birkhead	0.65	0.77	2.0	-	Alexander *et al.*, 1988

Refer to Table 6.1 for definitions of **1** and **3**

The Queensland rock extract data of Alexander *et al.* (1988) do not include values for 2-MP/1-MP. However, it is still possible to compare their 1-MP/9-MP data with those from South Australia.

Most of the Birkhead extracts from the NJ Ridge in Queensland have 1-MP/9-MP ratios which are greater than those in the Cooper Basin region of South Australia. In Queensland the highest 1-MP/9-MP value of 7.8 is recorded from the Westbourne Formation at Thargomindah-2 in the southeast of the NJ Ridge. Other high values are recorded from Arrabury (3.3 and 3.7), Naccowlah East-1 (3.2) and Challum (2.7). The only exception is a rock extract from Chookoo-1 which has a 1-MP/9-MP value of 1.1. However, the overall impression is that the 1-MP/9-MP ratio is similarly high for the Birkhead and Westbourne Formations along the NJ Ridge, as it is for the Birkhead Formation west of the Birdsville Track Ridge in South Australia. By contrast, Birkhead Formation extracts have distinctly lower values at Padulla-1 (1.07), Gidgealpa-19 (1.44 and 1.68), and Wancoocha-4 (1.64 and 1.98) just south of the Birkhead depocentre.

The best model to explain this geographic distribution is that the sedimentary environment during deposition of the Birkhead Formation, near its depocentre (approximately the northern Patchawarra Trough and adjacent areas in South Australia and Queensland) was dominated by fluviolacustrine deposition environments and therefore less favourable to the preservation of plant material, including araucariacean conifer resins. It is envisaged that the NJ Ridge in Queensland was a topographic high during much of the deposition of the Birkhead (and Westbourne Formations) and consequently was less frequently inundated by lacustrine environments. This is consistent with the model of Birkhead Formation deposition proposed by Boult *et al.* (1998) who interpreted an open lacustrine setting in the centre of the basin. However, the size and areal extent of "Lake Birkhead" varied as a consequence of tectonic uplift on the boundaries of the Australian plate which altered the sediment supply to the Hutton (braided-fluvial) the Birkhead (meandering-fluvial/peat swamp/lacustrine) environments of deposition (*cf.* Boult *et al.*, 1998).

Two extant araucareacean genera (*Agathis* and *Araucaria*) comprising five species inhabit tropical rainforests along Queensland's northeastern Pacific coastline. *Agathis* (3 species) occupy environments ranging from sea level to 1500 m, and *Araucaria* (2 species) live between sea level and 1200 m (Hyland *et al.*, 1998). Although the central Eromanga Basin occupied a palaeolatitude of *ca* 60–70° south during the Jurassic, Araucareaceae lived in a warm to hot environment (*e.g.* BMR Palaeogeographic Group, 1992) probably not dissimilar to that of the present-day coastal rainforests of central and northern Queensland.

In summary, it is postulated that forests of araucariacean conifers were more significant where topographic relief was greater (around the upland margins) than in the vicinity of the basin depocentre which was covered to varying degrees by paludal and lacustrine environments. Evidently, lacustrine conditions were less favourable to the sedimentary concentration and preservation of conifer resins and the diagenesis of their acid compounds to form biomarkers which were preserved in the geological record.

7.3.1.2 Poolowanna Formation

Values of the ratio 1-MP/9-MP for Poolowanna Formation rock extracts are lower at Hollows-1 (0.80–0.93) and Pandieburra-1 (0.90 and 0.93) in the western Eromanga Basin, than to the east in the Sturt/Tantanna (1.03–1.73) area above the Cooper Basin "zero edge" (Fig. 7.3). It was during deposition of the Poolowanna Formation that Araucariaceae evolved into an important and widespread flora (Alexander *et al.*, 1988) and it is therefore conceivable that higher concentrations of the araucariacean biomarker 1-methylphenanthrene could indicate that the Poolowanna Formation is on average younger towards the east. Indeed, palynological data summarised by Alexander and Sansome (1996) indicates that the top Poolowanna Formation is *ca* 7 My younger in the Cooper Basin area, than where it overlies the Simpson Basin (Poolowanna Trough) in the western Eromanga Basin.

7.3.2 Aromatic hydrocarbons in oils

7.3.2.1 Data of Michaelsen et al. (1995d)

Other aromatic hydrocarbon data (Michaelsen *et al.*, 1995d) for oils in the South Australian sector of the Cooper Basin and Eromanga Basins are provided below and plotted in Figure 7.8.

Well	Sample type/ID	Unit	R_c 1 (%)	R_c 3 (%)	1-MP / 9-MP	2-MP / 1-MP	Interpreted age of source rock(s) ‡
Gidgealpa-20	DST-2	Namur Sst	0.58	0.71	1.52	0.38	Jurassic
Gidgealpa-20	DST-2	Namur Sst	0.56	0.69	1.50	0.40	Jurassic
Mulapula-1	DST-1	Namur Sst	0.73	0.83	-	0.73	Mostly Permian/Mixed
Strzelecki-19	DST-3	Namur Sst	0.77	0.87	1.3	0.63	Mixed/Mostly Jurassic
Bookabourdie-1	DST-12	Birkhead Fm	0.64	0.76	1.62	0.50	Jurassic
Callabonna-1	DST-1	Birkhead Fm	0.49	0.62	1.77	0.31	Jurassic
Charo-1	DST-1	Birkhead Fm	0.48	0.62	1.41	0.30	Jurassic
Gidgealpa-20	DST-3	Birkhead Fm	0.57	0.70	2.61	0.43	Jurassic
Kenny-1	DST-1	Birkhead Fm	0.38	0.54	5.14	0.18	Jurassic
Merrimelia-9	DST-4	Birkhead Fm	0.70	0.81	1.68	0.62	Mixed/Mostly Jurassic
Spencer-3	DST-2	Birkhead Fm	0.53	0.66	2.09	0.33	Jurassic
Spencer-4	DST-2	Birkhead Fm	0.56	0.69	1.90	0.35	Jurassic
Strzelecki-19	DST-1	Birkhead Fm	0.75	0.86	1.47	0.59	Mostly Jurassic
Wancoocha-2	DST-4	Birkhead Fm	0.44	0.59	2.25	0.25	Jurassic
Strzelecki-3	DST-3	Hutton Sst	0.72	0.83	1.6	0.79	Mixed
Wancoocha-2	DST-5	Hutton Sst	0.49	0.63	1.26	0.33	Mostly Jurassic
Cuttapirrie-1	Prod.	Poolowanna Fm	0.58	0.71	1.31	0.48	Mostly Jurassic
Moolion-1	DST-1	Poolowanna Fm	0.65	0.77	0.88	0.69	Mostly Jurassic

‡ Tentative assignment based solely on 1-MP/9-MP ratio; Refer to Table 6.1 for definitions of **1** and **3**

Although these data were obtained using several different GC-MS systems, they are broadly comparable with the data of Table 6.1 obtained with a Hewlett-Packard 6890 GC/5973 MS (Section 6.3.2). However, inspection of Figure 7.8 shows that "mixing curve 1" and "mixing curve 2" are not adequately defined to allow these data to be interpreted with the same clarity as those in Table 6.1. Nevertheless, it appears that Birkhead oils from Kenny-1, Gidgealpa-20, Spencer 3 and 4, and Wancoocha-2 are entirely of Jurassic (presumably Birkhead) origin. Two Birkhead oils near the western margin of the Cooper Basin from Charo-1 and Callabonna-1 also seem to have a 100% Jurassic affinity, as does a Birkhead oil at Bookabourdie-1 on the GMI Ridge. This interpretation is in agreement with Boreham and Summons (1999) who described a Birkhead oil from Bookabourdie-4 to be entirely of Jurassic origin (see Section 7.5).

In Figure 7.8 oils from the Poolowanna Formation in the Sturt/Tantanna area, which were the subject of more detailed biomarker analyses in Chapter 2, clearly plot intermediate between the Cooper Basin oils and most of the oils from the Birkhead Formation and the Namur and Hutton Sandstones. This is consistent with the notion that these Poolowanna oils are partly or wholly derived from intra-Poolowanna source rocks (Chapter 2). The Poolowanna-reservoired oils from Cuttapirrie-1 and Sturt East-2 are almost identical. Since the latter is of inferred Poolowanna or part Poolowanna origin, this suggests that the Jurassic component of the Cuttapirrie-1 oil is also derived from the Poolowanna Formation. A Poolowanna-reservoired oil from Moolion-1 is also inferred to have a similar Poolowanna Formation source input (Fig. 7.8).

A sub-economic oil accumulation is known to be trapped within the Namur Sandstone at Mulapula-1 (Fig. 3.1) in the Birdsville Track Ridge area. This oil pool is significant because it is the only crude discovered to date in the western Eromanga Basin outside of the Poolowanna Trough (Fig. 1.5). To the best of the author's knowledge, no sample of the Mulapula-1 oil was curated and therefore no further analytical work will be possible. However, an aromatic fraction of this crude was analysed by McKirdy *et al.* (1987), and although 1-MP/9-MP was not determined by these workers, the oil was found to have a 2-MP/1-MP ratio of 0.73 (Fig. 7.9a). Without 1-MP/9-MP data it is not possible to assign this crude to either "mixing curve 1" or "mixing curve 2". As indicated in Figure 7.9a, if this oil were to plot on "mixing curve 1" it is possible to infer a *ca* 35% pre-Jurassic/65% Jurassic source affinity. However, since all the Eromanga oils from the nearby southwestern margin of the Cooper Basin belong to "mixing curve 2" it is perhaps more reasonable to assume that this oil also falls in this category. Consequently, an 80% pre-Jurassic/20% Jurassic source affinity for the Mulapula oil is interpreted. Although this conclusion should be treated with caution, it is nevertheless an important observation because the Permian "zero edge" of the Cooper Basin is *ca* 70 km to the

northeast (the Permian strata of the Pedirka Basin are *ca* 220 km to the northwest). Conceivably a Permian component of this oil (Family 2 and/or hypothetical Family 3) may have migrated updip from the western margin of the Cooper Basin, where the Permian "zero edge" is typically at a depth of around 1700–2200 m (*cf.* Gravestock and Jensen-Schmidt, 1998, figs 5.16 & 5.17). The Namur Sandstone reservoir in Mulapula-1 occurs at 955 m depth where tested by DST-1. It is possible that the Permian hydrocarbons which were generated in the Nappamerri Trough during the first expulsion event were remobilised during later structural and thermal accommodation and migrated along northeast–southwest trending ridges as shown in Figures 7.10 and 7.11. As such the Mulapula locality and other structural "domes" which comprise the Birdsville Track Ridge are ideally positioned to receive charges of Permian hydrocarbons from the Cooper Basin. Moreover, the regional ground-water flow within the Hutton and Namur Sandstone aquifers (northeast → southwest) may have facilitated the flushing of Permian (Family 1) hydrocarbons from the Patchawarra Trough where large accumulations of Cooper Basin oil are found at Tirrawarra, Moorari/Woolkina and Fly Lake (Chapter 1). These may have migrated up-dip due to bouyancy forces and been focussed against the Birdsville Track Ridge as shown in Figure 7.10. However, the lack of oil shows in the Nappamerri Group and Poolowanna Formation in this area, and the "pure" Jurassic chemistry of the Birkhead oils at Charo-1 and Callabonna-1, do not further the argument that Permian hydrocarbons have permeated the regional seal *en route* to higher aquifers.

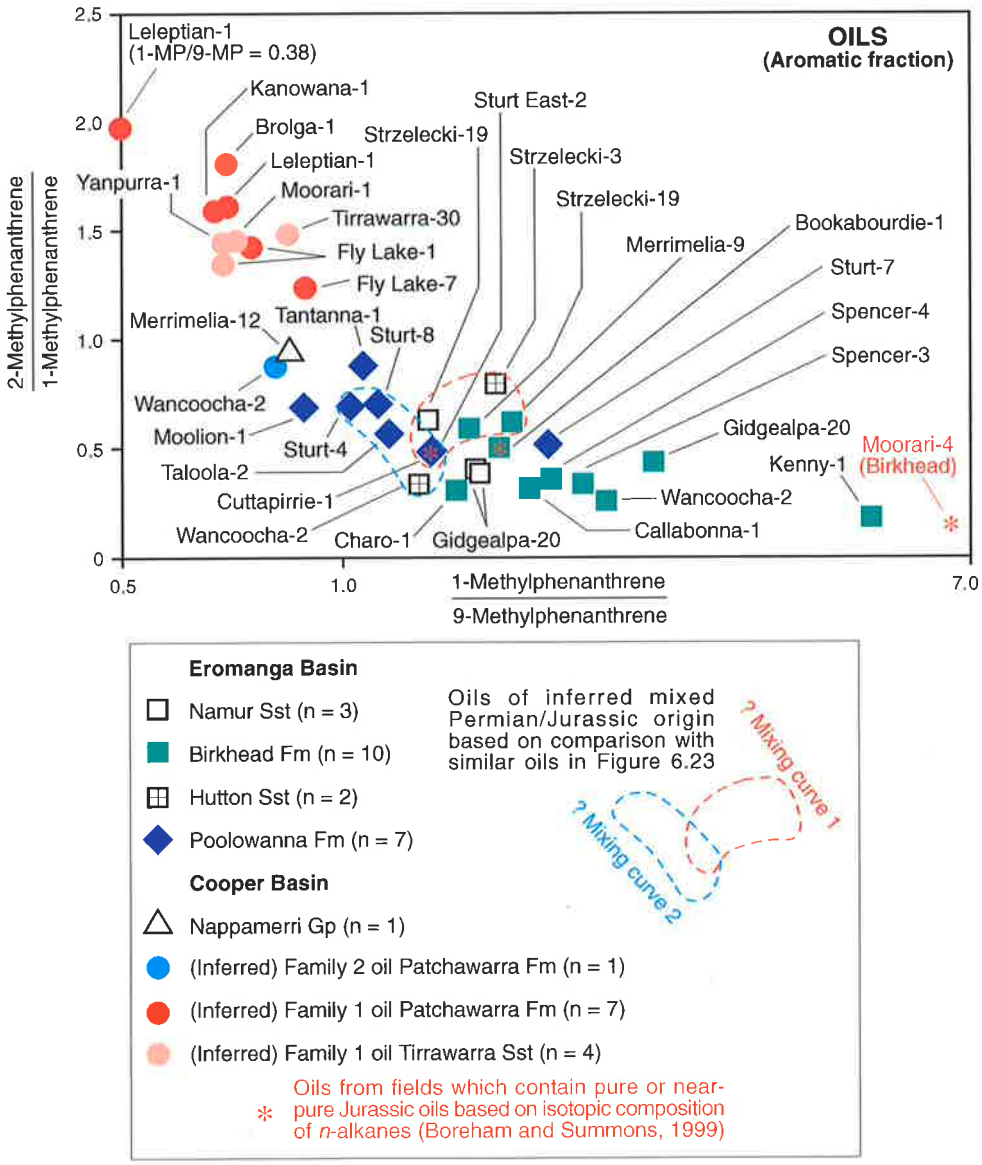


Figure 7.8 Cross-plot of 1-MP/9-MP versus 2-MP/1-MP based on GC-MS analyses of the aromatic hydrocarbon fraction of oils and condensates by various laboratories between 1986 and 1997 (Adelaide University: 6; Amdel Ltd: 11; Analabs:17). Data sources: Chapter 2 and other data compiled by Michaelsen *et al.* (1995d)

Alternatively, the non-Jurassic component of this oil may have been derived from the Peera Perra Formation (*ca* 95 km northwest), the major inferred source rock of the (Triassic) Simpson Basin (Harvey and Hibburt, 1999). A third scenario is that the non-Jurassic component of this oil was sourced from the underlying (Cambro-Ordovician) Warburton Basin. Notwithstanding these possibilities, the 2-MP/1-MP ratio of 0.73 indicates that at least 20% of the Namur Sandstone oil at Mulapula is derived from a Jurassic source. Very high quality organic matter (HI > 500) is known to occur in the Birkhead Formation at this locality (Chapter 3). Consequently, a Birkhead source is inferred for the Jurassic component of this oil.

7.3.2.2 Data of Boreham and Summons (1999)

Boreham and Summons (1999, appendix 2) published 1-MP/9-MP data for 34 oils from the Cooper and Eromanga Basins in South Australia and Queensland. Because all of their South Australian data derive from the Dullingari, Gidgealpa and Merrimelia Fields they are not considered further here since related oils from the same fields have been previously discussed (Chapter 6). However, Boreham and Summons (1999) provide much new data from Eromanga oil fields in the Queensland sector. Although 2-MP/1-MP data were not calculated by these workers, it is possible to plot their 1-MP/9-MP data onto the mixing curve in Figure 7.9b to estimate the proportion of Permian *versus* Jurassic/Cretaceous oil for individual Eromanga oil pools. Based on the reasonable assumption that all the Queensland oils belong to "mixing curve 1", the oils analysed by Boreham and Summons (1999) for which 1-MP/9-MP values were thereby estimated are as follows:

Well	Sample type/ID	Unit	R_c **1**# (%)	R_c **3*** (%)	$\frac{1\text{-MP}}{9\text{-MP}}$ †	Interpreted age of source rock(s) ‡
Ipundu-1	DST-5	Cadna-owie Fm##	0.47	0.61	1.29	Mostly Jurassic/Cretaceous
Cuddapan-1	DST-1	Cadna-owie Fm	0.55	0.68	1.02	Mostly Permian
Jackson-1	DST-1	Murta Fm	0.57	0.69	1.15	Mixed
Nockatunga-1	DST-1	Murta Fm	0.51	0.65	1.18	Mixed
Utopia-1		Murta Fm	0.51	0.64	1.41	Jurassic/Cretaceous
Winna-1	FT	Murta Fm	0.56	0.69	1.74	Jurassic/Cretaceous
Morney-3	DST-1	Murta Fm**	0.57	0.70	1.29	Mostly Jurassic/Cretaceous
Wilson-1	DST-6	Namur Sst	0.54	0.67	1.48	Jurassic/Cretaceous
Jackson-1	DST-4	Westbourne Fm	0.86	0.95	1.02	Mostly Permian
Talgeberry-1	DST-7	Birkhead Fm	0.56	0.69	1.82	Jurassic/Cretaceous
Bodalla South-1	?DST-3	Hutton Sst	0.56	0.69	1.20	Mostly Jurassic/Cretaceous
Cook-3A	DST-1	Hutton Sst	0.63	0.75	1.05	Mostly Permian
Inland-1	DST-1	Hutton Sst	0.58	0.71	1.07	Mixed
Jackson-1	DST-7	Hutton Sst	0.91	0.99	1.02	Mostly Permian
Jackson-2	DST-1	Hutton Sst	0.87	0.96	1.10	Mixed
Bargie-1	?DST-2	Poolowanna Fm	0.53	0.66	0.79	Permian
Black Stump-1	?DST-1	Poolowanna Fm	0.58	0.71	0.98	Mostly Permian

Values calculated by author; * Values calculated by Boreham and Summons (1999); † Values calculated by author from logarithmic data of Boreham and Summons (1999); ‡ Assignment by author based solely on 1-MP/9-MP ratio; ## Wyandra Sandstone Member (of upper Cadna-owie Fm); ** McKinlay Member (of basal Murta Fm); Refer to Table 6.1 for definitions of **1** and **3**

These oil data are important because they provide additional insights into the origins of hydrocarbons from the northern Cooper (Inland area) and the eastern Cooper region (Bodalla South area).

Inland area, Queensland

Cuddapan-1, DST-1 oil (Cadna-owie oil)

The 1-MP/9-MP ratio of Cadna-owie Formation oil from Cuddapan-1 indicates a mostly Permian (*ca* 75% Permian and *ca* 25% Jurassic/Cretaceous) origin (Fig. 7.9b). This is broadly

in accord with the observation of Gilby and Mortimore (1989) who, interpreting Jenkins' (1989) dataset, concluded that this oil has a Jurassic source affinity (presumably based on the presence of the saturated araucariacean biomarker 19-norisopimarane: Alexander *et al.*, 1988). Boreham and Summons (1999) also interpreted the Cuddapan-1 crude to be a mixture of Permian and Jurassic oil. However, they identified an additional component of pre-Permian hydrocarbons derived from the underlying early Palaeozoic rocks.

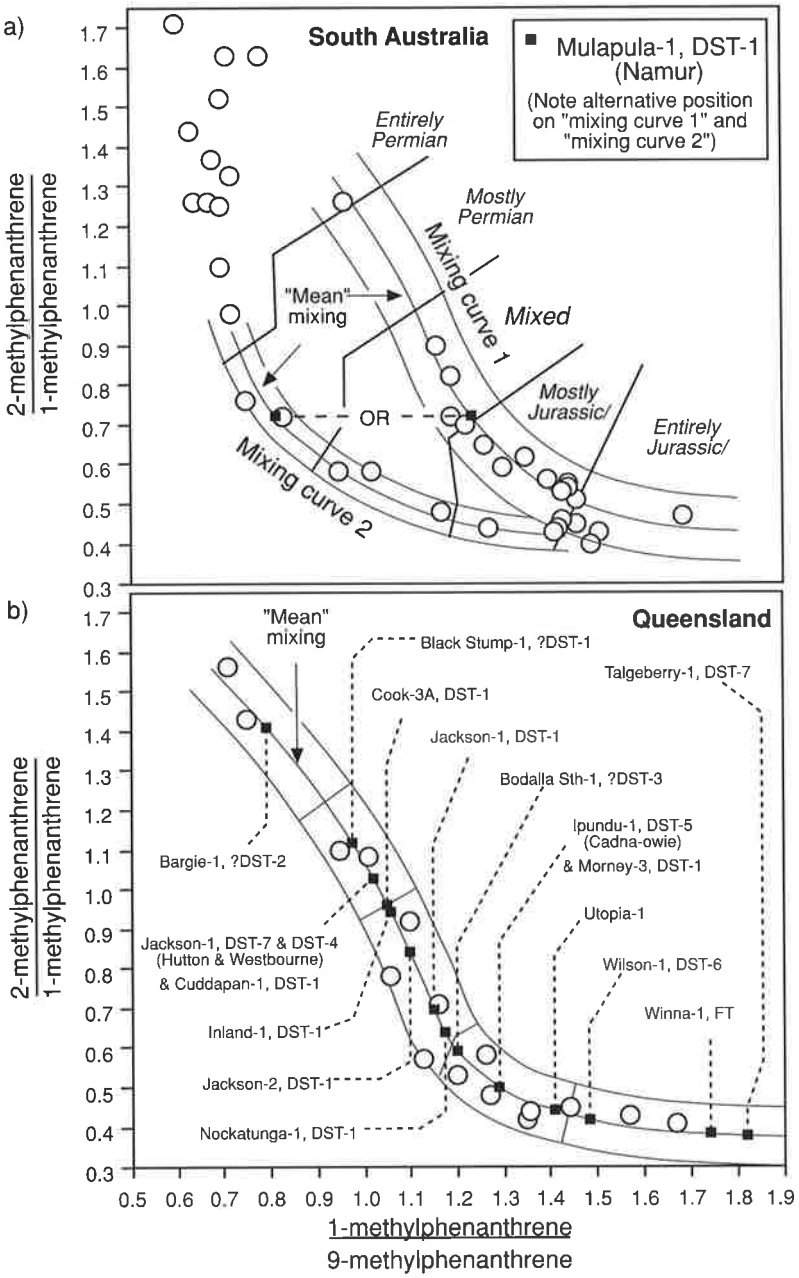


Figure 7.9 a) Estimate of source affinity for Namur oil (aromatic fraction) from Mulapula-1. 1-MP/9-MP *versus* 2-MP/1-MP for oils in South Australia (Table 6.1: open circles; note the linear horizontal axis). Alternative positions of the Mulapula-1 oil on the two mixing curves are represented by black squares and are determined by virtue of where its 2-MP/1-MP value intersects the respective "mean mixing curve"; b) Estimate of source affinity for some oils (aromatic fractions) from Boreham and Summons' (1999, appendix 2) study. 1-MP/9-MP *versus* 2-MP/1-MP for oils in Queensland (Table 6.1: open circles; note the linear horizontal axis). Boreham and Summons (1999) data which are represented by black squares, are labelled with well and stratigraphic information and are positioned on the graph by virtue of where their 1-MP/9-MP values intersect the "mean mixing curve"

Morney-3, DST-1 oil (Murta Formation)

The Murta Formation oil at Morney-3 has a 1-MP/9-MP ratio of 1.29 (Fig. 7.9b) which is consistent with a mainly Jurassic/Cretaceous source (minimum of *ca* 85%) and in good agreement with the findings of Boreham and Summons (1999) who reported that this oil had a

subhorizontal *n*-alkane isotopic profile (*ibid.*, fig. 21), consistent with a predominantly non-Permian source.

Clearly the Permian source influence for these oil accumulations and the Inland (Hutton and Namur Sandstones) oil diminishes towards the north-northwest. The easiest way to explain the composition of these hydrocarbon pools and crude at Inland-1 is that the Permian component of these oils is derived from the Cooper Basin and migrated from presently overmature source rocks in the Windorah Trough (Fig. 1.12). However, the maturity of the largely pre-Jurassic Cuddapan oil (*ca* 70% pre-Jurassic; **1** = 0.55%, **3** = 0.68%) is almost equal to or slightly less than the maturity of the predominantly Eromanga-sourced Murta oil at Morney-3 (≥ 85% Jurassic/Cretaceous oil; **1** = 0.57%; **3** = 0.70%). It is therefore possible to infer that the Permian hydrocarbons which partly charged these Eromanga reservoirs were generated at low maturities in the Windorah Trough (*i.e.* were not Family 1 hydrocarbons), possibly from the first hydrocarbon expulsion event at *ca* 250 Ma when the principal hydrocarbon source rocks (Patchawarra and Toolachee Formations) were less deeply buried.

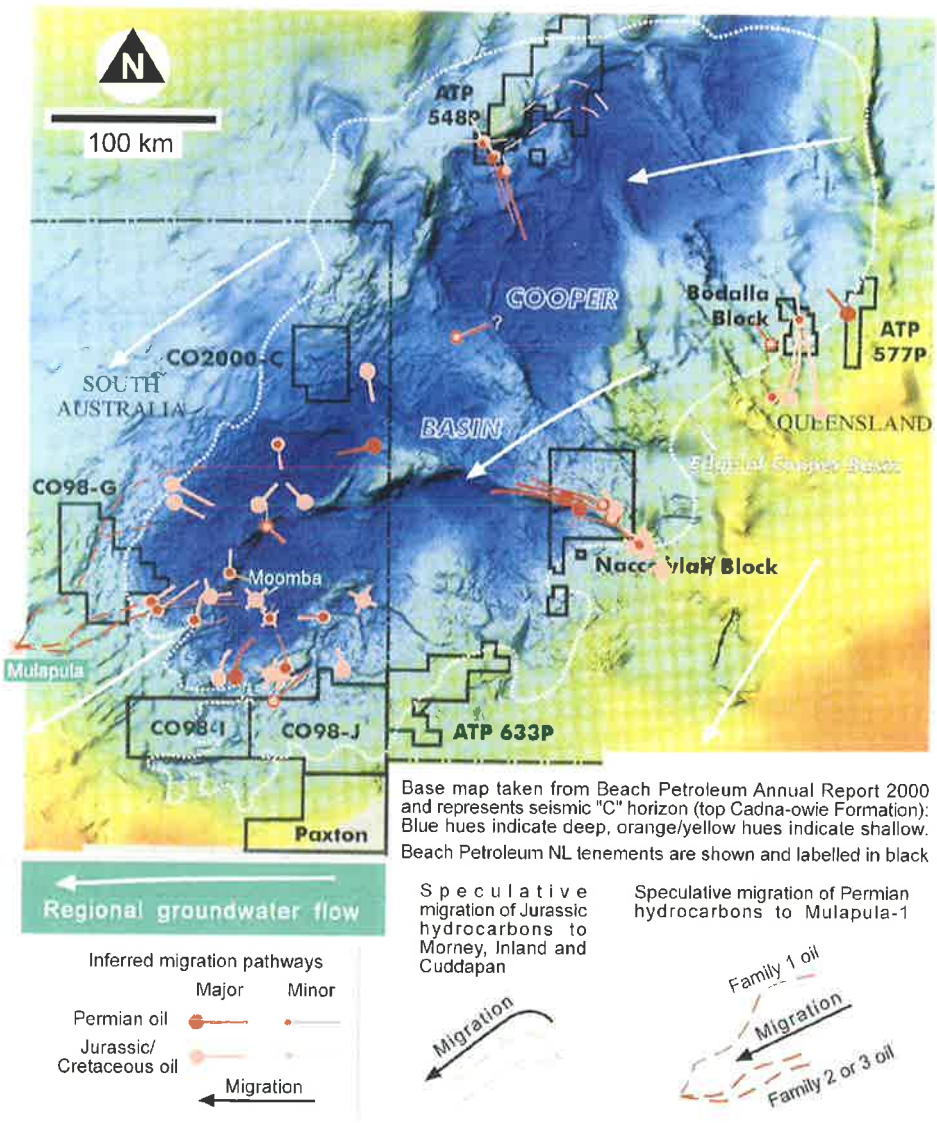


Figure 7.10 Inferred migration pathways for oils within the Eromanga Basin. Regional groundwater flow after Habermehl (1986)

However, the Jurassic component of these oils is derived from more local, probably Birkhead Formation source rocks. The scenario favoured here is that the Jurassic hydrocarbons were derived from source rocks in the vicinity of the Morney Anticline or down-dip to the northwest in the Haddon Syncline (Figs 7.10 & 7.11). In the Morney, Inland and Cuddapan region, the Birkhead Formation has an inferred maturity of *ca* 0.8–0.9% R_o (Boreham and Summons, 1999, fig. 10) and is relatively thick (> 100 m) as this area represents a subsidiary depocentre.

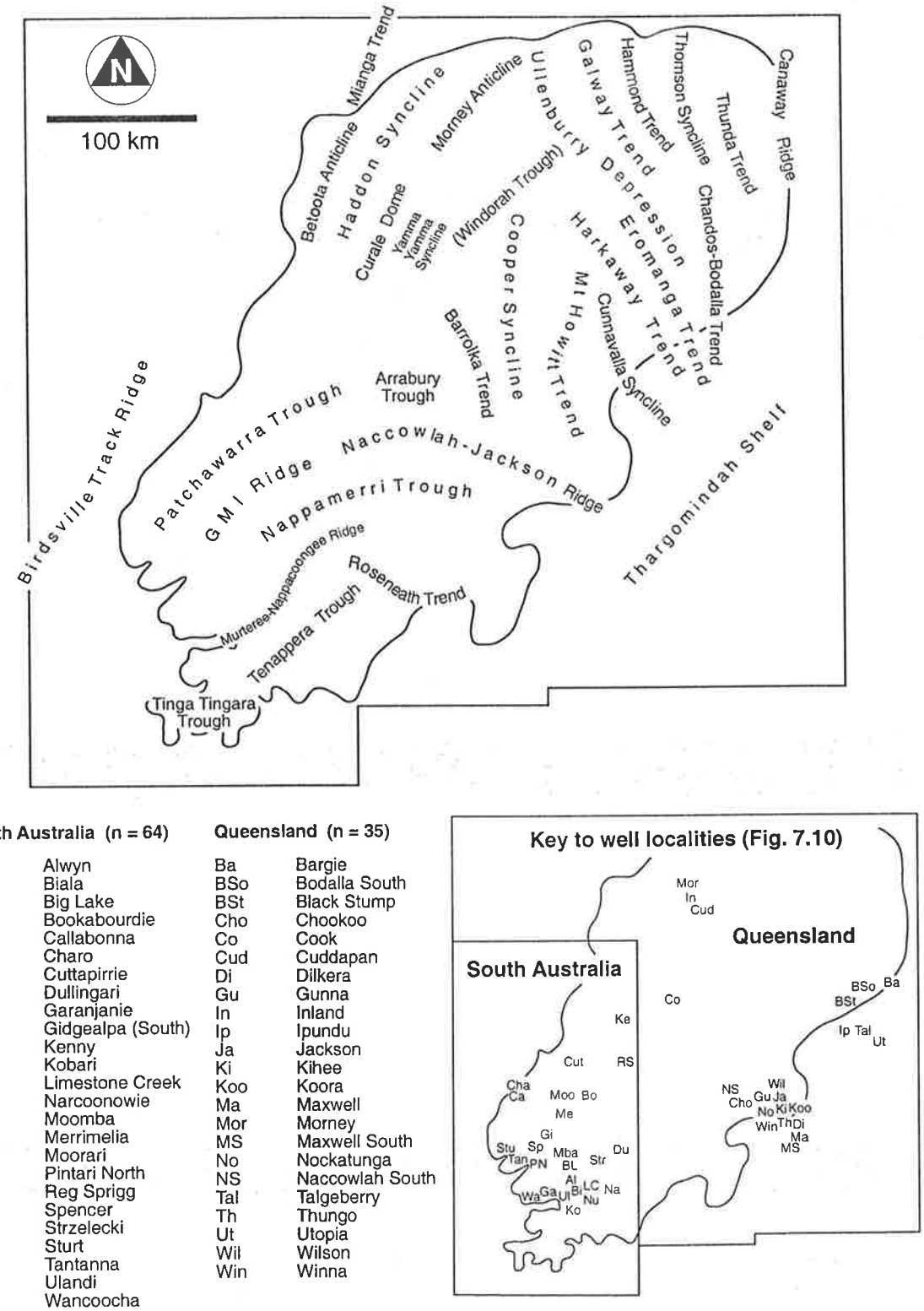


Figure 7.11 Structural interpretation of Figure 7.10 with particular emphasis on the Queensland sector

A second but more complex (and less favoured) scenario is that the Jurassic oil was generated in a more distant Birkhead hydrocarbon kitchen (present maturity > 0.8% R_o) to the northeast in the Ullenburry Depression. This oil firstly migrated up-dip with bouyancy to the northwestern margin of the Windorah Trough and was then swept by the dominant east-northeast → west-southwest groundwater flow (Habermehl, 1986) into the Morney structure, progressively displacing the earlier-generated Permian hydrocarbons.

Bodalla South area, Queensland

The 1-MP/9-MP ratios for the Poolowanna-reservoired oils at Bargie-1 (0.79) and Black Stump-1 (0.98) are lower than for any other Eromanga crudes. The oil at Bargie-1 has a clear 100% Permian affinity, whereas the crude at Black Stump-1 is inferred to be of mostly Permian (*ca* 85%) origin. The maturities of the Bargie-1 (**1** = 0.53%, **3** = 0.66%) and Black Stump-1 (**1** = 0.58%, **3** = 0.71%) oils indicate that the Permian source kitchen of these hydrocarbons was generating and expelling hydrocarbons in the early oil window ($R_o \approx 0.55$–0.70%). These maturities are much less that the present-day maturity of the Patchawarra Formation (> 1.35% R_o) where it exists west of the Bodalla South Field (Fig. 1.12). However, the inferred maturity of the Toolachee Formation is considerably lower in this area (*cf.* Hunt *et al.*, 1989, fig. 6), and therefore it is conceivable that these oils were either sourced from the Patchawarra Formation during an early expulsion event (and underwent long-distance migration of at least 20–30 km), or were locally sourced from the Toolachee Formation (< 1.0% R_o). The latter scenario is easier to accommodate because it does not require the long-distance migration of hydrocarbons.

It is significant that oils analysed from wells southeast of the Permian "zero edge" are overwhelmingly derived from Eromanga Basin source rocks. The Murta oil recovered from Utopia-1 (1-MP/9-MP = 1.41) is an inferred pure Jurassic/Cretaceous crude. Likewise the Birkhead oil pooled at Talgeberry-1 (1-MP/9-MP = 1.82) is a pure Jurassic/Cretaceous oil of probable intra-Birkhead origin. The maturities of the Murta oil from Utopia-1 (**1** = 0.51%, **3** = 0.64%), and the Birkhead oil at Talgeberry-1 (**1** = 0.56%, **3** = 0.69%) indicate expulsion from their respective source rocks very early in the oil window which is consistent with the local maturity of the Birkhead Formation (Fig. 1.13).

Inferred migration vectors for Permian and Jurassic hydrocarbons in the Bodalla South area are shown in Figure 7.10. It would seem that most of the Jurassic oil has migrated from the north along the Chandos-Bodalla Trend into Birkhead and Murta Formation reservoirs as far south as Talgeberry and Utopia respectively. A likely source kitchen for these indigenous Eromanga crudes is the Birkhead Formation in the southern Ullenburry Depression which has a present maturity of around 0.7% R_o (Boreham and Summons, 1998, fig. 10) estimated from burial history modelling (I. Deighton and A.J. Hill, Paltech Pty Ltd and PIRSA, 1998, unpublished data). By contrast, it is more likely that the pure Permian oil within the Poolowanna Formation at Black Stump (above the Nappamerri Group "zero edge") was focussed along the Eromanga Trend (Figs 7.10 & 7.11) and may have migrated as far south as the Ipundu Field (*ca* 25 km beyond the Cooper Basin "zero edge") where it is represented as a minor component of the oil trapped within the Cadna-owie Formation. The Poolowanna Formation oil at Bargie was probably sourced from the depression immediately east of the Chandos-Bodalla Trend, as was the Permian hydrocarbon component of the Hutton Sandstone oil at Bodalla South.

Cook Field, Queensland

Hutton Sandstone oil recovered at Cook-3A (1-MP/9-MP = 1.05) is interpreted to be mostly of Permian (*ca* 70%) origin. This is in good agreement with Gilby and Mortimore's (1989) interpretation of Jenkins' (1989) data from Cook-1 (Hutton Sandstone oil) which indicates that the Cook oil is essentially of Permian origin with a minor Jurassic component. However, these interpretations seem to be at variance with Boreham and Summons (1999, p. 282) who believe that the "Hutton oil in Cook-3A has a much stronger Eromanga Basin source (? Birkhead Formation) input resulting in the flattening of the *n*-alkane isotopic profile and a shift to ^{13}C-depleted low molecular weight *n*-alkanes" (*ibid.*, fig. 22). The maturity of the Cook-3A oil (**1** = 0.63%, **3** = 0.75%) is higher than that of the oils from the Inland and Bodalla South areas, by virtue of its location above mature Permian rocks in the Arrabury Trough (*e.g.* Toolachee Formation is *ca* 1.0% R_o at this locality).

7.4 DISCUSSION: DISTRIBUTION OF HYDROCARBONS WITH RESPECT TO SOURCE ROCK MATURITY AND OTHER FACTORS

7.4.1 South Australia

Within the vicinity of the northern Tennapera Trough (Fig. 1.9c) in South Australia there are numerous minor oil accumulations within the Patchawarra Formation. Most are confined to an area where the maturity of the Patchawarra Formation is between 1.00 and 1.35% R_o (wet gas window). The only exceptions are the Patchawarra Formation oil at Plotosus where the maturity is slightly less than 1.0% R_o, and the oils at Gahnia and Kerna where the Patchawarra Formation has an inferred maturity of *ca* 1.4% R_o. There are also a number of small oil pools within the Toolachee Formation at, and immediately east of Strzelecki (Fig. 1.9b). However, it is

curious that neither Nappamerri Group nor Poolowanna Formation oils have yet been discovered in this area. An exception is some sub-economic Nappamerri Group oil at Della where there is an outlier of less mature Patchawarra Formation (*ca* 1.3% R_o). In this area there are oils found within the Namur Sandstone and the Murta and Cadna-owie Formations at *inter alia* Plotosus, Narcoonowie, Strzelecki and Dullingari. If large volumes of Permian oil have migrated into the Eromanga Basin in this region, it may be reasonable to expect some residual hydrocarbons to be present within the Nappamerri Group and Poolowanna Formation through which the Permian oil must have migrated. It is postulated here that the stratigraphic distibution of hydrocarbon pools in this area suggests that the Eromanga-reservoired oils in this region are derived mostly from Jurassic/Cretaceous source rocks.

This generalisation is consistent with the interpretations of Chapter 6, *viz* that most of the hydrocarbons tested from Narcoonowie-2 (Namur reservoir: 100% Jurassic/Cretaceous), Dullingari-29 (Murta reservoir: 100% Jurassic/Cretaceous) and Strzelecki-6 (Hutton and Namur reservoirs: *ca* 50% Jurassic/Cretaceous) are derived from intra-Eromanga source rocks. Clearly it is impossible to positively assign source affinity to individual oil pools from this area without geochemically testing each oil. However, from an exploration perspective, when considering the area as a whole, the stratigraphic distribution of the oils recovered by drilling seems to suggest that only minor quantities of Permian oil have infiltrated the Eromanga Basin in South Australia.

7.4.2 Queensland

7.4.2.1 Naccowlah-Jackson Ridge

The geographic and stratigraphic distribution of pooled hydrocarbons in Queensland also provides a clue as to whether large quantities of Permian oil have passed through the Nappamerri Group and Poolowanna Formation *en route* to Eromanga Basin traps. The distribution of Tirrawarra Sandstone and Patchawarra Formation oils in Queensland are shown in Figure 1.12c. Tirrawarra oils are present at Pepita and Macadamia (northwest extremity of the NJ Ridge) where this unit is developed (note: the Tirrawarra Sandstone is absent elsewhere in Queensland) and where the Patchawarra Formation is either absent or post-mature (> 1.35% R_o) for liquid hydrocarbon generation. Patchawarra Formation oils are restricted to where this unit is highly mature for liquid hydrocarbon generation (1.00–1.35% R_o) in the central NJ Ridge and at Stokes and Chiron in the vicinity of the Roseneath Ridge. Similarly, Toolachee Formation oils are found in the central NJ Ridge and at Epsilon and Raffle where the Patchawarra Formation is also highly mature. Incongruously, Cooper Basin oils (irrespective of reservoir) are absent in areas where the Patchawarra Formation is optimally mature (0.75–1.00% R_o). However, given that Permian oils with maturities clearly less than 1.0% R_c (*i.e.* Family 2 oils) are presently pooled within the Cooper Basin in South Australia, it is evident that other reasons (such as reduced source quality or inefficient trapping mechanisms) have adversely influenced the quantity of hydrocarbons generated, expelled and/or trapped within the Patchawarra Formation in this area.

The Poolowanna Formation has poor source potential in this area (relative to the Poolowanna Formation overlying the southwestern Cooper Basin: A.J. Hill, PIRSA, pers. comm., 2000). Thus the oils which reside at this level along the NJ Ridge at *inter alia* Chookoo, Gunna and Jackson (Fig. 1.13c) most likely indicate that Permian hydrocarbons have passed through the basal Jurassic unit *en route* to the higher stratigraphic reservoirs. This interpretation is supported by evidence and interpretations presented earlier (Section 7.2.2).

7.4.2.2 Bodalla South area

It should be noted that the Bodalla South Field is located above the Patchawarra "zero edge" (Fig. 1.12). Although the present composition of the Hutton oil at this locality indicates a predominantly Jurassic source (Chapter 6), the field is ideally positioned to have received ongoing charges of Patchawarra-sourced oil throughout the Cooper Basin's burial history. The fact that the Bodalla South crude forms part of the 2° curve in Figure 7.7 may indicate that this locality received hydrocarbon charges *after* the earliest Permian oil comingled with indigenous Eromanga oils along the NJ Ridge (1° curve oils, *viz* at Jackson and Kihee), but *before* Family 1 oils invaded the NJ Ridge (3° curve oils, *viz* at Chookoo, Naccowlah South, Jackson and Gunna). However, detailed burial history and thermal modelling at these localities would be required to validate this interpretation.

7.4.2.3 Inland area

Recognition that the Inland oils also plot on 2° curve (Fig 7.7) is important for exploration strategies beyond the Permian "zero edge" because the Permian component of these two oils is likely to have originated during the same hydrocarbon expulsion event that produced the Permian charge of the Hutton Sandstone oil at Bodalla South. If the Permian hydrocarbons trapped at Inland are derived from the Patchawarra Formation, which has a maturity in excess of 3% R_o (and therefore is considerably past the stage of liquid hydrocarbon generation) in the deepest areas of the Windorah Trough (Fig. 1.12), it is *unlikely* that this petroleum commenced secondary migration during a recent hydrocarbon expulsion event. Alternatively, the Permian component of the Inland oils may be derived from the Toolachee Formation which is only *ca* 65 km to the southeast, or 50 km to the northeast, and which in this area defines the Permian "zero edge". By contrast the Patchawarra "zero edge" is located *ca* 90 km to the southeast. The maturity of the Toolachee Formation in the Windorah Trough is only 1.25–2.5% R_o (Hunt *et al.*, 1989). Consequently, explorationists should entertain the notion that the Permian component of the Hutton and Namur oils at Inland may be derived from Toolachee Formation source rocks. Separate burial history analysis could elucidate when the Patchawarra and Toolachee Formations attained *ca* 1% R_o in this area, the inferred maturity of the Permian component of the Hutton and Namur Sandstone oils at Inland. Such modelling would help to constrain the timing of secondary migration of Permian hydrocarbons in this area.

7.5 DISCUSSION: THE ISOTOPE MODEL OF BOREHAM AND SUMMONS (1999)

The paper by Boreham and Summons (1999) is an important contribution to our understanding of the petroleum habitat of the Cooper and Eromanga Basins. Their paper uses a comprehensive suite of geochemical techniques (*viz* GC, GC-MS, pyrolysis and GC-C-irMS) to assess the source affinity of 162 oil samples in both the South Australian and Queensland sectors of the Cooper and Eromanga Basins. Each of their 162 oils were analysed by GC to determine Pr/Ph and Pr/*n*-C_{17} and Ph/*n*-C_{18} ratios (*ibid.*, appendix 1). Fewer oils were analysed for saturated hydrocarbon biomarkers (GC-MS: 84 oils), aromatic hydrocarbons (GC-MS: 39 oils) and compound-specific (*n*-alkane) carbon isotope composition (GC-C-irMS: 54 oils). Notwithstanding the range of techniques employed, the major conclusions developed by these workers are based almost entirely upon the $\delta^{13}C$ values of individual *n*-alkanes, which are claimed to provide a crucial and hitherto unseen perspective on the source affinity of these oils.

Boreham and Summons (1999) used their data to semiquantify the Permian *versus* Jurassic/Cretaceous source inputs for Eromanga-reservoired crudes. However, it is postulated here that considerable questions overshadow their interpretations. Their model has several perceived weaknesses which are discussed below. Evidently they did not identify any pure Eromanga-sourced oils in the Queensland sector. Therefore, in the interests of brevity, only their analyses of oils from the South Australian sector are discussed here:

1. Of the 54 oils analysed by Boreham and Summons (1999) using GC-C-irMS, only three have horizontal *n*-alkane isotopic profiles, *viz* crudes from Moorari-4 (Birkhead Formation), Bookabourdie-8 (Birkhead Formation) and Cuttapirrie-1 (Poolowanna Formation). Boreham and Summons' (1999) interpretation is that these are the only pure or near-pure Jurassic-sourced oils. It is curious and probably significant that the hydrocarbons in question are restricted to a relatively small area in the northern Patchawarra Trough which overlies the Birkhead Formation's depocentre. However, it remains unclear why only pure or near-pure Jurassic oils should to be restricted to this area since high quality Jurassic source rocks are known to be more widespread (*cf.* Chapter 3).
2. Boreham and Summons (1999) provide no evidence that Jurassic/Cretaceous kerogen pyrolysates and/or rock extracts have only flat *n*-alkane isotopic profiles (their criterion for identifying a pure or near-pure Jurassic oil). On the contrary, the three Birkhead Formation kerogen pyrolysates analysed by Boreham and Summons (1999, fig. 11) using GC-C-irMS have *n*-alkane carbon isotopic profiles with strong negative slopes. Only two of the Birkhead kerogen pyrolysates (#1450 and #1460) have flat isotopic profiles between *n*-C_{25} and *n*-C_{30}, but their profiles for ≤ *n*-C_{24} have an obvious negative slope (ibid., fig. 11). The *n*-alkane isotopic profile of Birkhead kerogen pyrolysate #1450 has a negative gradient between *n*-C_{10} and *n*-C_{30} (*ca* -25‰ → *ca* -28‰) which is broadly similar to that of an oil (#394) from the Toolachee Formation (of undisputed Permian origin) at Gidgealpa-2 (ibid. fig 9). Therefore it appears that both Permian and

Jurassic/Cretaceous kerogens yield *n*-alkane isotopic profiles with pronounced negative slopes. Indeed, Jurassic/Cretaceous source facies with strongly negative carbon isotopic profiles may be more common than source facies with near-horizontal profiles.

3. As correctly acknowledged by Boreham and Summons (1999), there are considerable lateral and vertical lithological, depositional and (probably) organic facies variations within the Birkhead Formation (Paton, 1986, Boult *et al.*, 1998) which they correctly identify as the main Jurassic source rock. However, their analysis of Birkhead-reservoired oils is limited to only two crudes (from Bookabourdie-8 and Moorari-4) from the Birkhead depocentre within the northern Patchawarra Trough (*cf.* Krieg, 1995). It is here that "open water" lacustrine shales and coals of the Birkhead Formation are thickest. Boreham and Summons (1999) imply that three additional Birkhead oils from Big Lake-37, Gidgealpa-17, Merrimelia-9 and Strzelecki-5 have a mixed Permian/Jurassic source affinity, a proposition which is supported in this thesis (Chapter 6). However, it may have been more sagacious for Boreham and Summons (1999) to have tested some Birkhead or Hutton oils from a larger geographic area, including those closer to the Cooper Basin "zero edge" where both Permian and Jurassic source kitchens are less deeply buried. It is noteworthy that their Eromanga Basin data in South Australian are strongly biased towards oils recovered from the GMI Ridge (notably the Gidgealpa and Merrimelia Fields) and nearby areas where the adjacent Permian hydrocarbon kitchens are known to be highly mature or over-mature. Furthermore, they did not analyse any Eromanga oils from the Sturt/Tantanna area immediately overlying the Permian "zero edge". The origin of these oils has attracted considerable controversy (Chapter 2; Heath *et al.*, 1989; Kagya, 1997).

4. Oils from the Murta Formation in South Australia are poorly represented in the suite of samples chosen by Boreham and Summons (1999) for analysis by GC-C-irMS. In fact only one Murta crude, from Merrimelia-6, was analysed by these workers. This oil pool is arguably the least typical of all Murta-reservoired oils in South Australia and Queensland. Importantly, its quoted maturity (R_c = 0.6MPI + 0.4 = 0.79%, equivalent to parameter **3**, Table 6.1; *ibid.*, appendix 2) is higher than any of the other Murta oils analysed by them, and in accord with the maturity of a Murta oil from Merrimelia-35 (R_c = 0.81%: parameter **3**, Table 6.1) described in Chapter 6. The high maturity of the Murta oil in the Merrimelia Field was recognised as early as 1989 by Michaelsen and McKirdy who supported the notion that this, and possibly the Murta crude from the Gidgealpa Field were derived from source rocks deeper in the stratigraphic sequence, which is the position argued in Chapter 6.

   A better (more representative) choice of Murta oil for GC-C-irMS analysis would have been crude from Dullingari Field which is widely accepted to be either predominantly or entirely sourced from intra-Murta shales (*e.g.* Michaelsen and McKirdy, 1989; Deighton and Hill, 1998; D. Warner, Santos Ltd, pers. comm., 1998; A.J. Hill, PIRSA, pers. comm., 2000). It would also have been useful for them to analyse other oils which have an inferred partial or entirely intra-Murta origin from the Murteree Ridge (*e.g.* Biala and Limestone Creek Fields: Michaelsen and McKirdy, 1989; Powell *et al.*, 1989).

5. Boreham and Summons (1999) readily accommodate variability in the *n*-alkane isotope composition of Permian oils, but apparently discount the notion that differences in organic facies could significantly affect the *n*-alkane profiles of Jurassic/Cretaceous extracts, kerogen pyrolysates and/or oils. A serious flaw in their work is that they do not publish *n*-alkane isotopic data for any Jurassic/Cretaceous rock extracts. Presumably these data do not exist. Based on the aforementioned observations, it is predicted that Jurassic and Cretaceous extracts would have isotopic profiles similar to some or many of the Birkhead and Murta kerogen pyrolysates (*i.e.* with an obvious negative slope).

6. Boreham and Summons (1999) present data to show that the Poolowanna Formation oil at Cuttapirrie-1 has a "flat" *n*-alkane isotopic profile. Their rationale would dictate that this oil is of pure or near-pure Jurassic origin. However, no mention is made in their paper of the Poolowanna Formation as an effective source rock. Indeed, they explicitly recognise that the Birkhead and Murta Formations are the only effective Eromanga source kitchens (*ibid.*, fig. 27). It follows that they also consider the Jurassic oil within the Poolowanna Formation to be sourced from the Birkhead Formation. If this is true, the oil must have been generated somewhere down-dip (from presently over-mature source rocks located just to the south, southeast or east) in the Patchawarra Trough, and migrated up-dip through Hutton Sandstone carrier-beds into the Poolowanna reservoir (*i.e.* a Birkhead-Poolowanna source-reservoir couplet). Alternatively (and possibly more realistically), the

Jurassic component of the Cuttapirrie-1 (Poolowanna Formation) crude was expelled locally from an intra-Poolowanna Formation oil-prone source facies, as discussed in Chapter 6.

In summary, the proposition advanced in this thesis is that substantial variations in *n*-alkane isotopic composition are likely to exist for both Jurassic and Cretaceous kerogen pyrolysates and source rock extracts. It is probable that this inferred variability is an expression of major differences in depositional environment (*e.g.* fluvial, paludal or lacustrine) within the Birkhead Formation, as well as the Poolowanna (Kagya, 1997) and Murta Formations (Ambrose *et al.*, 1986; Michaelsen and McKirdy, 1989; Chapter 5). *n*-Alkane isotopic data published by Boreham and Summons (1999) do not demonstrate a predominant Permian source component for most of the Eromanga oil pools. Within the Cooper/Eromanga Basin system, horizontal or sub-horizontal *n*-alkane isotopic profiles may well be unique to indigenous Eromanga oil but could be restricted to particular source facies (and oils derived therefrom) developed where the Birkhead Formation is very thick (> 100 m) near its depocentre in the northern Patchawarra Trough of South Australia. There is no good evidence to suggest that pure Jurassic/Cretaceous oil cannot have a negative-sloping *n*-alkane isotopic profile. Consequently, the approach adopted by Boreham and Summons (1999) is likely to significantly over-emphasise the contribution of Permian hydrocarbons to Eromanga oil pools.

7.6 SYNOPSIS

1. In South Australia, Family 1 oils (which volumetrically represent more than 95% of the liquid hydrocarbon discoveries in that state) have invaded the Eromanga Basin only in the areas where potential Cooper Basin source rocks are mature or post-mature for oil generation (>1.0% R_o). It is inferred that Family 1 oils have not migrated into the southern Patchawarra Trough or beyond the western margin of the Cooper Basin.
2. Low-maturity oil from the Murta Formation (**1** = 0.53%, **3** = 0.67%) at Garanjanie-1 in the southwestern corner of the Cooper Basin was derived entirely from Permian source rocks. Although no oils presently trapped within the Cooper Basin are known to have such low maturities (*cf.* Chapter 2), the Garanjanie crude represents indirect evidence that source rocks within the Cooper Basin began expelling hydrocarbons prior to attaining maturities of *ca* 0.7% R_o. Moreover, based on the distribution of methylphenanthrene isomers from other nearby oils which plot on "mixing curve 2", especially those at Pintari North-1 (Namur Sandstone) and Tantanna-5 (Birkhead Formation), it is possible to deduce that Cooper Basin source rocks commenced hydrocarbon expulsion at maturities as low as *ca* 0.6% R_o.
3. "Mixing curve 1" for the Queensland data can be explained as three episodes of hydrocarbon migration and mixing. These may correspond to one or more of Deighton and Hill's (1998) four hydrocarbon expulsion events (*ca* 250, 105, 90 and 20–0 Ma). A major diagenetic event at *ca* 100 Ma (Rezaee *et al.*, 1997) may have prevented high maturity oil from the 90 Ma expulsion event migrating into reservoirs along the southeastern NJ Ridge.
4. Based on its 2-MP/1-MP value (0.73), the Namur Sandstone oil at Mulapula-1, *ca* 70 km southwest of the Cooper Basin "zero edge" in South Australia is provisionally interpreted as a mixed (*ca* 80% pre-Jurassic/*ca* 20% Jurassic) crude. It is speculated that the pre-Jurassic component of this oil may represent low-maturity Permian oil (< 0.70% R_c) and/or Family 2 oil from the Cooper Basin. However, other Birkhead Formation oils from Callabonna-1 and Charo-1 in the vicinity of the western Cooper Basin "zero edge" were derived entirely from Jurassic (Birkhead Formation) source rocks.
5. Oils in the Bodalla South area have variable Permian *versus* Jurassic/Cretaceous source affinities. Based on their 1-MP/9-MP values the Poolowanna oils at Black Stump-1 (*ca* 85%) and Bargie-1 (100%) are overwhelmingly derived from Permian source rocks. By contrast, oils from Bodalla South-1 (Hutton Sandstone) and Ipundu-1 (Cadna-owie Formation) are inferred to be of mixed origin, whilst crudes pooled at Talgeberry (Birkhead Formation) and Utopia (Murta Formation) have been sourced entirely from Eromanga source rocks. Based on the structure of the Eromanga Basin in this area, a north → south Jurassic hydrocarbon fareway (along the Chandos-Bodalla Trend) is likely, impling a local Eromanga source kitchen in the southern Ullenburry Depression. Alternatively, the Jurassic/Cretaceous hydrocarbons in the Utopia, Talgeberry and Ipundu Fields may be wholly or partly derived from more local source rocks.

6. Oils in the Inland area of the northwestern Cooper Basin have multiple sources. As discussed in Chapter 6, Hutton and Namur Sandstone oils at Inland are of mixed origin (*ca* 50% Permian/50% Jurassic). The Murta oil at Morney-3 (*ca* 85% Permian) and the Cadna-owie oil at Cuddapan-1 (*ca* 25% Permian) demonstrate that the inputs from the Cooper Basin vary widely. The Permian source influence at these localities appears to diminish towards the northwest. Consequently, a local Jurassic source kitchen is inferred within the northern Haddon Syncline and/or Morney Anticline.

7. Serious flaws beset the *n*-alkane isotope model used by Boreham and Summons (1999) to estimate the relative contributions of pre-Permian, Permian and Jurassic/Cretaceous inputs to Cooper and Eromanga Basin oil pools. It remains to be demonstrated that potential source rocks of Jurassic age are the only ones to possess horizontal or sub-horizontal *n*-alkane $\delta^{13}C$ profiles (the criterion they use to define a predominantly or wholly sourced Jurassic oil). Therefore, it is concluded that Boreham and Summons' (1999) model may over-emphasise the Permian component of Eromanga Basin oils.

CHAPTER 8

Conclusions

CHAPTER 8

Conclusions

8.1 COOPER BASIN SOURCE ROCKS AND OILS

The hydrocarbons trapped in the Cooper and Eromanga Basins of central Australia are derived from land plant material, originally laid down in peat swamp and lacustrine environments upon the Gondwana Supercontinent. The principal source units in the Cooper Basin are the Patchwarra Formation (Early Permian) and Toolachee Formation (Late Permian) which contain coal and shale source lithologies. As demonstrated by Rock-Eval pyrolysis, the best source rocks are the coals of the Patchawarra Formation. Consequently, it is inferred that this unit sourced most of the Cooper Basin's hydrocarbons. The Patchawarra source rocks commenced hydrocarbon generation at *ca* 250 Ma within the Nappamerri Trough (Deighton and Hill, 1998). There are probably few hydrocarbon pools remaining from this early event that have not been mixed with petroleum generated from later expulsion events. One exception may be a small oil accumulation in the Murta Formation at Garanjanie which has the lowest calculated maturity of any pure Permian-sourced crude (R_c = 0.6 MPI + 0.4 = 0.67%).

The oils which are presently reservoired in the Cooper Basin belong to one of two families. Condensate-like Family 1 oils (46–50° API) contain elevated concentrations of rearranged hopanes (*viz* 18α-neohopanes and 17α-diahopanes) relative to the 17α-hopanes and occur in the Fly Lake, Moorari/Woolkina and Tirrawarra Fields. In these oils the homohopanes are entirely depleted and have been replaced by a pseudohomologous series of homodiahopanes. Other features of these mature oils include characteristic gas chromatographic profiles which are dominated by gasoline-range *n*-alkanes, particularly *n*-heptane. Calculated maturities indicate they were generated from their respective Cooper Basin source rocks at maturation levels in the range 0.99–1.19% R_c. Based on similarly high maturities and *n*-alkane profiles, it is likely that the Nappamerri Formation oils which are pooled in the northern Patchawarra Trough of South Australia at Reg Sprigg (R_c = 1.18%) and Telopea (R_c = 1.04%) also belong to Family 1.

The second type of Cooper Basin oil, Family 2, is more conventional (34–36° API) and occurs in the Gidgealpa (Tirrawarra Sandstone, Patchawarra Formation), Malgoona (Merrimelia Formation) and Daralingie (Patchawarra Formation) Fields. It has a "normal" hopanoid distribution (*i.e.* 17α-hopane > rearranged hopanes), a lower calculated vitrinite reflectance values ($R_c \leq 0.99\%$) and an *n*-alkane profile dominated by higher-carbon-number *n*-alkanes. Based on their lower calculated maturities and *n*-alkane profiles, oils at Sturt (Patchawarra Formation: R_c = 0.83%) and Wancoocha (Patchawarra Formation: R_c = 0.83%) are also assigned to Family 2.

For both families of Permian oil, the overwhelming factor which controls their geographic distribution is the maturity of the Patchawarra Formation:

- Predictably, liquid hydrocarbons are absent where the Patchawarra Formation is post-mature ($R_o \geq 1.35\%$).
- Family 1 oils are pooled where the Patchawarra Formation is highly mature (R_o = 1.00–1.35%) for liquid hydrocarbon generation.
- Family 2 oils are pooled where the Patchawarra Formation is optimally mature (R_o = 0.75–1.00%) for liquid hydrocarbon generation.

Quantitatively, most hydrocarbon generation from Cooper Basin source rocks occurred during a second (*ca* 105 Ma) and third (*ca* 90 Ma) expulsion event (Deighton and Hill, 1998). The oil pool in the Nappamerri Group (R_c = 0.98%) of the Merrimelia Field is ideally positioned to represent an oil charge from the 105 Ma expulsion event in the Nappamerri Trough (which was the last major event to affect this depocentre: Deighton and Hill, 1998). However, the calculated maturity of this oil (R_c = 0.94%) and its *n*-alkane profile suggests that it belongs to Family 2. Consequently the oil may partially represent hydrocarbons which were generated by local

(Nappamerri Trough) source rocks prior to attainment of their present maturity levels, and therefore may contain a proportion of hydrocarbons from the 250 Ma expulsion event.

Based on comparison of the calculated maturity of oils (R_c) and the measured maturity of rock samples (R_o), migration distances between source and trap for both Cooper Basin oil families is inferred to be generally less than 5 km. However, Family 2 oils probably migrated further from their source to their place of entrapment. Notably, the Merrimelia Formation oil at Malgoona is interpreted to have migrated more than 10 km from younger (*i.e.* intra-Patchawarra Formation) source rocks to the northeast.

Other than the Murta oil accumulation at Garanjanie, there are at least two Permian-derived oils which are pooled in the South Australian sector of the Eromanga Basin. One is the Hutton oil at Reg Sprigg-1 which, at a calculated vitrinite reflectance of 1.26%, is the most mature oil detected in either the Cooper or Eromanga Basins and almost certainly represents Family 1 petroleum. The Poolowanna Formation oil at Sturt-2 may also represent pure Permian-derived hydrocarbons but belongs to Family 2. Of the hydrocarbons tested in the Queensland sector, only the Hutton Sandstone oils at Chookoo (R_c = 1.13%) and Naccowlah South (R_c = 1.14%) are inferred to be entirely of Permian origin.

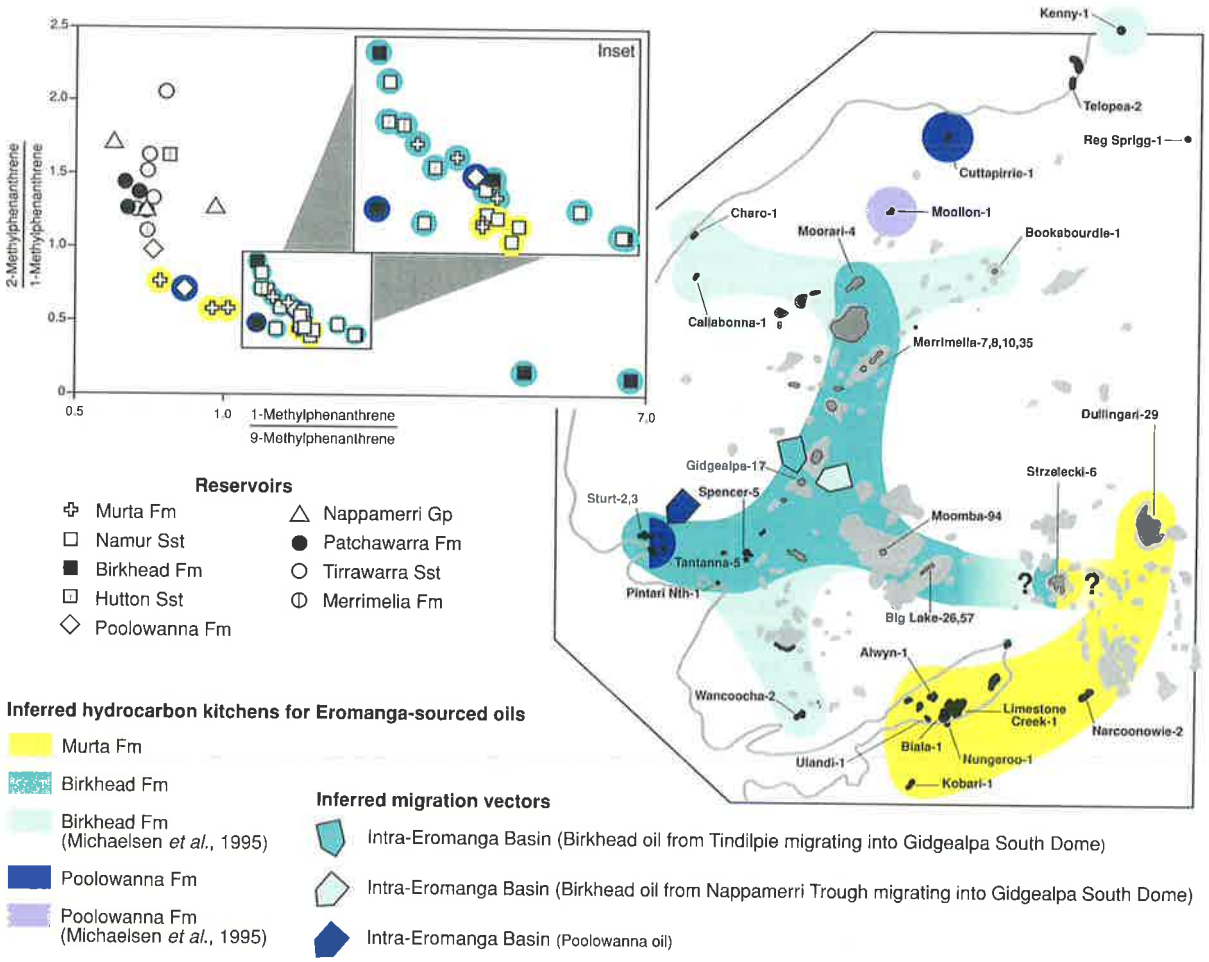


Figure 8.1 Inferred hydrocarbon kitchens for Eromanga-sourced oils in South Australia and their identification on the mixing curves described in Chapters 6 and 7

8.2 EROMANGA BASIN SOURCE ROCKS AND OILS

Petrographic and Rock-Eval pyrolysis data indicate that the principal Eromanga source rocks are the Poolowanna, Birkhead and Murta Formations. The Early Jurassic Poolowanna Formation is likely to have sourced hydrocarbons only in the Sturt/Tantanna and Cuttapirrie areas of South Australia (Fig. 8.1). However, the best Eromanga source facies are developed as Type II kerogen-bearing coals and organic-rich argillites within the Middle–Late Jurassic Birkhead Formation. The latter has generated oil over a vast area of the Cooper Basin region in South Australia (Fig. 8.1). In Queensland the Birkhead Formation is the inferred source rock for the Eromanga component of oils reservoired in the Jackson and Gunna Fields on the NJ Ridge (Fig. 8.2), in the Bodalla South area, and within the Hutton and Namur Sandstones at Inland in

the northern Cooper Basin area where a local Birkhead hydrocarbon kitchen is postulated in the northern Haddon Syncline/Morney anticline.

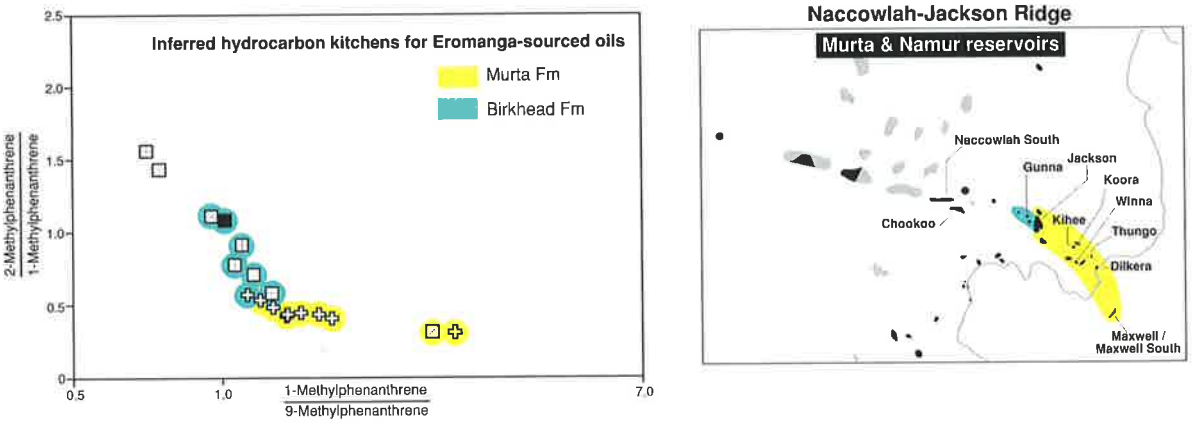


Figure 8.2 Inferred hydrocarbon kitchens for Eromanga-sourced oils in Queensland and their identification on the mixing curves described in Chapters 6 and 7

Exceptionally oil-prone Birkhead (including "Birkhead equivalent") source rocks are developed west of the Birdsville Track Ridge, particularly at Poonarunna, Putamurdie and Mulapulla where hydrogen indices above 500 are common for organic-rich rocks, including thin shales developed within the Namur Sandstone. In the western Eromanga Basin coals and carbonaceous siltstones within the Poolowanna and Birkhead Formations are rich in fossil resinite derived from araucariacean conifers. Consequently, vitrinite reflectance suppression (defined as the difference between maturity measured by FAMM and conventional vitrinite reflectance) is greatest at these localities, in particular within the Birkhead Formation overlying the Arckaringa Basin (0.50% R_o absolute at Poonarunna), but also the "Birkhead equivalent" (0.20% R_o absolute) overlying the Eringa Trough of the Pedirka Basin. Vitrinite reflectance suppression is also important (0.34% R_o absolute) in Birkhead coals at Gidgealpa, suggesting that it may be a basin-wide phenomenon. The concentration of araucariacean biomarkers appears to be lower in Jurassic rocks from the Eromanga Basin overlying the southern Cooper Basin and therefore it is a reasonable proposition that vitrinite reflectance suppression is less severe east of the Birdsville Track Ridge. However, very high concentrations of aromatic hydrocarbon biomarkers derived from araucariacean conifers (relative to non-biomarker aromatic hydrocarbons) in Birkhead-sourced and reservoired oils from Sturt (1-MP/9-MP = 4.0) and Moorari (1-MP/9-MP = 6.6) constitute indirect evidence that exceptionally oil-prone resinite-enriched Eromanga source facies also exist in the Cooper Basin region. A useful way of estimating true (= unsuppressed) maturity is with the Rock-Eval parameter T_{max} using the algebraic expression $R_{FAMM} = 0.02 T_{max} - 7.85$, where R_{FAMM} is the unsuppressed maturity based on the vitrinite reflectance scale.

The fine-grained siltstones and shales of the Early Cretaceous (Neocomian) Murta Formation represent the highest stratigraphic unit with liquid hydrocarbon potential. However, it is only marginally mature for hydrocarbon generation and expulsion (based on conventionally measured R_o) around the margins of the Cooper Basin and some structural highs (*e.g.* Murteree Ridge). In South Australia, it is in the Murteree Ridge area (Fig. 8.1) where the highest quality oil-prone siltstones with hydrogen indices in excess of 250 are developed. The Eromanga component of the oils reservoired in the Murta Formation and Namur Sandstone along the Murteree Ridge and at Dullingari are inferred to be sourced from the Murta Formation (Fig. 8.1). In the Queensland sector, the Murta Formation is interpreted to be the major Eromanga source rock between Jackson and Maxwell on the southeastern extension of the NJ Ridge (Fig. 8.2).

Murta oils are characterised by low MPI-derived maturities (0.5–0.7% R_c) which match the measured and inferred maturities of local Murta rocks. However, the Eromanga-sourced components of the Murta oils at Merrimelia and Gidgealpa are interpreted to be derived from deeper Jurassic source rocks (*i.e.* Birkhead Formation). Indeed, comparative gas chromatography of Murta and Namur oil at Gidgealpa indicates that the chemistries of stacked oil pools in the Eromanga sequence are essentially identical. The Murta Formation in the Nappamerri Trough, interpreted as a deep water and distal depositional environment, contains low quality (oxidised) source material (HI < 250). Consequently, the Murta and Namur oils at

Moomba and Big Lake, which have a clear "Jurassic" aromatic hydrocarbon signature, were probably derived from the Birkhead Formation.

Relative to Birkhead-derived oils, Murta-derived oils are likely to be overrepresented because of the inferred high migration efficiency of Murta-Murta source-reservoir couplets. Furthermore, it is easier to accept that the expulsion efficiency of Murta source rocks is higher than would normally be expected at these apparently incipient levels of organic metamorphism (*viz* 0.5–0.6% R_O) if one also accepts that vitrinite reflectance suppression is also a factor in the Murta Formation. A calculated maturity of *ca* 0.8% R_{FAMM} is predicted for high-quality Murta source rocks in the Murteree Ridge area.

8.3 Mixing of petroleum in the Eromanga Basin

One question which continues to perplex explorers is where (and when) hydrocarbons from the Permo–Triassic Cooper Basin invaded the overlying Eromanga Basin, and in what proportions have they mixed with indigenous Jurassic and Cretaceous crude. A novel cross-plot employing the aromatic hydrocarbon parameters 1-MP/9-MP and 2-MP/1-MP can be used to visualise and estimate the proportions of Permian (pre-Jurassic) *versus* Jurassic/Cretaceous hydrocarbons within an oil pool in the Eromanga Basin. In the South Australian sector, mixing of Permian hydrocarbons can be identified on two separate mixing curves which are explicable in terms of the observed geographic distribution of Family 1 and Family 2 hydrocarbons in the underlying Cooper Basin:

- Family 1 oils have invaded and mixed with Birkhead-sourced oil most evidently within fields at Big Lake (Birkhead Formation), Merrimelia (Hutton Sandstone and Murta Formation) and Strzelecki (Hutton and Namur Sandstones). More subtle mixing is inferred for oil within the stacked reservoirs at Gidgealpa (Hutton Sandstone, Birkhead Formation, Namur Sandstone and Murta Formation).
- Family 2 oil has permeated into the Jurassic and Cretaceous reservoirs above the southwestern margin of the Cooper Basin where the Patchawarra Formation has a maturity less than 1.0% R_O. It has mixed with local Murta-sourced hydrocarbons in Murta Formation and Namur Sandstone reservoirs at Alwyn and Limestone Creek (Murteree Ridge). The Eromanga component of the oil in the Murta reservoir at Kobari may have been derived from the Murta Formation. However, approximately 80% of the Kobari oil has an inferred Permian (low-maturity Family 2) origin. Minor proportions of the predominantly Birkhead-sourced oils at Tantanna and Pintari North can also be attributed to an influx of low-maturity Family 2 oil.
- The degree of mixing of Permian hydrocarbons with Jurassic/Cretaceous petroleum in South Australia is greatest in the Eromanga Basin above or immediately adjacent to where the Cooper Basin (Patchawarra Formation) is most deeply buried and most mature in the Nappamerri Trough.
- Between the GMI Ridge and the Cooper Basin's western "zero edge" very little Permian oil has infiltrated the Eromanga Basin. Consequently, Birkhead-reservoired oils such as those at Kenny, Charo, Callabonna, Moorari, Bookabourdie, Spencer and Sturt originated entirely from Birkhead source facies.

The relative abundance of methylphenanthrene isomers defines a single mixing curve in the Queensland sector. Oils from the NJ Ridge have had variable inputs from the Cooper Basin and can be classified into three groups. Oils in Jurassic (Hutton Sandstone) reservoirs at Chookoo and Naccowlah South (northwest NJ Ridge) appear to be derived entirely from a Permian source kitchen. Eromanga oils at Jackson and Gunna (central NJ Ridge) represent Permian hydrocarbons which have breached the Cooper Basin regional seal and invaded the Jurassic reservoirs to comingle with indigenous Eromanga oil. Finally, Eromanga oils from Koora, Winna, Thungo, and Maxwell (southeast NJ Ridge) are wholly Jurassic/Cretaceous in origin.

Three discrete episodes of hydrocarbon generation, expulsion and migration are evident from the composition of the Queensland oils. It is postulated that these discrete hydrocarbon charges may correspond to Deighton and Hill's (1998) three main episodes of oil expulsion from Cooper Basin source rocks at *ca* 250, 105 and 90 Ma:

- The first influx of early-generation Permian hydrocarbons (presumably *ca* 0.6–0.7% R_c), migrating from the northwest towards the southeast, was trapped within shallow Namur and Murta anticlinal traps where they comingled with indigenous Murta crude in the Gunna/Jackson/Kihee area of the central NJ Ridge. Permian oil was not trapped in Murta

reservoirs in the southeast of the NJ Ridge either because hydrocarbon pools were already filled to spill-point with indigenous Murta oil, or because suitable traps had not yet formed over the Cooper Basin margin where the Eromanga sequence is shallow lying. Because the 250 Ma expulsion event predated deposition of the Eromanga Basin by around 50 My, it is not possible for oil from this event to have migrated into the Namur and Murta reservoirs unless the first influx of oil represented *remobilised* hydrocarbons.

- The Eromanga-reservoired oils at Inland and Bodalla South in the northern Eromanga Basin contain a Permian source component from a second episode of hydrocarbon expulsion (*ca* 0.95% R_c). Oils from the Hutton and Namur Sandstones at Inland, contain hydrocarbons of mixed Permian (50%) and Jurassic (50%) origin thereby demonstrating long distance lateral migration (≥ 50 km) of Cooper Basin hydrocarbons into the Eromanga succession; and the potential of Eromanga-Eromanga source-reservoir couplets beyond the northern margin of the Cooper Basin.
- A third influx of very mature (*ca* 1.0–1.2% R_c) Permian oil into the northeast of the NJ Ridge comingled with Permian hydrocarbons from earlier charges and/or indigenous Jurassic and Cretaceous crude in the deeper Hutton, Birkhead and Westbourne reservoirs. Consequently, oils in Eromanga reservoirs at Gunna and Jackson are of mixed Permian/Jurassic origin.

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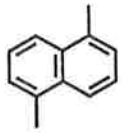
APPENDIX 1

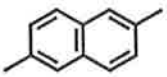
Molecular structures of important hydrocarbon biomarkers

Appendix 1a **Aromatic hydrocarbons and drimanes**

Bicyclic aromatics



1,5-Dimethynaphthalene



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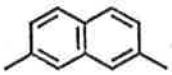

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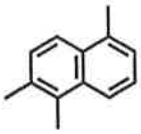
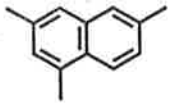


1,2,5-Trimethynaphthalene
Araucariacean marker



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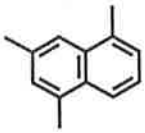

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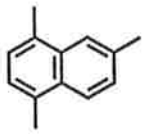

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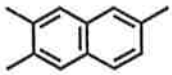
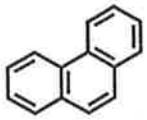
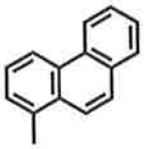


2,3,6-Trimethynaphthalene

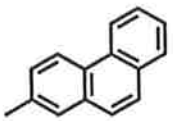
Tricyclic aromatics



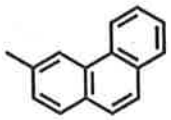
Phenanthrene



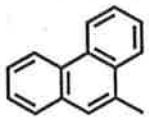
1-Methylphenanthrene
Araucariacean marker



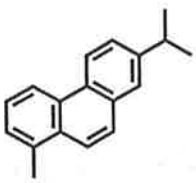
2-Methylphenanthrene



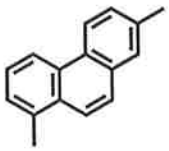
3-Methylphenanthrene



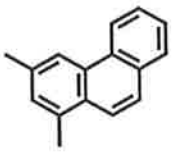
9-Methylphenanthrene



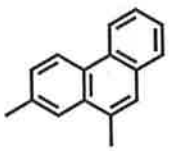
Retene
Araucariacean marker



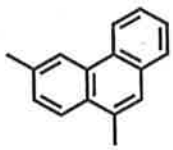
1,7-Dimethylphenanthrene
Araucariacean marker



1,3-Dimethylphenanthrene

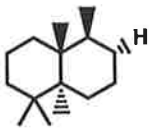


2,10-Dimethylphenanthrene

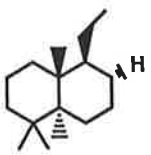


3,10-Dimethylphenanthrene

Drimanes

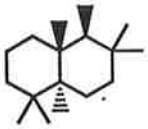


8β-drimane

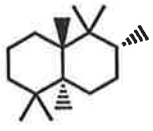


8β-homodrimane

Rearranged drimanes



Structure 1 #

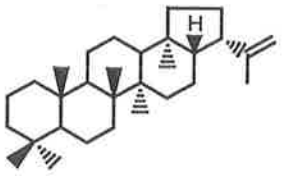


Structure 2 #

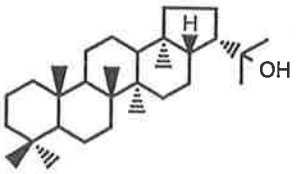
Peters and Moldowan (1993, p. 167)

Appendix 1b **Triterpenoid biomarkers (1 of 2)**

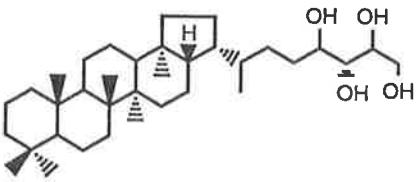
Hopanoids in bacterial membranes



Diploptene

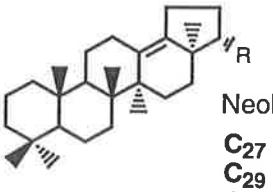


Diplopterol



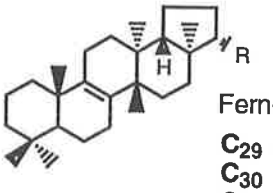
Bacteriohopanetetrol

Other compounds in bacteria and ferns



Neohop-13(18)-enes

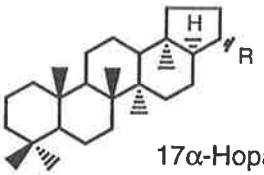
- C_{27} 22,29,30-trisnorneohop-13(18)-ene
- C_{29} 30-norneohop-13(18)-ene
- C_{30} neohop-13(13)-ene
- C_{31} homoneohop-13(18)-ene



Fern-8(9)-enes

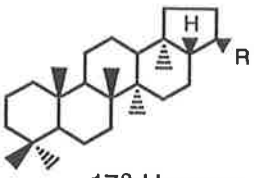
- C_{29} 30-norfernene
- C_{30} fernene
- C_{31} homofernene

Major hopanes in sediments and petroleum



17α-Hopanes

- C_{27} 22,29,30-trisnorhopane [T_m]
- C_{29} 30-norhopane
- C_{30} hopane
- C_{31} homohopane



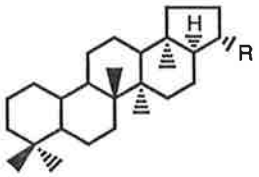
17β-Hopanes
[moretanes]

- C_{27} 22,29,30-trisnormoretane
- C_{29} 30-normoretane
- C_{30} moretane
- C_{31} homomoretane

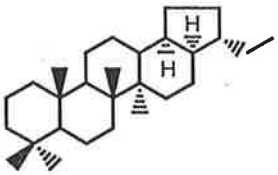
For C_{27}, C_{29}, C_{30}, and C_{31} compounds R = H, C_2H_5, *i*-C_3H_7, and *s*-C_4H_9, respectively.

Appendix 1b **Triterpenoid biomarkers (2 of 2)**

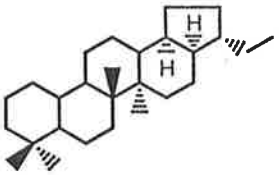
Demethylated hopanes



17α-25-Norhopanes

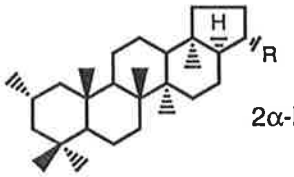


17α-28,30-Bisnorhopane
[28,30-BNH]

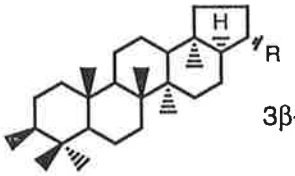


17α-25,28,30-Trisnorhopane
[25,28,30-TNH]

Methylhopanes

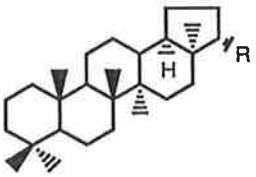


2α-Methylhopanes

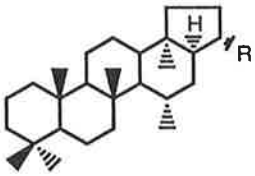


3β-Methylhopanes

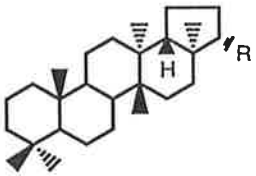
Rearranged hopanes and fernanes



18α-Neohopanes
- C_{27} 22,29,30-trisnorneohopane [T_s]
- C_{29} 30-norneohopane [$C_{29}T_s$]
- C_{30} neohopane [$C_{30}T_s$]



17α-Diahopanes
- C_{29} 30-nordiahopane
- C_{30} diahopane
- C_{31} homodiahopane

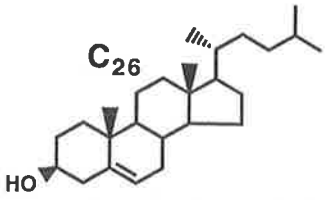


Fernanes
- C_{29} 30-norfernane
- C_{30} fernane
- C_{31} homofernane

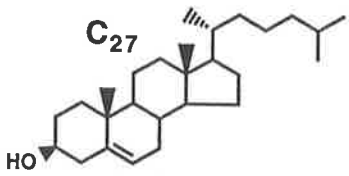
For C_{27}, C_{29}, C_{30}, and C_{31} compounds R = H, C_2H_5, *i*-C_3H_7, and *s*-C_4H_9, respectively.

Appendix 1c **Steroid biomarkers (1 of 2)**

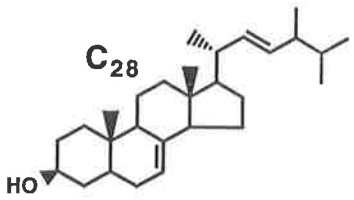
Steroids in eukaryotic cell membranes



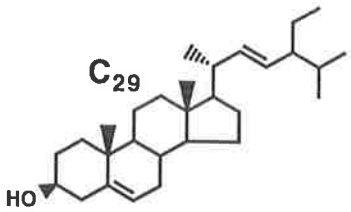
24-Norcholesterol
marine algae



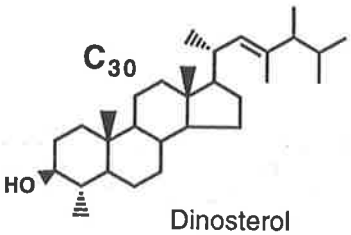
Cholesterol
animals, plants



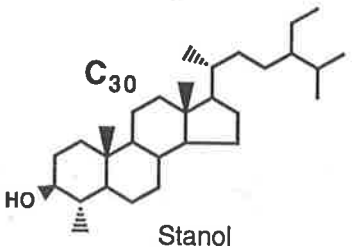
Dihydroergosterol
algae



Stigmasterol
plants

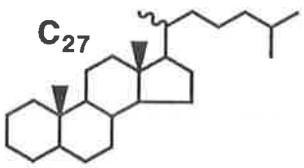


Dinosterol
dinoflagellates

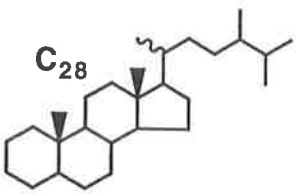


Stanol
marine diatoms, prymnesiophyte algae

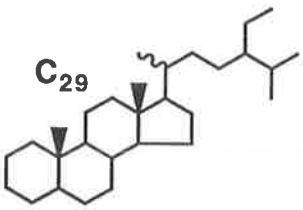
Major steranes in sediments and petroleum



Cholestane
marine algae



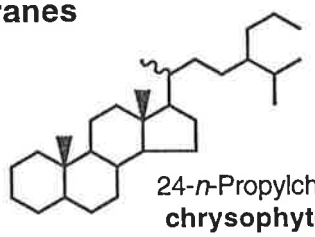
Methylcholestane
(? lacustrine) algae



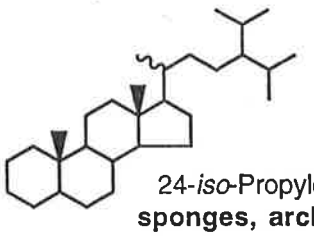
Ethylcholestane
land plants

Appendix 1c **Steroid biomarkers (2 of 2)**

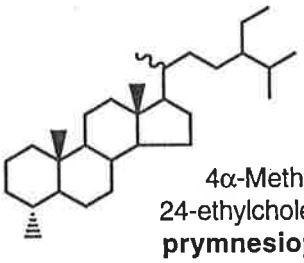
C_{30} steranes



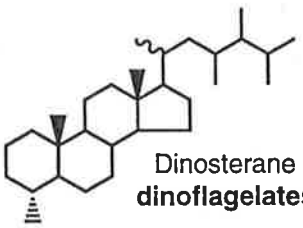
24-*n*-Propylcholestane
chrysophyte algae



24-*iso*-Propylcholestane
sponges, archaeocyatha

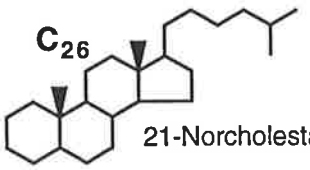


4α-Methyl-
24-ethylcholestane
prymnesiophyte algae, dinoflagelates

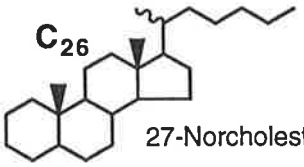


Dinosterane
dinoflagelates

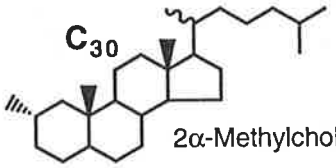
Steranes of bacterial affinity



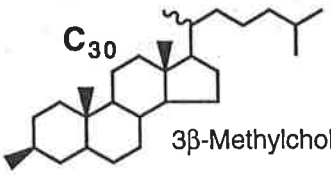
21-Norcholestane



27-Norcholestane

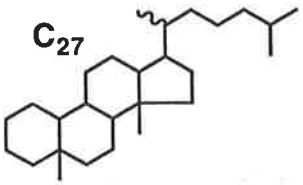


2α-Methylcholestane

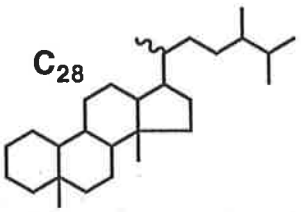


3β-Methylcholestane

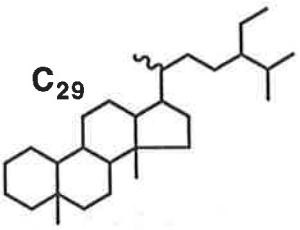
Rearranged steranes



Diacholestane



Methyldiacholestane



Ethyldiacholestane

APPENDIX 2

Tables

Table 2.1: Sample details for coals and shales

Well	Depth	Formation	Sample type	Lithology analysed
Cooper Basin (coal/shale pairs)				
Tirrawarra-16	9641'	Tirrawarra	Core	Shaley coal
Tirrawarra-17	9742'9"	Tirrawarra#	Core	Shale
Fly Lake-3	9526'6"	Basal Patchawarra	Core	Coal
Gidgealpa-17	7164'5"	Undiff. Patchawarra	Core	Shale
Kanowana-1	10017'1"	Basal Patchawarra	Core	Coal
Kanowana-1	10029'3–5"	Basal Patchawarra	Core	Shale
Moorari-1	9275'	Basal Patchawarra	Core	Coal
Moorari-1	9276'	Basal Patchawarra	Core	Shale
Tirrawarra-2	9724'3"	Basal Patchawarra	Core	Shale
Tirrawarra-2	9727'6"	Basal Patchawarra	Core	Coal
Daralingie-19	9464'6"	Mid-upper Patchawarra	Core	Coal
Daralingie-19	9465'6"	Mid-upper Patchawarra	Core	Shale
Eromanga Basin				
Sturt East-4	6110–6120'	Poolowanna†	Cuttings	Coal
Sturt-4	6100–6110'	Poolowanna	Cuttings	Coaly shale
Sturt-4	6170–6180'	Poolowanna	Cuttings	Shaley coal
Sturt East-1	6040–6050'	Poolowanna	Cuttings	Shale
Tantanna-2	5901'	Poolowanna	Core	Shale

Merrimelia Fm/Tirrawarra Sst contact † Patchawarra Fm/Poolowanna Fm contact

Table 2.2: Sample details for oils

Well	Depth	Formation	Sample type	Specific gravity (° API)
Cooper Basin reservoirs				
Malgoona-1A**	7430–7444'	Merrimelia	Production	34.0
Gidgealpa-41**	7298–7327'	Tirrawarra	Production	34.9
Moorari-1*	9560–9745'	Tirrawarra	Production	50.4
Tirrawarra-2*	9771–9846'	Tirrawarra	Production	45.9
Tirrawarra-8*	9565–9631'	Tirrawarra	Production	-
Woolkina-1*	9840–9868'	Tirrawarra	Production	48.3
Fly Lake-8*	9483–9540'	Tirrawarra & Basal Patchawarra	Production	46.3
Daralingie-18**	7438–7447'	Patchawarra	Production	36.3
Eromanga Basin reservoirs				
Sturt-4	6142–6168'	Poolowanna	DST-1	48.9
Sturt-7	6139–6154'	Poolowanna	DST-3	49.2
Sturt-8	6168–6181'	Poolowanna	DST-1	48.8
Sturt East-2	6053–6230'	Poolowanna	DST-1	51.3
Taloola-2	6001–6024'	Poolowanna	DST-1	53.0
Tantanna-1	5906–5951'	Poolowanna	DST-1	50.1

* Family 1 oil ** Family 2 oil

Table 2.3: Vitrinite reflectance data and petrographic descriptions of Cooper Basin samples

Sample	Lithology	R_O (%)	n	Petrographic description
Daralingie-19				
9464'6"	Coal	1.03	42	Inertinite ≥ vitrinite > liptinite. Liptinites are mainly sporinite, very minor exsudatinite. Also minor ?cutinite.
9465'6"	Shale	0.90	13	Inertinite > vitrinite > liptinite. Inertinite comprises mostly inertodetrinite and semifusinite. Dark "degradation" haloes around inertinites, associated with ?non-fluorescing bituminite. *Botryococcus*-type telalginite is rare but almost the only liptinite, except for liptodetrinite.
Fly Lake-3				
9526'6"	Coal	1.06	50	Well layered bright and dull bands. Telovitrinite > inertinite > liptinite. Liptinites are predominantly sporinite and liptodetrinite, with less common resinite.
Gidgealpa-17				
7164'5"	Siltstone	0.86	9	Inertinite > vitrinite > liptinite. Liptinites are scarce comprising sporinite, liptodetrinite and ?bituminite. Vitrinites are possibly oxidised.
Kanowana-1				
10017'1"	Coal	1.21	41	Well layered. Layers comprise inertinite and vitrinite-rich layers; also mixed layers (clarite). Inertinite ≈ vitrinite > liptinite. Inertinite comprises approx. equal proportions of fusinite and semifusinite. Detrovitrinite > telovitrinite. Resinite is abundant and virtually the only liptinite maceral present.
10029'3–5"	Shale	n.d.	-	Inertinite > vitrinite >> liptinite. Almost entirely highly comminuted inertinites (inertodetrinite and semifusinite). Liptinites absent except possibly very minor bituminite.
Moorari-1				
9275'	Coal	0.92	35	Inertinite > telovitrinite > detrovitrinite > liptinite. Liptinites are predominantly sporinite and liptodetrinite. Minor cutinite and resinite.
9276'	Shale	0.96	35	Vitrinite ≈ inertinite > liptinite. Liptinites are predominantly sporinite and liptodetrinite. Bituminite is associated with degraded humic macerals.
Tirrawarra-2				
9224'3"	Shale	n.d.	-	Inertinite >> vitrinite > liptinite. Inertinite is mainly fusinite, semifusinite and inertodetrinite; very minor macrinite. Liptinite is almost entirely absent — possibly bituminite ± sporinite.
9727'6"	Coal	1.62	26	Poorly layered. Vitrinite ≈ inertinite > liptinite. Vitrinites are generally well gelified being predominantly telocollinite, desmocollinite and corpogellinite. Inertinites are mainly fusinite and semifusinite. Resinite (including cellular resinite) and liptodetrinite are common. ?Exsudatinite rare.
Tirrawarra-16				
9641'	Shaley coal	0.96	29	Poorly layered. Inertinite > vitrinite >> liptinite. Major liptinite is resinite (minor). Very minor sporinite and liptodetrinite.
Tirrawarra-17				
9742'9"	Shale	1.04	18	Inertinite >> vitrinite > liptinite. Vitrinites are strongly degraded. Minor **bitumen** (residual oil) present.

R_O = mean of maximum vitrinite reflectance; n = number of determinations used to calculate R_O

Table 2.4: Rock-Eval pyrolysis data

Well	Depth	Lithology	T_{max}	S_1	S_2	S_3	S_1+S_2	S_2/S_3	PI	PC	TOC	HI	OI
Tirrawarra Sst													
Tirrawarra-16	9641'	Shaley coal	459	11.86	65.19	2.74	77.05	23.79	0.15	6.42	45.40	143	6
Tirrawarra-17	9742'9"	Shale	461	2.84	16.15	0.43	18.99	37.55	0.15	1.58	9.88	163	4
Patchawarra Fm													
Fly Lake-3	9526'6"	Coal	455	30.38	149.33	1.52	179.71	98.24	0.17	14.97	83.20	179	1
Gidgealpa-17	7164'5"	Shale	445	0.64	3.11	0.16	3.75	19.43	0.17	0.31	3.21	96	4
Kanowana-1	10017'1"	Coal	467	21.70	96.00	1.40	117.70	68.57	0.18	9.80	79.30	121	1
Kanowana-1	10029'3–5"	Shale	480	0.22	0.51	0.11	0.73	4.63	0.31	0.06	1.31	38	8
Moorari-1	9275'	Coal	453	23.85	127.39	2.81	151.24	45.33	0.16	12.60	84.50	150	3
Moorari-1	9276'	Shale	452	0.92	5.99	0.16	6.91	37.43	0.13	0.57	3.76	159	4
Tirrawarra-2	9724'3"	Shale	484	0.35	2.16	0.22	2.51	9.81	0.14	0.20	4.56	47	4
Tirrawarra-2	9727'6"	Coal	464	14.79	62.75	2.65	77.54	23.67	0.19	6.46	69.60	90	3
Daralingie-19	9464'6"	Coal	452	28.40	151.17	2.44	179.57	61.95	0.61	14.96	80.80	187	3
Daralingie-19	9465'6"	Shale	451	1.04	4.93	0.09	5.97	54.77	0.17	0.49	4.38	112	2
*Poolowanna Fm**													
Sturt East-4	6110–6120'	Coal	437	5.14	115.43	4.85	120.57	23.80	0.04	10.01	68.10	170	7
Sturt-4	6100–6110'	Coaly shale	435	2.05	37.53	1.46	39.58	25.71	0.05	3.29	21.40	175	7
Sturt-4	6170–6180'	Shaley coal	435	15.55	132.82	4.04	148.37	32.88	0.10	12.31	51.90	256	8
Sturt East-1	6040–6050'	Shale	438	0.91	21.98	0.94	22.89	23.38	0.04	1.90	7.76	283	12
Tantanna-2	5901'	Shale	439	3.60	53.52	1.55	57.12	34.53	0.06	4.74	18.10	296	9

* Eromanga Basin data from Michaelsen *et al.* (1996); T_{max} = temperature of maximum generation of S2 hydrocarbons; S1 = mg hydrocarbons/g rock; S2 = mg hydrocarbons/g rock; S3 = mg CO_2/g rock; PI = S1/(S1+S2); PC = pyrolysable carbon; TOC = total organic carbon; HI = S2/g TOC; OI = S3/g TOC

Table 2.5: Compositional data on sediment extracts

Well	Depth	TOC (%)	EOM (ppm)	EOM (mg/g TOC)	C_{15+} composition Sat (%)	Aro (%)	Pol (%)	Sat/Aro
Tirrawarra Sst (coal/shale pair)								
Tirrawarra-16	9641'	45.40	12820	28	13.2	27.7	59.1	0.48
Tirrawarra-17	9742'9"	9.88	4049	41	19.5	26.0	45.5	0.75
Patchawarra Fm (coal/shale pairs)								
Fly Lake-3	9526'6"	83.20	38117	46	12.1	21.9	66.0	0.55
Gidgealpa-17	7164'5"	3.21	1298	40	6.8	27.6	65.6	0.25
Kanowana-1	10017'1"	79.30	22190	28	12.0	26.0	62.0	0.46
Kanowana-1	10029'3–5"	1.31	556	42	11.4	27.4	61.2	0.42
Moorari-1	9275'	84.50	49921	59	12.1	22.7	65.2	0.53
Moorari-1	9276'	3.76	1822	48	10.6	22.1	67.3	0.48
Tirrawarra-2	9724'3"	4.56	953	21	4.6	22.5	72.9	0.20
Tirrawarra-2	9727'6"	69.60	34061	49	4.4	10.5	85.1	0.42
Daralingie-19	9464'6"	80.80	40802	50	15.4	23.8	60.8	0.65
Daralingie-19	9465'6"	4.38	1360	31	14.2	22.4	63.4	0.63
Poolowanna Fm								
Sturt East-4	6110–6120'	68.10	26083	38	7	33	60	0.21
Sturt-4	6100–6110'	21.40	12373	58	16	32	52	0.50
Sturt-4	6170–6180'	51.90	38585	74	22	27	51	0.81
Sturt East-1	6040–6050'	7.76	4256	55	22	25	53	0.88
Tantanna-2	5901'	18.10	8018	44	29	30	41	0.97

TOC = Total Organic Carbon; Sat = saturated hydrocarbons; Aro = aromatic hydrocarbons; Pol = polar compounds = resins + asphaltenes

Table 2.6: Compositional data on oils

Well	Depth	Sample type	C_{15+} composition Sat (%)	Aro (%)	Pol (%)	Sat/Aro
Cooper Basin reservoirs						
Malgoona-1A**	7430–7444'	Production	67.7	17.9	14.4	3.8
Gidgealpa-41**	7298–7327'	Production	75.9	21.6	2.5	3.5
Moorari-1*	9560–9745'	Production	38.1	6.9	55.0	5.5
Tirrawarra-2*	9771–9846'	Production	65.1	11.4	23.5	5.7
Tirrawarra-8*	9565–9631'	Production	64.6	10.9	24.5	5.9
Woolkina-1*	9840–9868'	Production	46.8	11.4	41.8	4.1
Fly Lake-8*	9483–9540'	Production	71.9	12.6	15.5	5.7
Daralingie-18**	7438–7447'	Production	74.2	19.7	6.1	3.8
Eromanga Basin reservoirs						
Sturt-4	6142–6168'	DST-187.0	8.2	4.8	10.6	
Sturt-7	6139–6154'	DST-377.5	6.2	24.8	12.5	
Sturt-8	6168–6181'	DST-187.2	8.1	4.7	10.8	
Sturt East-2	6053–6230'	DST-177.4	9.2	13.4	8.4	
Taloola-2	6001–6024'	DST-164.7	12.1	23.8	5.3	
Tantanna-1	5906–5951'	DST-147.6	4.7	47.7	10.1	

* = Family 1 oil ** = Family 2 oil

Table 2.7: Summary of source richness parameters (*cf.* Table 2.4), EOM (*cf.* Table 2.5) and kerogen type (Figs 2.4 & 2.5)

Lithology	Rock-Eval pyrolysis				Kerogen
	av. **TOC** (%)	av. $S_1 + S_2$ (mg HC/g)	av. **HI**	av. **EOM** (mg/g TOC)	Type
Tirrawarra Sst					
Shaley Coal (1)	45.4	77.05	143	28	II
Shale (1)	9.88	18.99	163	41	II
Patchawarra Fm					
Coal (5)	79.5	141.15	145	46	II
Shale (5)	3.44	3.97	90	36	III ± ?II
Poolowanna Fm					
Coal (1)	68.10	120.57	170	38	III
Shaley coal (1)	51.90	148.37	256	74	II/III
Coaly shale (1)	21.40	39.58	175	58	III
Shale (2)	12.93	40.01	290	50	II/III

Lithological definitions according to TOC: Shale or siltstone 0 – 20%; Coaly shale 21 – 40%; Shaley coal 41 – 60%; Coal ≥ 61%

Table 2.8: Summary of maturities estimated from Rock-Eval pyrolysis (*cf.* Table 2.4) and measured vitrinite reflectance (*cf.* Table 2.3)

Well	Depth	Lithology	Measured vitrinite reflectance (Table 2.3) R_O (%)	Maturity estimated from Figure 2.4 R_{re} (%)	Estimated maturity‡ R_{est} (%)
Tirrawarra Sst					
Tirrawarra-16	9641'	Shaley coal	0.96	1.15	1.00
Tirrawarra-17	9742'9"	Shale	1.04	1.15	1.05
Patchawarra Fm					
Fly Lake-3	9526'6"	Coal	1.06	1.0	1.05
Gidgealpa-17	7164'5"	Shale	0.86	0.8	0.85
Kanowana-1	10017'1"	Coal	1.21	1.35	1.20
Kanowana-1	10029'3 – 5"	Shale	-	≥ 1.4	1.20
Moorari-1	9275'	Coal	0.92	1.0	0.95
Moorari-1	9276'	Shale	0.96	1.0	0.95
Tirrawarra-2	9724'3"	Shale	-	≥ 1.4	1.20†
Tirrawarra-2	9727'6"	Coal	1.62	1.35	1.20†
Daralingie-19	9464'6"	Coal	1.03	0.95	0.95
Daralingie-19	9465'6"	Shale	0.90	0.95	0.95
Poolowanna Fm					
Sturt East-4	6110 – 6120'	Coal	0.61*	0.6	0.60
Sturt-4	6100 – 6110'	Coaly shale	0.69*	0.6	0.60
Sturt-4	6170 – 6180'	Shaley coal	0.62*	0.6	0.60
Sturt East-1	6040 – 6050'	Shale	0.63*	0.65	0.65
Tantanna-2	5901'	Shale	0.73*	0.65	0.70

* M.N.L. Kagya unpublished results; ‡ Values rounded to nearest 0.05%. NB: Juxtaposed coals and shales from Daralingie-19, Kanowana-1, Moorai-1, Tirrawarra-2 must have identical values. R_{est} values are based mostly on R_O where there are a large number (n ≥ 25) of reliable reflectance values; † R_{est} maturities of 1.20% for the Tirrawarra samples are deduced from the similarity of T_{max} values with those of the Kanowana-1 coal/shale pair (*cf.* Section 2.4.1)

Table 2.9: Aromatic hydrocarbon database for rock extracts and measured vitrinite reflectance

Well	Depth	DNR	TNR	1,2,5-TMN / 1,3,6-TMN	1-MP / 9-MP	MPR: 2-MP / 1-MP	1,7-DMP / X	Retene / 9-MP	MPI	R_c (%) (1)	R_c (%) (2)	R_c (%) (3)	R_c (%) (4)	R_o† (%)	n
Tirrawarra Sst															
Tirrawarra-16	9641'	6.07	1.07	1.25	0.93	1.74	0.40	<0.004	0.91	0.86	0.95	1.17	1.17	0.96	29
Tirrawarra-17	9742'9"	-	1.50	0.03	0.65	2.13	0.31	0.004	1.15	1.02	1.09	1.27	-	1.04	18
Patchawarra Fm															
Fly Lake-3	9526'6"	6.80	0.90	0.46	1.06	1.03	0.72	0.016	0.82	0.79	0.89	0.95	1.20	1.06	50
Gidgealpa-17	7164'5"	4.53	0.81	0.87	0.77	1.23	0.59	0.020	0.63	0.66	0.78	1.03	1.10	0.86	9
Kanowana-1	10017'1"	-	1.94	0.11	1.27	2.12	0.44	0.102	1.13	1.01	1.08	1.26	-	1.21	41
Kanowana-1	10029'3–5"	-	1.83	0.06	1.15	2.45	0.31	0.009	1.34	1.16	1.20	1.33	-	-	-
Moorari-1	9275'	5.98	1.06	0.48	0.70	1.31	0.42	0.022	0.67	0.69	0.80	1.06	1.17	0.92	35
Moorari-1	9276'	5.00	0.97	0.26	0.75	1.24	0.31	0.011	0.75	0.74	0.85	1.03	1.12	0.96	35
Tirrawarra-2	9724'3"	-	2.15	0.19	1.01	1.51	0.57	0.009	0.95	0.89	0.97	1.12	-	-	-
Tirrawarra-2	9727'6"	-	1.04	0.12	0.85	2.22	0.60	0.005	1.03	0.94	1.02	1.28	-	1.62	26
Daralingie-19	9464'6"	4.61	0.76	1.01	0.87	1.11	0.41	<0.004	0.66	0.68	0.80	0.98	1.10	1.03	42
Daralingie-19	9465'6"	-	1.18	1.50	0.80	1.36	0.40	0.009	0.82	0.79	0.89	1.07	-	0.90	13
*Poolowanna Fm**															
Sturt East-4	6110'	2.29	0.82	2.42	1.18	1.02	1.38	0.57	0.44	0.53	0.66	0.95	1.00	0.61	41
Sturt-4	6100'	2.36	1.09	9.42	1.26	0.80	3.73	0.20	0.36	0.47	0.62	0.84	1.00	0.69	40
Sturt-4	6170'	3.18	1.06	1.79	1.03	0.81	0.89	0.54	0.31	0.44	0.59	0.85	1.04	0.62	41
Sturt East-1	6040'	1.02	1.75	7.73	1.24	0.50	1.47	0.34	0.27	0.41	0.56	0.64	0.94	0.63	22
Tantanna-2	5901'	2.26	1.09	5.64	1.73	0.46	3.14	0.34	0.26	0.40	0.56	0.61	0.99	0.73	45

(1) R_c (%) = 0.7 MPI + 0.22 (for R_c < 1.7%: Boreham *et al.*, 1988); (2) R_c (%) = 0.6 MPI + 0.4 (for R_c < 1.35%: Radke and Welte, 1983); (3) R_c (%) = 0.99 $\log_{10}$MPR + 0.94 (R_c = 0.5 – 1.7%: Radke *et al.*, 1984); (4) R_c (%) = 0.046DNR + 0.89 (for R_c = 0.9 – 1.5%: Radke and Welte, 1983; Radke *et al.*, 1984); † R_o = mean of maximum vitrinite reflectance converted from the mean of random (measured) vitrinite reflectance (R_r) using Kilby's (1991) formula (*cf.* Experimental). Cooper Basin data from Table 2.3. Eromanga Basin data from M. N. L. Kagya, unpublished results; * Eromanga Basin data from Michaelsen *et al.* (1995d)

Table 2.10: Aromatic hydrocarbon database for oils

Well	I.D.	DNR	TNR	1,2,5-TMN / 1,3,6-TMN	1-MP / 9-MP	2-MP / 1-MP	1,7-DMP / X	Retene / 9-MP	MPI	R_c (%) (1)	R_c (%) (2)	R_c (%) (3)	R_c (%) (4)
Cooper Basin reservoirs													
Malgoona-1A**	Production	4.27	0.97	0.27	0.81	1.16	0.59	0.17†	1.09	0.98	1.05	1.01	1.09
Gidgealpa-41**	Production	4.00	1.09	0.45	0.79	1.23	0.40	0.84	1.19	1.05	1.11	1.03	1.07
Moorari-1*	Production	7.48	1.40	0.10	1.00	1.24	0.49	0.025	1.01	0.93	1.01	1.03	1.23
Tirrawarra-2*	Production	-	1.88	0.03	0.91	1.68	0.36	0.022	1.21	1.07	1.13	1.16	-
Tirrawarra-8*	Production	12.53	1.74	0.01	0.92	1.43	0.50	0.017	1.19	1.05	1.11	1.09	1.47
Woolkina-1*	Production	-	1.34	0.07	0.92	1.46	0.35	0.020	1.17	1.04	1.10	1.10	-
Fly Lake-8*	Production	8.74	1.20	0.05	0.78	1.08	0.60	0.017	0.88	0.84	0.93	0.97	1.29
Daralingie-18**	Production	5.53	-	-	0.73	1.44	0.36	0.19	1.26	1.10	1.16	1.10	1.14
Eromanga Basin reservoirs													
Sturt-4	DST-1	-	0.49	1.50	1.02	0.70	0.77	0.33	0.58	0.63	0.75	0.79	-
Sturt-7	DST-3	-	0.41	1.73	1.87	0.52	0.73	1.33	0.58	0.62	0.75	0.66	-
Sturt-8	DST-1	1.39	0.60	1.70	1.11	0.71	0.67	1.26	0.62	0.65	0.77	0.79	0.95
Sturt East-2	DST-1	3.80	0.44	1.63	1.31	0.49	0.73	0.87	0.51	0.58	0.71	0.63	1.06
Taloola-2	DST-1	-	0.58	1.01	1.15	0.57	0.67	0.54	0.54	0.60	0.72	0.70	-
Tantanna-1	DST-1	6.69	0.76	0.52	1.06	0.88	0.84	0.09	0.70	0.71	0.82	0.89	1.20

* = Family 1 oil ** = Family 2 oil † = determined using whole-oil injection (*cf.* Chapter 6)

(1) R_c (%) = 0.7 MPI + 0.22 (for R_c < 1.7%: Boreham *et al.*, 1988); (2) R_c (%) = 0.6 MPI + 0.4 (for R_c < 1.35%: Radke and Welte, 1983); (3) R_c (%) = 0.99 $\log_{10}$MPR + 0.94 (R_c = 0.5 – 1.7%: Radke *et al.*, 1984); (4) R_c (%) = 0.046DNR + 0.89 (for R_c = 0.9 – 1.5%: Radke and Welte, 1983; Radke *et al.*, 1984)

Table 2.11: Average of maturation parameters **1**, **2** and **3** for Cooper and Eromanga Basin source rocks

Well	Formation	Sample depth	Lithology	$\overline{R}_c$ (%)	$\overline{\overline{R}}_c$ (%)
Tirrawarra Sst					
Tirrawarra-16	Tirrawarra	9641'	Coal	0.99	
Tirrawarra-17	Tirrawarra	9742'9"	Shale	1.13	
Patchawarra Fm					
Fly Lake-3	Patchawarra	9526'6"	Coal	0.88	
Gidgealpa-17	Patchawarra	7164'5"	Shale	0.82	
Kanowana-1	Patchawarra	10017'1"	Coal	1.12	1.17
Kanowana-1	Patchawarra	10029'3-5"	Shale	1.23	
Moorari-1	Patchawarra	9275'	Coal	0.85	0.86
Moorari-1	Patchawarra	9276'	Shale	0.87	
Tirrawarra-2	Patchawarra	9724'3"	Coal	0.99	1.04
Tirrawarra-2	Patchawarra	9727'6"	Shale	1.08	
Daralingie-19	Patchawarra	9464'6"	Coal	0.82	0.87
Daralingie-19	Patchawarra	9465'6"	Shale	0.92	
Poolowanna Fm					
Sturt East-4	Poolowanna	6110'	Coal	0.71	
Sturt-4	Poolowanna	6100'	Coaly shale	0.64	
Sturt-4	Poolowanna	6170'	Shaley coal	0.63	
Sturt East-1	Poolowanna	6040'	Shale	0.54	
Tantanna-2	Poolowanna	5901'	Shale	0.52	
Poolowanna Fm average (n = 5)				0.61	

$\overline{\overline{R}}_c$ refers to the average of parameters **1**, **2** and **3** for both the coal *and* shale for isometamorphic samples (*i.e.* where appropriate the average of six R_c values)

Table 2.12: Average of maturation parameters **1**, **2** and **3** for Cooper and Eromanga Basin oils

Well	Formation	Sample type	$\overline{R}_c$ (%)	R_{est}
Cooper Basin reservoirs				
Malgoona-1A**	Merrimelia	Production	1.01	0.95
Gidgealpa-41**	Tirrawarra	Production	1.06	1.00
Moorari-1*	Tirrawarra	Production	0.99	1.05
Tirrawarra-2*	Tirrawarra	Production	1.12	1.20
Tirrawarra-8*	Tirrawarra	Production	1.08	1.15
Woolkina-1*	Tirrawarra	Production	1.08	1.10
Fly Lake-8*	Tirrawarra & basal Patchawarra	Production	0.91	1.10
Daralingie-18**	Patchawarra	Production	1.12	0.90
Eromanga Basin reservoirs				
Sturt-4	Poolowanna	DST-1	0.72	
Sturt-7	Poolowanna	DST-3	0.68	
Sturt-8	Poolowanna	DST-1	0.74	
Sturt East-2	Poolowanna	DST-1	0.64	
Taloola-2	Poolowanna	DST-1	0.67	
Tantanna-1	Poolowanna	DST-1	0.81	
Poolowanna oils (n = 6)		0.71		
Cooper Family 1 oils (n = 5)			1.04	≥ 1.05
Cooper Family 2 oils (n = 3)			1.06	≤ 1.00

* = Family 1 oil ** = Family 2 oils

Table 2.13: Alternative calculated maturities based on MPI, MPR, DNR and TNR for oils

Well	I.D.	MPI#	R_c (%) (5)	MPR#	R_c (%) (6)	DNR#	R_c (%) (7)	R_c (%) (8)	R_c (%) (9)	R_c (%) (10)	TNR#	R_c (%) (11)	R_c (%) (12)	R_c (%) (13)	R_c (%) (14)
Cooper Basin reservoirs															
Malgoona-1A**	Prod.	1.09	1.18	1.16	0.90	4.27	0.84	0.86	0.82	0.84	0.97	0.94	0.91	0.89	0.88
Gidgealpa-41**	Prod.	1.19	1.26	1.23	0.93	4.00	0.81	0.85	0.79	0.82	1.09	1.06	0.98	1.04	0.96
Moorari-1*	Prod.	1.01	1.13	1.24	0.94	7.48	1.16	1.03	1.14	1.01	1.40	1.36	1.11	1.34	1.09
Tirrawarra-2*	Prod.	1.21	1.27	1.68	1.10	-	-	-	-	-	1.88	1.83	1.25	1.81	1.24
Tirrawarra-8*	Prod.	1.19	1.26	1.43	1.02	12.53	1.66	1.20	1.64	1.20	1.74	1.69	1.21	1.67	1.21
Woolkina-1*	Prod.	1.17	1.24	1.46	1.03	-	-	-	-	-	1.34	1.30	1.08	1.28	1.13
Fly Lake-8*	Prod.	0.88	1.03	1.08	0.86	8.74	1.28	1.08	1.26	1.06	1.20	1.16	1.03	1.14	1.01
Daralingie-18**	Prod.	1.26	1.31	1.44	1.02	5.53	0.96	0.93	0.94	0.91	-	-	-	-	-
Eromanga Basin reservoirs															
Sturt-4	DST-1	0.58	0.82	0.70	0.62	-	-	-	-	-	0.49	0.47	0.47	0.45	0.46
Sturt-7	DST-3	0.58	0.85	0.52	0.46	-	-	-	-	-	0.41	0.39	0.33	0.41	0.31
Sturt-8	DST-1	0.62	0.85	0.71	0.63	1.39	0.55	0.61	0.53	0.58	0.60	0.58	0.64	0.56	0.61
Sturt East-2	DST-1	0.51	0.77	0.49	0.43	3.80	0.79	0.83	0.77	0.81	0.44	0.42	0.26	0.40	0.24
Taloola-2	DST-1	0.54	0.79	0.57	0.51	-	-	-	-	-	0.58	0.56	0.62	0.54	0.59
Tantanna-1	DST-1	0.70	0.91	0.88	0.75	6.69	1.08	0.99	1.06	0.97	0.76	0.73	0.79	0.71	0.77

* = Family 1 oils; ** = Family 2 oils; # From Table 2.10; See Figs 2.8, 2.9 and 2.11 for derivation of parameters **5 – 10**. Parameters **11 – 14** are derived by substituting DNR = 9.80TNR – 4.22 into **7 – 10**; (**5**) R_c (%) = 0.72 MPI + 0.4; ; (**6**) R_c (%) = $1.26\log_{10}$MPR + 0.82; (**10**) R_c (%) = $1.25\log_{10}$MPR + 0.82; (**11**) R_c (%) = $1.27\log_{10}$MPR + 0.81; (**7**) R_c (%) = 0.10MPR + 0.41; (**8**) R_c (%) = $0.55\text{MPR}^{0.31}$; (**9**) R_c (%) = 0.10MPR + 0.39; (**10**) R_c (%) = $0.52\text{MPR}^{0.33}$; (**11**) R_c (%) = 9.80TNR – 0.01; (**12**) R_c (%) = $5.5(9.80\text{TNR} - 4.22)^{0.31}$; (**13**) R_c (%) = 0.98TNR – 0.03; (**14**) R_c (%) = $5.2(9.80\text{TNR} - 4.22)^{0.33}$

Table 2.14: Summary of aromatic hydrocarbon parameters: arithmetic means and ranges

	1,2,5-TMN / 1,3,6-TMN	1-MP / 9-MP	2-MP / 1-MP	1,7-DMP / X	retene / 9-MP
Tirrawarra Sst					
Shaley coal (n = 1)	1.25	0.93	1.74	0.40	<0.004
Shales (n = 1)	0.03	0.65	2.13	0.31	0.004
Patchawarra Fm					
Coals (n = 5)	0.44 0.11–1.01	0.95 0.70–1.27	1.56 1.03–2.22	0.52 0.41–0.72	≈0.030 <0.004–0.102
Shales (n = 5)	0.58 0.06–1.50	0.90 0.75–1.15	1.56 1.23–2.45	0.44 0.31–0.59	0.012 0.004–0.020
Poolowanna Fm					
Coal (n = 1)	2.42	1.18	1.02	1.38	0.57
Shales* (n = 4)	6.15 1.79–9.42	1.32 1.03–1.73	0.64 0.46–0.81	2.31 0.89–3.73	0.36 0.20–0.54
Poolowanna oils (n = 6)	1.62 0.52–1.73	1.25 1.02–1.87	0.65 0.49–0.88	0.74 0.67–0.84	0.74 0.09–1.33
Cooper Family 1 oils (n = 5)	0.05 0.01–0.10	0.91 0.78–1.00	1.38 1.08–1.68	0.46 0.35–0.60	0.020 0.017–0.025
Cooper Family 2 oils (n = 3)	0.37 0.39–0.45	0.78 0.73–0.81	1.28 1.16–1.44	0.45 0.36–0.59	0.40 0.17–0.84

Ranges are indicated in smaller font. * includes coaly shale and shaley coal

Table 2.15: Saturated hydrocarbon (biomarker) database for rock extracts

		DRIMANES		HOPANES								STERANES			
Well	Depth	$\frac{C_{15}}{C_{16}}$	$\frac{R}{N}$	$\frac{T_s}{T_m}$	$\frac{C_{29}T_s}{C_{29}\alpha\beta}$	$\frac{C_{30}T_s}{C_{30}\alpha\beta}$	$\frac{C^*_{30}}{C_{30}\alpha\beta}$	$\frac{C_{29}\alpha\beta}{C_{30}\alpha\beta}$	$\frac{C_{30}}{\beta\alpha}$	$\frac{C_{31}}{22S/22R}$	$\frac{BNH}{C_{30}\alpha\beta}$	$\frac{C_{29}\ \alpha\alpha\alpha}{20S/20R}$	$\frac{C_{29}}{\alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)}$	$\frac{C_{29}}{\beta\alpha/(\alpha\alpha\alpha+\alpha\beta\beta)}$	$\frac{Hop}{Ster}$
Cooper Basin															
Tirrawarra-16	9641'	0.70	0.97	4.01	2.36	-	6.93	0.65	large	large	-	0.95	0.52	0.30	0.13
Tirrawarra-17	9742'9"	0.76	2.18	0.80	2.29	-	11.60	0.85	large	large	-	0.87	0.53	0.59	0.09
Fly Lake-3	9526'6"	1.59	0.69	0.87	0.60	0.12	0.59	0.46	3.41	1.50	-	0.98	0.47	0.39	0.91
Gidgealpa-17	7164'5"	0.29	0.25	0.08	0.07	0.09	0.10	0.65	8.13	1.41	-	0.72	0.44	0.74	6.09
Kanowana-1	10017'1"	-	-	-	-	-	-	not determined		-	-	-	-	-	
Kanowana-1	10029'3–5" 0.23	1.69	0.69	0.31	0.09		0.26	0.62	5.09	1.32	-	0.41	0.47	0.67	2.54
Moorari-1	9275'	1.55	0.59	2.76	1.05	0.05	0.72	0.52	5.32	0.99	-	0.86	0.49	0.75	2.53
Moorari-1	9276'	0.24	0.37	1.09	0.53	0.06	0.55	0.50	4.00	1.15	-	0.68	0.43	0.47	2.31
Tirrawarra-2	9724'3"	0.68	0.76	0.61	0.16	0.03	0.30	0.94	4.87	1.40	-	0.75	0.49	0.54	2.07
Tirrawarra-2	9727'6"	-	-	4.32	1.13	-	4.53	0.71	large	large	-	0.90	0.53	0.30	0.26
Daralingie-19	9464'6"	1.28	0.43	0.82	0.46	0.04	0.22	0.38	8.21	1.13	-	0.79	0.52	0.83	3.10
Daralingie-19	9465'6"	0.43	0.55	0.57	0.57	0.51	0.45	0.48	5.34	1.21	-	0.76	0.53	1.34	2.18
Eromanga Basin															
Sturt East-4	6110'	0.32	2.23	0.01	-	0.13	0.04	0.80	2.00	1.44	0.03#	0.75	0.28	0.29	5.23
Sturt-4	6100'	0.11	0.33	0.01	-	0.03	0.02	1.24	2.68	1.82	0.01#	0.71	0.27	0.29	7.74
Sturt-4	6170'	-	-	0.04	-	0.12	0.07	0.85	3.02	1.28	0.05#	1.00	0.31	0.51	3.41
Sturt East-1	6040'	0.13	0.34	0.10	0.10	0.07	0.05	0.87	3.29	1.66	-	0.85	0.27	0.53	13.17
Tantanna-2	5901'	0.14	0.36	0.07	0.11	0.03	0.06	0.70	4.00	1.54	0.03#	0.80	0.28	0.59	12.09

See Abbreviations (p. xxiii) for key to biomarker ratios; # Bisnorhopane tentatively identified

Table 2.16: Saturated hydrocarbon (biomarker) database for oils

		DRIMANES		HOPANES								STERANES			
									C_{30}	C_{31}		C_{29} ααα	C_{29}	C_{29}	
Well	I.D.	$\frac{C_{15}}{C_{16}}$	$\frac{R}{N}$	$\frac{T_s}{T_m}$	$\frac{C_{29}T_s}{C_{29}\alpha\beta}$	$\frac{C_{30}T_s}{C_{30}\alpha\beta}$	$\frac{C^*_{30}}{C_{30}\alpha\beta}$	$\frac{C_{29}\alpha\beta}{C_{30}\alpha\beta}$	$\frac{\alpha\beta}{\beta\alpha}$	$\frac{22S}{22R}$	$\frac{BNH}{C_{30}\alpha\beta}$	$\frac{20S}{20R}$	$\frac{\alpha\beta\beta}{\alpha\alpha\alpha+\alpha\beta\beta}$	$\frac{\beta\alpha}{\alpha\alpha\alpha+\alpha\beta\beta}$	$\frac{Hop}{Ster}$
Cooper Basin reservoirs															
Malgoona-1A**	Production	1.02	0.44	1.03	0.43	0.10	0.18	0.42	5.7	1.13	-	0.82	0.53	1.01	2.00
Gidgealpa-41**	Production	0.77	0.50	0.96	0.28	0.03	0.21	0.54	9.64	1.40	-	1.18	0.60	1.49	1.18
Moorari-1*	Production	0.99	0.73	2.79	1.13	-	1.44	0.67	large	0.99	-	1.24	0.61	1.96	0.12
Tirrawarra-2*	Production	1.80	1.02	6.51	4.33	-	6.51	0.67	large	large	-	1.23	0.62	2.80	0.01
Tirrawarra-8*	Production	2.36	1.45	3.52	2.69	-	4.65	0.82	large	large	-	1.03	0.59	1.98	0.04
Woolkina-1*	Production	1.57	1.03	3.22	1.51	-	2.85	0.99	large	large	-	1.20	0.61	1.28	0.06
Fly Lake-8*	Production	0.83	0.72	4.86	2.08	0.11	2.58	0.62	large	large	-	1.05	0.58	1.11	0.07
Daralingie-18**	Production	0.53	0.58	0.47	0.39	0.65	0.08	0.38	7.2	1.10	-	0.66	0.44	0.52	6.11
Eromanga Basin reservoir															
Sturt-4	DST-1	0.21	0.69	0.24	0.07	0.06	0.10	0.58	6.04	1.45	0.03#	0.89	0.46	0.89	5.42
Sturt-7	DST-3	0.23	0.68	0.24	0.05	0.06	0.10	0.61	6.02	1.53	0.03#	0.96	0.48	1.02	6.05
Sturt-8	DST-1	0.18	0.52	0.20	0.08	0.08	0.10	0.51	5.03	1.26	0.02#	0.93	0.49	0.75	7.33
Sturt East-2	DST-1	0.38	0.56	0.21	0.12	0.06	0.10	0.61	5.13	1.47	0.02#	0.95	0.46	0.97	5.72
Taloola-2	DST-1	0.18	0.56	0.42	0.12	0.07	0.12	0.52	7.17	1.31	0.02#	0.92	0.51	1.36	5.99
Tantanna-1	DST-1	0.30	0.76	0.46	0.10	0.07	0.15	0.59	7.13	1.34	0.06#	1.04	0.52	1.34	5.69

* = Family 1 oil ** = Family 2 oil # Bisnorhopane tentatively identified See Abbreviations (p. xxiii) for key to biomarker ratios

Note: $\frac{C^*_{30}}{C_{30}\alpha\beta}$ is a biomarker ratio and is not referable to Family 1 oil

Table 2.17: Summary of saturated hydrocarbon biomarker parameters: arithmetic means and ranges

	DRIMANES		HOPANES				STERANES			
							C_{29}	C_{29}	C_{29}	
	$\frac{C_{15}}{C_{16}}$	$\frac{R}{N}$	$\frac{T_s}{T_m}$	$\frac{C_{29}T_s}{C_{29}\alpha\beta}$	$\frac{C^*_{30}}{C_{30}\alpha\beta}$	$\frac{C_{29}\alpha\beta}{C_{30}\alpha\beta}$	$\frac{20S}{20R}$	$\frac{\alpha\alpha\alpha}{\alpha\alpha\alpha+\alpha\beta\beta}$	$\frac{\beta\alpha}{\alpha\alpha\alpha+\alpha\beta\beta}$	$\frac{Hop}{Ster}$
Tirrawarra Sst										
Shaley coal (n = 1)	0.70	0.97	4.01	2.36	6.93	0.65	0.95	0.52	0.30	0.13
Shale (n = 1)	0.76	2.18	0.80	2.29	11.60	0.85	0.87	0.53	0.59	0.09
Patchawarra Fm										
Coals (n = 5)	1.47 1.28–1.59	0.57 0.43–0.69	2.19 0.82–4.32	0.81 0.46–1.13	1.52 0.22–4.53	0.52 0.38–0.71	0.88 0.79–0.98	0.50 0.47–0.53	0.57 0.30–0.83	1.70 0.26–3.10
Shales (n = 5)	0.37 0.23–0.68	0.72 0.25–1.69	0.61 0.08–1.09	0.33 0.07–0.57	0.33 0.10–0.55	0.64 0.48–0.94	0.66 0.41–0.76	0.47 0.43–0.53	0.75 0.47–1.34	3.04 2.07–6.09
Poolowanna Fm										
Coal (n = 1)	0.32	2.23	0.01	<0.05	0.04	0.80	0.75	0.28	0.29	5.23
Shales# (n = 4)	0.13 0.11–0.14	0.34 0.33–0.36	0.06 0.01–0.10	≈0.05 ≤0.11	0.05 0.02–0.07	0.92 0.70–1.24	0.84 0.71–1.00	0.28 0.27–0.31	0.48 0.29–0.59	9.10 3.41–13.17
Poolowanna oils (n = 6)	0.25 0.18–0.38	0.63 0.52–0.76	0.30 0.20–0.46	0.09 0.05–0.12	0.12 0.10–0.15	0.57 0.51–0.61	0.95 0.89–1.04	0.49 0.46–0.52	1.06 0.75–1.36	6.03 5.42–7.33
Cooper Family 1 oils (n = 5)	1.51 0.83–2.36	0.99 0.72–1.45	4.18 2.79–6.51	2.35 1.13–2.69	3.61 1.44–6.51	0.75 0.62–0.99	1.15 1.03–1.24	0.52 0.44–0.60	1.83 1.11–2.80	0.06 0.01–0.12
Cooper Family 2 oils (n = 3)	0.77 0.53–1.02	0.51 0.44–0.58	0.82 0.47–1.03	0.37 0.28–0.43	0.16 0.08–0.21	0.45 0.38–0.54	0.89 0.66–1.18	0.60 0.58–0.62	1.01 0.52–1.49	3.10 1.18–6.11

Ranges are indicated in smaller font. # includes coaly shale and shaley coal

Table 3.1: Sample details (core samples unless otherwise indicated)

Well	Depth	Stratigraphy	Lithology
Pandieburra-1	5142'6"	Birkhead Fm	Siltstone/Shale
Pandieburra-1	5752'4"	Birkhead Fm	Siltstone
Pandieburra-1	6157'	Poolowanna Fm	Coal (thin layer in sandstone)
Pandieburra-1	6159'5"	Poolowanna Fm	Coal (thin layer in sandstone)
Pandieburra-1	7133"	Dullingari Gp	Siltstone
Poonarunna-1*	800–890'	Winton Fm	Coal
Poonarunna-1	4986'	Namur Sst	Coaly shale
Poonarunna-1	4994'9"	Namur Sst	Siltstone
Poonarunna-1	5001'	Namur Sst	Shale/Siltstone
Poonarunna-1	5018'3"	Namur Sst	Siltstone
Poonarunna-1	5019'0–2'	Namur Sst	Siltstone
Poonarunna-1	5194'2"	Birkhead Fm	Coaly shale
Poonarunna-1	5209'3"	Birkhead Fm	Siltstone
Poonarunna-1	5253'6–10"	Birkhead Fm	Siltstone
Poonarunna-1	5256'	Birkhead Fm	Siltstone
Poonarunna-1	5318'6–9"	Birkhead Fm	Siltstone
Poonarunna-1	5324'1–3"	Birkhead Fm	Shale/Siltstone
Poonarunna-1	5331'6–8"	Birkhead Fm	Coaly shale
Poonarunna-1	5332'7–9"	Birkhead Fm	Coal shale
Poonarunna-1	5338'2"	Birkhead Fm	Shaley coal
Putamurdie-1	4778'9"	Birkhead Fm	Siltstone/Shale
Putamurdie-1	4785'1"	Birkhead Fm	Siltstone
Putamurdie-1	4785'4"	Birkhead Fm	Shale

* cuttings sample

Table 3.2: Vitrinite reflectance data and petrographic descriptions

Sample	Lithology	R_O (%)	n	Petrographic description
Pandieburra-1				
5142'6"	Siltstone/Shale	0.54	26	Vitrinite ≥ liptinite > inertinite. Liptinites are almost entirely sporinite with minor liptodetrinite. Traces of resinite and cutinite. Rare ?lamalginite.
5752'4"	Siltstone	0.60	22	Vitrinite ≈ liptinite > inertinite (inertinite rare). Sporinite, liptodetrinite and resinite are common.
6157' Coal		0.67	22	Entirely telocollinite.
6159'5"	Coal	0.66	24	As above, but also some eu-ulminite.
7133' Siltstone		n.d.	-	Organically barren. Pyritic.
Poonarunna-1				
800'–890' *	Coal	0.43	45	Almost entirely telovitrinite (telocollinite, eu-ulminite, texto-ulminite). Minor resinite.
4986' Coaly shale		0.38 0.40 (repeat)	41 41	Vitrinite > liptinite > inertinite. Abundant cutinite. Sporinite, liptodetrinite and bituminite common. Minor resinite/fluorinite.
4994'9"	Siltstone	0.37	15	Vitrinite > liptinite > inertinite. Sporinite and liptodetrinite common. Minor cutinite and resinite.
5001' Shale/Siltstone		n.d.	-	Liptinite > vitrinite. Sporinite and liptodetrinite very common. Minor cutinite, and rare *Botryococcus*-type telalginite and resinite.
5018'3"	Siltstone	0.42	13	Organically lean. Vitrinite ≈ liptinite ≈ inertinite. Sporinite is the most abundant liptinite. Rare cutinite, resinite and *Botryococcus*-type telalginite. **Possible R_O suppression.**
5019'0–2"	Siltstone	0.50	31	Organically-lean. Vitrinite > liptinite > inertinite. Minor sporinite and liptodetrinite.
5194'2"	Coaly shale	0.48	37	Vitrinite > liptinite. Liptinites are almost entirely sporinite and liptodetrinite. Rare resinite and bituminite. Cutinite is very rare. Vitrinites are well-gelified (telocollinite) or degraded and associated with bituminite.
5209'3"	Siltstone	0.42	21	Exceptionally liptinite-rich sample. Cutinite > sporinite ≈ resinite > telalginite (*Botryococcus*-type). Some vitrinites are degraded and associated with bituminite. Other vitrinites are well gelified and occur as large phytoclasts up to 4 mm in maximum dimension.
5253'6–10"	Siltstone	0.47	22	Vitrinite ≥ liptinite > inertinite. Sporinite is the most abundant liptinite. *Botryococcus*-type telalginite present.
5256' Siltstone		0.51	37	Vitrinite ≥ liptinite > inertinite (inertinite rare/absent). Sporinite and cutinite very common. Minor resinite, fluorinite and *Botryococcus*. Lamalginite (phytoplankton) also present.
5318'6–9"	Siltstone	0.33	5	Liptinite >> vitrinite > inertinite. Sporinite and sporinite-derived liptodetrinite are the dominant liptinites. Minor cutinite and rare *Botryococcus*-type telalginite. **R_O suppression.**
5324'1–3"	Shale/siltstone	0.40	8	Vitrinite ≈ sporinite > inertinite (inertinite rare/absent). Very minor resinite. **Possible R_O suppression.**
5331'6–8"	Coaly shale	0.60	37	Vitrinite > liptinite > inertinite. Most vitrinites are degraded and associated with bituminite. Other vitrinites have absorbed syngenetic resins causing vitrinite supression of some phytoclasts. Cutinite > sporinite ≈ resinite.
5332'7–9"	Coaly shale	0.58	36	Vitrinite > liptinite >> inertinite (inertinite rare/absent). Cutinite sporinite and resinite common.
5338'2"	Shaley coal	0.43	34	Well-layered coal containing predominantly vitrinite and cutinite. Banded vitrinites are highly gelified (telocollinite predominates). Telocollinite > cutinite > fluorinite/resinite > bituminite/liptodetrinite.

Table 3.2 cont.: Vitrinite reflectance data and petrographic descriptions

Putamurdie-1				
4778'9"	Siltstone/Shale	0.58	33	Vitrinite ≥ liptinite > inertinite. Vitrinites are well gelified and include telocollinite. Cutinite abundant, resinite common. Traces of *Botryococcus*-related telalginite.
4785'1"	Siltstone	0.50	18	Organically lean. Vitrinite ≈ liptinite (inertinite almost entirely absent). Sporinite is the most common maceral, very minor resinite. Rare cutinite and ?*Botryococcus*-type telalginite.
4785'4"	Shale	0.46	36	Organically lean. However, some horizons are liptinite rich where resinite > sporinite > cutinite. Minor *Botryococcus*-type telalginite. Vitrinite ≈ liptinite >> inertinite (inertinite almost absent).

R_O = mean of maximum vitrinite reflectance; n = number of determinations used to calculate R_O.
* = cuttings sample; all other samples are core.

Table 3.3: Rock-Eval pyrolysis data: Eromanga and Pedirka Basins

Well	Depth	Sample type	T_{max} (° C)	S_1	S_2	S_3	S_1+S_2	S_2/S_3	PI	PC	TOC	HI	OI	Reference
Cadna-owie Formation														
Mulapula-1	3044'	SWC-54	430	0.13	0.73	0.27	0.86	2.70	0.15	0.07	0.26	280	103	McKirdy *et al.* (1987)
Namur Sandstone														
Mulapula-1	3802'	SWC-33	430	0.76	7.81	0.65	8.57	12.01	0.09	0.71	2.50	312	26	McKirdy *et al.* (1987)
Poonarunna-1	4986'	Core	442	1.56	26.41	0.49	27.97	53.89	0.06	2.33	6.04	437	8	Michaelsen & McKirdy (1997)
Poonarunna-1	4994'9"	Core	437	0.90	11.38	0.27	12.28	42.14	0.07	1.02	2.86	397	9	Michaelsen & McKirdy (1997)
Poonarunna-1	4999'	Core	433	0.01	0.08	0.07	0.09	1.14	0.12	0.00	0.36	22	19	McKirdy & Watson (1986)
Poonarunna-1	5001'	Core	441	0.27	7.76	0.32	8.03	24.25	0.03	0.66	1.44	538	22	Michaelsen & McKirdy (1997)
Poonarunna-1	5002'3"	Core	438	0.56	12.32	0.17	12.88	72.47	0.04	1.07	2.25	548	8	McKirdy & Watson (1986)
Poonarunna-1	5018'3"	Core	440	0.06	1.97	0.29	2.03	6.79	0.03	0.16	0.77	255	37	Michaelsen & McKirdy (1997)
Poonarunna-1	5019'0–2'	Core	440	0.11	2.59	0.14	2.70	18.50	0.04	0.22	1.03	251	13	Michaelsen & McKirdy (1997)
Birkhead Formation														
Mulapula-1	3968'	SWC-26	434	0.32	2.42	2.68	2.74	0.90	0.12	0.22	0.93	260	288	McKirdy *et al.* (1987)
Mulapula-1	3993'	SWC-23	435	0.30	4.88	3.70	5.18	1.31	0.06	0.43	1.62	301	228	McKirdy *et al.* (1987)
Mulapula-1	3999'9"	Core-1	434	0.26	5.87	1.09	6.13	5.38	0.04	0.51	1.25	470	87	McKirdy *et al.* (1987)
Mulapula-1	4009'6"	Core-1	432	0.25	3.48	2.40	3.73	1.45	0.07	0.31	1.75	199	137	McKirdy *et al.* (1987)
Mulapula-1	4013'1"	Core-1	432	0.14	2.95	1.18	3.09	2.50	0.05	0.25	1.28	230	92	McKirdy *et al.* (1987)
Mulapula-1	4017'	Core-1	433	0.14	2.67	0.82	2.81	3.25	0.05	0.23	1.34	199	61	McKirdy *et al.* (1987)
Mulapula-1	4022'11"	Core-1	432	0.23	3.57	2.22	3.80	1.60	0.06	0.31	1.54	357	222	McKirdy *et al.* (1987)
Mulapula-1	4023'7"	Core-1	429	0.23	1.96	0.48	2.19	4.08	0.11	0.18	1.05	187	46	McKirdy *et al.* (1987)
Mulapula-1	4124'	SWC-17	432	0.41	2.44	4.74	2.85	0.51	0.14	0.23	0.89	274	533	McKirdy *et al.* (1987)
Mulapula-1	4023'9"	Core-1	422	7.24	78.06	2.44	85.30	31.99	0.08	7.10	21.10	370	12	McKirdy *et al.* (1987)
Pandieburra-1	5142'6"	Core	438	0.06	1.60	0.52	1.66	3.07	0.04	0.13	1.01	158	51	Michaelsen & McKirdy (1997)
Pandieburra-1	5752'4"	Core	437	0.04	1.39	0.77	1.43	1.80	0.03	0.11	0.84	165	91	Michaelsen & McKirdy (1997)
Poonarunna-1	5194'2"	Core	437	1.49	24.42	0.37	25.91	66.00	0.06	2.15	4.35	561	9	McKirdy & Watson (1986)
Poonarunna-1	5194'2"	Core	441	4.20	38.95	1.08	43.15	36.06	0.10	3.59	9.34	417	11	Michaelsen & McKirdy (1997)
Poonarunna-1	5209'3"	Core	442	1.37	19.70	0.47	21.07	41.91	0.07	1.75	3.56	553	13	Michaelsen & McKirdy (1997)
Poonarunna-1	5253'6–10"	Core	442	0.34	4.78	0.34	5.12	14.05	0.07	0.42	1.72	277	19	Michaelsen & McKirdy (1997)
Poonarunna-1	5256'	Core	440	0.29	4.65	0.64	4.94	7.26	0.06	0.41	1.61	288	39	Michaelsen & McKirdy (1997)
Poonarunna-1	5318'6–9"	Core	443	1.05	9.98	0.52	11.03	19.19	0.10	0.91	1.96	509	26	Michaelsen & McKirdy (1997)
Poonarunna-1	5324'1–3"	Core	438	0.89	7.42	0.42	8.31	17.66	0.11	0.69	1.96	378	21	Michaelsen & McKirdy (1997)
Poonarunna-1	5326'2"	Core	435	0.94	8.25	0.69	9.19	11.95	0.10	0.76	2.05	402	34	McKirdy & Watson (1986)
Poonarunna-1	5331'6–8"	Core	444	4.25	36.64	0.84	40.89	43.61	0.10	3.40	9.19	398	9	Michaelsen & McKirdy (1997)
Poonarunna-1	5332'7–9"	Core	444	5.22	32.66	0.45	37.88	72.57	0.14	3.15	8.88	367	5	Michaelsen & McKirdy (1997)

Table 3.3 cont. : Rock-Eval pyrolysis data: Eromanga and Pedirka Basins

Well	Depth	Sample type	T_{max} (° C)	S_1	S_2	S_3	S_1+S_2	S_2/S_3	PI	PC	TOC	HI	OI	Reference
Poonarunna-1	5332'7–9"	Core	444	5.22	32.66	0.45	37.88	72.57	0.14	3.15	8.88	367	5	Michaelsen & McKirdy (1997)
Poonarunna-1	5335'4"	Core	437	7.37	79.51	0.97	86.88	81.96	0.08	7.24	15.20	523	6	McKirdy & Watson (1986)
Poonarunna-1	5338'2"	Core	443	11.33	86.31	1.42	97.64	60.78	0.12	8.13	19.70	438	7	Michaelsen & McKirdy (1997)
Putamurdie-1	4778'9"	Core	440	1.06	23.39	0.49	24.45	47.73	0.04	2.03	5.98	391	8	Michaelsen & McKirdy (1997)
Putamurdie-1	4785'1"	Core	438	0.14	3.30	0.34	3.44	9.70	0.04	0.28	1.11	297	30	Michaelsen & McKirdy (1997)
Putamurdie-1	4785'4"	Core	441	0.19	6.16	0.55	6.35	11.20	0.03	0.52	1.74	354	31	Michaelsen & McKirdy (1997)
Birkhead Formation equivalent														
AFMECO Cur-3	251.6 m	Core	421	11.88	123.20	13.20	135.08	9.33	0.09	11.21	34.30	359	38	Staples *et al.* (1995a)
AFMECO Cur-3	251.9 m	Core	423	16.79	151.50	13.86	168.29	10.93	0.10	13.97	39.00	388	36	Staples *et al.* (1995a)
AFMECO Cur-3	259.5 m	Core	419	23.65	255.76	17.50	279.41	14.61	0.08	23.19	47.20	542	37	Staples *et al.* (1995a)
AFMECO Cur-5	209.2 m	Core	421	3.51	45.90	24.97	49.41	1.84	0.07	4.10	52.90	87	47	Staples *et al.* (1995a)
AFMECO Cur-5	210.1 m	Core	424	18.27	157.45	19.72	175.72	7.98	0.10	14.58	50.50	312	39	Staples *et al.* (1995a)
AFMECO Cur-5	249.4 m	Core	424	32.52	216.07	27.19	248.59	7.95	0.13	20.63	58.70	368	46	Staples *et al.* (1995a)
Hutton Sandstone														
Mulapula-1	4461'	SWC-8	431	0.74	6.27	0.20	7.01	31.35	0.11	0.58	2.30	273	9	McKirdy *et al.* (1987)
Mulapula-1	4471'	SWC-7	431	0.58	3.48	0.27	4.06	12.88	0.14	0.33	1.58	220	17	McKirdy *et al.* (1987)
Purni Formation (Pedirka Basin)														
Dalmatia-1	1940–1990'	Ctgs	423	5.32	150.09	11.96	155.41	12.55	0.03	12.90	49.20	305	24	Staples *et al.* (1995a)
Dalmatia-1	2010–2050'	Ctgs	425	4.11	118.72	13.03	122.83	9.11	0.03	10.19	44.30	268	29	Staples *et al.* (1995a)
Dalmatia-1	2080–2120'	Ctgs	426	1.85	91.11	12.87	92.96	7.08	0.02	7.72	37.70	242	34	Staples *et al.* (1995a)
Dalmatia-1	2340–2370'	Ctgs	425	3.90	122.36	8.45	126.26	14.48	0.03	10.48	38.50	318	22	Staples *et al.* (1995a)
Dalmatia-1	2600–2660'	Ctgs	422	4.23	125.09	11.25	129.32	11.12	0.03	10.73	39.40	317	29	Staples *et al.* (1995a)
Mt Hammersley-1	2020–2070'	Ctgs	424	2.12	80.18	17.96	82.30	4.46	0.03	6.83	63.10	127	28	Staples *et al.* (1995a)
Mt Hammersley-1	2160–2210'	Ctgs	425	1.58	71.21	17.66	72.79	4.03	0.02	6.04	62.80	113	28	Staples *et al.* (1995a)
Mt Hammersley-1	2310–2360'	Ctgs	425	2.77	96.20	15.74	98.97	6.11	0.03	8.21	58.70	164	27	Staples *et al.* (1995a)
Mt Hammersley-1	2500–2540'	Ctgs	425	6.37	172.94	9.70	179.31	17.83	0.04	14.88	59.10	293	16	Staples *et al.* (1995a)
Mt Hammersley-1	2750–2800'	Ctgs	427	6.34	200.38	8.17	206.72	24.53	0.03	17.16	55.80	359	15	Staples *et al.* (1995a)
Mt Hammersley-1	2860–2910'	Ctgs	427	5.38	139.13	9.13	144.51	15.24	0.04	11.99	52.80	264	17	Staples *et al.* (1995a)
Mt Hammersley-1	4000–4060'	Ctgs	nd	0.03	0.16	0.14	0.19	1.14	0.16	0.02	0.41	39	34	Staples *et al.* (1995a)
Mt Hammersley-1	4620–4670'	Ctgs	nd	0.07	0.12	0.12	0.19	1.00	0.37	0.02	0.35	34	34	Staples *et al.* (1995a)

T_{max} = temperature of maximum generation of S_2 hydrocarbons; S_1 = mg hydrocarbons/g rock; S_2 = mg hydrocarbons/g rock; S_3 = mg CO_2/g rock; PI = $S_1/(S_1+S_2)$; PC = pyrolysable carbon; TOC = total organic carbon; HI = S_2/g TOC; OI = S_3/g TOC

Table 3.4: Extract data for selected rock samples

Well	Depth	TOC (%)	EOM (ppm)	EOM (mg/g TOC)	EOM bulk composition Sat (%)	Aro (%)	Pol (%)
Namur Sandstone							
Poonarunna-1	5001'	1.44	1089	76	50.0	24.2	25.8
Poonarunna-1	5018'3"	0.77	621	81	37.8	23.7	21.6
Birkhead Formation							
Poonarunna-1	5209'3"	3.56	3125	88	62.1	21.4	16.3
Poonarunna-1	5253'6–10"	1.72	1641	95	41.4	34.0	19.5
Putamurdie-1	4778'9"	5.98	3928	66	33.2	48.0	18.8

TOC = Total Organic Carbon ; EOM = Extractable Organic Matter ; Sat = Saturated hydrocarbons; Aro = Aromatic hydrocarbons ; Pol = Polar compounds = Resins + Asphaltenes

Table 3.5: Aromatic hydrocarbon database for selected rock extracts

Well	Depth	DNR	TNR	1,2,5-TMN / 1,3,6-TMN	1-MP / 9-MP	2-MP / 1-MP	1,7-DMP / X	Retene / 9-MP	MPI	MPDF	Calculated vitrinite reflectance (% R_c) (1)	(2)	(3)	(4)	(5)	(6)	R_o (%) (7)	n
Namur Sandstone																		
Poonarunna-1	5001'	2.82	-	-	3.96	0.21	4.45	10.03	0.22	0.22	0.37	0.53	2.17	0.27	0.33	1.02	n.d.	-
Poonarunna-1	5018'3"-	-	-	3.60	0.24	4.86	6.69	0.26	0.22	0.40	0.55	2.14	0.33	0.33	-	-	0.42	13
Birkhead Formation																		
Poonarunna-1	5209'3"2.22	-	-	5.04	0.17	3.96	17.34	0.21	0.20	0.37	0.53	2.17	0.18	0.28	0.99	-	0.42	21
Poonarunna-1	5253'6–10"	-	-	-	5.16	0.16	5.60	11.28	0.18	0.18	0.35	0.51	2.19	0.15	0.24	-	0.47	22
Putamurdie-1	4778'9"1.88	-	-	7.50	0.15	5.11	25.00	0.19	0.18	0.35	0.51	2.19	0.12	0.24	0.98	-	0.58	33

$$DNR = \frac{2,6\text{-DMN} + 2,7\text{-DMN}}{1,5\text{-DMN}} \quad ; \quad TNR = \frac{2,3,6\text{-TMN}}{1,3,5\text{-TMN} + 1,4,6\text{-TMN}} \quad ; \quad MPR = \frac{2\text{-MP}}{1\text{-MP}} \quad ; \quad MPI = \frac{1.5\,[2\text{-MP} + 3\text{-MP}]}{P + 1\text{-MP} + 9\text{-MP}} \quad ; \quad MPDF = \frac{2\text{-MP} + 3\text{-MP}}{2\text{-MP} + 3\text{-MP} + 1\text{-MP} + 9\text{-MP}}$$

where 1,5-DMN = 1,5-dimethylnaphthalene ; 2,6-DMN = 2,6-dimethylnaphthalene ; 2,7-DMN = 2,7-dimethylnaphthalene

1,3,5-TMN = 1,3,5-trimethylnaphthalene ; 1,4,6-TMN = 1,4,6-trimethylnaphthalene ; 2,3,6-TMN = 2,3,6-trimethylnaphthalene

P = phenanthrene ; 1-MP = 1-methyphenanthrene ; 2-MP = 2-methylphenanthrene ; 3-MP = 3-methylphenanthrene

9-MP = 9-methylphenanthrene ; 1,7-DMP = 1,7-dimethylphenanthrene ; X = 1,3 + 3,9 + 2,10 + 3,10-dimethylphenanthrene

(1) R_c (%) = 0.7MPI + 0.22 (for R_c < 1.7%: Boreham *et al.*, 1988)**(2)** R_c (%) = 0.6MPI + 0.4 (for R_c < 1.35%: Radke and Welte, 1983)

(3) R_c (%) = - 0.6MPI + 2.3 (for R_c > 1.35%: Radke and Welte, 1983) **(4)** R_c (%) = 0.99 $\log_{10}$MPR + 0.94 (for R_c = 0.5 – 1.7%: Radke *et al.*, 1984)

(5) R_c (%) = 2.242MPDF - 0.166 (Kvalheim *et al.*, 1987) **(6)** R_c (%) = 0.046DNR + 0.89 (for R_c = 0.9 – 1.5%: Radke *et al.*, 1984)

(7) R_o (%) = mean of maximum vitrinite reflectance converted from the mean of random (measured) vitrinite reflectance (R_r) using Kilby's (1991) formula (cf. Experimental). n = number of vitrinite reflectance determinations in calculating R_o.

Table 3.6: Saturated hydrocarbon biomarker database for selected rock extracts

		DRIMANES		HOPANES							STERANES			
Well	Depth	$\frac{C_{15}}{C_{16}}$	$\frac{R}{N}$	$\frac{T_s}{T_m}$	$\frac{C_{29}T_s}{C_{29}\alpha\beta}$	$\frac{C_{30}T_s}{C_{30}\alpha\beta}$	$\frac{C^*_{30}}{C_{30}\alpha\beta}$	$\frac{C_{29}\alpha\beta}{C_{30}\alpha\beta}$	$\frac{C_{30}}{\alpha\beta / \beta\alpha}$	$\frac{C_{31}}{22S/22R}$	$\frac{C_{29}\ \alpha\alpha\alpha}{20S/20R}$	$\frac{C_{29}}{\alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)}$	$\frac{C_{29}}{\beta\alpha/(\alpha\alpha\alpha+\alpha\beta\beta)}$	$\frac{Hop}{Ster}$
Namur Sandstone														
Poonarunna-1	5001'	0.58	0.23	0.31	0.21	0.097	0.058	0.72	4.78	1.35	0.92	0.39	0.68	3.26
Poonarunna-1	5018'3"	0.46	0.23	0.18	0.16	0.086	0.058	0.67	5.44	1.28	0.62	0.37	0.52	2.82
Birkhead Formation														
Poonarunna-1	5209'3"	1.07	0.38	0.49	0.30	0.090	0.090	0.54	7.86	1.28	1.01	0.47	1.16	3.55
Poonarunna-1	5253'6–10"	0.65	0.41	0.43	0.57	0.114	0.090	0.34	4.98	1.39	0.68	0.44	0.52	6.73
Putamurdie-1	4778'9"	0.75	0.33	0.46	0.39	0.097	0.133	0.36	5.10	1.20	0.68	0.42	0.67	3.59

Table 4.1: Sample details for FAMM study

Well	Depth (m)	Sample type	Stratigraphy (Formation)	Lithofacies
AFMECO Cur-3	251.60	Core	Birkhead equiv.	Coal/shaley coal
AFMECO Cur-3	259.50	Core	Birkhead equiv.	Coal
AFMECO Cur-5	210.10	Core	Birkhead equiv.	Coal
AFMECO Cur-5	249.40	Core	Birkhead equiv.	Coal
Comalco 1069-01 (Coal Hole-1)	170 – 196	Cuttings	Mt Toondina	Coal
Comalco 1069-02 (Coal Hole-2)	192 – 210	Cuttings	Mt Toondina	Coal
Comalco 1072-01 (Coal Hole-3)	187 – 192	Cuttings	Mt Toondina	Coal
Comalco 1072-01 (Coal Hole-3)	199 – 204	Cuttings	Mt Toondina	Shaley coal
Cootanoorina-1	531.06 – 531.11	Core	Stuart Range	Argillaceous siltstone
Dalmatia-1 *	713.2–722.4	Cuttings	Purni	Coal/shaley coal
Gidgealpa-29	1832.45	Core	Birkhead	Shale
Gidgealpa-29	1838.83	Core	Birkhead	Coal
Manya-2 †	267.3	Core	Mt Toondina	Coal (coaly detritus in sandstone)
Mt Hammersley-1 *	658.4–673.6	Cuttings	Purni	Coal
Mt Hammersley-1 *	838.2–853.4	Cuttings	Purni	Coal
Mt Hammersley-1 *	871.7–887.0	Cuttings	Purni	Coal
Pandieburra-1	1876.65	Core	Poolowanna	Coal (thin layer in sandstone)
Pandieburra-1	1877.39	Core	Poolowanna	Coal (thin layer in sandstone)
Poonarunna-1 #	1587.78	Core	Birkhead	Siltstone
Poonarunna-1 #	1601.27–1601.37	Core	Birkhead	Siltstone
Poonarunna-1 #	1621.08–1621.16	Core	Birkhead	Siltstone
Poonarunna-1 #	1622.78–1622.83	Core	Birkhead	Shale/siltstone
Toodla-1 ††	329.78	Core	Algebuckina	Interbedded siltstone/ fine sandstone

Significant R_O suppression suspected (Michaelsen and McKirdy, 1996); * Minor R_O suppression suspected (Staples *et al.*, 1995a); † Only R_O and FAMM analyses undertaken; †† Only R_O, FAMM and Rock-Eval pyrolysis undertaken.

Table 4.2: Vitrinite reflectance data and petrographic descriptions

Well Depth (m)	Lithology	R_O (%)	n	Petrographic description
AFMECO Cur-3 251.60	Humic coal/ shaley coal	0.43	30	Complex maceral assemblage, poorly layered. Comprises vitrinite (texto-ulminite and corpo-gelinite), minor inertinite, and abundant resinite fluorinite, sporinite and cutinite.
259.50	Humic coal	0.44	30	Similar to the above sample but contains more resinite and fluorinite.
AFMECO Cur-5 210.10	Humic coal	0.41	30	Similar to the *AFMECO Cur-3* samples but contains much larger resinite phytoclasts.
249.40	Humic coal	0.42	32	Comprises intimate layers of vitrinite, minor inertinite, sporinite, liptodetrinite and resinite.
Comalco 1069-01 170–196	Sapropelic coal	0.38	36	Non-layered cannel coal. Detrovitrinite ≈ sporinite+ liptodetrinite > telalginite ≈ inertinite. Detrovitrinite is present in varying degrees of gelification, ranging from poorly gelified (more common - attrinite) to highly gelified (less common - desmocollinite). Bituminite and ?lamalginite present. Inertinite is predominantly semifusinite. Fusinite is sparse and associated with pyrite. *Botryococcus*-type telalginite is common and dispersed evenly throughout the slide. Some grains of coal are more humic in character. However, the dominant maceral in these is detrovitrinite which is associated with minor resinite.
Comalco 1069-02 192–210	Sapropelic coal	0.37	15	Non-layered cannel (or cannel-boghead) coal. Very similar to the above sample but contains more structured (less comminuted) humic material. Contains more *Botryococcus*-type telalginite than the above sample; however, sporinite + liptodetrinite > telalginite. Bituminite present.
Comalco 1072-01 187–192	Sapropelic coal	0.40	39	Non-layered cannel coal (possibly transitional between humic and sapropelic). Liptinite ≈ vitrinite ≈ inertinite. Some grains contain intact cross-sections of plant rootlets surrounded by a sheath of cutinite. Cutinite > sporinite + liptodetrinite > resinite/fluorinite. Other grains are more similar to the samples from *Comalco 1069-01* and *1069-02* wherein sporinite > telalginite >> cutinite. Bituminite present.
199–204	Sapropelic coal	0.44	28	Non-layered boghead (or boghead-cannel coal). Various grains have different organic assemblages. Overall liptinite > vitrinite ≈ inertinite, and *Botryococcus*-type telalginite > sporinite + liptodetrinite > cutinite. Bituminite present. A lesser proportion of grains lack telalginite but contain abundant sporinite (cannel coal).
Cootanoorina-1 531.06–531.11	Siltstone/shale	0.49	11	Liptinite ≈ inertinite > vitrinite. Humic phytoclasts > 30 μm scarce. Sporinite > *Botryococcus*-type telalginite ≈ cutinite ≈ liptodetrinite.
Dalmatia-1 713.2–722.4	Shaley humic coal	0.34	30	Vitrinite > liptinite > inertinite. Vitrinite macerals in order of abundance: texto-ulminite (structured vitrinite), eu-ulminite (gelified structured vitrinite), densinite and corpogelinite. Inertinite macerals in order of abundance: semifusinite, fusinite. Liptinite macerals in order of abundance: sporinite, resinite ?telalginite. Resinite occurs as very small (1 – 2 μm) globule-like phytoclasts widely dispersed within the sample. Other

Table 4.2 cont.: Vitrinite reflectance data and petrographic descriptions

				resinite occurs as more conventional (larger) phytoclasts in a densinite matrix.
Gidgealpa-29				
1832.45	Shale	0.52	25	DOM. Sporinite-rich: Sporinite + liptodetrinite /lamalginite ≈ vitrinite > inertinite.
1838.83	Humic coal	0.56	34	Well-layered. Alternating layers of highly gelified telovitrinite (telocollinite), with well gelified layers of detrovitrinite (desmocollinite) incorporating common resinite/fluorinite, sporinite, cutinite, and sporinite-derived liptodetrinite. Rare *Botryococcus*-type telalginite in detrovitrinite layers. Some layers are very resinite/fluorinite-rich and contain individual resinite phytoclasts several mm in max. dimension. Other detrovitrinite layers are resinite-poor but sporinite/liptodetrinite-rich. Overall: Inertinite is absent. Vitrinite > liptinite. Proportion of bright bands is *ca* 35% telovitrinite and *ca* 65% detrovitrinite. In the detrovitrinite-rich layers: detrovitrinite > sporinite + liptodetrinite > resinite + fluorinite ≈ cutinite. In the telovitrinite-rich layers: 100% telocollinite.
Manya-2				
267.3	Humic coal layer in sandstone	0.41	15	Predominantly bogen-structured fusinite/pyrofusinite and texto-ulminite.
Mt Hammersley-1				
658.4–673.6	Humic coal	0.37	30	Almost entirely texto-ulminite, oxidised vitrinite and semifusinite. Minor sporinite.
838.2–853.4	Humic coal	0.33	30	Vitrinite is the dominant maceral group and comprises degraded densinite and corpogelinite. Only minor inertinite. Sporinite and resinite are the dominant liptinites. Bituminite and ?exsudatinite present.
871.7–887.0	Humic coal	0.36	30	Vitrinite ≈ inertinite > liptinite. Vitrinite macerals are predominantly eu-ulminite and texto-ulminite. Inertinites are predominantly semifusinite.
Pandieburra-1				
1876.65	Humic coal	0.67	22	Entirely telocollinite.
1877.39	Humic coal	0.66	24	Similar to above, but also some eu-ulminite. Minor resinite and sporinite dispersed throughout.
Poonarunna-1				
1587.78	Siltstone	0.42	21	DOM. Exceptionally liptinite-rich sample. Cutinite > sporinite ≈ resinite > telalginite (*Botryococcus*-type). Some vitrinites are degraded and associated with bituminite. Other vitrinites are well gelified and occur as large phytoclasts up to 4 mm in maximum dimension.
1601.27–1601.37	Siltstone	0.47	22	DOM. Vitrinite ≥ liptinite > inertinite. Sporinite is the most abundant liptinite. *Botryococcus*-type telalginite present.
1621.08–1621.16	Siltstone	0.33	5	DOM. Liptinite >> vitrinite > inertinite. Sporinite and sporinite-derived liptodetrinite are the dominant liptinites. Minor cutinite and rare *Botryococcus*-type telalginite.
1622.78–1622.83	Shale/siltstone	0.40	8	DOM. Vitrinite ≈ sporinite > inertinite (inertinite rare/absent). Very minor resinite.
Toodla-1				
329.78 m	Layered siltstone/ fine sandstone with black laminations	0.35	37	Black laminations are organic-rich comprising texto-ulminite fine sandstone with resinite/fluorinite inclusions. Minor sporinite and liptodetrinite. Trace *Botryococcus*-type telalginite. Vitrinite >> liptinite ≈ inertinite.

DOM = dispersed organic matter. R_O = mean of maximum vitrinite reflectance; n = number of measurements used to calculate R_O. * = cuttings sample; all other samples are core.

Table 4.3: Measured and FAMM-derived equivalent vitrinite reflectance data

Well	Depth (m)	Formation	Measured R_{ran} (%) (1) (n)	R_O (%) (2)	Measured R_O (%) (3) (n)	**FAMM equiv. R_{ran}** (%) (4) (n)	**R_{FAMM}** (%) (5)	Corrections to measured R_O based on FAMM (% abs.) (6)	**ΔR_O** (% abs.) (7)
AFMECO Cur-3	251.60	Birkhead equiv.	0.40 (30)	0.43	-	**0.50** (7)	**0.54**	+0.05	**0.11**
AFMECO Cur-3	259.50	Birkhead equiv.	0.41 (30)	0.44	-	**0.47** (9)	**0.51**	+0.05	**0.07**
AFMECO Cur-5	210.10	Birkhead equiv.	0.37 (30)	0.41	-	**0.60** (9)	**0.65**	+0.08	**0.24**
AFMECO Cur-5#	249.40	Birkhead equiv.	0.39 (32)	0.42	-	**0.58** (8)	**0.63**	+0.05	**0.21**
Comalco 1069-01	170–196	Mt Toondina	0.35 (36)	0.38	0.33 (32)	**0.42** (8)	**0.45**	+0.05	**0.07**
Comalco 1069-02	192–210	Mt Toondina	0.34 (15)	0.37	0.33 (29)	**0.51** (7)	**0.55**	+0.12	**0.18**
Comalco 1072-01	187–192	Mt Toondina	0.37 (39)	0.40	0.37 (34)	**0.41** (6)	**0.44**	+0.10	**0.04**
Comalco 1072-01	199–204	Mt Toondina	0.40 (28)	0.44	0.37 (24)	**0.47** (8)	**0.51**	+0.10	**0.07**
Cootanoorina-1	531.06–531.11	Stuart Range	0.45 (11)	0.49	0.38 (31)	**0.62** (6)	**0.67**	+0.10	**0.18**
Dalmatia-1	713.2–722.4	Purni	0.32 (30)	0.34	-	**0.46** (7)	**0.50**	+0.10	**0.16**
Gidgealpa-29*	1832.45	Birkhead	0.47 (25)	0.52	-	**0.81** (7)	**0.88**	+0.25	**0.36**
Gidgealpa-29	1838.83	Birkhead	0.51 (34)	0.56	-	**0.81** (6)	**0.88**	+0.20	**0.32**
Manya-2	267.3	Mt Toondina	0.38 (15)	0.41	-	**0.54** (13)	**0.58**	+0.12	**0.17**
Mt Hammersley-1	658.4–673.6	Purni	0.34 (30)	0.37	-	**0.40** (5)	**0.43**	+0.05	**0.06**
Mt Hammersley-1	838.2–853.4	Purni	0.31 (30)	0.33	-	**0.45** (6)	**0.49**	+0.05	**0.16**
Mt Hammersley-1	871.7–887.0	Purni	0.33 (30)	0.36		**0.48** (8)	**0.52**	+0.05	**0.16**
Pandieburra-1	1876.65	Poolowanna	0.62 (22)	0.67	-	**0.66** (10)	**0.71**	+0.15	**0.04**
Pandieburra-1	1877.39	Poolowanna	0.61 (24)	0.66	-	**0.77** (11)	**0.83**	+0.10	**0.17**
Poonarunna-1	1587.78	Birkhead	0.38 (21)	0.42	-	**0.78** (7)	**0.84**	+0.25	**0.42**
Poonarunna-1	1601.27–1601.37	Birkhead	0.43 (22)	0.47	-	**0.78** (6)	**0.84**	+0.25	**0.37**
Poonarunna-1	1621.08–1621.16	Birkhead	0.30 (5)	0.33	-	**0.91** (8)	**0.99**	+>0.3	**0.66**
Poonarunna-1	1622.78–1622.83	Birkhead	0.37 (8)	0.40	-	**0.96** (7)	**1.04**	+>0.3	**0.64**
Toodla-1	329.78	Algebuckina	0.32 (37)	0.35	-	**0.57** (7)	**0.62**	+0.15	**0.27**

(1) Measured R_{ran} = mean of random vitrinite reflectances (in oil) measured by B. H. Michaelsen ; (2) Calibrated R_O [= 1.083 x **1**: Kilby, 1991] ; (3) Measured R_O = mean of maximum vitrinite reflectances (in oil) measured by B. L. Watson ; (4) FAMM equiv. R_{ran} = mean of random vitrinite reflectance estimated by FAMM ; (5) R_{FAMM} = mean of maximum vitrinite reflectance estimated by FAMM [= 1.083 x **4**: Kilby, 1991] ; (6) Estimated R_{ran} or R_O (% absolute) suppression (by FAMM) ; (7) ΔR_O = vitrinite reflectance suppression (% absolute) = FAMM equiv. R_O (**5**) – Calculated R_O (**2**) ; n = number of determinations made to derive the respective R_O measurement/FAMM equiv. R_O ; # Parameter **2** recalculated to replace value of 0.45% (Staples *et al.*, 1995) ; * Parameters **1** and **2** measured by M. J. Ryan (University of Adelaide) and recalculated by B. H. Michaelsen

Table 4.4: Rock-Eval pyrolysis data

Well	Depth (m)	T_{max}	S_1	S_2	S_3	S_1+S_2	S_2/S_3	PI	PC	TOC	HI	OI	Reference
AFMECO Cur-3	251.60	421	11.88	123.20	13.20	135.08	9.33	0.09	11.21	34.3	359	38	Staples *et al.* (1995)
AFMECO Cur-3	259.50	419	23.65	255.76	17.50	279.41	14.61	0.08	23.19	47.2	542	37	Staples *et al.* (1995)
AFMECO Cur-5	210.10	424	18.27	157.45	19.72	175.72	7.98	0.10	14.58	50.5	312	39	Staples *et al.* (1995)
AFMECO Cur-5	249.40	424	32.52	216.07	27.19	248.59	7.95	0.13	20.63	58.7	368	46	Staples *et al.* (1995)
Comalco 1069-01	170–196	416	2.01	105.19	13.72	107.20	7.67	0.02	8.93	55.9	187	24	Michaelsen & McKirdy (1997)
Comalco 1069-02	192–210	421	1.25	93.48	14.91	94.73	6.27	0.01	7.89	45.9	203	32	Michaelsen & McKirdy (1997)
Comalco 1072-01	187–192	419	0.70	96.26	16.56	96.96	5.81	0.01	8.08	59.1	163	28	Michaelsen & McKirdy (1997)
Comalco 1072-01	199–204	426	2.24	98.62	8.04	100.86	12.27	0.02	8.40	37.0	266	21	Michaelsen & McKirdy (1997)
Cootanoorina-1	531.06–531.11	426	0.13	2.12	1.85	2.25	1.15	0.06	0.18	2.12	100	87	Michaelsen & McKirdy (1997)
Dalmatia-1	713.2–722.4	425	3.90	122.36	8.45	126.26	14.48	0.03	10.48	38.5	318	22	Staples *et al.* (1995)
Gidgealpa-29	1832.45	435	1.19	8.55	0.48	9.74	17.81	0.12	0.81	2.17	394	22	Ryan (1996)
Gidgealpa-29	1838.83	433	34.89	195.1	3.72	229.99	52.44	0.15	19.16	58.6	332	6	Ryan (1996)
Mt Hammersley-1	658.4–673.6	425	1.58	71.21	17.66	72.79	4.03	0.02	6.04	62.8	113	28	Staples *et al.* (1995)
Mt Hammersley-1	838.2–853.4	427	6.34	200.38	8.17	206.72	24.53	0.03	17.16	55.8	359	15	Staples *et al.* (1995)
Mt Hammersley-1	871.7–887.0	427	5.38	139.13	9.13	144.51	15.24	0.04	11.99	52.8	264	17	Staples *et al.* (1995)
Pandieburra-1	1876.65	432	13.47	192.39	5.97	205.86	32.23	0.07	17.09	68.0	283	9	Michaelsen & McKirdy (1997)
Pandieburra-1	1877.39	439	9.89	109.59	5.00	119.48	21.92	0.08	9.92	52.0	211	10	Michaelsen & McKirdy (1997)
Poonarunna-1	1587.78	442	1.37	19.70	0.47	21.07	41.91	0.07	1.75	3.56	553	13	Michaelsen & McKirdy (1996)
Poonarunna-1	1601.27–1601.37	442	0.34	4.78	0.34	5.12	14.05	0.07	0.42	1.72	277	19	Michaelsen & McKirdy (1996)
Poonarunna-1	1621.08–1621.16	443	1.05	9.98	0.52	11.03	19.19	0.10	0.91	1.96	509	26	Michaelsen & McKirdy (1996)
Poonarunna-1	1622.78–1622.83	438	0.89	7.42	0.42	8.31	17.66	0.11	0.69	1.96	378	21	Michaelsen & McKirdy (1996)
Toodla-1	329.78	425	0.57	4.65	0.78	5.22	5.96	0.11	0.43	2.12	219	37	Michaelsen & McKirdy (1997)

T_{max} = temperature of maximum generation of S_2 hydrocarbons ; S_1 = mg hydrocarbons/g rock; S_2 = mg hydrocarbons/g rock; S_3 = mg CO_2/g rock ; PI = $S_1/(S_1+S_2)$; PC = pyrolysable carbon; TOC = total organic carbon (%) ; HI = S_2/g TOC; OI = S_3/g TOC

Table 4.5: Rock extract database

Well	Depth (m)	TOC (%)	EOM (ppm)	EOM (mg/g TOC)	EOM bulk composition Sat (%)	Aro (%)	Pol (%)	Reference
AFMECO Cur-3	251.60	34.3	46519	432	20.6	4.7	74.7	Staples *et al.* (1995b)
AFMECO Cur-3	259.50	47.2	76429	162	4.8	3.0	92.2	Staples *et al.* (1995b)
AFMECO Cur-5	210.10	50.5	71317	141	2.4	5.5	92.1	Staples *et al.* (1995b)
AFMECO Cur-5	249.40	58.7	80691	137	1.9	2.9	95.2	Staples *et al.* (1995b)
Comalco 1069-01	170–196	55.9	10070	18.0	10.8	11.5	31.7	Michaelsen & McKirdy (1997)
Comalco 1069-02	192–210	45.9	5830	12.7	12.7	6.6	35.5	Michaelsen & McKirdy (1997)
Comalco 1072-01	187–192	59.1	8610	14.6	8.5	11.5	32.1	Michaelsen & McKirdy (1997)
Comalco 1072-01	199–204	37.0	7590	20.5	10.5	16.3	38.4	Michaelsen & McKirdy (1997)
Cootanoorina-1	531.06–531.11	2.12	367	17.3	25.8	15.3	34.7	Michaelsen & McKirdy (1997)
Dalmatia-1	713.2–722.4	38.5	30298	79	6.3	4.9	88.8	Staples *et al.* (1995b)
Gidgealpa-29	1832.45	2.17	3263	3.26	22.1	35.9	36.6	Ryan (1996)
Gidgealpa-29	1838.83	58.6	23200	39.7	18.8	34.4	19.5	Michaelsen & McKirdy (1997)
Mt Hammersley-1	658.4–673.6	62.8	16985	27	5.5	8.5	86.0	Staples *et al.* (1995b)
Mt Hammersley-1	838.2–853.4	55.8	31680	57	7.1	7.9	85.0	Staples *et al.* (1995b)
Mt Hammersley-1	871.7–887.0	52.8	26155	50	11.2	8.3	80.5	Staples *et al.* (1995b)
Pandieburra-1	1876.65	68.0	10480	15.4	15.7	40.3	44.0	Michaelsen & McKirdy (1997)
Pandieburra-1	1877.39	52.0	14390	27.7	13.7	28.3	58.0	Michaelsen & McKirdy (1997)
Poonarunna-1	1587.78	3.56	3125	88	62.1	21.4	16.3	Michaelsen & McKirdy (1996)
Poonarunna-1	1601.27–1601.37	1.72	1641	95	41.4	34.0	19.5	Michaelsen & McKirdy (1996)
Poonarunna-1	1621.08-1621.16	1.96	2901	148	39.9	12.3	47.8	Michaelsen & McKirdy (1997)
Poonarunna-1	1622.78–1622.83	1.96	1960	100	63.8	16.6	19.6	Michaelsen & McKirdy (1997)

TOC = Total Organic Carbon; EOM = Extractable Organic Matter; Sat = Saturated hydrocarbons; Aro = Aromatic hydrocarbons; Pol = Polar compounds = Resins + Asphaltenes

Table 4.6: Aromatic hydrocarbon database for rock extracts

Well	Depth (m)	DNR	TNR	1,2,5-TMN / 1,3,6-TMN	1-MP / 9-MP	2-MP / 1-MP	1,7-DMP / X	Retene / 9-MP	MPI	MPDF	Calculated vitrinite reflectance (1)	(2)	(3)	(4)	(5)	(6)	Ref.
AFMECO Cur-3	251.60	-	-	-	-	-	-	17.72	-	-	-	-	-	-	-	-	4
AFMECO Cur-3	259.50	4.54	-	6.48	-	-	-	-	-	-	-	-	-	-	-	1.10	4
AFMECO Cur-5	210.10	-	-	-	0.74	1.37	-	-	0.70	0.52	0.71	0.82	1.88	-	1.00	-	4
AFMECO Cur-5	249.40	-	-	-	-	-	-	39.35	-	-	-	-	-	-	-	-	4
Comalco 1069-01	170–196	6.97	0.90	0.70	0.54	2.19	0.39	1.83	1.52	0.60	1.28	1.31	1.39	1.28	1.18	1.21	1
Comalco 1069-02	192–210	6.39	1.06	0.79	0.37	1.91	0.32	3.89	1.10	0.48	0.99	1.06	1.64	1.22	0.91	1.18	1
Comalco 1072-01	187–192	7.76	1.56	0.58	0.47	1.71	0.44	0.84	0.72	0.50	0.72	0.83	1.87	1.17	0.96	1.25	1
Comalco 1072-01	199–210	11.09	0.81	0.37	0.63	1.53	0.51	3.14	0.84	0.55	0.80	0.90	1.80	1.12	1.07	1.40	1
Cootanoorina-1	531.06–531.11	3.80	0.72	1.09	0.85	0.75	0.94	10.78	0.41	0.38	0.51	0.65	2.05	0.82	0.69	1.06	1
Dalmatia-1	713.2–722.4	-	-	-	0.48	1.14	-	-	0.82	0.39	0.79	0.89	1.81	1.00	0.71	-	4
Gidgealpa-19†	1832.45	5.00	0.66	1.87	1.68	0.56	1.64	0.46	0.62	0.36	0.61	0.65	1.93	0.69	0.64	1.12	3
Gidgealpa-19	1838.83	3.57	0.72	2.48	1.44	0.59	9.97	0.56	0.57	0.38	0.61	0.74	1.96	0.71	0.69	1.05	1
Mt Hammersley-1	658.4–673.6	5.38	0.61	0.50	0.34	0.99	-	-	0.52	0.32	0.58	0.71	1.99	0.94	0.55	1.14	4
Mt Hammersley-1	838.2–853.4	4.46	0.48	0.30	0.55	0.87	0.65	3.48	0.38	0.35	0.49	0.63	1.97	0.88	0.61	1.10	4
Mt Hammersley-1	871.7–887.0	4.32	0.78	0.42	0.40	1.13	0.38	1.15	0.56	0.38	0.61	0.74	1.86	0.99	0.69	1.09	4
Pandieburra-1	1876.65	2.52	0.60	4.38	0.90	0.74	0.96	3.90	0.47	0.37	0.55	0.68	2.02	0.81	0.66	1.01	1
Pandieburra-1	1877.39	3.24	0.56	4.67	0.93	0.73	0.90	0.90	0.46	0.37	0.54	0.50	2.02	0.80	0.66	1.04	1
Poonarunna-1	1587.78	2.22	-	-	5.04	0.17	3.96	17.34	0.21	0.20	0.37	0.53	2.17	0.18	0.28	0.99	2
Poonarunna-1	1601.27–1621.37	-	-	-	5.16	0.16	5.60	11.28	0.18	0.18	0.35	0.51	2.19	0.15	0.24	-	2
Poonarunna-1	1621.08–1621.16	1.75	0.43	8.80	3.96	0.19	4.10	10.66	0.29	0.20	0.42	0.57	2.13	0.23	0.28	0.97	1
Poonarunna-1	1622.78–1622.83	1.76	0.41	7.54	4.10	0.19	4.06	11.61	0.29	0.20	0.42	0.57	2.13	0.23	0.28	0.97	1

$$DNR = \frac{2,6\text{-DMN} + 2,7\text{-DMN}}{1,5\text{-DMN}} \quad ; \quad TNR = \frac{2,3,6\text{-TMN}}{1,3,5\text{-TMN} + 1,4,6\text{-TMN}} \quad ; \quad MPR = \frac{2\text{-MP}}{1\text{-MP}} \quad ; \quad MPI = \frac{1.5\,[2\text{-MP} + 3\text{-MP}]}{P + 1\text{-MP} + 9\text{-MP}} \quad ; \quad MPDF = \frac{2\text{-MP} + 3\text{-MP}}{2\text{-MP} + 3\text{-MP} + 1\text{-MP} + 9\text{-MP}}$$

(**1**) R_c (%) = 0.7MPI + 0.22 (for R_c < 1.7%: Boreham *et al.*, 1988)

(**2**) R_c (%) = 0.6MPI + 0.4 (for R_c < 1.35%: Radke and Welte, 1983)

(**3**) R_c (%) = - 0.6MPI + 2.3 (for R_c > 1.35%: Radke and Welte, 1983)

(**4**) R_c (%) = 0.99 $\log_{10}$MPR + 0.94 (R_c = 0.5 – 1.7%: Radke *et al.*, 1984)

(**5**) R_c (%) = 2.242MPDF – 0.166 (Kvalheim *et al.*, 1987)

(**6**) R_c (%) = 0.046DNR + 0.89 (for R_c = 0.9 – 1.5%: Radke *et al.*, 1984)

References: 1. Michaelsen & McKirdy (1997); 2. Michaelsen and McKirdy (1996); 3. Ryan (1996); 4. Some values originally reported in Staples *et al.* (1995) but these have been recalculated by Michaelsen: Aromatic data for these samples (especially Cur-3 and Cur-5) are difficult to interprete and somewhat unreliable due to low signal to noise ratios and/or possible coelution with unknown compounds ; † DNR and parameter **6** calculated by Michaelsen.

Table 5.1: Source and maturation-dependent biomarker parameters in selected Eromanga Basin and Cooper Basin oils

	Formation	1,2,5-TMN / 1,3,6-TMN	1-MP / 9-MP	MPI	R_c (%)	C_{29} ααα 20S† / 20R	C_{30} βα‡ / αβ
South Australia (PEL 5 & 6)							
Merimelia-15	Cadna-owie	-	-	-	-	0.58	0.16
Merrimelia-15	Murta	-	1.4	0.88	0.84	0.71	0.15
Merimelia-6	Murta	-	1.4	0.73	0.73	-	-
Dullingari North-1	Murta	10.4	1.3	0.52	0.59	0.82	0.22
Limestone Creek-2,3	Murta	-	1.3	0.49	0.56	0.80	0.15
Biala-1	Murta	-	2.0	0.50	0.57	0.70	0.23
McKinlay-1	Murta	-	1.6	0.56	0.61	-	-
Dullingari-29	Namur	-	1.4	0.49	0.56	0.74	0.20
Bookabourdie-1	Birkhead	9.4	1.6	0.60	0.64	-	-
Kenny-1	Birkhead	22.1	5.1	0.81*	0.79*	0.96	0.13
Moolion-1	Poolowanna	6.8	0.88	0.61	0.65	1.07	0.16
Poolowanna-1	Poolowanna	-	1.2	0.79	0.77	1.04	0.10
Poolowanna	Peera Peera	-	0.86	1.26	1.10	1.14	-
Gidgealpa-7	Patchawarra	0.69	0.71	1.04	0.95	-	-
Fly Lake-1	Tirrawarra	0.23	0.69	1.06	0.96	1.05	-
Moorari-1	Tirrawarra	0.15	0.72	1.15	1.03	1.02	-
Yanpurra-1	Tirrawarra	0.37	0.69	1.15	1.03	0.98	-
Queensland (ATP 259P)							
Jackson-1	Murta	-	1.2	0.47	0.55	0.58	0.19
Tinpilla-1	Murta	-	-	-	-	0.55	0.19
Jackson South-1	Westbourne	-	2.4	0.66*	0.68*	0.82	0.13
Jackson-1,2	Hutton	-	1.4	1.17	1.04	0.96	0.12
Tindilla-1	Hutton	-	-	-	-	1.16	0.09
Karmona-1	Toolachee	0.76	0.63	1.06	0.96	1.00	0.02
Queensland (ATP 267P)							
Nockatunga-4	Murta	0.43	1.6	0.45	0.54	0.53	0.20
Winna-1	Murta	0.69	1.8	0.55	0.61	0.69	0.19
Thungo-1	Westbourne	0.72	2.6	0.78*	0.76*	0.94	0.17
Koora-1	Adori	2.4	6.2	0.78*	0.76*	1.05	0.14
Koora-2	Birkhead	1.7	2.8	0.71*	0.72*	1.10	0.13

Data sources: Vincent *et al.* (1985), McKirdy and Cox (1986), McKirdy (1987), Powell *et al.* (1989), R.S. Heath (Santos), T.G. Powell (AGSO), D.M. McKirdy (unpublished results)

* = values calculated assuming 1-MP/9-MP = 1; R_c (%) = 0.7MPI + 0.22 (Boreham *et al.*, 1988)

†Ratio of 20*S* to 20*R* epimer of 5α,14α,17α-24-ethylcholestane; ‡Ratio of 17α-hopane to 17β-hopane (moretane)

Table 5.2: Stratigraphic variation in gas composition, Dullingari North-1

Reservoir	R_o	$C_1 / (C_1 - C_4)$	CO_2 (%)	N_2 (%)	*i*-C_4 / *n*-C_4	$\delta^{13}C$ (CH_4) (‰)	$\delta^{13}C$ (CO_2) (‰)
Murta	0.67	0.88	3.1	1.1	0.92	-35.2	-14.4
Toolachee	1.15	0.87	13.2	0.4	0.54	-31.6	-7.2
Epsilon	1.30	0.87	16.9	0.2	0.56		
Patchawarra	1.48 – 1.84	0.96	24.1	0.4	1.16	-31.1	-6.8

Data source: McKirdy (1982 and references cited therein)

Table 5.3: Summary table of Rock-Eval pyrolysis, vitrinite reflectance and liptinite data for Cretaceous shales, Eromanga Basin

	n	TOC (%)	HI	$S_1 + S_2$ (kg/t)	R_O (%)	n	Liptinite (%)	Telalginite (%)
South Australia (PEL 5 & 6)								
Moomba Area								
M2	2	1.8–2.1	170–260	3.30–5.6		2	33.3–45.6	9.1–10.5
M3	1	1.7	152	2.8		1	26.3	0.1
M4	8	0.8–1.7	126–198	1.1–3.5		8	13.3–39.1	0–14.7
M5	4	1.2–1.7	125–185	2.0–2.9	0.61	4	20.3–45.8	0–11.0
Namur	1	3.5	185	7.4	0.62	6	12.3	0–1.77
Murteree Ridge								
M1	3	1.0–1.5	228–261	2.6–4.4	0.56		13.2–28.8	2.5–9.9
M2	5	1.8–2.1	244–541	5.1–11.8	0.58		31.4–57.7	0.2–26.1
M3 (unstained)	3	1.6–2.3	185–332	2.1–10.0		9	8.3–50.6	0–7.3
M3 (stained)	6	0.8–2.6	194–310	6.0–14.9				
M4	3	0.8–2.2	217–332	2.1–8.0			25.0–32.8	0–3.3
M5	11	1.6–2.3	175–280	3.2–6.5			30.9–50.0	1.1–21.6
Queensland (ATP 267P)								
Cadna-owie (Koora-1)	7	0.88–1.18	118–156	1.2–1.9		1	35.7	9.6
M1/2 (Koora-1)	3	0.95–1.49	168–212	2.7–5.0				
M1/2 (Nockatunga-1)	9	0.83–1.59	166–270	1.7–5.6				
M1/2 (Nockatunga-2)	4	0.58–1.33	97–212	0.7–3.2		2	36.9–57.0	4.3–6.9
M1/2 (Nockatunga-3)	7	0.54–1.22	81–237	0.5–5.6		2	52.0–63.7	3.87–4.43
M2/3 (Winna-1)	3	0.80–1.33	195–251	2.5–6.5	0.50	1	28.8	0.53

Table 5.4: Summary of liptinite characteristics in Cretaceous DOM, Eromanga Basin

Area	Telalginite				Sporinite + Liptodetrinite	
	Colouration		*Dimensions* (μm)		*Colouration*	
	White light	Fuorescence	Mean	Max. observed	White light	Fluorescence
South Australia (PEL 5&6)						
Moomba Area						
Moomba-18	dG	mO – mY	37	52	mB	mO – dY
Murteree Horst						
Biala-1	l – dB	m – iY	38	78	l – mB	iO – mY
Limestone Creek-6	l – mB	iY	52	115	l – mB	iO – mY
McKinlay-2	mB	mY	40	75	l – mB	iO – mY
Queensland (267P)						
Koora-1	l – mB	m – iY	31	50	m–dB	mO – mY
Nockatunga-2	d – mB	mY	30	51	l–dB	mO – mY
Nockatunga-3	m – dB	mY	30	65	l–dB	mO – mY
Winna-1	lB	iY	32	40	l–dB	d – mY

All liptinite characteristics are described using a Berik prism, K 510 barrier filter, BG 12 and BG 38 exciter filters.

White light		*Intensity*	
B	Brown	l	Light
G	Grey	m	Medium
		d	Dark

Fluorescence-mode		*Intensity*	
Y	Yellow	i	Intense
O	Orange	m	Moderate
		d	Dull

Table 6.1: Whole-oil GC and GC-MS database: Isoprenoid and aromatic hydrocarbons

Well	ID	Pr / Ph	Pr / n-C_{17}	Ph / n-C_{18}	DNR	TNR	1,2,5 / 1,3,6	1-MP / 9-MP	2-MP / 1-MP	1,7 / X	Retene / 9-MP	MPI	MPI_n	Calculated vitrinite reflectance 1 (%)	2 (%)	3 (%)	4 (%)	5 (%)
South Australia																		
Murta Formation																		
Alwyn-1	DST-1	3.37	0.31	0.08	5.92	0.72	1.40	1.02	0.58	0.82	3.24	0.46	0.46	0.54	0.54	0.68	0.68	0.70
Biala-1	DST-1	3.05	0.28	0.08	4.74	0.72	1.95	1.42	0.44	0.97	2.32	0.46	0.52	0.55	0.59	0.68	0.71	0.58
Dullingari-29	DST-3	3.96	0.36	0.09	2.79	0.43	4.60	1.41	0.43	0.76	1.40	0.43	0.48	0.52	0.56	0.66	0.69	0.58
Gidgealpa-17	DST-1	4.56	0.36	0.09	4.76	0.58	2.33	1.46	0.51	0.66	1.17	0.55	0.62	0.60	0.66	0.73	0.77	0.65
Kobari-1	DST-1	4.92	0.38	0.09	5.29	0.68	1.32	0.75	0.76	0.68	1.23	0.47	0.47	0.55	0.55	0.68	0.68	0.82
Limestone Creek-1	DST-1	3.49	0.31	0.08	5.10	0.74	1.42	0.95	0.58	0.85	1.81	0.42	0.42	0.52	0.52	0.65	0.65	0.71
Merrimelia-35	DST-1	4.13	0.35	0.10	4.96	0.65	1.82	1.35	0.62	0.75	0.54	0.68	0.76	0.70	0.75	0.81	0.85	0.73
Big Lake-57#	DST-2	4.37	0.41	0.10	3.90	0.62	1.76	1.26	0.65	1.10	0.54	0.68	0.74	0.70	0.74	0.81	0.84	0.76
Namur Sandstone																		
Biala-1	DST-2	2.86	0.28	0.08	3.59	0.62	2.51	1.51	0.43	0.96	2.53	0.44	0.51	0.53	0.58	0.67	0.71	0.57
Gidgealpa-17	DST-2	3.89	0.36	0.10	4.10	0.52	2.82	1.43	0.53	0.72	1.50	0.54	0.61	0.60	0.65	0.73	0.77	0.66
Merrimelia-8	DST-2	3.78	0.34	0.10	5.59	0.65	1.67	1.44	0.55	0.77	0.72	0.66	0.75	0.68	0.75	0.79	0.85	0.69
Moomba-94	Prod.	7.63	0.74	0.15	4.97	0.56	2.29	1.69	0.47	1.18	1.95	0.57	0.69	0.62	0.70	0.74	0.81	0.61
Narcoonowie-2	DST-2	4.90	0.57	0.12	3.10	0.44	3.35	1.49	0.40	1.36	1.94	0.36	0.41	0.47	0.51	0.62	0.65	0.54
Nungeroo-1	DST-2	3.54	0.36	0.09	4.08	0.67	2.21	1.46	0.45	0.94	2.89	0.48	0.55	0.56	0.60	0.69	0.73	0.60
Pintari North-1	DST-2	5.49	0.46	0.10	3.63	0.91	3.22	1.27	0.44	0.86	1.98	0.37	0.39	0.48	0.50	0.62	0.64	0.59
Spencer-5	-	4.10	0.39	0.09	3.97	0.58	3.35	1.83	0.40	1.68	1.33	0.46	0.57	0.54	0.62	0.68	0.74	0.55
Strzelecki-6	Prod.	3.47	0.29	0.08	4.71	0.71	1.65	1.19	0.82	0.86	0.54	0.83	0.88	0.80	0.84	0.90	0.93	0.85
Ulandi-1	DST-2	3.61	0.34	0.08	3.78	0.62	2.49	1.43	0.46	0.80	2.71	0.45	0.51	0.54	0.58	0.67	0.71	0.60
Birkhead Formation																		
Big Lake-26	DST-1	5.63	0.54	0.10	6.36	0.94	0.23	1.16	0.90	0.96	0.09	0.87	0.92	0.83	0.87	0.93	0.95	0.90
Gidgealpa-17	DST-3	4.18	0.36	0.09	4.31	0.56	2.71	1.44	0.54	0.73	1.44	0.56	0.63	0.61	0.66	0.74	0.78	0.68
Moorari-4	DST-3	9.27	2.49	0.29	1.69	0.30	11.88	6.56	0.11	4.26	5.72	0.20	0.52	0.36	0.58	0.52	0.71	-0.01
Spencer-5	-	3.86	0.39	0.09	4.02	0.59	3.32	1.84	0.40	1.68	1.33	0.46	0.58	0.55	0.63	0.68	0.75	0.55
Sturt-3	DST-1B	6.25	1.22	0.20	2.79	0.35	7.65	4.02	0.15	3.03	7.03	0.24	0.42	0.39	0.52	0.54	0.65	0.13
Tantanna-5	DST-1	6.36	0.80	0.14	3.17	0.42	5.05	1.17	0.48	1.03	2.63	0.38	0.40	0.49	0.50	0.63	0.64	0.62
Hutton Sandstone																		
Gidgealpa-17	DST-4	4.55	0.36	0.09	3.59	0.53	3.37	1.30	0.59	0.95	0.98	0.56	0.61	0.61	0.65	0.74	0.76	0.71
Merrimelia-10	Prod.	4.12	0.35	0.09	4.28	0.64	2.07	1.19	0.72	0.80	0.24	0.65	0.69	0.68	0.70	0.79	0.81	0.80
Reg Sprigg-1	DST-1	2.87	0.24	0.08	7.45	1.04	0.71	0.78	1.63	0.43	0.16	1.43	1.43	1.22	1.22	1.26	1.26	1.15
Strzelecki-6	Prod.	3.33	0.30	0.08	3.51	0.59	2.93	1.22	0.70	0.99	0.98	0.63	0.67	0.66	0.69	0.78	0.80	0.79
Poolowanna Formation																		
Cuttapirrie-1	DST-1	5.57	0.69	0.12	3.54	0.65	1.54	1.40	0.56	1.08	0.55	0.60	0.67	0.64	0.69	0.76	0.80	0.69

Table 6.1 cont.: Whole-oil GC and GC-MS database: Isoprenoid and aromatic hydrocarbons

Sturt-2	DST-1	5.93	1.01	0.18	4.40	0.63	1.13	0.72	0.98	0.50	0.56	0.70	0.70	0.71	0.71	0.82	0.82	0.93
Sturt-3	DST-1A	6.66	1.13	0.17	2.89	0.48	3.40	0.83	0.72	1.09	1.36	0.53	0.53	0.59	0.59	0.72	0.72	0.80
Nappamerri Group																		
Merrimelia-7	DST-5	3.21	0.33	0.09	5.99	0.81	0.61	0.70	1.25	0.36	0.09	0.96	0.96	0.89	0.89	0.98	0.98	1.04
Reg Sprigg-1†	DST-1	3.77	0.27	0.08	9.13	1.01	0.16	0.60	1.71	0.25	0.10	1.30	1.30	1.13	1.13	1.18	1.18	1.17
Telopea-2§	DST-1	5.17	0.64	0.11	6.45	0.93	0.73	0.96	1.26	0.50	0.24	1.06	1.06	0.96	0.96	1.04	1.04	1.04
Patchawarra Formation																		
Daralingie-18**	Prod.	2.76	0.34	0.11	6.46	0.85	0.39	0.68	1.37	0.34	0.03	0.90	0.90	0.85	0.85	0.94	0.94	1.08
Gidgealpa-17	DST-6	3.60	0.34	0.08	5.29	0.67	0.83	0.63	1.44	0.32	0.12	0.88	0.88	0.83	0.83	0.93	0.93	1.10
Sturt-6	DST-3	5.52	0.88	0.17	5.77	0.81	0.59	0.70	1.25	0.42	0.29	0.93	0.93	0.87	0.87	0.96	0.96	1.03
Wancoocha-3	DST-3	3.45	0.42	0.10	6.13	0.67	1.09	0.64	1.26	0.45	0.19	0.72	0.72	0.72	0.72	0.83	0.83	1.04
Tirrawarra Sandstone																		
Fly Lake-8*¶	Prod.	6.12	0.68	0.12	9.19	1.30	0.08	0.72	1.33	0.43	0.04	0.98	0.98	0.91	0.91	0.99	0.99	1.06
Gidgealpa-41**	Prod.	4.31	0.37	0.08	7.10	0.96	0.45	0.67	1.26	0.40	0.12	0.99	0.99	0.91	0.91	0.99	0.99	1.04
Moorari-1*	Prod.	5.10	0.58	0.13	10.52	1.35	0.10	0.70	1.52	0.37	0.04	1.05	1.05	0.96	0.96	1.03	1.03	1.12
Tirrawarra-2*	Prod.	5.70	0.62	0.11	20.17	2.04	0.01	0.76	2.05	0.37	0.04	1.32	1.32	1.14	1.14	1.19	1.19	1.25
Woolkina-1*	Prod.	5.48	0.60	0.12	13.06	1.61	0.03	0.71	1.63	0.36	0.03	1.10	1.10	0.99	0.99	1.06	1.06	1.15
Merrimelia Formation																		
Malgoona-1A**	Prod.	5.72	0.82	0.16	5.64	0.95	0.46	0.70	1.10	0.48	0.17	0.89	0.89	0.85	0.85	0.94	0.94	0.98
Queensland																		
Murta Formation																		
Dilkera-1	DST-7	5.11	0.43	0.09	6.34	0.69	1.22	1.44	0.45	0.74	3.60	0.49	0.55	0.56	0.61	0.69	0.73	0.59
Gunna-1	DST-1	5.75	0.44	0.09	6.78	0.68	0.96	1.13	0.57	0.88	2.50	0.55	0.57	0.60	0.62	0.73	0.74	0.70
Jackson-1	DST-2	5.34	0.42	0.08	6.36	0.65	1.11	1.20	0.53	0.97	2.40	0.51	0.54	0.58	0.60	0.71	0.72	0.67
Kihee-2	DST-1	4.99	0.42	0.09	4.97	0.62	1.33	1.27	0.48	1.22	3.43	0.48	0.52	0.55	0.58	0.69	0.71	0.62
Koora-2	DST-4	3.79	0.37	0.09	2.88	0.63	3.80	2.95	0.31	1.67	3.20	0.48	0.76	0.55	0.75	0.69	0.85	0.43
Maxwell-2	DST-1	4.73	0.41	0.09	6.00	0.76	1.10	1.36	0.44	1.35	3.10	0.43	0.47	0.52	0.55	0.66	0.68	0.58
Maxwell South-1	DST-2	5.17	0.41	0.09	6.14	0.66	1.36	1.35	0.42	1.25	4.31	0.45	0.50	0.53	0.57	0.67	0.70	0.57
Thungo-1	DST-1	4.58	0.43	0.09	6.78	0.74	1.11	1.67	0.41	1.10	3.76	0.50	0.61	0.57	0.65	0.70	0.77	0.55
Winna-2	DST-1	4.35	0.52	0.12	6.27	0.67	1.32	1.57	0.43	0.98	3.05	0.52	0.61	0.58	0.65	0.71	0.77	0.58
Namur Sandstone																		
Inland-1	DST-2	4.18	0.38	0.10	3.58	0.75	1.24	1.16	0.71	0.74	0.26	0.58	0.61	0.63	0.65	0.75	0.76	0.79
Westbourne Formation																		
Jackson-3	DST-3	2.99	0.27	0.08	7.77	0.95	0.83	0.95	1.10	0.41	0.53	1.09	1.09	0.98	0.98	1.05	1.05	0.98
Thungo-1	DST-4	3.69	0.40	0.09	6.60	0.79	0.90	2.66	0.30	1.14	3.72	0.65	1.18	0.67	1.05	0.79	1.11	0.42
Birkhead Formation																		
Gunna-1‡	DST-3	3.19	0.26	0.07	6.39	0.98	0.95	1.01	1.08	0.44	0.77	1.10	1.11	0.99	1.00	1.06	1.07	0.97

Table 6.1 cont.: Whole-oil GC and GC-MS database: Isoprenoid and aromatic hydrocarbons

Hutton Sandstone																		
Bodalla South-1	-	4.25	0.42	0.11	2.45	0.48	2.99	1.26	0.58	0.96	1.79	0.51	0.55	0.58	0.61	0.71	0.73	0.70
Chookoo-1	DST-2	3.18	0.22	0.07	8.00	0.96	0.50	0.71	1.56	0.34	0.08	1.22	1.22	1.08	1.08	1.13	1.13	1.13
Inland-1	DST-1	3.99	0.39	0.11	3.69	0.76	1.05	1.06	0.78	0.68	0.19	0.56	0.57	0.61	0.62	0.74	0.74	0.83
Jackson-2	Clean-up	3.23	0.25	0.07	5.08	0.94	1.20	1.10	0.92	0.51	1.84	1.02	1.06	0.94	0.96	1.01	1.04	0.90
Naccowlah South-1	DST-2	3.14	0.23	0.07	7.36	0.97	0.65	0.75	1.43	0.37	0.12	1.23	1.23	1.08	1.08	1.14	1.14	1.09

* Family 1 oil ** Family 2 oil # McKinlay Mbr/Namur Sst † Tinchoo Fm § Basal Paning Fm ¶ Tirrawarra Sst & Basal Patchawarra Fm ‡ Birkhead Fm/Hutton Sst

$$DNR = \frac{2,6\text{-DMN} + 2,7\text{-DMN}}{1,5\text{-DMN}} \qquad TNR = \frac{2,3,6\text{-TMN}}{1,3,5\text{-TMN} + 1,4,6\text{-TMN}} \qquad MPR = \frac{2\text{-MP}}{1\text{-MP}} \qquad MPI = \frac{1.5\,[2\text{-MP} + 3\text{-MP}]}{P + 1\text{-MP} + 9\text{-MP}}$$

MPI_n = MPI in which 1-MP is assumed to equal 9-MP (used where 1-MP > 9-MP in Mesozoic samples)

(**1**) R_c (%) = 0.7MPI + 0.22 (for R_c < 1.7%: Boreham *et al.*, 1988)

(**2**) R_c (%) = $0.7MPI_n$ + 0.22 (for R_c < 1.7%: Boreham *et al.*, 1988)

(**3**) R_c (%) = 0.6MPI + 0.4 (for R_c < 1.35%: Radke and Welte, 1983)

(**4**) R_c (%) = $0.6MPI_n$ + 0.4 (for R_c < 1.35%: Radke and Welte, 1983)

(**5**) R_c (%) = 0.99 $\log_{10}$MPR + 0.94 (R_c = 0.5 – 1.7%: Radke *et al.*, 1984)

Table 6.2 Means of Pr/Ph, Pr/n-C_{17} and Ph/n-C_{18} ratios according to geographic area and stratigraphic level

	Pr/Ph	Pr/n-C_{17}	Ph/n-C_{18}	n	Pr/Ph	Pr/n-C_{17}	Ph/n-C_{18}	n
	South Australia				**Queensland**			
Eromanga Basin								
Murta Fm	3.98	0.35	0.09	8	4.87	0.43	0.09	9
Namur Sst	4.33	0.41	0.10	10	4.18	0.38	0.10	1
Westbourne	-	-	-	-	3.34	0.34	0.09	2
Birkhead Fm	5.93	0.97	0.15	6	3.19	0.26	0.07	1
Hutton Sst	3.72	0.31	0.09	4	3.56	0.30	0.09	5
Poolowanna Fm	6.05	0.94	0.16	3	-	-	-	-
Cooper Basin								
Nappamerri Gp	3.38	0.41	0.09	3	-	-	-	-
Patchawarra Fm	3.83	0.50	0.12	4	-	-	-	-
Tirrawarra Fm	5.34	0.57	0.11	5	-	-	-	-
Merrimelia Fm	5.72	0.82	0.16	1	-	-	-	-
*Cooper Basin Family 1**	*5.60*	*0.62*	*0.12*	*4*				
*Cooper Basin Family 2***	*4.26*	*0.51*	*0.12*	*3*				
Gunna Field								
Murta Fm					5.75	0.44	0.09	1
Birkhead Fm					3.19	0.26	0.07	1
Jackson Field								
Murta Fm					5.34	0.42	0.08	1
Westbourne Fm					2.99	0.27	0.08	1
Birkhead Fm					3.23	0.25	0.07	1
Inland Field								
Namur Sst					4.18	0.38	0.10	1
Hutton Sst					3.99	0.39	0.11	1
Thungo Field								
Murta Fm					4.58	0.43	0.09	1
Westbourne Fm					3.69	0.40	0.09	1
Big Lake Field								
Murta Fm	4.37	0.41	0.10	1				
Birkhead Fm	5.63	0.54	0.10	1				
Gidgealpa Field								
Murta Fm	4.56	0.36	0.09	1				
Namur Sst	3.89	0.36	0.10	1				
Birkhead Fm	4.18	0.36	0.09	1				
Hutton Sst	4.55	0.36	0.09	1				
Patchawarra Fm	3.60	0.34	0.08	1				
Tirrawarra Sst	4.31	0.37	0.08	1				
Merrimelia Field								
Murta Fm	4.13	0.35	0.10	1				
Namur Sst	3.78	0.34	0.10	1				
Hutton Sst	4.12	0.35	0.09	1				
Nappamerri Gp	3.21	0.33	0.09	1				
Reg Sprigg								
Hutton Sst	2.87	0.24	0.08	1				
Nappamerri Gp	3.77	0.27	0.08	1				
Strzelecki Field								
Namur Sst	3.47	0.29	0.08	1				
Hutton Sst	3.33	0.30	0.08	1				
Sturt Field								
Birkhead Fm	6.25	1.22	0.20	1				
Poolowanna Fm	6.30	1.07	0.18	2				
Patchawarra Fm	5.52	0.88	0.17	1				

* Fly Lake-8 Prod., Moorari-1 Prod., Tirrawarra-2 Prod., Woolkina-1 Prod.; see also Table 6.1
** Daralingie-18 Prod., Gidgealpa-41 Prod., Malgoona-1A Prod.

Table 6.3: Means of maturity parameters **2**, **4** and **5** according to geographic area and stratigraphic level

	Parameter				Parameter			
	2 (%)	**4** (%)	**5** (%)	n	**2** (%)	**4** (%)	**5** (%)	n
	South Australia				**Queensland**			
Eromanga Basin								
Murta Fm	0.61	0.73	0.69	8	0.62	0.74	0.59	9
Namur Sst	0.63	0.75	0.63	10	0.65	0.76	0.79	1
Westbourne	-	-	-	-	1.02	0.92	0.70	2
Birkhead Fm	0.63	0.75	0.69§	6	1.00	1.07	0.97	1
Hutton Sst	0.82	0.91	0.86	4	0.87	0.96	0.93	5
Hutton Sst#	0.68	0.79	0.77	3	-	-	-	-
Reg Sprigg-1 (Hutton)	1.22	1.26	1.15	1				
Poolowanna Fm	0.66	0.78	0.81	3	-	-	-	-
Cooper Basin								
Nappamerri Gp	0.99	1.07	1.08	3	-	-	-	-
Patchawarra Fm	0.82	0.92	1.06	4	-	-	-	-
Tirrawarra Fm	0.98	1.05	1.12	5	-	-	-	-
Merrimelia Fm	0.85	0.94	0.98	1	-	-	-	-
*Cooper Basin Family 1**	*1.00*	*1.07*	*1.15*	*4*				
*Cooper Basin Family 2***	*0.87*	*0.96*	*1.03*	*3*				
Gunna Field								
Murta Fm					0.62	0.74	0.70	1
Birkhead Fm					1.00	1.07	0.97	1
Jackson Field								
Murta Fm					0.60	0.72	0.67	1
Westbourne Fm					0.98	1.05	0.98	1
Birkhead Fm					0.96	1.04	0.90	1
Inland Field								
Namur Sst					0.65	0.76	0.79	1
Hutton Sst					0.62	0.74	0.83	1
Thungo Field								
Murta Fm					0.65	0.77	0.55	1
Westbourne Fm					1.05	1.11	0.42	1
Big Lake Field								
Murta Fm	0.74	0.84	0.76	1				
Birkhead Fm	0.87	0.95	0.90	1				
Gidgealpa Field								
Murta Fm	0.66	0.77	0.65	1				
Namur Sst	0.65	0.77	0.66	1				
Birkhead Fm	0.66	0.78	0.68	1				
Hutton Sst	0.65	0.76	0.71	1				
Patchawarra Fm	0.83	0.93	1.10	1				
Tirrawarra Sst	0.91	0.99	1.04	1				
Merrimelia Field								
Murta Fm	0.75	0.85	0.73	1				
Namur Sst	0.75	0.85	0.69	1				
Hutton Sst	0.70	0.81	0.80	1				
Nappamerri Gp	0.89	0.98	1.04	1				
Reg Sprigg								
Hutton Sst	1.22	1.26	1.15	1				
Nappamerri Gp	1.13	1.18	1.17	1				
Strzelecki Field								
Namur Sst	0.84	0.93	0.85	1				
Hutton Sst	0.69	0.80	0.79	1				
Sturt Field								
Birkhead Fm	0.52	0.65	0.13	1				
Poolowanna Fm	0.65	0.77	0.87	2				
Patchawarra Fm	0.87	0.96	1.03	1				

§ Excluding data from Moorari-4 and Sturt-3.

Excluding data from Reg Sprigg-1 (DST-1); see Table 6.1 for key.

* Fly Lake-8 Prod., Moorari-1 Prod., Tirrawarra-2 Prod., Woolkina-1 Prod.; see also Table 6.1.

** Daralingie-18 Prod., Gidgealpa-41 Prod., Malgoona-1Λ Prod.

Table 6.4: Summary of source affinity for Eromanga-reservoired crudes from "mixing curve 1"

Formation	Entirely Permian	Mostly Permian	Mixed	Mostly Jurassic or Cretaceous	Entirely Jurassic or Cretaceous
South Australia					
Murta Fm				Gidgealpa-17 Big Lake-57 Merrimelia-35	Biala-1 Dullingari-29
Namur Sst			Strzelecki-6	Gidgealpa-17 Merrimelia-8 Moomba-94 Narcoonowie-2	Biala-1 Nungeroo-1 Spencer-5 Ulandi-1
Birkhead Fm			Big Lake-26	Gidgealpa-17	Moorari-4 Spencer-5 Sturt-3
Hutton Sst	Reg Sprigg-1		Merrimelia-10 Strzelecki-6	Gidgealpa-17	Biala-1
Poolowanna Fm				Cuttapirie-1*	
Queensland					
Murta Fm			Gunna-1	Dilkera-1 Jackson-1 Kihee-2 Maxwell-2 Maxwell Sth-1	Koora-2 Thungo-1 Winna-2
Namur Sst			Inland-1		
Westbourne Fm		Jackson-3			Thungo-1
Birkhead Fm		Gunna-1			
Hutton Sst	Chookoo-1 Naccowlah Sth-1	Jackson-2	Inland-1	Bodalla Sth-1	

* Possibly sourced from the (upper) Poolowanna Formation

APPENDIX 3

(Microfiche)
Laboratory Manual — Organic Geochemical Procedures

Appendix 3:
(Microfiche)

Preparative Organic Geochemistry

(Version 3, November 1997)

B.H. Michaelsen and D. Padley

Official Written Safe Work Procedure

Organic Geochemistry Laboratory
Department of Geology and Geophysics
The University of Adelaide

APPENDIX 4

Author's publications relevant to this thesis

Appendix 4:

List of Publications

1. Alexander E.M., Pegum D., Tingate P., Staples C.J., Michaelsen B.H. and McKirdy D.M. (1996) Petroleum potential of the Eringa Trough in South Australia and the Northern Territory. *Australian Petroleum Production and Exploration Association Journal* 36(1), 322–349.
2. Boult P.J., Ryan M.J., Michaelsen B.H., McKirdy D.M., Tingate P.R., Lanzilli E. and Kagya M.L.N. (1997) The Birkhead Hutton (!) petroleum system of the Gidgealpa area, Eromanga Basin, Australia. In *Petroleum Systems of SE Asia and Australasia Conference*, Jakarta, Indonesia (ed. J.V.C. Howes and R.A. Noble). Indonesian Petroleum Association, Jakarta, Indonesia, pp. 213–235.
3. Boult P.J., Lanzilli E., Michaelsen B.H., McKirdy D.M. and Ryan M.J. (1998) A new model for the Hutton/Birkhead reservoir/seal couplet and the associated Birkhead-Hutton(!) Petroleum System. *Australian Petroleum Production and Exploration Association Journal* 38(1), 724–744.
4. McKirdy D.M., Michaelsen B.H., Kagya M.L.N. and Ryan M.J. (1997) Biomarker signatures of oils from the Patchawarra Trough, Cooper/Eromanga Basin, South Australia. In *18th International Meeting on Organic Geochemistry, Abstracts.* European Association of Organic Geochemists, Maastricht, The Netherlands. pp. 415–416.
5. Michaelsen B.H. and McKirdy D.M. (1989) Organic facies and petroleum geochemistry of the lacustrine Murta Member (Mooga Formation) in the Eromanga Basin, Australia. In *The Cooper and Eromanga Basins, Australia*: 1989 (ed. B. O'Neill), Proceedings of the Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (S.A. Branches), Adelaide, pp. 541–558.
6. Michaelsen B.H. and McKirdy D.M. (1993) An unusual correlation between methylphenanthrene index and some bacterial biomarkers in the Dampier Sub-basin, North West Shelf, Australia. In *Organic Geochemistry: Poster sessions from the 16th International Meeting on Organic Geochemistry, Stavanger 1993* (ed. K Øygard), Falch Hurtigtrykk, Oslo, pp. 205–208 (extended abstract).
7. Michaelsen B.H. and McKirdy D.M. (1995) A C_{30} 18α-neohopane and its application to basin analysis. In *Organic Geochemistry: Developments and Applications to Energy, Climate, Environment and Human History* (ed. J.O. Grimalt and C. Dorronsoro). Selected papers from the 17th International Meeting on Organic Geochemistry. A.I.G.O.A., Donostia-San Sebastián, The Basque Country, Spain, pp. 542–544 (extended abstract).
8. Michaelsen B.H. and McKirdy D.M. (1996b) Source rock distribution and hydrocarbon geochemistry. In *Petroleum Geology of South Australia. Vol. 2: Eromanga Basin* (ed. E.M. Alexander and J.E. Hibburt), Department of Mines and Energy South Australia. Report Book 96/20, pp. 101–110.
9. Michaelsen B.H. and McKirdy D.M. (1999) Aromatic hydrocarbon signatures of oils from the Cooper and Eromanga Basins, central Australia: Evidence of multiple sources and in-reservoir mixing. *19th International Meeting on Organic Geochemistry, Abstracts.* European Association of Organic Geochemists, Istanbul, Turkey, pp. 645–646.
10. Michaelsen B.H. and McKirdy D.M. (2000) Migration and mixing of oils in the Cooper/Eromanga Basin. In *Australian Organic Geochemistry Conference, Book of Abstracts. Reefs: Past and Present.* Australian Institute of Marine Science, Townsville, Queensland.
11. Michaelsen B.H. and McKirdy D.M. (2001) Migration and mixing of oils in the Cooper and Eromanga Basins, central Australia. *In Eastern Australasian Basins Symposium, A Refocused Energy Perspective for the Future* (ed. K.C. Hill and T. Bernecker), Petroleum Exploration Society of Australia, Special Publication, pp. 289–300.
12. Michaelsen B.H., Kamali M.R. and McKirdy D.M. (1995) Unexpected molecular fossils from Early Cambrian marine carbonates of the Officer Basin, South Australia. In *Organic Geochemistry: Developments and Applications to Energy, Climate, Environment and Human History* (ed. J.O. Grimalt and C. Dorronsoro). Selected papers from the 17th International Meeting on Organic Geochemistry. A.I.G.O.A., Donostia-San Sebastián, The Basque Country, Spain, pp. 218–221.
13. Michaelsen B.H., Paull R., McKirdy D.M., Nytoft P. and Kamali M.R. (1996) GC-MS-MS characterization and possible origins of a C_{30} rearranged hopane and coeluting C_{29} fernane. In *4th Conference on Petroleum Geochemistry and Exploration in the Afro-Asian Region, Programme and Abstracts.* Afro-Asian Association of Petroleum Geochemists, Arusha, Tanzania, pp. 48–49.
14. Paull R., Michaelsen B.H. and McKirdy D.M. (1997) Fernenes and fernanes in *Dicroidium*-bearing Triassic mudstones and coals from South Australia. In *18th International Meeting on Organic Geochemistry, Abstracts.* European Association of Organic Geochemists, Maastricht, The Netherlands, pp. 267–268.
15. Paull R., Michaelsen B.H. and McKirdy D.M. (1998) Fernenes and other triterpenoid hydrocarbons in *Dicroidium*-bearing Triassic mudstones and coals from South Australia. In *Advances in Organic Geochemistry 1997* (ed. B. Horsfield, M. Radke, R.G. Schaefer and H. Wilkes), *Organic Geochemistry* 29, 1331–1343.
16. Powell T.G., Boreham C.J., McKirdy D.M., Michaelsen B.H. and Summons R.E. (1989) Petroleum geochemistry of the Murta Member, Mooga Formation, and associated oils, Eromanga Basin, Australia. *Australian Petroleum Exploration Association Journal* 29(1), 114–129.

PETROLEUM POTENTIAL OF THE ERINGA TROUGH IN SA AND THE NT

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ABSTRACT

The Eringa Trough occupies an area of over 8,000 km² in SA and the NT and contains an estimated 1,500 m of Permo-Carboniferous and over 1,000 m of Mesozoic sediments. Early Permian depositional history of this frontier region is similar to that of the Cooper Basin in northeastern SA. The Eringa Trough has limited seismic coverage and sparse petroleum and mineral exploration drillholes are located on the trough margins. Interpretation of 255 km of new seismic and reprocessed data has delineated a number of undrilled prospects.

Excellent quality reservoirs are present. Early mature to mature, Permian and Jurassic source rocks occur, including good to excellent Type-II kerogens within an equivalent of the Jurassic Birkhead Formation. Apatite fission track analysis of Permian and Jurassic sediment shows palaeo-temperatures were approximately 30-40°C higher than at present and that cooling occurred within the last 60 Ma. This suggests that Permian and Jurassic sediments in the deeper parts of the Eringa Trough have experienced temperatures suitable for petroleum generation.

An integrated evaluation of the Eringa Trough in SA and the NT has resulted in a greater understanding of this frontier area which has the potential for significant commercial petroleum discoveries.

REGIONAL SETTING

The Eringa Trough is located in the central part of the northern border region of SA and extends into the NT remote from population centres. The nearest town is Alice Springs, 300 km to the northwest and the nearest port is Port Bonython, 750 km to the south. Oil and gas fields of the Amadeus and Cooper Basins lie about 350 km distant (Fig. 1). Alice Springs and Port Augusta are linked by the sealed Stuart Highway and the central Australian railway which pass 200 km to the west of the area.

The 8,000 km² area is covered partly by gibber plains and slopes with low escarpments and ridges, and partly by the N-NW trending sand dunes of the western Simpson Desert. The main primary industry in the region is cattle grazing.

The Eringa Trough forms the westernmost tectonic element of the Pedirka Basin (cf Youngs, 1976) and contains an estimated 1,500 m of Permo-Carboniferous sediments which unconformably overlie folded and faulted Neoproterozoic to Devonian Amadeus and Warburton Basin sediments. The Pedirka Basin is unconformably overlain by over 1,000 m of Mesozoic sediments of the Simpson and Eromanga Basins and is blanketed by a thin Cainozoic veneer.

EXPLORATION HISTORY

Petroleum exploration

The first petroleum exploration permits in the SA Pedirka Basin area were granted to Delhi Petroleum Pty. Ltd. (Delhi) and Santos Ltd (Santos) in 1954. Permits in the NT include that of Beach Petroleum, who in 1960 commenced a 26-year exploration effort in the area. Initial exploration concentrated on Early to Middle Palaeozoic Amadeus Basin sediments. The first petroleum exploration well, McDills-1 (drilled by French Petroleum Company Australia Ltd) was a test of the Early Palaeozoic section. The discovery of Permian gas in the Cooper Basin in 1963 turned attention to sequences of similar age in the Simpson Desert area (Sprigg, 1986; Moore 1986b; Hollingsworth, 1989). The 1977 discovery of Jurassic and Triassic oil in Poolowanna-1 focussed exploration effort towards younger Mesozoic reservoirs.

In 1994-95 the SA Department of Mines and Energy (MESA) acquired 255 line km of 60 fold vibroseis and reprocessed 293 km of Delhi and Santos seismic data under the SA Exploration Initiative (SAEI). Additional SAEI funding was directed towards re-appraisal of the source rock potential of Permo-Carboniferous and Jurassic-Cretaceous units.

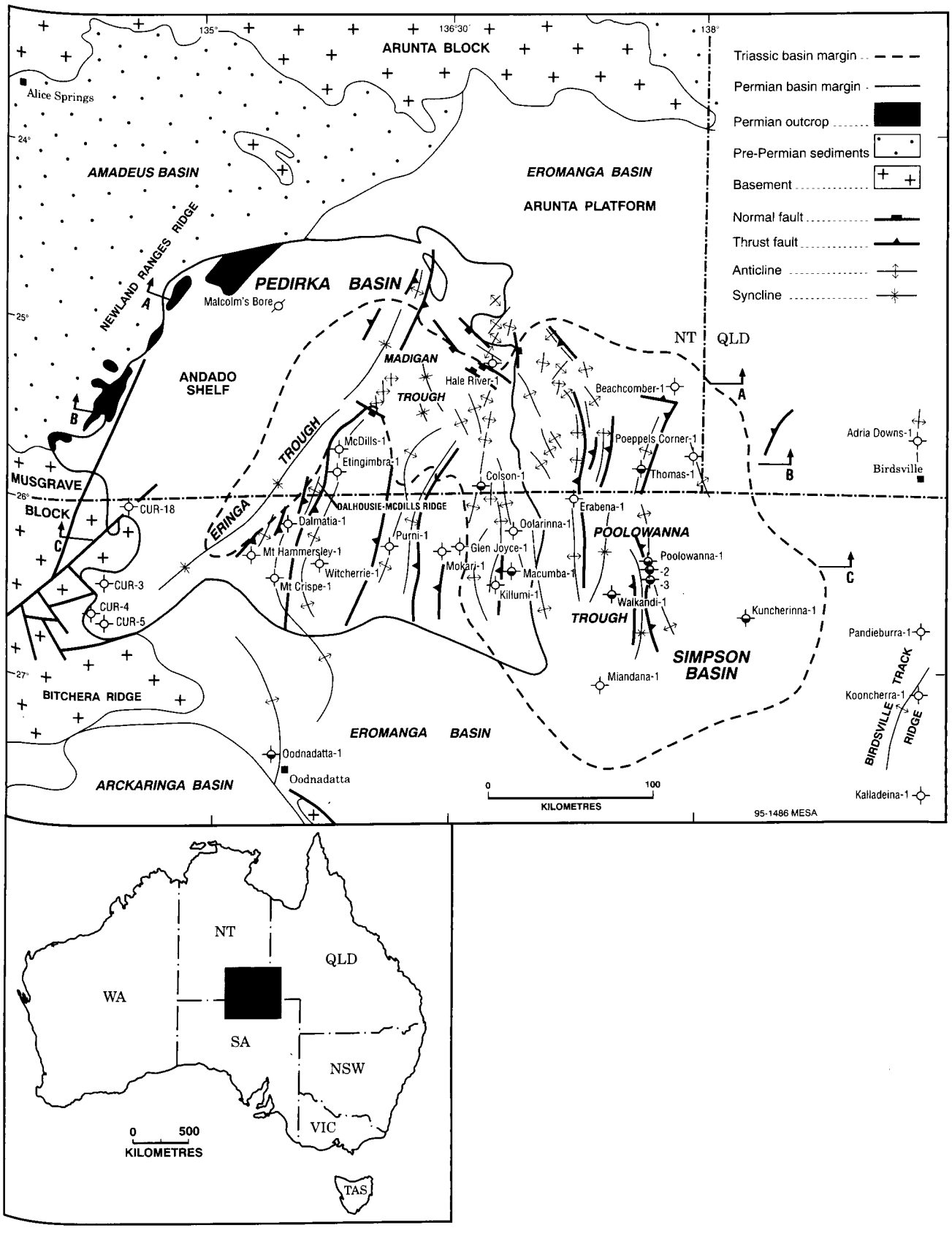


Figure 1. Location map of Pedirka Basin and Eringa Trough.

Mineral exploration

Coal, uranium and diamonds have been sought in the region. Uranium exploration carried out by Afmeco Pty Ltd (Afmeco) in 1979 (French, 1980) included 5 fully cored diamond drillholes, 2 of which (Afmeco Cur–3 and 5) were sampled for source rock and thermal history evaluation.

GEOLOGICAL SETTING

Structural framework

The shape and internal geometry of the Pedirka Basin have been strongly controlled by pre-existing structures. The Pedirka Basin onlaps the Arunta Platform and the Newland Ranges Ridge, and is faulted against the Musgrave Block and Bitchera Ridge (Figs. 1 and 2). The Musgrave Block forms a major rigid crustal block against which sediments of the Officer and Amadeus Basins have been compressed and deformed. There are two major depocentres, the Eringa-Madigan Trough which developed during the Late Palaeozoic, and the Poolowanna Trough which developed during the Mesozoic. Major anticlinal ridges are oriented northeasterly to northerly. The westernmost and most prominent of these is the Dalhousie–McDills Ridge where uplift has been greatest (Fig. 2). Down-to-west reverse fault sets strike northeast over a distance of more than 250 km and form the eastern margin of the Eringa Trough (Fig. 2). The southern culmination of the ridge crops out as the Dalhousie Anticline (Krieg, 1985a and b). North of this feature, the ridge plunges north for over 150 km to a saddle between the Eringa and Madigan Troughs (Fig. 2, section A-A. A series of en echelon anticlines has been mapped along the Dalhousie McDills Ridge, 4 of which have been drilled (Mount Hammersley–1, Dalmatia–1, McDills–1 and Etingimbra–1).

Other structural ridges in the basin are sub-parallel to the Dalhousie-McDills Ridge, but have less well developed vertical displacement. They are typically asymmetric due to reverse faulting, usually down-to-east (Fig. 2). Structures in the Pedirka Basin region are related to episodes of major basement fault reactivation with a significant component of dextral shear.

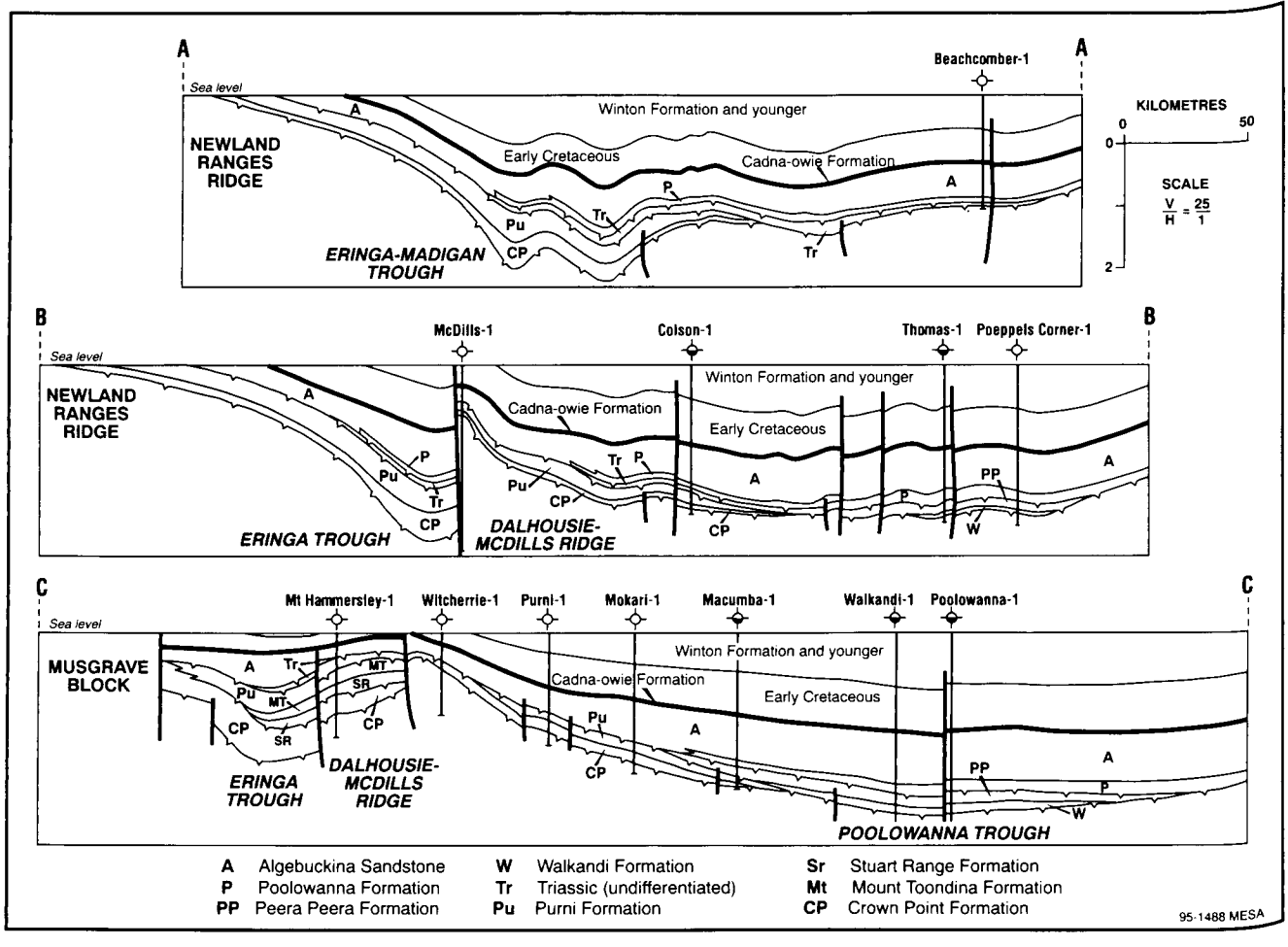


Figure 2. Structural cross-sections, western Eromanga Basin.

STRATIGRAPHY

Early Palaeozoic and older basement

Mesoproterozoic gneiss, amphibolite and granite of the Musgrave Block occur on the western margin of the Eringa Trough in SA and in the NT (Rogers, 1986; Edgoose et al, 1993). Neoproterozoic to Late Devonian intracratonic sediments of the Amadeus and Officer Basins outcrop southwest of the Eringa Trough and occur extensively in the subsurface, where they have been have been folded and are locally steeply dipping. The top Early Palaeozoic surface corresponds to the Z seismic horizon over the area (Fig. 3). Late Devonian deposition in the northeastern Officer Basin and western Warburton Basin area was halted by compression and uplift associated with the Alice Springs Orogeny. In the Amadeus Basin, syntectonic sedimentation occurred (Finke and Pertnjara Groups).

Permo-Carboniferous sediments

The Pedirka Basin and Eringa Trough were initiated during the Middle to Late Carboniferous during the final NW-SE compressional phase of the Alice Springs Orogeny. Renewed subsidence, with some reactivation of Devonian thrust faults occurred during Early Permian deposition (Hibburt and Gravestock, 1995). The Eringa and Madigan Troughs formed the main Permo-Carboniferous depocentres in the region with only relatively thin Permo-Carboniferous sediments occurring east of the Dalhousie-McDills Ridge (Fig. 2).

The Permo-Carboniferous record in central Australia is dominated by the widespread glaciation which affected Gondwana. Localised ice masses formed on highlands such as the Musgrave Block during the Carboniferous (Wopfner, 1980) and enormous volumes of sediment were released during the Early Permian as ice sheets decayed. Basal diamictites, overlain by glaciomarine and/or non-marine sediments, constitute a typical succession in many Gondwanan basins (Crowell and Frakes, 1971; Gilby and Foster, 1988) including the Pedirka, Arckaringa and Cooper Basins.

Permo-Carboniferous sediments of the Pedirka Basin were divided by Jacque (1966) into basal diamictite of the Crown Point Formation and fluvial sandstones of the Purni Formation (Fig. 3). The contact between the Crown Point and Purni Formations was interpreted as 'possibly disconformable' by Youngs (1975; p.9). Further evidence for a disconformity in the Pedirka Basin has emerged from recent MESA seismic in the Eringa Trough, from palynological data acquired for Santos Ltd (Gamarra, 1995) and from a revision of Mount Hammersley–1 stratigraphy (Alexander and Jensen-Schmidt, 1995). Two units occurring in this well between the Crown Point and Purni Formations were identified as equivalents of the Stuart Range and Mount Toondina Formations of the Arckaringa Basin (Fig. 4) on the basis of lithology and stratigraphic position by Alexander and Jensen-Schmidt (1995). Since then, additional palynological data indicate that the Pedirka Basin equivalents are older than those in the Arckaringa Basin (Gamarra, 1995). Thus both the Stuart Range and Mount Toondina Formations are diachronous and inferred to young southward by onlap.

CROWN POINT FORMATION

Late Carboniferous to Early Permian Crown Point Formation consists of sandstone and muddy to cobbly diamictite deposited in periglacial, interglacial, fluvioglacial and glaciolacustrine environments (Giuliano, 1988). The formation outcrops on the Pedirka Basin margin in the NT and reaches a maximum thickness of 347 m in Mount Hammersley–1.

STUART RANGE FORMATION

Stuart Range Formation lithofacies were intersected in Mount Hammersley–1 and were originally named 'Crown Point Formation Unit–B' (New, 1988). The unit consists of 157 m of light to medium green siltstone and claystone. The Stuart Range Formation in the Arckaringa Basin consists of a similar lithology and was deposited under quiet water, restricted marine conditions with brief episodes of lacustrine deposition (Gilby and Foster, 1988, McBain, 1987). Cook (1981) identified abundant exinite, rich in tasmanitids with possible oil shale potential.

The upper Boorthanna Formation (equivalent to the Crown Point Formation) may intertongue with the Stuart Range Formation in the southeastern Arckaringa Basin (Benbow, 1993; Hibburt, 1995). The Stuart Range Formation equivalent is significantly older in the Eringa Trough. Jones (1987) postulated that an Early Permian marine transgression progressed from the northwest (Pedirka) towards the southeast (Arckaringa) and the recent identification of older palynological zones within equivalent units in the Eringa Trough suggests this is a reasonable interpretation.

MOUNT TOONDINA FORMATION

Mount Hammersley–1 intersected 197 m of interbedded grey sandstone, siltstone and conglomerate above the Stuart Range Formation equivalent, originally named 'Crown Point Unit A' (New, 1988) but correlated with the Mount Toondina Formation of the Arckaringa Basin by Alexander and Jensen-Schmidt (1995).

PURNI FORMATION

Youngs (1975) distinguished three members in the type section in Purni–1 (1417–1698m), which can be identified on wireline logs across the basin (Fig. 5). Purni Formation consists of thinly interbedded grey shale, carbonaceous siltstone and fine to medium grained sandstone, with minor conglomerate and coal, deposited

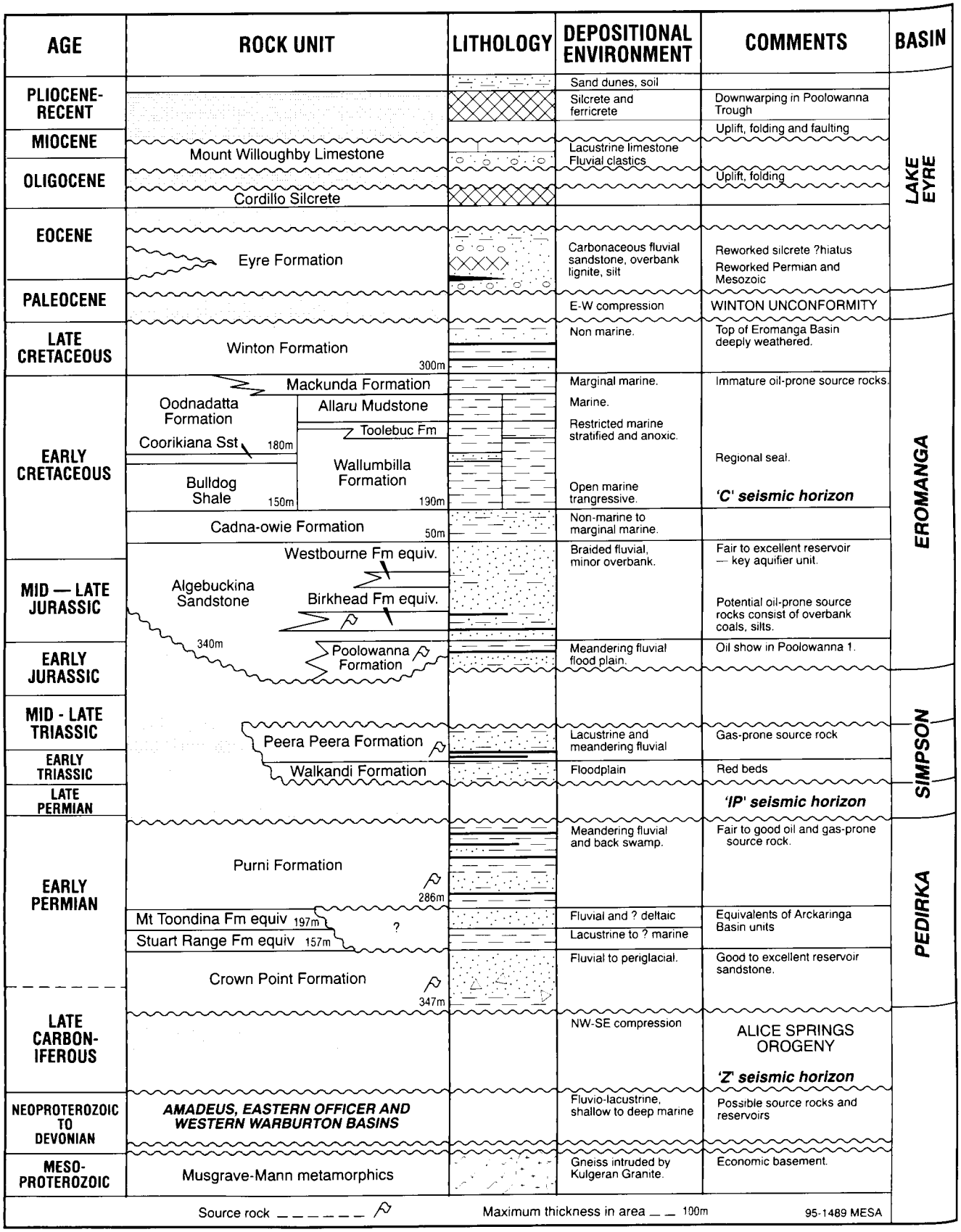


Figure 3. Geological summary.

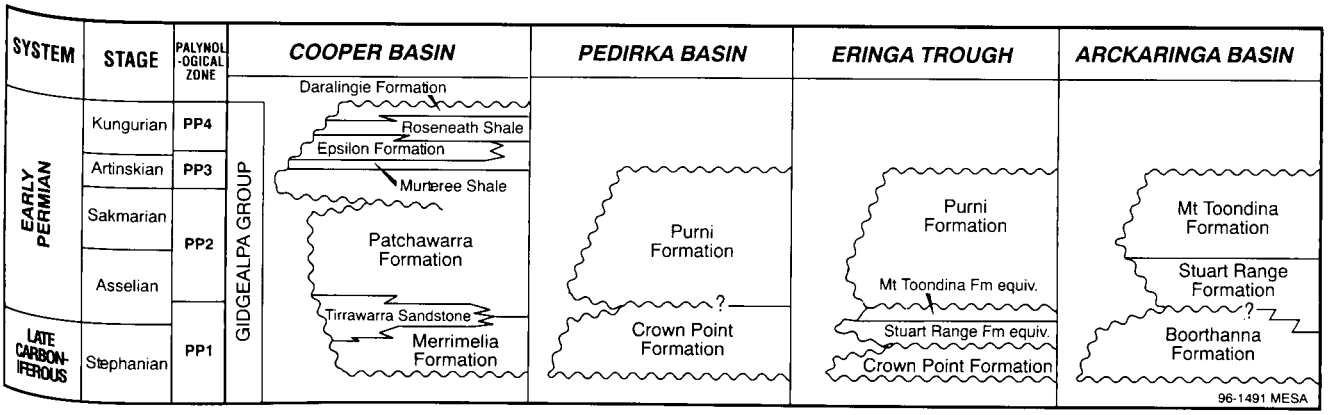


Figure 4. Early Permian correlations, Pedirka, Arckaringa and Cooper Basins.

in a flood-plain environment crossed by high sinuosity fluvial channels and containing extensive coal swamps. Purni Formation thickness reaches a maximum of 350 m in Mokari–1.

Purni Formation is correlated on palynological evidence with the Patchawarra Formation and Tirrawarra Sandstone of the Cooper Basin (Fig. 4). However younger Cooper Basin equivalents (Murteree Shale, Epsilon Formation, Daralingie Formation, Toolachee Formation and Nappamerri Group) do not occur in the Pedirka Basin and were either never deposited, or were totally eroded during the Late Permian or Late Triassic.

Simpson Basin

TRIASSIC FORMATIONS

Compressional reactivation of older fault systems deformed and eroded Pedirka Basin sediments (Hibburt and Gravestock, 1995), particularly along the Dalhousie McDills Ridge. Sediment was shed into the adjacent Poolowanna Trough, the main depocentre of the Simpson Basin, where 300 m of Triassic sediments are preserved. Triassic sediments onlap major structures on the Dalhousie McDills Ridge, but are absent from the crests of structures such as McDills–1 and Mount Hammersley–1 (NT Geological Survey, 1990; Alexander and Jensen-Schmidt, 1995). The IP seismic horizon corresponds to the unconformity at the base of Triassic, or base of the Jurassic where the Triassic is absent (Fig. 3).

The Late Triassic climate led to widespread subaerial weathering and pedogenesis. Two units described by Moore (1986a) are shown on Figure 3. The basal unit is Walkandi Formation, which consists of interbedded shale, siltstone and minor sandstone deposited in shallow ephemeral lacustrine and oxidising flood plain environments (Moore, 1986a). Peera Peera Formation consists of grey and black carbonaceous shale, coal and thin sandstone interbeds deposited in a high sinuosity fluvial environment. Peera Peera Formation onlaps older units on the flanks of the Poolowanna Trough and the Dalhousie McDills Ridge.

Eromanga Basin

POOLOWANNA FORMATION

The lowermost Eromanga Basin unit is the Poolowanna Formation of Early to Middle Jurassic age and has not been drilled in the Eringa Trough, but is interpreted to be present in the northern part of the Trough (NT Geological Survey, 1990) (Fig. 2).

BIRKHEAD AND WESTBOURNE FORMATIONS

Birkhead Formation consists of interbedded siltstone, coal and sandstone of Middle to Late Jurassic age (PJ4 to PJ6 palynozones) and the Westbourne Formation consists of similar lithologies of Late Jurassic age (PJ6 to K1 palynozones). Most previous interpretations restricted the Birkhead and Westbourne Formation to the east of the Birdsville Track Ridge. Drilling and seismic surveys have however shown that the distribution of both units can be extended west into the Simpson Basin region (e.g. Williams, 1984; Teakle, 1990). Westbourne and Birkhead Formations intertongue with and are lateral equivalents of Algebuckina Sandstone (Nugent, 1969).

On the western margin of the Eringa Trough, Afmeco drillholes cored pale to dark grey carbonaceous siltstone and mudstone with carbonised plant fragments, minor sub-bituminous coal and sandstone interbeds in the basal part of the Algebuckina Sandstone. Alley (1985) and Morgan (1995) have assigned this unit to the PJ4.2 palynozone in Afmeco Cur–5 and Afmeco Cur–3 drillholes respectively, and correlated the unit with the Birkhead Formation.

ALGEBUCKINA SANDSTONE

Algebuckina Sandstone outcrops on the western margin of the Eringa Trough (Rogers, 1984) and extends in the sub-surface eastwards into the Poolowanna Trough depocentre where a maximum thickness of 750 m occurs (Moore, 1986a). In the NT, the unit is mapped as De Souza Sandstone (Edgoose et al, 1993). Algebuckina Sandstone is a fine to coarse-grained, cross-bedded, quartzose sand-

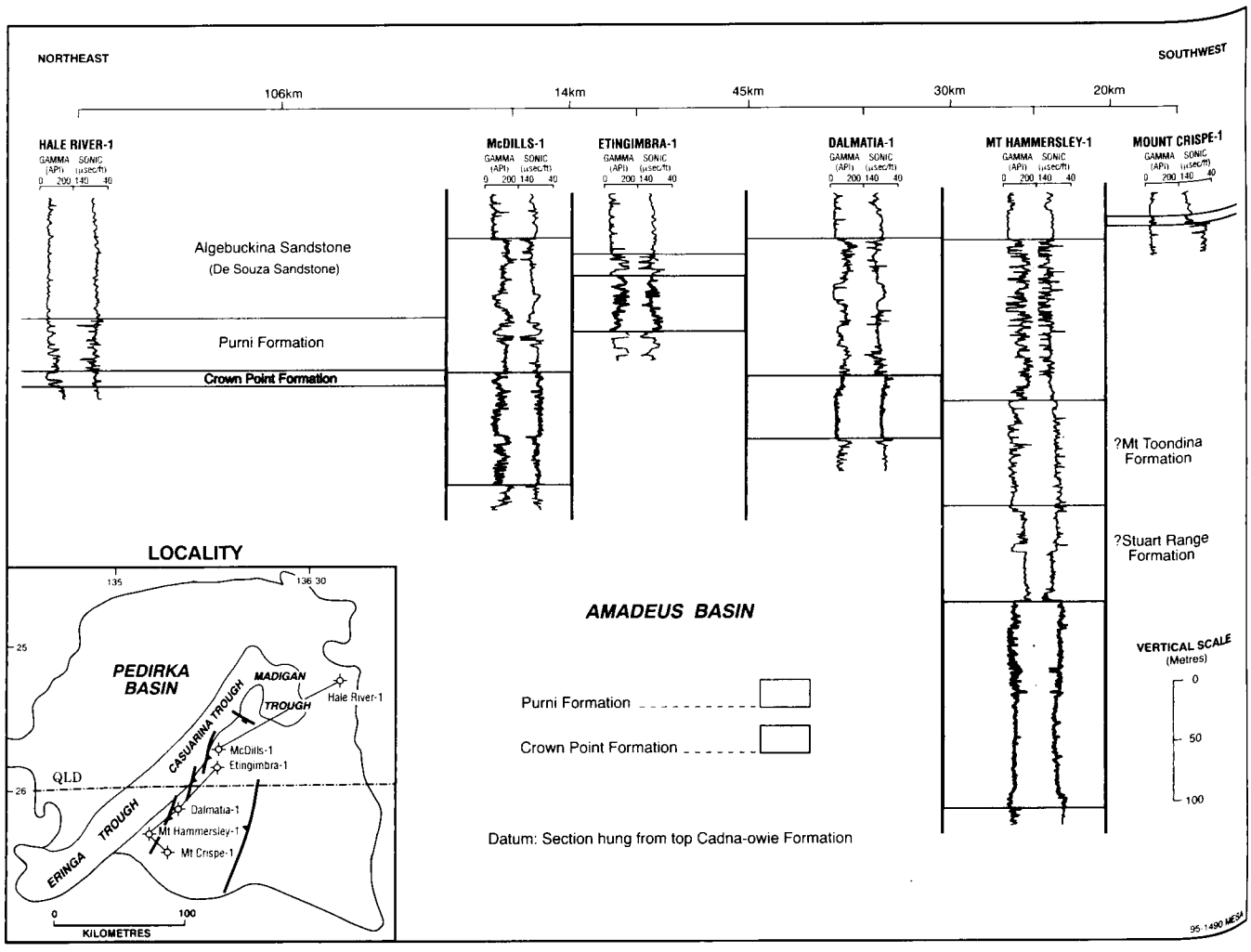


Figure 5. Wireline log cross section.

stone deposited in a braided fluvial environment (Moore, 1986a), with aeolian input and possible development of shallow sandy lakes (Wiltshire, 1989). Alluvial facies postulated to occur near the cratonic source areas in SA and the NT (Moore et al, 1986) have not been identified in outcrop or drill holes.

CADNA-OWIE FORMATION

The Cadna-owie Formation crosses the entire Eromanga Basin and outcrops along the basin margin in SA. The unit records the Early Cretaceous marine transgression (Moore and Pitt, 1985). Uplift and erosion on the crest of the Dalhousie McDills Ridge has exposed Cadna-owie Formation at Dalhousie Springs. In the subsurface, Cadna-owie Formation consists of inter-bedded very-fine to fine grained sandstone, siltstone and claystone with minor limestone. The contact between sandstone of the upper Cadna-owie Formation and the overlying marine shale of the Bulldog Shale or Wallumbilla Formation approximates a prominent seismic reflector, the C–horizon that is mappable basin-wide.

MARINE SUCCESSION

Marine formations of the Early Cretaceous (Aptian to Albian) are described in detail by Moore and Pitt (1985) and Krieg and Rogers (1995). Bulldog Shale and equivalent, Wallumbilla Formation reach 850 m in the Poolowanna Trough and consist of dark grey marine mudstone that forms a regional seal. Brief descriptions of the other, less economically significant marine formations are provided in Figure 3.

WINTON FORMATION

In the Late Cretaceous non-marine conditions returned and Winton Formation was deposited in a meandering fluvial and floodbasin environment. Sandstones contain abundant fresh volcanogenic debris, including apatites (Senior et al, 1978; Krieg, 1985b) sourced from the final pulse of volcanic activity on the eastern Australian magmatic arc (Veevers, 1984). The top of the Winton Formation has been deeply weathered indicating a long period of exposure (Wopfner et al, 1974). It thickens to at least 800 m in the Poolowanna Trough.

In the Late Cretaceous slow sea-floor spreading commenced between Australia and Antarctica, activity ceased on the eastern magmatic arc at 90 Ma and rapid uplift of the eastern highlands occurred (Veevers, 1984). The entire eastern margin of the Eromanga Basin was uplifted, forming the Great Dividing Range and establishing southwesterly groundwater flow. The Winton Formation was eroded and transported by high energy fluvial systems into the Ceduna Depocentre of the Southern Rift System (Veevers, 1984) where a thick package of Late Cretaceous fluvial and deltaic sediment accumulated. No post-Turonian to Early Paleocene sediments are preserved in the region.

Lake Eyre Basin

In contrast to the Cretaceous, Cainozoic deposition was less extensive, entirely non-marine (Krieg et al, 1990) and interrupted by significant episodes of structuring and erosion, and periods of silcrete and ferricrete formation (Fig. 3). Cainozoic formations are over 200 m thick in the Poolowanna Trough, but are typically less than 50 m over much of the study area.

During the Early Oligocene, major surface anticlines such as the Innamincka Dome, Stuart Range and Birdsville Track Ridge formed surface anticlines (Wopfner et al, 1974; Moore and Pitt, 1984) and the Cordillo Silcrete (Fig. 3) was gently folded and tilted. The Dalhousie McDills Ridge may also have been uplifted during this period, although Santos (1988) regards the main period of structuring as Miocene. Uplifted silcrete-covered structures were incised by fluvial systems so that silcrete distribution may point to palaeo-highs and lows as first pointed out by Jack (1925). A second phase of structuring during the Miocene produced large anticlinal closures and may have influenced hydrocarbon migration in the Eringa Trough (Santos, 1988).

HYDROCARBON POTENTIAL

Hydrocarbon shows

Oil shows have been recorded in several wells in the region (Fig. 1). Poolowanna-1 recovered oil from the Poolowanna Formation on drillstem test, but appraisal drilling failed to discover economic reserves. The oil is a water-washed, waxy, paraffinic crude (37° API gravity, 41°C pour point: McKirdy, 1981; Moore, 1986a). Re-examination of gas chromatography-mass spectrometry (GC-MS) data on the oil (McKirdy and Cox, 1986) reveals that its maturity (methylphenanthrene index = 0.55; VR_{calc} = 0.61 per cent) and aromatic biomarker distributions are consistent with an Early Jurassic (i.e. intra-Poolowanna Formation) source.

Previous work

The first geochemical investigations of potential source rocks in the region (McKirdy, 1981; Smyth and Saxby, 1981; Moore, 1986a) targeted the Permian Purni Formation of the southeastern Pedirka Basin and the Poolowanna Trough, the Triassic Walkandi and Peera Peera Formations of the Simpson Basin, and the overlying Jurassic sediments of the western Eromanga Basin. No drillholes in the Eringa Trough were sampled. Moreover, these early studies used classical techniques that provided little or no information on the biomarker characteristics of the source rocks.

Present study

The new results reported herein were obtained from Permian and Jurassic sediments on the margins of the Eringa Trough (Afmeco Cur-3 & 5, Dalmatia-1, Mount Hammersley-1) and across the Dalhousie-McDills Ridge (Witcherrie-1). Details of coal, shaly coal and carbonaceous siltstone samples from the Crown Point Formation, Stuart Range Formation equivalent, Purni Formation and basal Algebuckina Sandstone (Birkhead Formation) are given in Appendix 1, along with total organic carbon (TOC), Rock-Eval pyrolysis and vitrinite reflectance data. Maceral analyses of coal and dispersed organic matter (DOM) are summarised in Appendix 2. Extract yield and composition data are tabulated in Appendix 3. Biomarker data are presented in Appendix 4; and the structures of key saturated and aromatic hydrocarbons are shown in Appendix 5. For a description of sample preparation and analytical procedures the reader is referred to Staples (1995).

Hydrocarbon potential, organic facies and thermal maturity

CROWN POINT FORMATION AND STUART RANGE FORMATION

Very poor source potential is displayed by the Early Permian Crown Point Formation and Stuart Range Formation equivalent. With the exception of the Crown Point Formation in Witcherrie-1 (TOC = 3.4 per cent), these siltstones are organically lean (TOC <0.5 per cent; EOM <400 ppm); and even the Witcherrie-1 sample has a low hydrocarbon yield upon pyrolysis (S1+S2 <1 mg/g). Both formations contain poor quality Type III/IV kerogen (HI = 34-90) comprising mostly vitrinite and/or inertinite; and they are only marginally mature (*ca* 0.4–0.5 per cent R_o) (Figs 6 and 7; Appendix 1). A representative saturates chromatogram from the Stuart Range Formation shows a dominance of C_{16}–C_{23} alkanes (Fig. 8c). A slight predominance of odd-carbon-numbered *n*-alkanes in the C_{23+} range confirms their thermal immaturity (1,219–1,237 m in Mount Hammersley-1). The *n*-alkane distribution suggests a mixed algal, bacterial and land-plant source. Although alginite is not a recognisable component of its liptinite maceral group, the 24-methylcholestane-dominant sterane signature of this lacustrine to restricted marine siltstone (Appendix 4) confirms the

contribution of algae to its DOM. Cook (1981) reports the presence of abundant tasmanitid algae within the Stuart Range Formation of the Arckaringa Basin. The moderately high pristane/phytane ratio (Pr/Ph = 3.3) indicates that deposition occurred in an oxic environment.

PURNI FORMATION

The Purni Formation is represented by coals and shaly coals from Dalmatia–1 and Mount Hammersley–1 (TOC = 38–63 per cent) and a single carbonaceous siltstone (TOC = 7.5 per cent) from Purni–1. Vitrinite-rich DOM in the latter sample appears oxidised, otherwise source quality ranges from fair to good (S1+S2 = 4–25 mg/g; HI = 113–359). Kerogen varies from Type III to Type II/III and is thermally immature (0.4–0.5 per cent R_0: Fig. 6). Measured vitrinite reflectances are lower in several intervals (Appendix 1), and may be suppressed by some kind of bacterial re-working. The values of several maturation-dependent biomarker parameters (e.g. T_s/T_m, 17β,21α-/17α,21β-hopane: Appendix 4) and the predominance of steranes with biologically inherited 5β,14α,17α-stereochemistry, confirm that maturity is only marginally greater than 0.40 per cent R_0. In the main, Purni Formation coals comprise mostly telovitrinite (eu-ulminite) and detrovitrinite (densinite: Fig. 8; Appendix 2). Liptinite is more abundant in the Dalmatia–1 samples where bituminite > resinite > sporinite > cutinite. GC analysis of the saturates revealed a complex distribution of alkanes. A representative chromatogram (Fig. 8b) shows a distinctly bimodal *n*-alkane distribution and a broad bimodal (?trimodal) naphthene hump. As expected for low rank humic coals, pristane/phytane ratios are moderately high (Pr/Ph = 2–4: Appendix 3). A slight even carbon-numbered predominance among the C_{14}–C_{20} *n*-alkanes is tentatively attributed to major bacterial input. It is significant that the hopane/sterane ratio is high in this coal (but not all Purni Formation coals, Appendix 4) indicating a dominance of prokaryotic over eukaryotic (land plant) inputs. The coal with the highest hydrogen index (Mount Hammersley–1, 838.2 m; HI = 359) also has the highest hopane/sterane ratio (hop/ster = 20).

ALGEBUCKINA SANDSTONE (BIRKHEAD FACIES)

Five coal samples from the Birkhead Formation equivalent facies in the Algebuckina Sandstone, have good to excellent source potential based on Rock-Eval pyrolysis data (S1+S2 = 8–279 mg/g: Appendix 1). Hydrogen indices in the range 312 to 542 demonstrate that most of these samples contain Type II/III kerogen (Fig. 6). The sample with the highest generative potential (Afmeco Cur–3, 259.5 m) contains Type II kerogen. Petrographic observations suggest that its oil-prone nature may in part be attributable to a high content of resinite and fluorinite (essential oils). As in the Purni Formation the most abundant vitrinites are eu-ulminite and densinite (Appendix 2). The liptinite macerals in

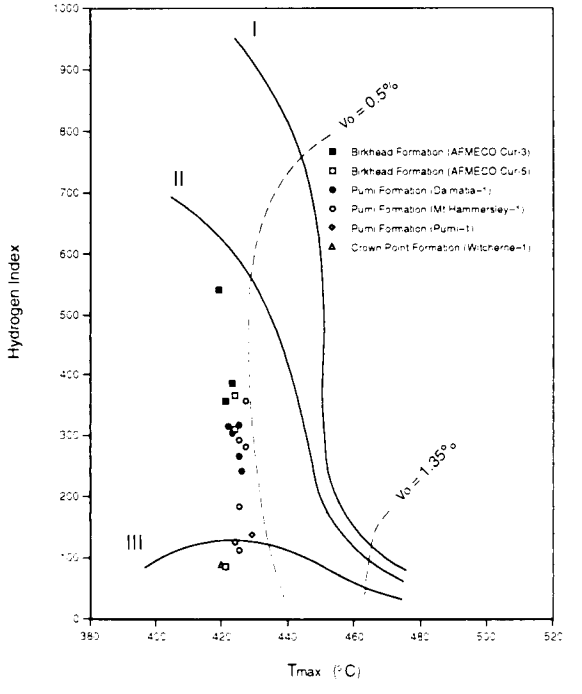


Figure 6. Plot of hydrogen index versus T_{max}, showing kerogen type and maturity.

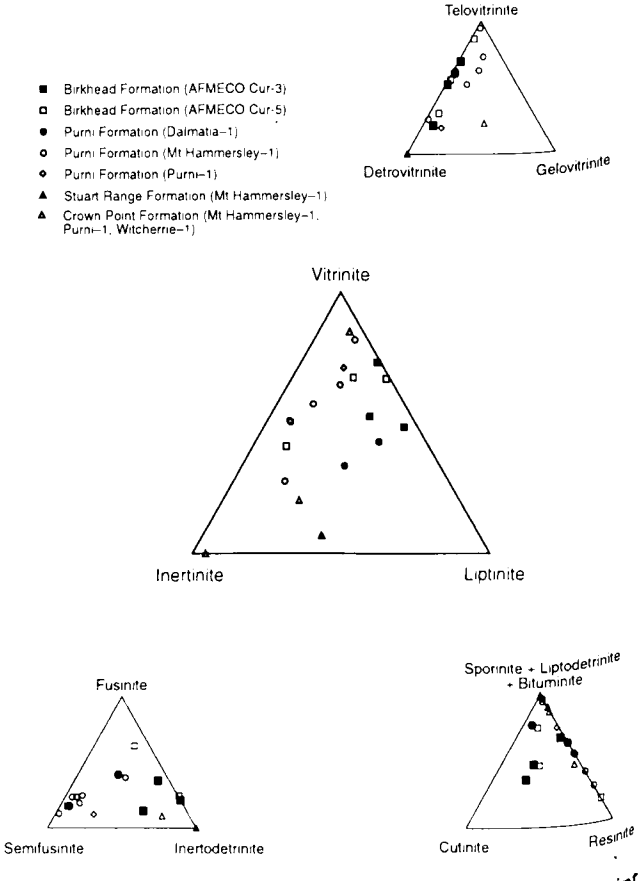


Figure 7. Maceral abundances in the Crown Point Formation, Stuart Range Formation equivalent and Birkhead Formation.

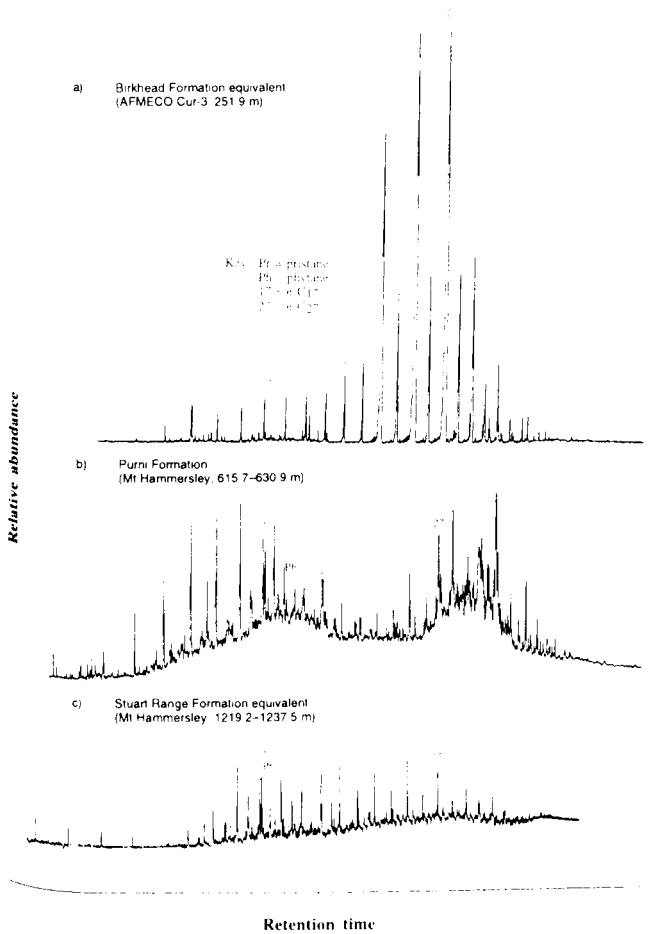


Figure 8. Representative saturates chromatographs of a) Birkhead Formation, b) Purni Formation and c) Stuart Range Formation equivalent.

decreasing order of abundance are liptodetrinite > cutinite > resinite > sporinite. Resinite and cutinite commonly occur as intimately associated layers. The fluorinite occurs as globules (< 10 μm to 200 μm) and as elongate phytoclasts (15 to 40 μm). A significant bacterial input is indicated by the high abundance of hopanes relative to steranes (Appendix 4). Intense bacterial reworking of vascular plant remains during deposition and early diagenesis has evidently played a major role in enhancing the ability of these coals to generate oil. Accordingly, there is a positive correlation between hopane/sterane ratio and hydrogen index. As in the Purni Formation, the most oil-prone Birkhead coal (Afmeco Cur-3, 259.5 m) exhibits the highest value of both parameters (hop/ster = 34; HI = 542).

Measured vitrinite reflectance values suggest a rank corresponding to 0.41–0.44 per cent R_o. This is in excellent agreement with maturity estimates derived from Rock-Eval pyrolysis (Fig. 6). According to Cook (1986), hydrocarbons can form from resinite as early as 0.40–0.45 per cent R_o. Powell's (1985) hydrocarbon generation model also suggests resinite-enriched and bacterially-modified source rocks (comprising predominantly vitrinite and inertinite) can generate hydrocarbons by 0.45 per cent R_o. Given that fluorinite is even more labile than resinite, it is conceivable that the Birkhead coals may have just entered the oil window and are about to become effective source rocks. Gas chromatograms of these coals show that waxy *n*-alkanes dominate (C_{22+}; Fig. 8a). These high-molecular-weight *n*-alkanes display a pronounced odd-carbon-number predominance which confirms that land plants were the major contributor, and also highlights their thermal immaturity. However, given the labile nature of some of the liptinites in these oil-prone coals, and their high content of bacterial lipids, they may be effective sources of liquid hydrocarbons at their present level of thermal maturity.

Age-specific biomarker characterisation of potential source rocks

Considerable effort has been made in recent years to establish robust correlations between liquid hydro-carbons and potential source rocks within the Cooper/Eromanga petroleum system. One of the most successful approaches was that of Alexander et al, (1988) who used aromatic biomarkers derived from resin acid precursors in the conifer family Araucariaceae to differentiate between oils sourced from the respective Permian and Jurassic kitchens of the Cooper and Eromanga Basins. Boreham (1995) employed a similar methodology to study the source rock and petroleum relationships of the Bowen and Surat Basins.

Araucariaceae did not become important members of the terrestrial plant community until the Early to Middle Jurassic, and therefore their biomarkers should only be abundant in Eromanga Basin strata. Conversely, the relative abundance of the araucariacean biomarkers can be expected to be low in Carboniferous-Permian sediments of the Pedirka Basin. We have tested this idea in Figure 9 which cross-plots log [1,2,5-TMN/1,3,6-TMN] vs log [1-MP/9-MP] (Staples et al 1995; Appendix 4). The conclusions to be drawn from these data are as follows:

1. Permian sediments have low concentrations of 1,2,5–trimethylnaphthalene (an araucariacean biomarker) relative to 1,3,6–trimethylnaph-thalene when compared to Jurassic sediments.
2. The ratio of 1–methylphenanthrene (another araucariacean biomarker) to 9–methylph-enanthrene alone is insufficient to distinguish between all Permian and Jurassic rocks, although Purni Formation samples consistently have 1–MP/9–MP values less than the those of the Jurassic samples.

Another molecular approach used in this study to discriminate between Permian and Jurassic sediments is based on the observed abundance of the unusually demethylated C_{28} hopanoid, 28,30–bisnorhopane (28,30–BNH) relative to the common prokaryotic marker 17α,21β–hopane (Figs. 10 and 11; Appendix 4). The ratio 28,30–BNH/17α,21β–hopane has been plotted against retene/phenanthrene in Figure 12. The biomarker 28,30–bisnorhopane (28,30–BNH) is derived from anaerobic bacteria (Peters and Moldowan, 1993) and can be present

in rock extracts spanning the entire Phanerozoic. However, unlike may other hopanoids, it is not ubiquitous and is therefore useful in source rock-oil correlations. Retene also occurs in sediments of Palaeozoic to Recent age, but has no unique natural precursor (Alexander et al, 1988). For example, retene may be derived from the aromatisation of phyllocladane (Alexander et al, 1987) or abietic acid (Alexander et al, 1988). These compounds originate from resins and higher plant tissues, notably those of the Araucariaceae. Hence, when retene occurs in high concentration an araucariacean input is inferred.

The data in Figure 12 show that:

1. Retene is present in low concentration in all Permian samples, and is effectively absent from the Purni Formation in Purni–1. By contrast, it is particularly abundant in the Birkhead coals.
2. Concentrations of 28,30–BNH are consistently higher relative to 17α,21β–hopane in Permian rocks than in Jurassic coals.

Although the higher concentration of retene in the Jurassic samples is to be expected (cf Alexander et al, 1988), there seems to be no 'a priori' reason why 28,30–BNH should be more abundant in Permian coals than in Jurassic coals. Nonetheless, it appears that the varying concentration of 28,30–BNH can be readily exploited in oil-source rock correlation studies.

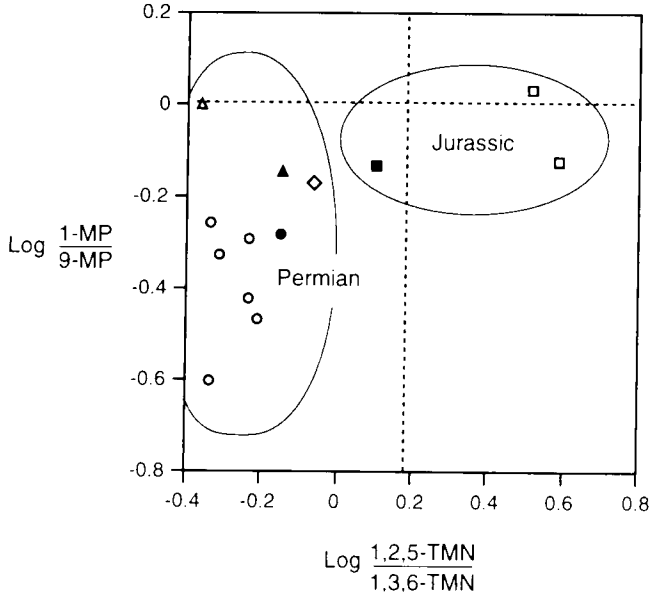


Figure 9. Log graph of source parameters using methylphenanthrenes and trimethylnaphthalenes (after Alexander et al, 1988).

The similar sterane distributions of the Purni and Birkhead Formations (Figs. 10 and 11; Appendix 4) preclude their use as oil-source rock correlation parameters. The dominant 20R 5α,14α,17α–ethylcholestane (C_{29}) is consistent with the accumulation of land-plant detritus in a swamp environment (Huang and Meinschein, 1979).

Finally, an unusual feature of the terpane fragmentograms of the Early Permian formations (Crown Point, Stuart Range and Purni Formations) is a C_{29} triterpane (labelled X) that elutes just prior to 17β,21β-30–norhopane (Fig. 11; Appendix 4). A review of the published literature indicates that this compound has not been identified, although it appears to be a common constituent of coals and carbonaceous mudstones (e.g. George et al, 1995). A study of Triassic sediments by Paull (1995) demonstrates that this compound is 'source specific'. Its absence in the Birkhead Formation coals (Fig. 12; Appendix 4), but conspicuous presence in the Purni and Stuart Range Formations, suggests that it may be useful as a discriminator of Permian vs Jurassic source affinity. Thus, future explorers of the Pedirka/Simpson/Eromanga and Cooper/Eromanga provinces now have at their disposal two new geochemical tools for distinguishing Permian from Jurassic oils.

THERMAL HISTORY

Wells selected for Apatite Fission Track Analysis (AFTA) include Afmeco Cur–3 and –5, Mount Hammersley–1, Purni–1 and Mount Crispe–1. Previously unpublished data from McDills–1 are also presented and the implications for petroleum generation examined.

AFTA Methods

AFTA data for 16 samples were generated by Geotrack International (1995) and 5 by Tingate (1990). Detrital apatite grains were separated from samples ranging from 0.5 to 3 kg in weight using conventional heavy liquid and magnetic techniques (Green, 1986). Apatites were analysed using the external detector method (Gleadow, 1981; Green, 1981) and fission track ages calculated using the zeta calibration technique (Fleischer and Hart, 1972; Hurford and Green, 1982, 1983). Irradiations were carried out at the X-7 facility of the Hifar Reactor, Lucas Heights, NSW. Apatite fission track ages were calculated from pooling single grain track counts unless the $P(\chi^2)$ value was less than 5 per cent, in which case the central age was used (Galbraith, 1981, 1992). Further details of data generation are given in Geotrack (1995) and Tingate (1990).

Apatite chemical composition can affect track annealing (Tingate, 1990; Green et al, 1985 and 1986) so apatites, except those from McDills–1, were chemically analysed. Apatites from McDills–1 are assumed to be similar to other Amadeus Basin apatites which are fluorine-rich with a mean chlorine content of 0.1 wt per cent (Tingate, 1990; 1991). Software used for modelling is

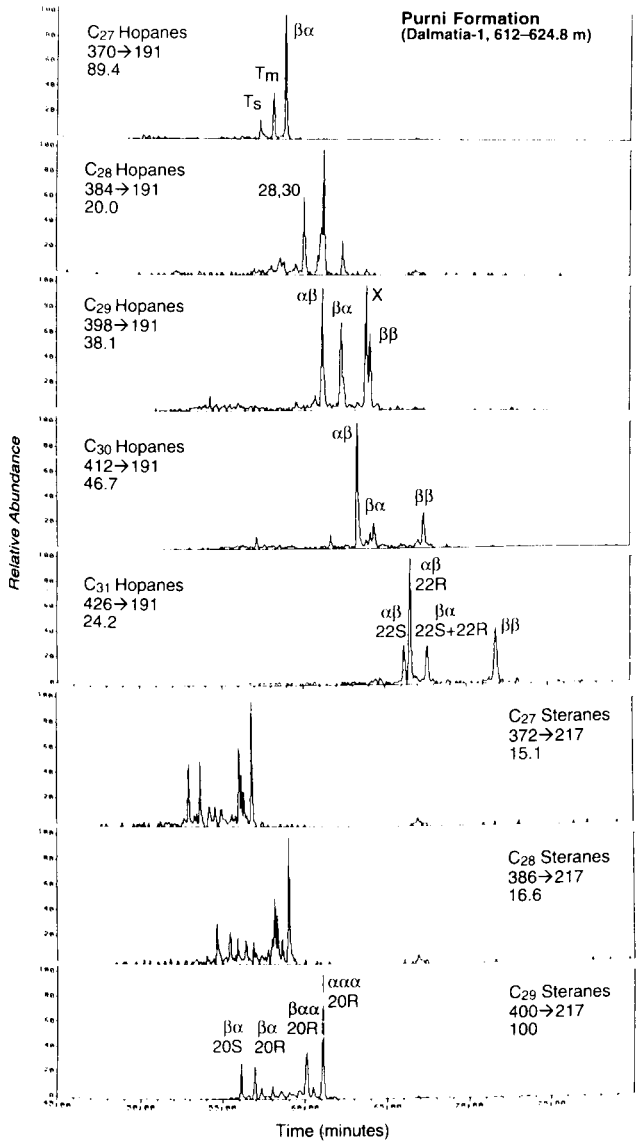


Figure 10. GC-MS (SRM) chromatograms showing hopane and sterane distributions in a representative sample of the Purni Formation. Chromatograms identified by carbon number, reaction transition, and relative abundance of the most intense peak in the trace. Peak assignments for the hopanes define the stereochemistry at C-22 (R and S); αβ, βα and ββ denote 17α,21β, 17β,21α and 17β,21β-hopanes, respectively. T_s denotes C_{27} 18α-22,29,30-trisnor-neohopane; T_m denotes C_{27} 17α-22,29,30-trisnorhopane and 28,30 signifies C_{28} 28,30-bisnorhopane. Peak assignment for the steranes, at C-20 (R and S), and βα, βαα and ααα denote 13β,17α diasteranes; 5β,14α,17α and 5α,14α,17α-steranes, respectively.

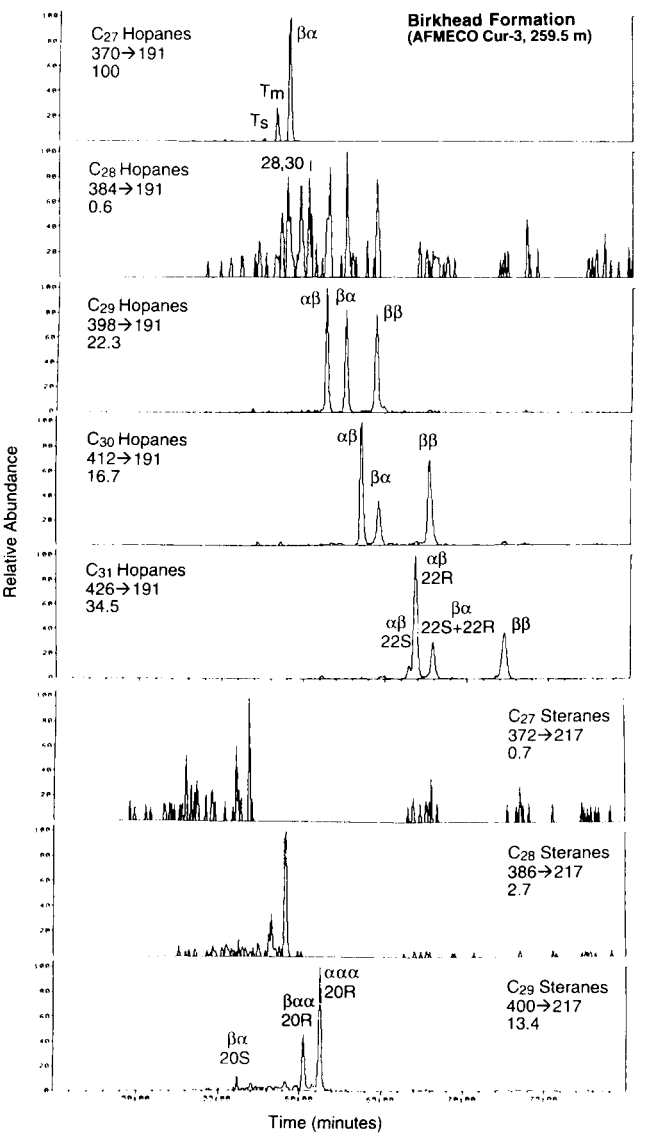


Figure 11. GC-MS (SRM) chromatograms showing hopane and sterane distributions in a representative sample of the Birkhead Formation. Peak assignment given in Figure 10.

based on the mathematical description of induced track annealing in mono-compositional Durango apatite (Laslett et al, 1987; Duddy et al, 1988; Green et al, 1989b).

Interpretation of AFTA data is based upon the annealing behaviour of spontaneous fission tracks (Gleadow et al, 1983; Green et al, 1989a), length data (Gleadow et al, 1986), and induced fission track annealing in laboratory experiments (Green et al, 1986; Laslett et al, 1987; Duddy et al, 1988) that have been extended to geological situations (Green et al, 1989b). Laboratory studies have concentrated on track length measurements, and their relation to fission track density (hence age) has been described by Laslett et al (1984) and Green (1988).

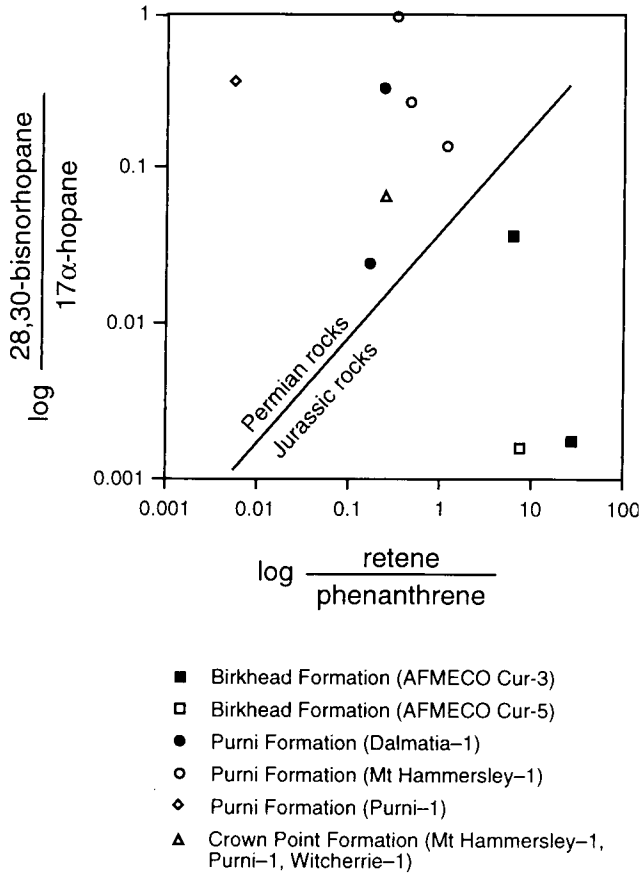


Figure 12. Log graph of source parameters 28,30-bisnorhopane/hopane versus retene/phenanthrene.

Results

McDILLS–1

McDills–1 is the most northerly well analysed on the eastern margin of the Eringa Trough. It has an uncorrected thermal gradient of 29°C/km (Smyth and Saxby, 1982) which has been corrected to 32°C/km using the method of Gorter (1984). All samples, except the shallowest have apatite fission track ages that are significantly less than the stratigraphic age of the Devonian Finke Group (Fig. 13). The mean track lengths of all the samples are less than 11 µm and decrease with increasing depth to ~9 µm, indicating that considerable annealing has occurred since deposition.

The fission track age decreases from ~ 350 to ~ 230 Ma down through the top 3 samples and then decreases more rapidly to ~ 75 and 15 Ma in the 2 lowest samples. All 4 top samples have significant spreads in single grain age, reflecting differences in apatite chemical composition. Track length histograms indicate that most of the samples have experienced higher temperatures in the past and the samples have cooled relatively recently to present thermal conditions.

Judging from the fission track parameters, all samples have been hotter in the past and cooling started at some time between 80 and 20 Ma. The fission track data clearly indicate that the Finke Group reached maximum temperatures after deposition of Cretaceous sediments. All samples show evidence of having been heated ~ 30°C hotter between 80 and 20 Ma (Fig. 14). The difference between the estimated maximum palaeo-temperature and present temperature is similar for each sample, suggesting that the present geothermal gradient was similar at the time of maximum temperature.

Assuming a cooling of ~ 30°C and using the present geothermal gradient, approximately 1 km of uplift and erosion is interpreted to have taken place between 80 and 20 Ma. The structure upon which McDills–1 was drilled had approximately 600 m of post-Cretaceous uplift and erosion (Fig. 2). This estimate does not appear to be sufficient to explain the amount of cooling interpreted in McDills–1 and regional uplift of ~ 400 m is likely.

AFMECO CUR–3 AND –5

The three Cambrian and Mesozoic samples in Afmeco Cur–3 and –5 were from shallow depths at temperatures less than 40°C, yet they exhibit annealing consistent with higher temperatures in the past (Fig. 15). Modelling of Afmeco Cur–5 suggests that it has cooled from palaeotemperatures in the range 60 to 90°C between 100 Ma and present day (Fig. 16). In Afmeco Cur–3 cooling occurred between 300 and 90 Ma. Two events of different age have probably affected each well, but a single event with cooling at ~ 100 Ma, is also possible. The time of cooling within Afmeco Cur–3 is consistent with a widespread Triassic–Early Jurassic regional cooling event in the Amadeus Basin, between 240 and 180 Ma (Tingate 1990).

The Cambrian Arcoellinna Sandstone samples have both experienced an earlier, higher temperature event (Fig. 16). Both samples have cooled from temperatures greater than 100°C between 360 and 320 Ma (combining their time constraints). The timing of cooling is consistent with the Alice Springs Orogeny (Shaw et al, 1992) when major uplift and erosion occurred between 360 and 300 Ma.

MOUNT HAMMERSLEY–1

Samples from the Algebuckina Sandstone (present temperature less than 50°C) in Mount Hammersley–1 show evidence of cooling from palaeotemperatures approximately 40°C higher than present between 180 and 0 Ma. Permian samples from the same well appear to have cooled from palaeotemperatures 10–20°C higher than present between 60 and 0 Ma. The lowest sample from the Early Palaeozoic Pacoota Sandstone, shows evidence of recent heating (<5 Ma) to its current temperature of 94°C from palaeotemperatures around

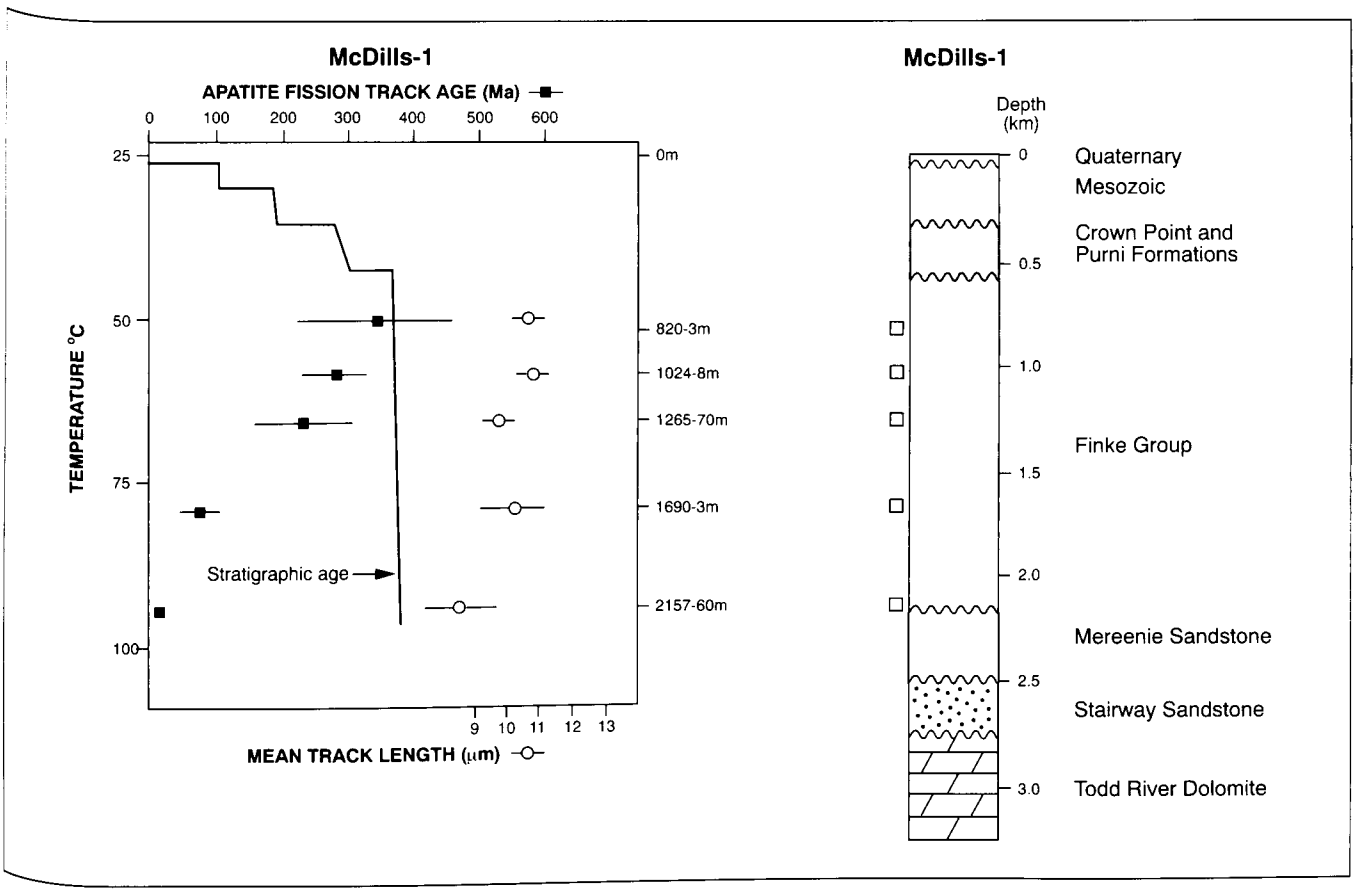


Figure 13. AFTA parameters plotted against present temperature and sample depths for McDills–1.

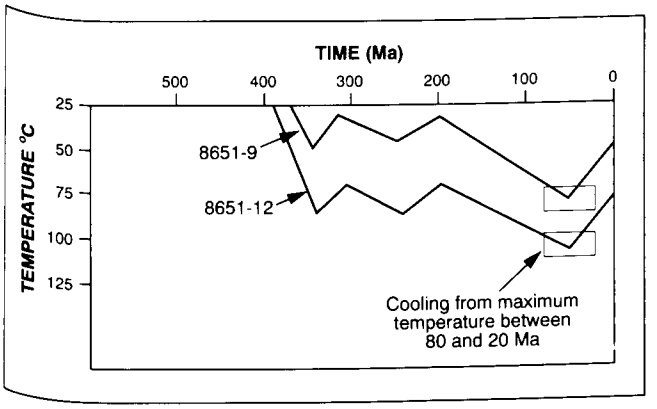
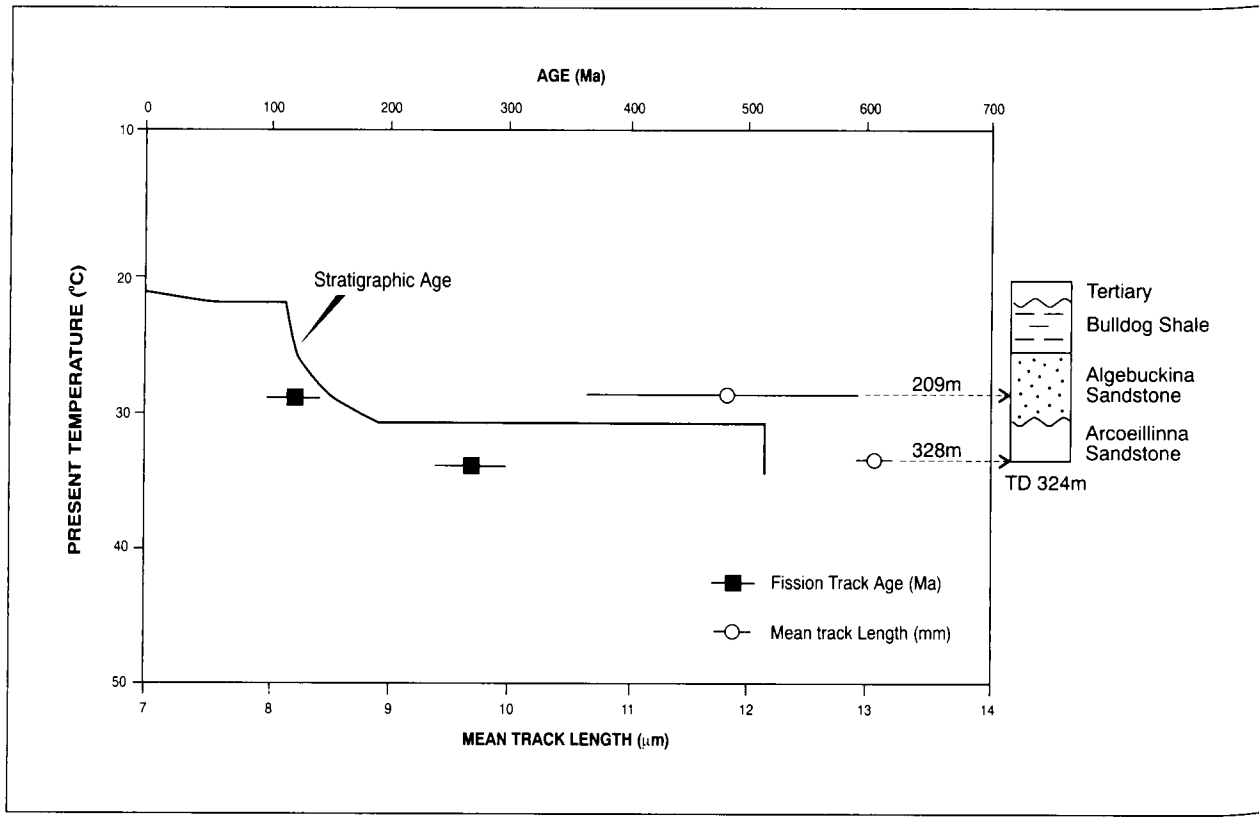


Figure 14. Schematic thermal histories, McDills–1.

80°C. The AFTA parameters from the Pacoota Sandstone sample are consistent with total annealing prior to cooling during the Alice Springs Orogeny, but the present high level of annealing does not allow precise assessment. Apart from the deepest, most samples indicate, or are consistent with, cooling from elevated temperatures between 60 to 0 Ma. The decrease in the amount of cooling with depth suggests that the present geothermal gradient has not remained constant through time. Two explanations are offered. The first is that the geothermal gradient has remained approximately linear through time but has recently (<5 Ma) increased in magnitude. The palaeo-temperatures down the well are consistent with an increase from 25–30°C/km to 40°C/km in the last 5 Ma. This variation in geothermal gradient combined with uplift and erosion of ~ 1 km starting between 60 and 5 Ma is consistent with the palaeo-temperature variation. The second explanation is that the elevated palaeo-temperatures suggested by the data higher in the well are partly related to heated water movement in Mesozoic aquifers which may have been associated with non-linear temperature–depth profiles.

MOUNT CRISPE–1

Mount Crispe–1 samples exhibit a similar thermal history to those from Mount Hammersley–1. AFTA data suggest Cambrian Mount Crispe beds' cooled from palaeo-temperatures greater than 110°C between 400 and 300 Ma, consistent with cooling during the Alice Springs Orogeny. The upper samples in the well have also experienced higher temperatures associated with a younger event. The highest samples in the well from the Algebuckina Sandstone and Mount Crispe beds probably experienced palaeo-temperatures ~ 40°C higher, prior to cooling in the last 50 Ma. Considering the younger event,



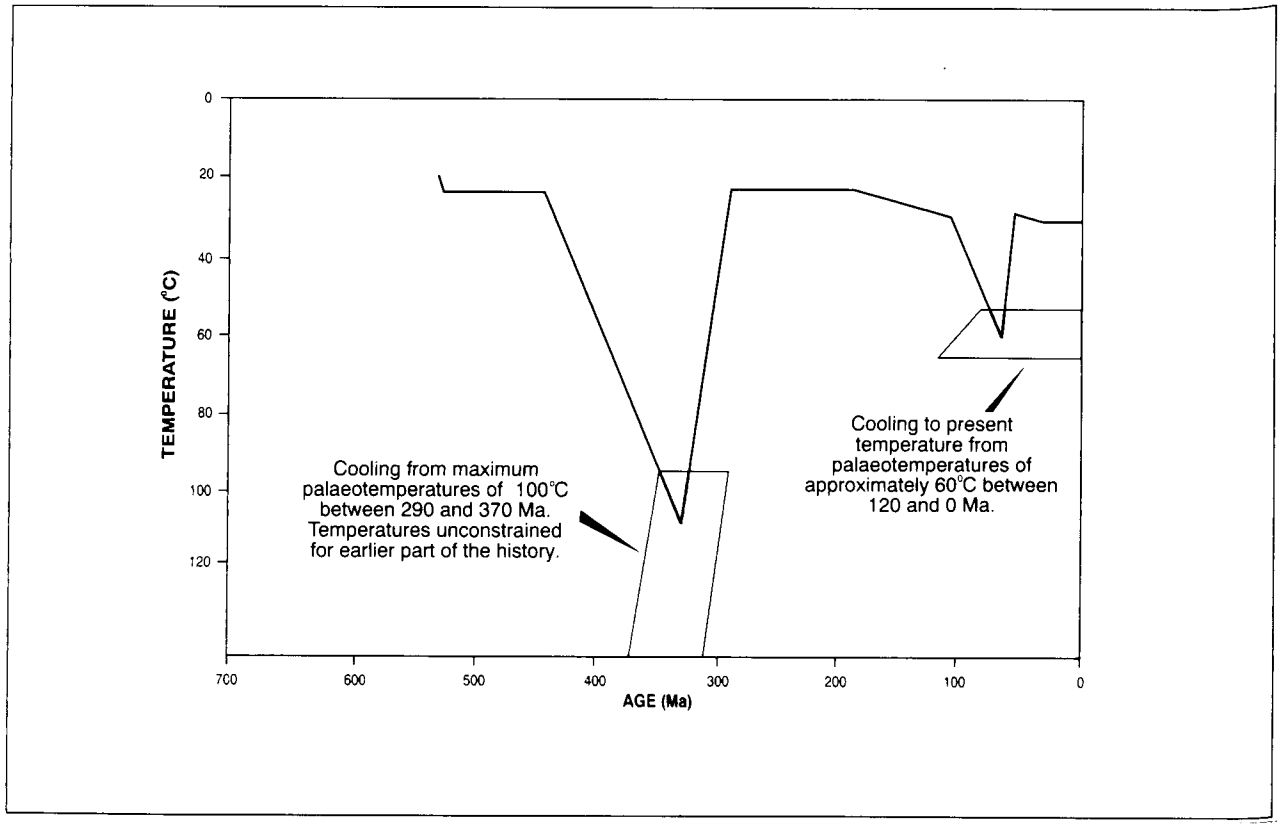


Figure 15 (top). AFTA parameters versus present temperature and sample depth for Afmeco Cur–5.
Figure 16 (bottom). Schematic thermal history of the Arcoellinna Sandstone in Afmeco Cur–5 based on AFTA constraints.

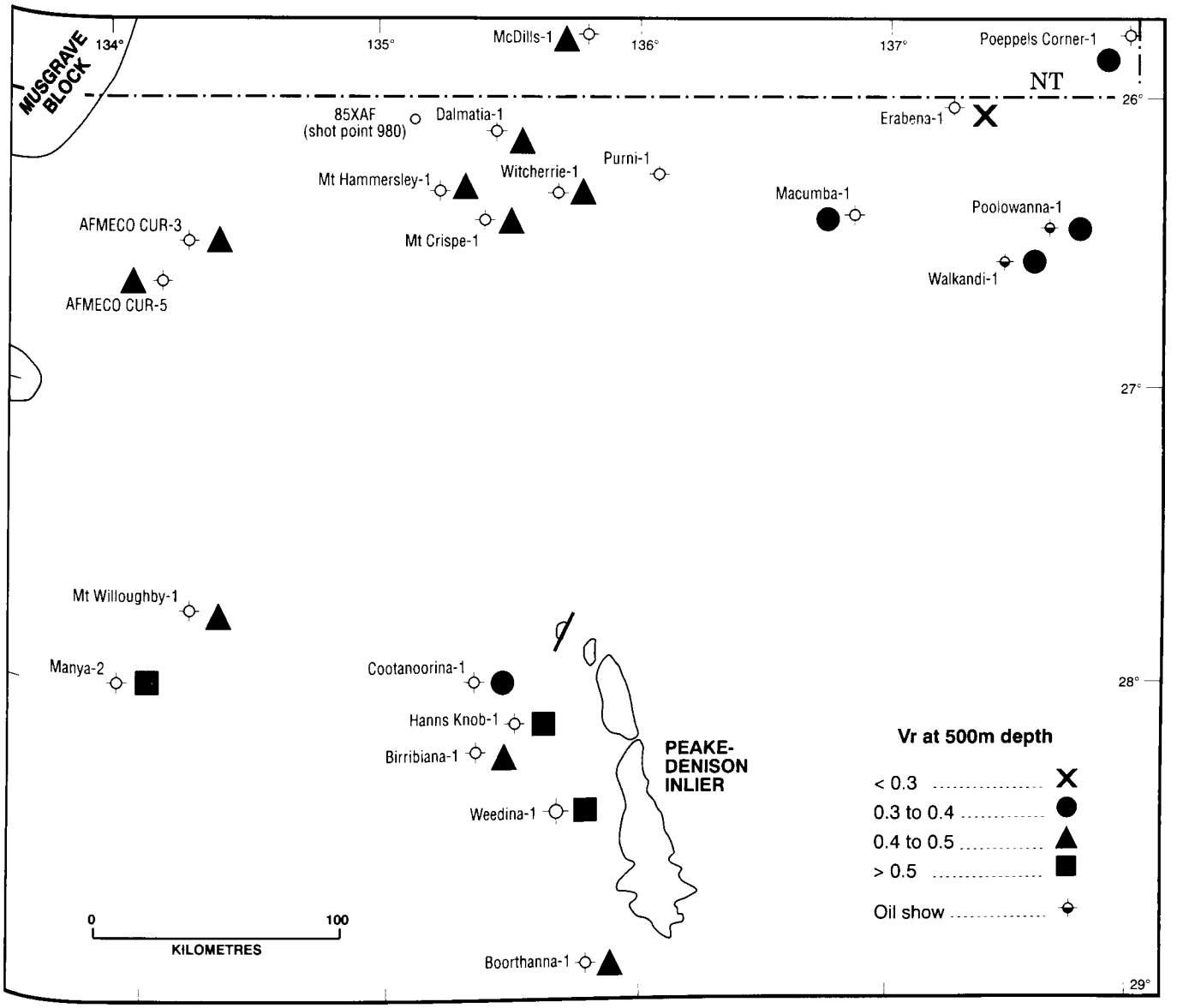


Figure 17. Vitrinite reflectance at 500 m depth.

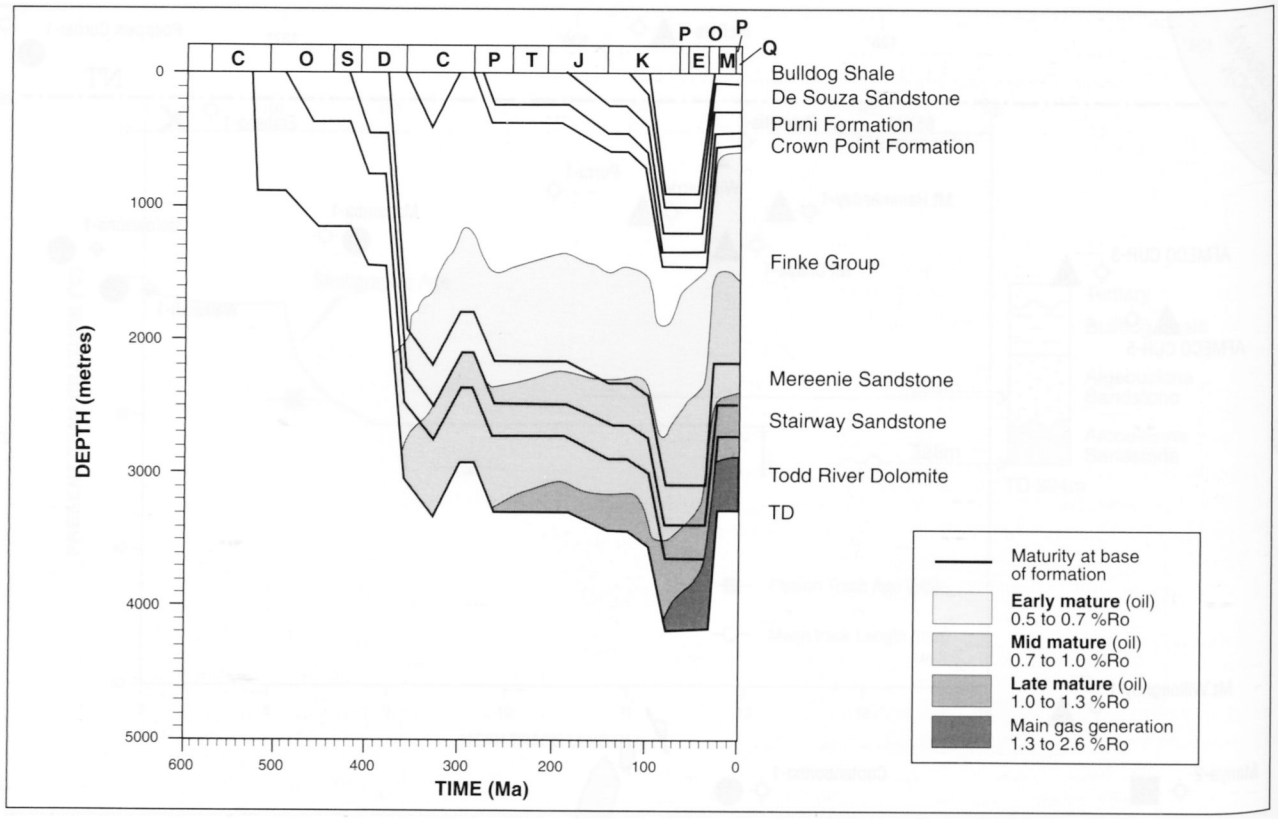
the difference between maximum palaeo-temperature and present temperature decreases downhole. The deepest sample from the Mount Crispe beds appears to have been heated to present temperatures within the last 5 Ma. A similar thermal history style to Mount Hammersley–1 is considered likely.

PURNI–1

Purni–1 is the easternmost well analysed and has the most complete Eromanga Basin sequence. Samples from the Winton Formation and Algebuckina Sandstone in Purni–1 are currently close to maximum temperature. AFTA data from the Algebuckina Sandstone suggest that approximately 10°C cooling has occurred in the last 100 Ma.

Discussion

In summary, the AFTA results indicate that thermal events of different ages have affected the margins of the Eringa Trough. The earliest event affects Cambro-Ordovician samples from Afmeco Cur–3 and –5, Mount Crispe–1 and probably Mount Hammersley–1. These wells experienced temperatures up to 100°C prior to cooling between 360 and 320 Ma, and this is correlated with uplift and erosion during the final stages of the Alice Springs Orogeny. The second event is only seen in Afmeco Cur–3; it involves cooling from temperatures ~ 40°C higher than present day between 300 and 90 Ma. It may be related to regional uplift and erosion between 240 and 180 Ma that affected the Amadeus Basin and Musgrave Block (Tingate, 1990).



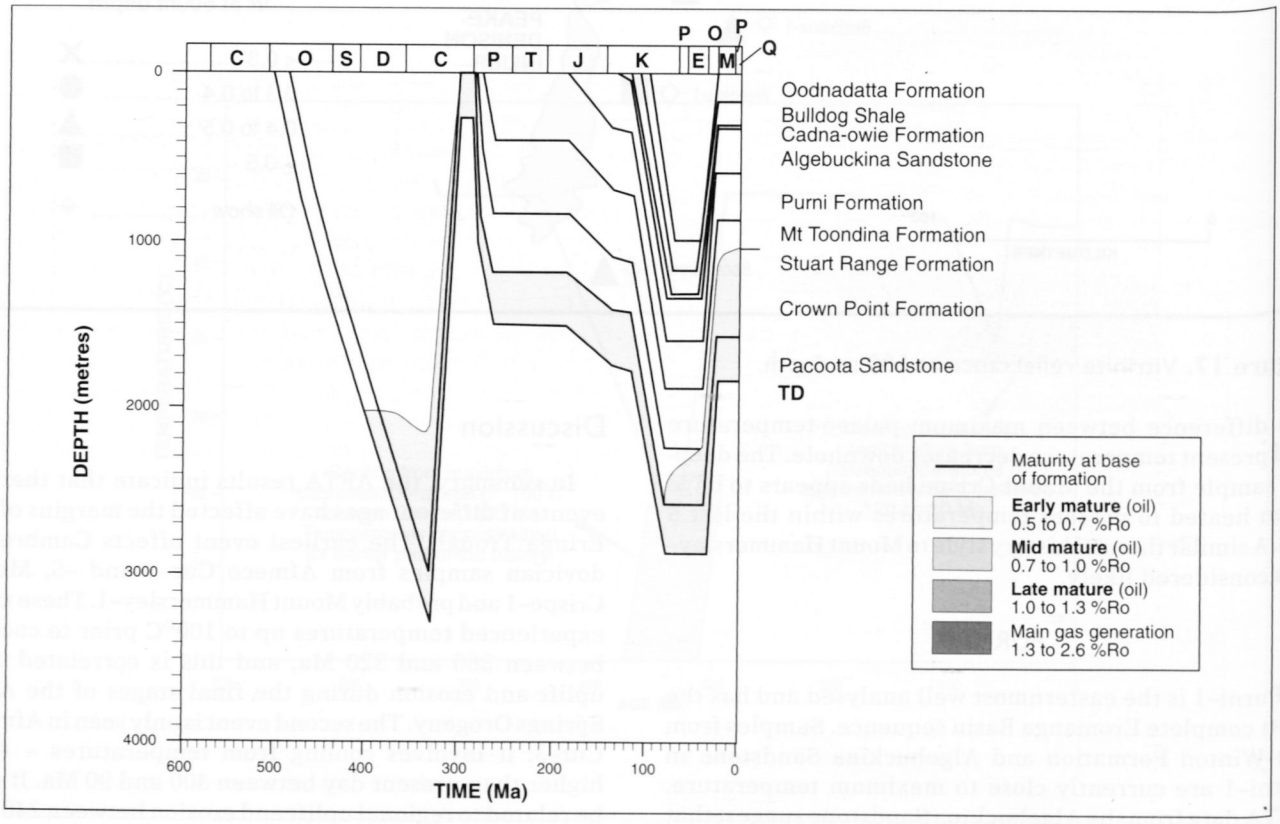
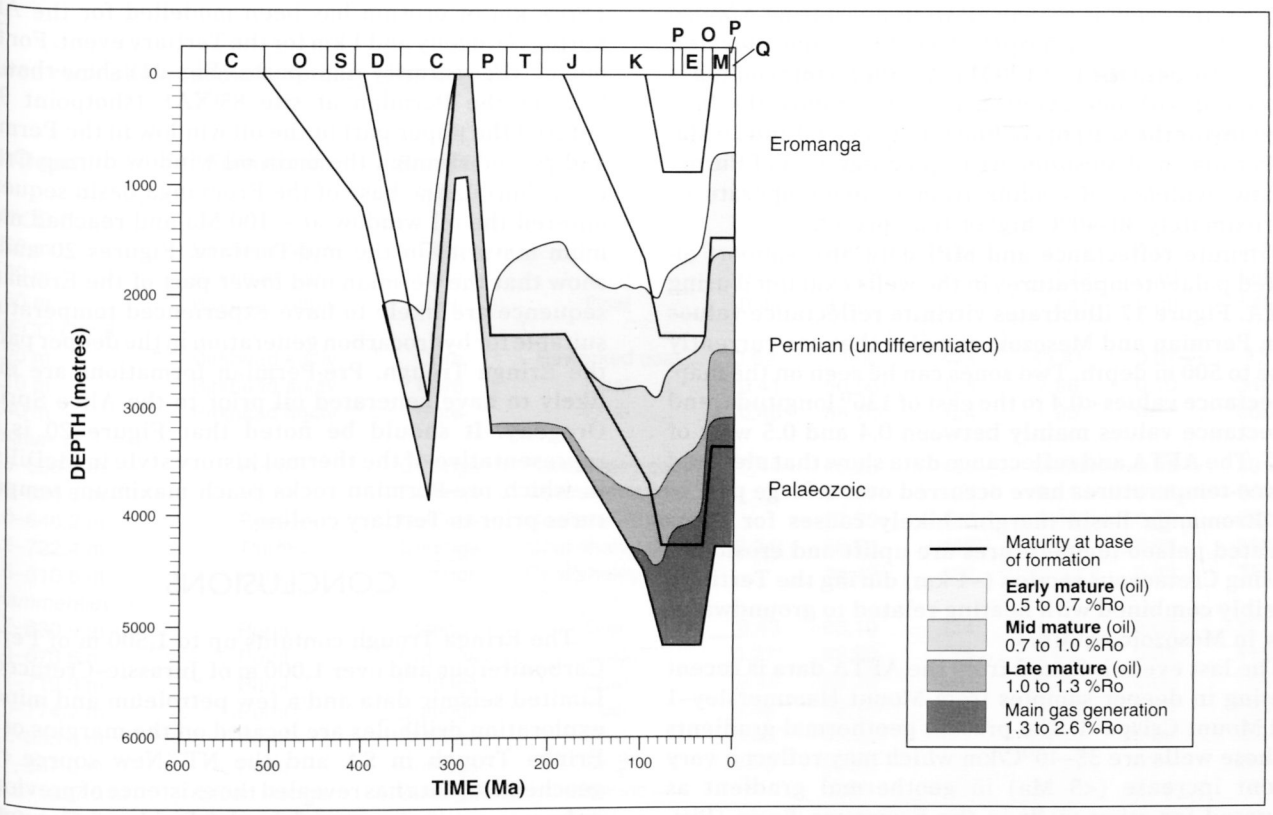


Figure 18 (above). Burial history plot for McDills–1 using AFTA palaeotemperature constraints.
Figure 19 (below). Burial history plot for Mount Hammersley–1 using AFTA palaeotemperature constraints.



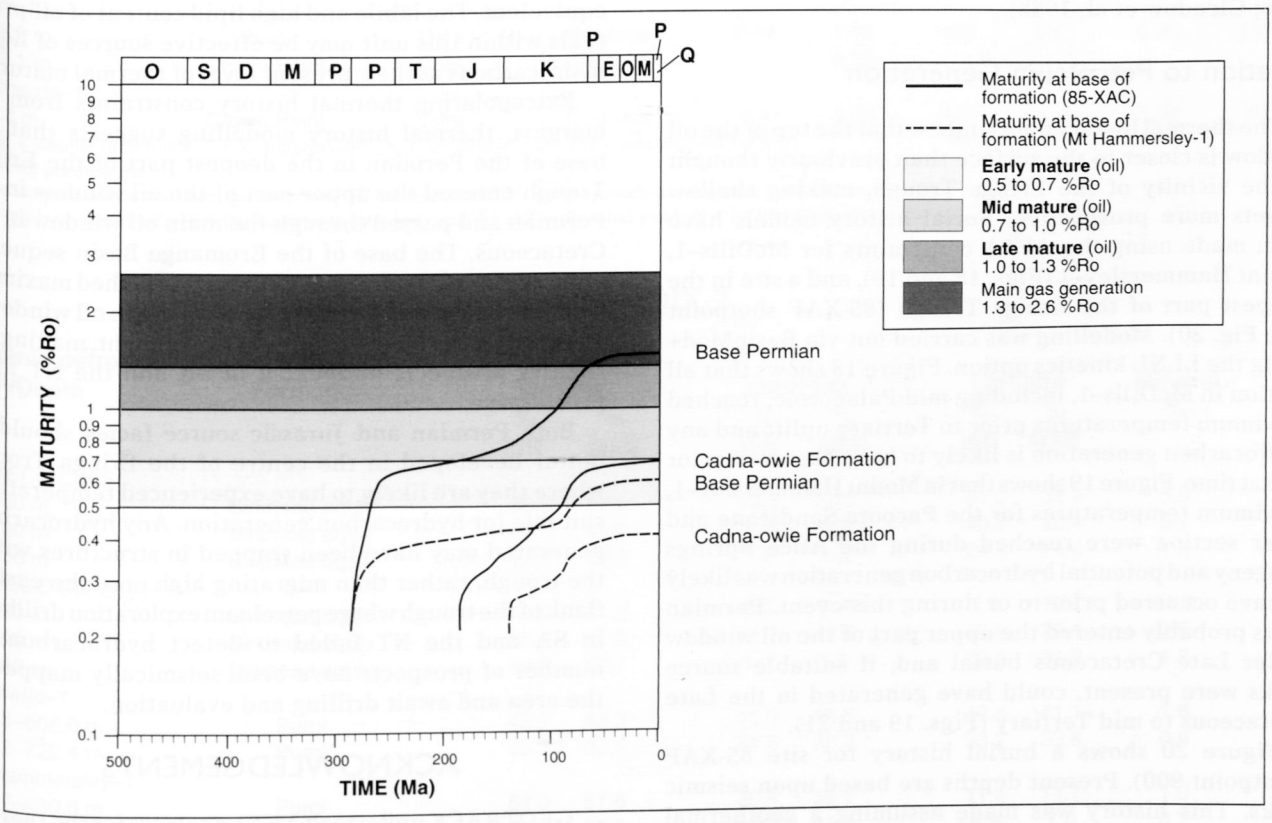


Figure 20 (above). Burial history plot at site 85-XAF (shotpoint 900) using AFTA palaeotemperature constraints.
Figure 21 (below). Maturity-time paths for the base of selected formations in Mount Hammersley–1 and site 85-XAF (shotpoint 900).

The third event is seen in all wells apart from Afmeco Cur–3. It involves widespread cooling from elevated temperatures in the last 100 Ma. Assuming this cooling is associated with one event, using all samples, the best estimate for the start of cooling is between 60 and 20 Ma. All Permian and Mesozoic AFTA samples west of Purni–1 show evidence of cooling from palaeotemperatures approximately 30–40°C higher than present.

Vitrinite reflectance and MPI data also support elevated palaeotemperatures in the wells examined using AFTA. Figure 17 illustrates vitrinite reflectance values from Permian and Mesozoic samples that are currently close to 500 m depth. Two zones can be seen on the map: reflectance values <0.4 to the east of 136° longitude, and reflectance values mainly between 0.4 and 0.5 west of 136°. The AFTA and reflectance data show that elevated palaeo-temperatures have occurred over a large part of the Eromanga Basin margin. Likely causes for these elevated palaeo-temperatures are uplift and erosion of missing Cretaceous section (~1 km) during the Tertiary, possibly combined with heating related to groundwater flow in Mesozoic aquifers.

The last event inferred from the AFTA data is recent heating in deeper samples from Mount Hammersley–1 and Mount Crispe–1. The present geothermal gradients in these wells are 35–40°C/km which may reflect a very recent increase (<5 Ma) in geothermal gradient as proposed for other wells in the Eromanga Basin (Pitt, 1986; Gleadow et al, 1988).

Relation to Petroleum Generation

The thermal history data suggest that the top of the oil window is closer to the surface than previously thought in the vicinity of the Eringa Trough, making shallow targets more prospective. Burial history models have been made using the AFTA constraints for McDills–1, Mount Hammersley–1 (Figs. 18 and 19), and a site in the deepest part of the Eringa Trough (85-XAF shotpoint 900; Fig. 20). Modelling was carried out via BasinMod+ using the LLNL kinetics option. Figure 18 shows that all section in McDills–1, including mid-Palaeozoic, reached maximum temperatures prior to Tertiary uplift and any hydrocarbon generation is likely to have occurred prior to that time. Figure 19 shows that in Mount Hammersley–1, maximum temperatures for the Pacoota Sandstone and older section were reached during the Alice Springs Orogeny and potential hydrocarbon generation was likely to have occurred prior to or during this event. Permian units probably entered the upper part of the oil window under Late Cretaceous burial and, if suitable source rocks were present, could have generated in the Late Cretaceous to mid Tertiary (Figs. 19 and 21).

Figure 20 shows a burial history for site 85-XAF (shotpoint 900). Present depths are based upon seismic picks. This history was made assuming a geothermal gradient of 30°C/km until 3 Ma, when it increased to 40°C/km. The recent increase in geothermal gradient has little effect on the present maturity levels (Fig. 21). Three km of erosion has been modelled for the Alice Springs Orogeny and 1 km for the Tertiary event. For this model, the maturity-time paths (Fig. 21) show that the base of the Permian at site 85-XAF (shotpoint 900) entered the upper part of the oil window in the Permian and passed through the main oil window during Cretaceous burial. The base of the Eromanga Basin sequence entered the oil window at ~ 100 Ma and reached maximum maturity in the mid-Tertiary. Figures 20 and 21 show that the Permian and lower part of the Eromanga sequence are likely to have experienced temperatures suitable for hydrocarbon generation in the deeper part of the Eringa Trough. Pre-Permian formations are more likely to have generated oil prior to the Alice Springs Orogeny. It should be noted that Figure 20 is not representative of the thermal history style in McDills–1, in which pre-Permian rocks reach maximum temperatures prior to Tertiary cooling.

CONCLUSIONS

The Eringa Trough contains up to 1,500 m of Permo-Carboniferous and over 1,000 m of Jurassic–Cretaceous. Limited seismic data and a few petroleum and mineral exploration drillholes are located on the margins of the Eringa Trough in SA and the NT. New source rock geochemical data has revealed the existence of previously unknown source potential in the Birkhead Formation equivalent. The labile and high lipid content of oil-prone coals within this unit may be effective sources of liquid hydrocarbons at their present level of thermal maturity.

Extrapolating thermal history constraints from the margins, thermal history modelling suggests that the base of the Permian in the deepest part of the Eringa Trough entered the upper part of the oil window in the Permian and passed through the main oil window in the Cretaceous. The base of the Eromanga Basin sequence entered the oil window at ~ 100 Ma and reached maximum maturity in the mid-Tertiary. The top of the oil window is closer to the surface than previously thought, making the shallow prospects delineated in SA and the NT more prospective.

Both Permian and Jurassic source facies should be better developed in the centre of the Eringa Trough, where they are likely to have experienced temperatures suitable for hydrocarbon generation. Any hydrocarbons generated may have been trapped in structures within the trough, rather than migrating high onto the eastern flank of the trough where petroleum exploration drillholes in SA and the NT failed to detect hydrocarbons. A number of prospects have been seismically mapped in the area and await drilling and evaluation.

ACKNOWLEDGEMENTS

GEOTRACK undertook AFTA analyses for the thermal history study and generously provided access to new interpretation software. The support of the Australian Research Council Collaborative Grant Program for the

APPENDIX 1

Source rock study: sample details, total organic carbon, Rock-Eval pyrolysis and vitrinite reflectance data.

Well/Depth	Formation	Sample type	Lithology	R_O (%)	TOC (%)	Rock-Eval pyrolysis			
						T_{max}	S1+S2	PI	HI
AFMECO Cur-3									
251.60 m	Birkhead equiv	Core	Coal/shaley coal	0.43	34.30	421	135.08	0.09	359
251.90 m	Birkhead equiv	Core	Coal	0.43	39.00	423	168.29	0.10	388
259.50 m	Birkhead equiv	Core	Coal	0.44	47.20	419	279.41	0.08	542
AFMECO Cur-5									
209.20 m	Birkhead equiv	Core	Reworked coal	0.62_	52.90	421	49.41	0.07	87
210.10 m	Birkhead equiv	Core	Coal	0.41	50.50	424	7.98	0.10	312
249.40 m	Birkhead equiv	Core	Coal	0.45	58.70	424	7.95	0.13	368
Dalmatia–1									
591.3–606.0 m	Purni	Cuttings	Coal/shaley coal	0.44	49.20	423	12.55	0.03	305
612.6–624.8 m	Purni	Cuttings	Coal/shaley coal		44.30	425	9.11	0.03	268
634.0–646.2 m	Purni	Cuttings	Coal/shaley coal		37.70	426	7.08	0.02	242
713.2–722.4 m	Purni	Cuttings	Coal/shaley coal	0.34*	38.50	425	14.48	0.03	318
792.5–810.8 m	Purni	Cuttings	Coal/shaley coal		39.40	422	11.12	0.03	317
Mt Hammersley–1									
615.7–630.9 m	Purni	Cuttings	Coal	0.43	63.10	424	4.46	0.03	127
658.4–673.6 m	Purni	Cuttings	Coal	0.37*	62.80	425	4.03	0.02	113
704.1–719.3 m	Purni	Cuttings	Coal	0.45	58.70	425	6.11	0.03	164
762.0–774.2 m	Purni	Cuttings	Coal	0.39*	59.10	425	17.83	0.04	293
838.2–853.4 m	Purni	Cuttings	Coal	0.33*	55.80	427	24.53	0.03	359
871.7–887.0 m	Purni	Cuttings	Coal	0.36*	52.80	427	15.24	0.04	264
1219.2–1237.5 m	Stuart Range	Cuttings	Siltstone		0.41	nd	1.14	0.16	39
1408.2–1423.4 m	Crown Point	Cuttings	Siltstone		0.35	nd	1.00	0.02	34
Purni–1									
1445.8 m	Purni	Core	Siltstone	0.89_	7.48	429	0.01	0.86	137
1772.1 m	Crown Point	Core	Siltstone		0.22				
Witcherrie–1									
556.2 m	Crown Point	Core	Siltstone	0.51	3.38	420	0.02	0.25	90

R_o (%) = vitrinite reflectance; * = R_o suppression; _ = R_o unreliable; TOC (%) = total organic carbon
Rock-Eval parameters:
T_{max} = temperature of maximum generation of S2 hydrocarbons; S1 = mg hydrocarbons/g rock (free hydrocarbons);
S2 = mg hydrocarbons/g rock (hydrocarbons from kerogen); S1+S2 = potential yield; PI = S1/(S1+S2); HI = S2/g TOC

APPENDIX 2

Organic petrographic (maceral) data.

Well/Depth	Formation	Vitrinite		Inertinite		Liptinite		Mineral
		% WR	% MFB	% WR	% MFB	% WR	% MFB	%
AFMECO Cur-3								
251.60 m	Birkhead equiv	50.2	52.9	13.5	14.2	31.3	32.9	5.0
251.90 m	Birkhead equiv	46.3	49.1	4.3	4.5	43.7	46.4	5.7
259.50 m	Birkhead equiv	72.6	73.9	1.2	1.3	24.4	24.8	1.8
AFMECO Cur-5								
209.20 m	Birkhead equiv	7.9	41.9	9.0	47.6	2.0	10.7	81.0
210.10 m	Birkhead equiv	66.2	67.9	11.7	12.0	19.6	20.1	2.5
249.40 m	Birkhead equiv	66.5	67.7	1.1	1.8	30.6	31.2	1.8
Dalmatia–1								
591.3–606.0 m	Purni	42.7	43.3	15.3	15.6	40.4	41.1	1.6
713.2–722.4 m	Purni	33.3	33.9	31.6	32.3	33.2	33.8	0.9
Mt Hammersley–1								
615.7–630.9 m	Purni	57.0	57.6	30.4	30.7	11.6	11.7	1.0
658.4–673.6 m	Purni	51.2	51.6	41.2	41.4	6.9	7.0	0.7
704.1–719.3 m	Purni	50.3	51.0	41.5	41.7	7.3	7.3	0.9
762.0–774.2 m	Purni	64.7	65.5	17.3	17.6	16.7	16.9	1.3

Well/Depth	Formation	Vitrinite % WR	Vitrinite % MFB	Inertinite % WR	Inertinite % MFB	Liptinite % WR	Liptinite % MFB	Mineral %
838.2–853.4 m	Purni	81.3	82.4	4.3	4.4	13.1	13.2	1.4
871.7–887.0 m	Purni	27.4	28.3	53.4	55.5	16.2	16.7	3.0
1219.2–1237.5 m	Stuart Range	0.2		1.9		1.4		96.5
1408.2–1423.4 m	Crown Point	0.8		1.0		1.0		96.1
Purni–1								
1445.8 m	Purni	45.3	72.0	9.6	14.9	8.5	13.1	36.6
1772.1m	Crown Point	0.0		0.1		3.0		96.9
Witcherrie–1								
556.2 m	Crown Point	31.3	85.6	3.7	10.1	1.6	4.3	63.4

WR = whole rock; MFB = mineral free basis

APPENDIX 3

Extract yield and composition.

Well/Depth	Formation	EOM ppm	Yield mg/g TOC	EOM Sat (%)	EOM Aro (%)	EOM Pol (%)	Alkane parameters Pr/Ph	Pr/n-C_{17}	Ph/n-C_{18}	n-alkanes range	n-alkanes max
AFMECO Cur-3											
251.6m	Birkhead equiv	46,519	432	20.6	4.7	74.7	2.3	0.16	0.06	13-33	27
251.9m	Birkhead equiv	69,412	178	4.3	3.8	91.9	2.0	0.23	0.11	13-33	25
259.5m	Birkhead equiv	76,429	162	4.8	3.0	92.2				13-33	25
AFMECO Cur-5											
210.1m	Birkhead equiv	71,317	141	2.4	5.5	92.1				19-33	27
249.4m	Birkhead equiv	80,691	137	1.9	2.9	95.2				19-33	27
Dalmatia–1											
591.3–606.0 m	Purni	26,427	54	6.3	7.0	86.7	4.0	0.91	0.16	13-33	16 & 27
612.6–624.8 m	Purni	21,482	48	6.8	8.6	84.6	3.0	1.27	0.28	13-33	16 & 27
713.2–722.4 m	Purni	30,298	79	6.3	4.9	88.8	4.2	1.50	0.23	13-33	16 & 25
Mt Hammersley–1											
615.7–630.9 m	Purni	18,267	29	4.7	7.1	88.2	3.4	0.81	0.33	11-33	14 & 31
658.4–673.6 m	Purni	16,985	27	5.5	8.5	86.0	2.3	1.00	0.50	11-33	14 & 31
704.1–719.3 m	Purni	19,704	34	4.7	9.0	86.3	3.8	1.25	0.38	12-33	16 & 31
762.0–774.2 m	Purni	31,962	54	6.4	10.2	83.4	3.5				
838.2–853.4 m	Purni	31,680	57	7.1	7.9	85.0	3.8	2.37	0.75	10-33	16 & 27
871.7–887.0 m	Purni	26,155	50	11.2	8.3	80.5	3.3	1.33	0.33	10-33	16 & 27
1219.2–1237.5 m	Stuart Range	367	89	25.8	6.6	67.6	3.3	0.87	0.22	9-33	16 & 25
Purni–1											
1445.8 m	Purni	3,119	42	5.4	14.2	80.4					
1772.1 m	Crown Point	116	52	4.7	2.3	93.0					

Sat = Saturates; Aro = Aromatics; Pol = Resins + Asphaltenes; Pr = Pristane; Ph = Phytane.

APPENDIX 4

Key maturity and source-specific biomarker ratios for Permian and Jurassic sediments.

Well/Depth	Formation	Maturity $\frac{T_s}{T_m}$	Maturity mor/hop	Maturity S/S+R	Maturity $\frac{\beta\alpha}{\beta\alpha+\alpha\alpha\alpha}$	Maturity 27:28:29	Maturity hop/ster	Source x/hop	Source BNH/hop	Source retene/phen	Source 1-MP/9-MP	Source 1,2,5-TMN/1,3,6-TMN
		a	b	c	d	e	f	g	h	i	j	k
AFMECO Cur-3												
251.60 m	Birkhead equiv	0.10	0.38	0.03	0.30	2:16:82	3.1		0.0371	5.95	0.74	1.26
259.50 m	Birkhead equiv	0.06	0.42	0.01	0.11	1:5:94	34.4		0.0018	25.95		
AFMECO Cur-5												
210.10 m	Birkhead equiv									6.44	0.75	3.85
249.40 m	Birkhead equiv	0.61	0.41	0.01	0.59	5:14:81	4.6		0.0016	7.43	1.08	3.24
Dalmatia–1												
591.3–606.0 m	Purni	0.40	0.20	0.28	0.59	7:20:73	1.4	1.33	0.340	0.23	0.61	
612.6–624.8 m	Purni	0.48	0.10	0.24	0.59	7:22:71	0.7	0.98	0.024	0.16	0.52	0.70
713.2–722.4 m	Purni	0.45	0.15	0.02	0.45	9:13:78	0.5	0.84	0.134			

Well/Depth	Formation	Maturity					Source					
		$\frac{T^s}{Tm}$	mor / hop	S / S+R	βαα / βαα+ααα	27:28:29	hop / ster	x / hop	BNH / hop	retene / phen	1-MP / 9MP	1,2,5-TMN / 1,3,6-TMN
		a	b	c	d	e	f	g	h	i	j	k
Mt Hammersley–1												
615.7–630.9 m	Purni	0.26	0.19	0.25	0.61	3:22:75	2.2	2.22	0.275	0.45	0.51	0.58
658.4–673.6 m	Purni									0.78	0.34	0.61
704.1–719.3 m	Purni	0.17	0.15	0.11	0.36	8:15:77	4.1	2.12	0.965	0.30	0.25	0.46
762.0–774.2 m	Purni									0.17	0.38	0.58
838.2–853.4 m	Purni	0.20	0.30	0.09	0.31	11:13:76	19.8	0.75	0.140	1.09	0.55	0.46
871.7–887.0 m	Purni									0.72	0.47	0.48
1219.2–1237.5 m	Stuart Range	0.36	0.08	0.15	0.42	6:56:38	0.5	0.22	0.066	0.23	0.71	0.71
Purni–1												
1445.7 m	Purni	0.09	0.26	0.15	0.47	9:21:70	12.4	0.351	0.005	0.67		0.86
1772.1 m	Crown Point		0.29					0.06		0.003	0.99	0.43

DERIVATION SPECIFICITY

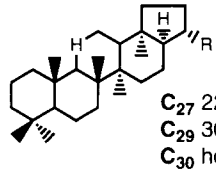
a	C_{27} 18a-22,29,30-trisnorneohopane (T_s)/C_{27} 17a-22,29,30-trisnorhopane (T_m)	maturity
b	C_{30} 17b,21a-moretane/17a,21b-hopane	maturity
c	C_{29} 5a,14a,17a-ethylcholestane 20S/C_{29} 5a,14a,17a-ethylcholestane 20S + 20R	maturity
d	C_{29} 5b,14a,17a-ethlycholestane 20R/C_{29} 5b,14a,17a-ethlycholestane 20R + C_{29} 5a,14a,17a-ethylcholestane 20R	maturity
e	C_{27}:C_{28}:C_{29} 5a,14a,17a-sterane 20R	C_{27} marine algae; C_{28} lacustrine algae; C_{29} land plants
f	$SC_{27,29,30}$ hopanes/SC_{29} steranes	bacterial versus algal input
g	C_{29} triterpane/C_{29} 17a,21b-30-norhopane	maturity, ?specific precursor
h	28,30-bisnorhopane/C_{30} 17a,21b-hopane	environment of deposition
i	retene/phenanthrene	aromatic source parameter
j	1-methylphenanthrene/9-methylphenanthrene	aromatic source parameter
k	1,2,5-trimethylnaphthalenes/1,3,6-trimethylnaphthalenes	aromatic source parameter

continued next page.

APPENDIX 5

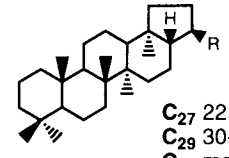
Structures of compounds discussed in the text.

Hopanes



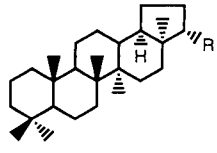
C_{27} 22,29,30-trisnorhopane [T_m]
C_{29} 30-norhopane
C_{30} hopane
C_{31} homohopane
S and *R* diastereosiomers at C_{22}

17α-Hopanes

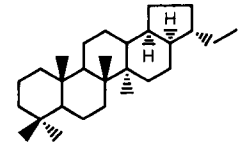


C_{27} 22,29,30-trisnormoretane
C_{29} 30-normoretane
C_{30} moretane
C_{31} homomoretane
S and *R* diastereosiomers at C_{22}

17β-Hopanes (moretanes)



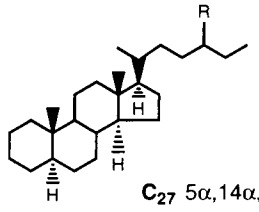
18α-22,29,30-Trisnorneohopane [T_s]



17α-28,30-Bisnorhopane

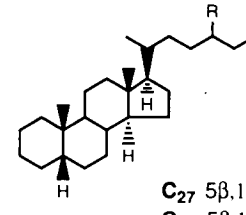
For C_{27}, C_{29}, C_{30}, C_{31} compounds R = H, C_2H_5, *i*-C_3H_7, *s*-C_4H_9

Steranes



C_{27} 5α,14α,17α-cholestane
C_{29} 5α,14α,17α-methylcholestane
C_{30} 5α,14α,17α-ethylcholestane
S and *R* diastereosiomers at C_{20}

5α,14α,17α-Steranes

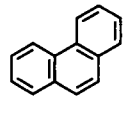


C_{27} 5β,14α,17α-cholestane
C_{28} 5β,14α,17α-methylsterane
C_{29} 5β,14α,17α-ethylcholsterane
S and *R* diastereoisomers at C_{20}

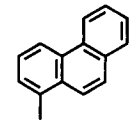
5β,14α,17α-Steranes

For C_{27}, C_{28}, C_{29} compounds R = H, CH_2, C_2H_5

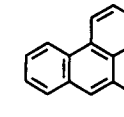
Aromatic Hydrocarbons



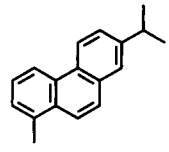
Phenanthrene



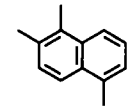
1-Methylphenanthrene



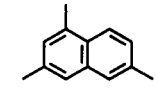
9-Methylphenanthrene



Retene



1,2,5-Trimethylnaphthalene



1,3,6-Trimethylnaphthalene

thermal history study is gratefully acknowledged. Lindsay Elliot (Santos Ltd.) reviewed the manuscript. Adrian Francis of MESA drafted most of the figures. Brent Jensen-Schmidt (consultant to MESA) provided the depth interpretions from seismic data. Wiltshire Geological Services provided digital wireline log data for NT drillholes.

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NOTE: This publication is included in the print copy of the thesis held in the University of Adelaide Library.

A NEW MODEL FOR THE HUTTON/BIRKHEAD RESERVOIR/SEAL COUPLET AND THE ASSOCIATED BIRKHEAD-HUTTON(!) PETROLEUM SYSTEM

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ABSTRACT

3D seismic, sequence stratigraphy, dipmeter interpretation and neodymium model age dating together with conventional correlation techniques, have provided a new model for the deposition of the Hutton Sandstone to Birkhead Formation transition in the Eromanga Basin. Analysis of seal and carrier bed properties through time, in combination with hydrocarbon geochemistry and thermal modelling, indicates that the Birkhead–Hutton (!)[1] petroleum system has produced significant quantities of oil in the Cooper Basin sector of the Eromanga Basin.

A disconformity near the base of the Hutton/Birkhead transition has controlled the location of oil–prone source rocks within the Birkhead Formation and stratigraphically focussed migration along palaeo–topographic ridges. A diachronous influx of volcanic–arc–derived (VAD) sediment within the Birkhead Formation has been traced right across the productive part of the Eromanga Basin. This influx of VAD sediment is associated with the main seal to underlying accumulations within both the lower Birkhead Formation and Hutton Sandstone. Sands comprising VAD sediment, which are juxtaposed, form the weak link within the main seal. The sediments between the VAD influx and the underlying unconformity in many locations constitute a waste zone.

Palaeo–oil columns are common beneath extant, live oil accumulations. This indicates that a possible decrease in seal potential of the VAD sediment has occurred over time. The main seals to underlying accumulations were originally static, water–wet capillary seals which, mostly through an alteration of wettability, changed to simple permeability seals for currently migrating oil. Seal analysis, biomarker studies and geothermal modelling indicate that a double migration pulse has occurred in some areas of the Eromanga Basin. Palaeo–oil columns are related to a Late Cretaceous charge, and live oil accumulations to presently migrating oil.

Biomarker analysis of source rocks and oils from the Permian and Jurassic of the central Patchawarra Trough and the Gidgealpa area, reveal that much of the oil in the Eromanga Basin may have a significant lateral migrational component and be of Jurassic (i.e. intra–Eromanga) origin. Differences in hopane signatures can be used to discriminate between palaeo–oil and presently migrating live oil, and to constrain migration pathways. Thus, in some locations the identification of new source kitchens has been made possible by a combination of seal and biomarker analysis taking into account stratigraphic inheritance on conventional structural drainage maps.

INTRODUCTION

The Jurassic section of the Eromanga Basin (Figure 1), in common with other fluvio–lacustrine sequences, is well known for its lithological heterogeneity which makes it a difficult environment in which to find and produce hydrocarbons. This is partially due to problems caused by the paucity of indicator palynomorphs, and a resultant over–dependence on lithostratigraphic correlation. Also, problems of correlation within the Eromanga Basin have, to some extent, been exacerbated by political division. In addition, conventional correlation, which tends to rely on 2D seismic and wireline logs, has not been focussed on the task of actually understanding trapping mechanisms within the basin. Thus the most important surfaces within the productive zone, namely the sealing surfaces, are not coincident with stratigraphic boundaries. For example, the Birkhead Formation is often quoted as the main seal to the underlying Hutton Sandstone, and yet significant production comes from reservoirs that are commonly developed within the lower to mid Birkhead Formation.

The Jurassic of the Eromanga Basin is a reservoir–rich, seal–poor sequence. Bearing this in mind, we present herein an interpretation of the Hutton/Birkhead reservoir and seal couplet by focussing on the seal, rather than the underlying reservoir. This interpretation is then combined with oil and source rock geochemistry to identify a petroleum system that exists entirely within Jurassic rocks.

To formulate our depositional hypothesis, we have

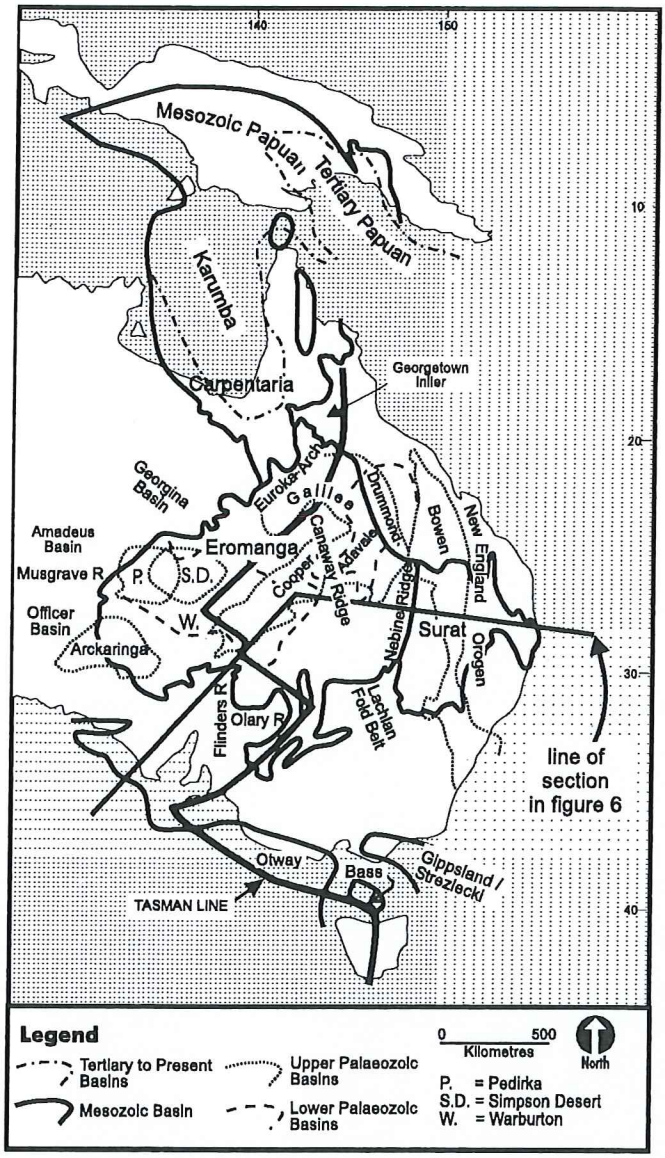

Figure 1. Palaeozoic, Mesozoic and Tertiary basins of eastern Australasia, showing some structural detail and the Tasman Line (Veevers, 1984) which divides the continent into Precambrian terrain to the west and Phanerozoic terrain to the east.

studied some widely spaced locations in detail. We have also developed a new classification of top seals to enhance our understanding of shows that occur within both the seal and reservoir. This classification is described below.

A NEW SEAL CLASSIFICATION SCHEME

To our knowledge, a basic classification system for seals has not previously been attempted. N.L. Watts (1987) classified seals as either 'capillary' or 'hydraulic' according to their capillary displacement pressure and their likely mode of failure. Sneider (1992) further classified capillary seals into five categories based on their capillary displacement pressures and the size of the oil column that they may retain. Demaison and Huizinga (1991) proposed a classification of petroleum systems in which seals played an important part. However, some important types of seals e.g. pressure and permeability seals, do not fit readily into these classifications. Furthermore, the previously published classification schemes have only addressed seals and their importance in entrapment despite their obvious influence on leakage and even production, albeit on a different time scale. In this paper we propose a new and very simple classification of seals that includes all aspects of entrapment by, and migration/flow through, seals. This classification is useful for both exploration and production purposes.

A seal is a surface that encloses a volume of low fluid pressure potential where, during the production of hydrocarbons, the location of the separate hydrocarbon phase is controlled by a baffle. The significance of a seal in exploration is that hydrocarbons reaching its location will accumulate. There are effectively three main and one minor types of seal which control the entrapment and production of hydrocarbons. These are summarised in Table 1 and below.

1. Pressure seals are total barriers to the flow of both hydrocarbons and water. They are normally of regional extent when effective in entrapment. Examples exist in the Nagaoka Plain Basin, Japan (Magara, 1986) and the North Sea where they are associated with overpressured shales. In theory, they may temporarily exist as confined barriers to flow (caused by low permeability) during production.
2. Capillary seals are total barriers only to the flow of separate–phase hydrocarbons. They can be effective during entrapment or production. In exceptional circumstances, as in the case of an oil wet barrier, they can impede water flow during production (Williams et al, 1994, Boult et al, 1997b). Once breached, capillary seals may then act as permeability barriers due to their finer grain size.
3. Permeability seals are total barriers to neither hydrocarbons nor water. They are very common in production situations where they may either prevent efficient hydrocarbon extraction or enhance it if the production strategy is optimised. Permeability seals are only effective in entrapment situations during active migration when hydrocarbons will 'back up' behind them or, for a limited time, as hydrocarbons leak away after a capillary seal has been breached.

Table 1. Simple seal classification.

Seal type	Static barrier to hydrocarbons	Static barrier to water
Pressure	Yes	Yes
Water wet capillary	Yes	No
Oil wet capillary (minor)	No	Yes
Permeability	No	No

The main criticism of the above classification is that it does not address the fractured seal. Our response to this argument is to emphasise that when using our classification the 'weak link' or the effective seal in any petroleum system must be identified correctly. Thus, if a formation is fractured, it is either not acting as the effective seal in a system or, if it is trapping hydrocarbons, it is acting as a permeability seal. A subdivision of permeability seals into matrix–flow or fracture–flow types could be invoked in this case.

THE GEOLOGIC SETTING OF THE EROMANGA BASIN

Convergent plate–margin tectonism was in operation in eastern Australia from at least 490 to 90 Ma (Veevers et al, 1991; D.I. Gravestock, MESA pers. comm., 1996). Eastward migration of successive volcanic arc complexes resulted in the superposition of intra–cratonic, sag basins on formerly active foreland and back–arc basins. The Drummond and Adavale Basins (Fig.1) are thus interpreted as Lower Palaeozoic foreland basins (Moore et al, 1986) whereas the overlying Cooper and Galilee Basins are regarded as Upper Palaeozoic, predominantly intra–cratonic sag basins. The Bowen Basin is considered to be part of a north–south, 2,000+ km long foreland basin system that extended from just south of Townsville in northern Queensland to the south of Sydney (Elliot, 1993; Baillie et al, 1994). Both the Mesozoic Eromanga and Surat Basins are interpreted by Moore et al (1986) as intra–cratonic sag basins with the development of mild Tertiary to present–day folding (Sprigg, 1986; Moore et al, 1986). However, the Surat Basin is regarded as a foreland basin that was contiguous with the Papuan Basin by Veevers (1984). The connection between the Surat and the Papuan Basin has now been obliterated by the uplift of the Great Dividing Range in northern Queensland but marked similarities in their geology still exist (Veevers, 1984). The Carpentaria Basin is an intra–cratonic sag basin associated with the Mesozoic foreland Papuan Basin. The present–day Karumba Basin, which overlies the Carpentaria Basin is the present intra–cratonic sag basin associated with the Tertiary to modern foreland Papuan Basin centred on the Aure Trough (Boult, 1997).

Throughout the period from 490 to 90 Ma there was a balance of sediment supply between successive volcanic arcs to the east of the Tasman Line (Veevers, 1984) and stable cratonic terrain to the west of the Tasman line. Figure 2 shows that during the Upper Palaeozoic, the Canaway Ridge, which occurs between the Cooper and Galilee Basins (Fig. 1) was a significant barrier to sediment supply. Thus the Canaway Ridge prevented VAD sediment being supplied to the Cooper Basin while the Galilee and Bowen Basins are dominated by VAD sediment. Sediments with a significant quartz content that occur within the Bowen and Galilee Basins were possibly derived from Precambrian terrain to the northwest of the Tasman Line. During the Mesozoic, uplift on the Canaway Ridge was less of a barrier to sediment supply and the distribution of VAD sediment across the interior became more widespread. The Birkhead Formation represents the furthest distribution of VAD sediment across the interior of Australia until the onset of marine conditions during the Cretaceous.

THE HUTTON SANDSTONE/BIRKHEAD FORMATION RESERVOIR AND SEAL COUPLET

The Hutton Sandstone and lower Birkhead Formation produce the bulk of the oil from the Eromanga Basin (Fig. 3). The main seal to these reservoirs occurs within the Birkhead Formation. Production is mostly from domal structures and variable stratigraphic influence on reservoir geometry and quality is caused by the transitional nature of the Hutton Sandstone to Birkhead Formation contact. In many locations a waste zone occurs between the regional seal and the reservoir. Economic hydrocarbons cannot be produced where this waste zone thickness is greater than either structural closure or maximum capillary seal capacity.

The Hutton Sandstone is a widespread unit consisting of a thick sequence of clean quartzose–dominated, braided–fluvial arenites, with minor thin shaly interbeds (Bowering, 1982; Gravestock et al, 1983; Hill, 1985; Ariesen, 1986; John and Almond, 1987; Fairburn, 1993) and is regionally consistent in terms of reservoir quality. The sediments of the Birkhead Formation were deposited within a lower energy, meandering to anastomosing fluvial, swampy deltaic to lacustrine environment (Solomon and Ormsby, 1984; Paton, 1986; Watts K.J., 1987; Lanzilli and Boult, 1996).

We interpret an influx of VAD sediment to have occurred within the Birkhead Formation at Kenmore, Bodalla South, Jackson, Gidgealpa and Moorari (Boult et al, 1997b). This influx has also been interpreted (Gibson et al, 1995) to occur at Mulapula which is 135 km southwest of Gidgealpa; and the Birkhead Formation as a whole has been identified more than 500 km west of the Birdsville Track Ridge in the Eringa Trough (Alexander and Jensen–Schmidt, 1995). Thus, within the Hutton/Birkhead transition there are three sedimentary units: the Hutton Sandstone, the Birkhead Formation below the influx of VAD sediment and the Birkhead Formation above this influx. The influx of VAD sediment is sharp to gradational in places. Where it is gradational, reservoirs can be developed within the base of the post–VAD influx lithofacies, as for example at Gidgealpa. Diagenesis of the VAD sediments and the formation of pore–blocking clays has been an important factor in the formation of the seal within the Birkhead Formation.

Relevant previous interpretation of the Hutton Sandstone

The Hutton Sandstone has a very blocky gamma ray log signature, with high gamma ray peaks representing

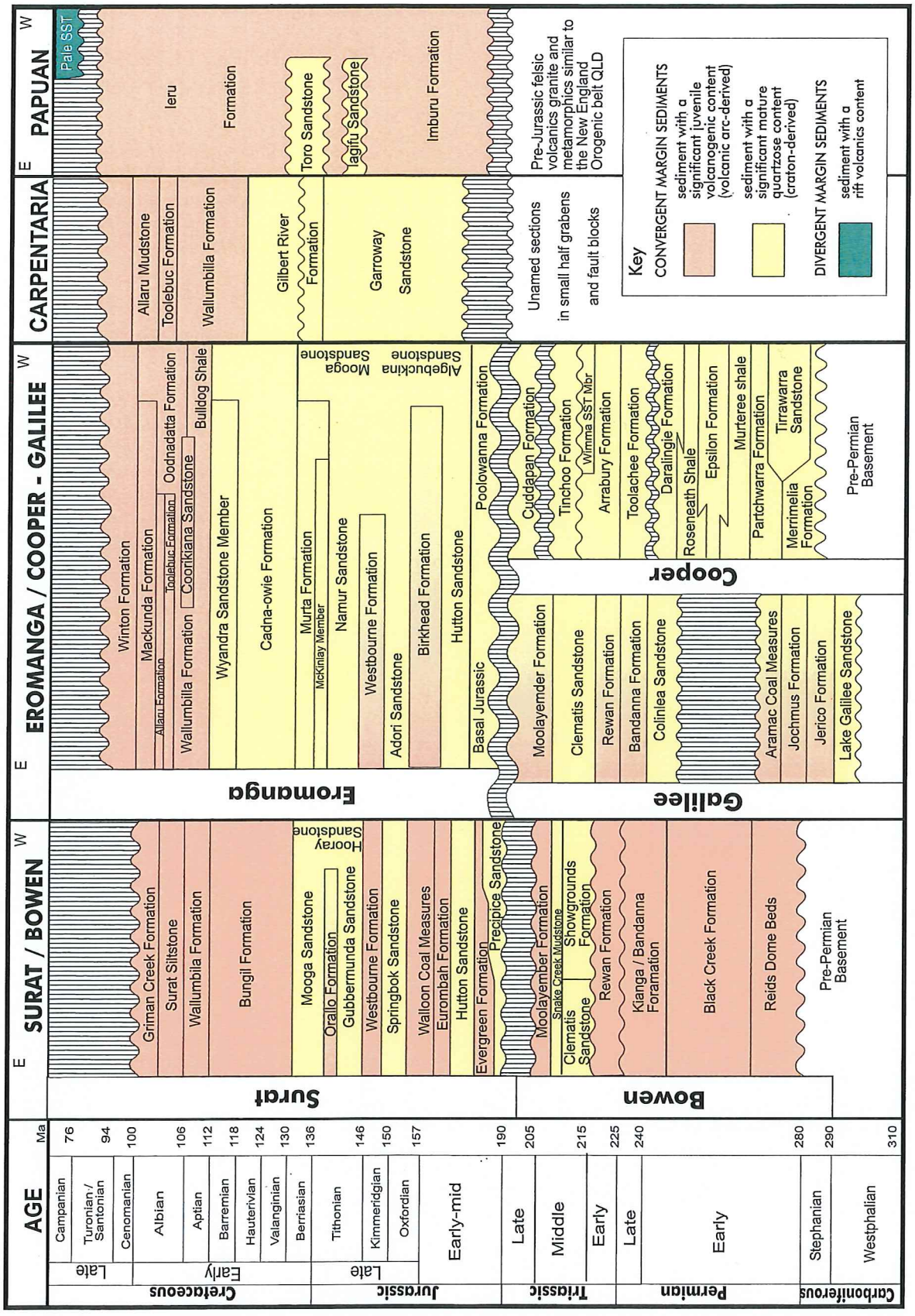

Figure 2. Correlation of stratigraphic columns for the Eromanga Basin and adjoining Phanerozoic basins (after Boult, 1996). This diagram shows the depositional balance between volcanic-arc-derived sediment and craton-derived sediment.

shales up to about one metre thick. The shales have poor lateral continuity as expected in a braided–fluvial setting. They probably represent flash flooding events but their continuity has been destroyed by subsequent erosional incisions of overlying channels. Towards the top of the Hutton Sandstone shales of the overlying Birkhead Formation can be demonstrated to inter–tongue with the upper Hutton Sandstone (Solomon and Ormsby, 1984; Yew and Mills, 1989).

Gravestock et al (1983) divided the Hutton Sandstone into three separate units[2], Units G1 through G3 from bottom to top. Unit G1 has since been redefined as the Poolowanna Formation in South Australia (D.I. Gravestock, pers. comm.,1995). These workers recognised Unit G2 as the typical braided–fluvial Hutton Sandstone and modelled Unit G3 as filling in all the post–Permian topography that existed prior to the deposition of the Birkhead Formation. They stated that 'well sorted fine sandstone interbeds are more common in Unit G3' indicating a change to lower energy conditions.

Relevant previous interpretation of the Birkhead Formation

The Birkhead Formation is of principal interest to oil explorers because its acoustic impedance is mappable, it is a seal to the underlying Hutton Sandstone reservoirs and it contains potential source rocks (Smyth et al, 1984). It was first referred to by Exon in 1966. Nugent (1969) described the depositional environment of the Birkhead Formation as dominantly lacustrine, grading to swamp or marsh. Exon (1974) correlated the Walloon Coal Measures of the Surat Basin with the Birkhead Formation of the Eromanga Basin. He also recognised the Eurombah Formation as representing an environment of 'sluggish streams and swamps', which is similar to the 'fluvial, meandering stream environment' interpreted by Paton (1986) for Unit P1[3].

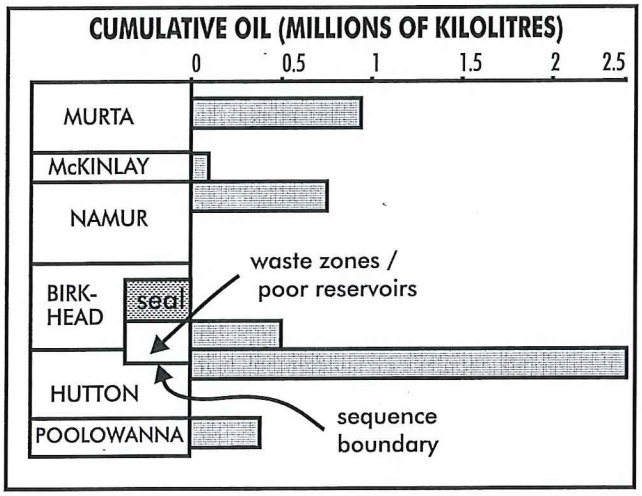

Figure 3. Cumulative oil production by formation, Eromanga Basin, South Australia (modified after Alexander et al., 1996) and simplified stratigraphic column.

A NEW INTERPRETATION OF THE HUTTON/BIRKHEAD TRANSITION

3D seismic, sequence stratigraphy, dipmeter interpretation and neodymium model age dating, together with conventional correlation techniques, have provided a new model for the deposition of the sediments which mark the transition from Hutton Sandstone to Birkhead Formation in the Eromanga Basin.

The new model described

Our model of deposition in the Eromanga Basin relies on sediment supply being controlled by a shifting balance between uplift on the eastern and south–western boundaries of the Australian plate. When uplift on the rifting margin to the southwest was greatest, cleaner reservoir quality sediments were deposited. However, when uplift and volcanic activity on the subducting margin to the east were greatest, a combination of the raising of drainage base levels and the spread of highly labile VAD material across the basin provided both the source rock and seals. The Hutton /Birkhead transition is the most widespread and economically significant example of change in this balance caused by significant uplift to the east.

Figure 4 presents a sequence stratigraphic model and a related chronostratigraphic section for the Hutton / Birkhead transition on the eastern and south–western flanks of the Birkhead Formation depocentre. The main feature of these sections, with regard to regional seal development, is the distribution of VAD sediments. To the east, where the sediments above the major sequence boundary (an unconformity) have an easterly provenance, the VAD sediment influx occurs below the transgressive surface. However, towards the southwest, the major influx of VAD sediment occurs above the transgressive surface. According to our dipmeter interpretation (Fig. 4), in the South Australian sector of the basin the change from south–westerly to easterly–derived sediment occurs at the transgressive surface, while in the east this change occurs at the sequence boundary. Our palaeocurrent direction interpretation also agrees with those of both Solomon and Ormsby (1984) and K.J. Watts (1987). In South Australia, in proximal locations the lower part of the lowstand systems tract, which infills the palaeo–valleys, appears to be equivalent to Unit G1 (described as part of the Hutton Sandstone: Gravestock et al, 1983) whereas in more distal locations it is equivalent to Unit P1 (described as part of the Birkhead Formation: Paton, 1986).

Figure 5 shows a localised, schematic, 3D reconstruction of palaeogeography during deposition of the lowstand systems tract of the Birkhead Formation in the area to the north of the prominent Gidgealpa–Merrimelia–Innamincka (GMI) Ridge. Interpretation of

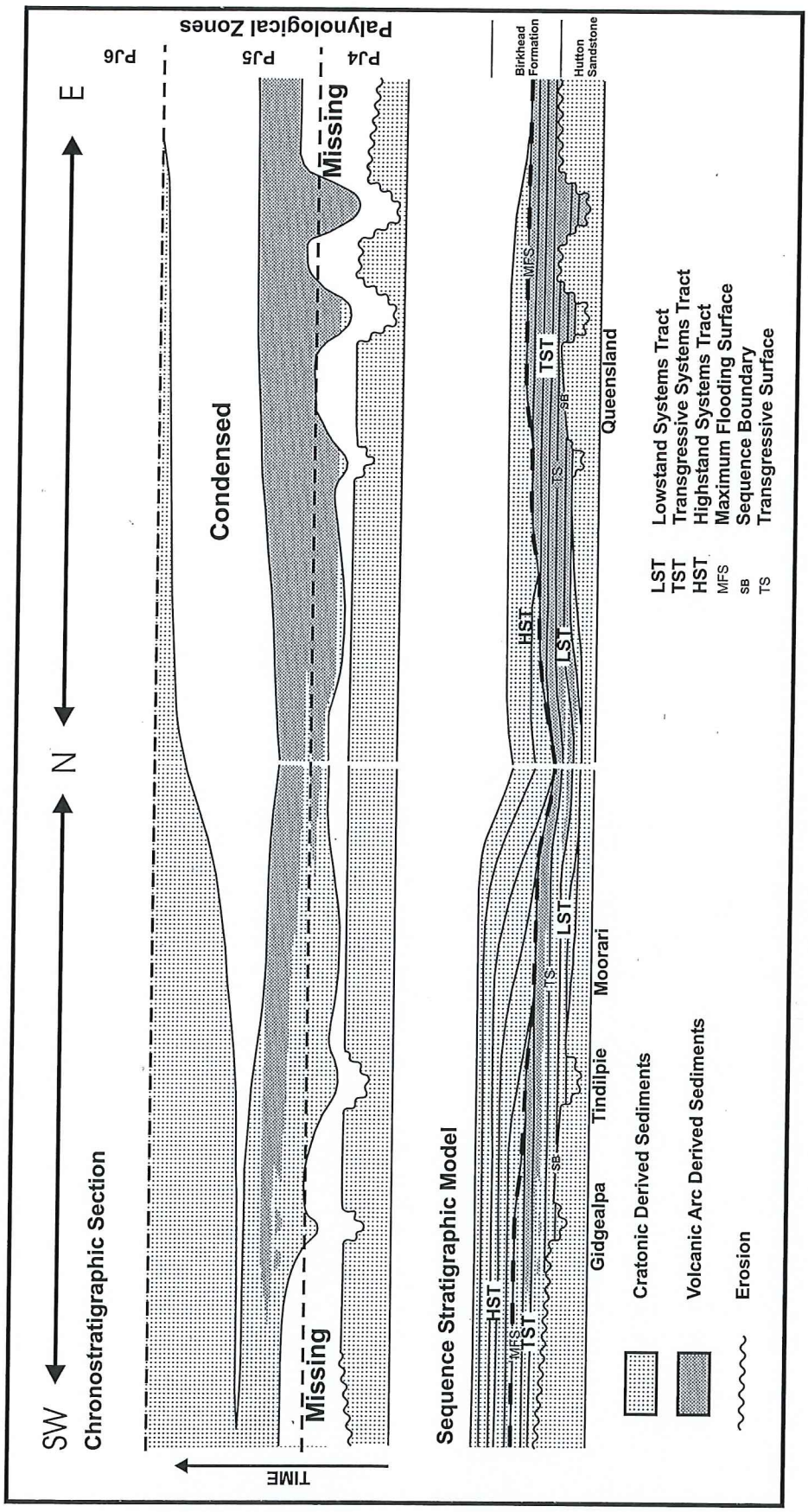

Figure 4. Sequence stratigraphic model and chronostratigraphic section for the depostion of the Birkhead Formation. See Figure 6 for the approximate location of this section.

2D seismic lines in the Tindilpie area (Figure 5) and 3D seismic at Gidgealpa, reveals a palaeo-landscape of flat-topped ridges up to 97 m (320 ft) high occurring between incised river valleys.

The lowstand systems tract, deposited between the sequence boundary and the transgressive surface, represents a balance between sediment influx and base-level rise. The lowstand systems tract is relatively well developed in the southwest. However, in the east it is locally missing over palaeo-highs due to continued uplift and tilting. This uplift and simultaneous erosion of the previous sequence (braided Hutton) (cf. Hamilton et al, 1996) to the east also provided the initial source of sediment for the transgressive systems tract further to the southwest.

Figure 4 shows the distribution of VAD sediment of easterly provenance. In the chronostratigraphic section the VAD sediment is shown to be younger in the west than in the east. Depth versus neodymium model ages of both shales and arenites, and mineralogical logs of cores spanning the Hutton Sandstone/Birkhead Formation boundary at Gidgealpa, Moorari, Bodalla South, Kenmore and Gumla (Whitford et al, 1994), confirm a new source of VAD sediment being supplied to the basin. Fission track ages of apatite grains indicate that the volcanism was contemporaneous with deposition of the Birkhead Formation (Gleadow et al, 1988; Gibson et al, 1995). The continued rise in drainage base-level in the south-western part of the basin resulted in the VAD input to the transgressive systems tract being deposited in lower deltaic to lacustrine settings. In the more proximal areas to the east, the VAD sediment was deposited within the lowstand systems tract. Thus the previously incised topography was initially back-filled with higher energy channel, VAD sands before the lower energy lacustrine inundation occurred.

Figure 6 shows a schematic representation of the above model in three dimensions. In front of the 'wedge' of advancing VAD sediment the lowstand systems tract is shown. This is represented by a valley-back-filling, south-westerly-derived, meandering depositional regime in South Australia and easterly-derived, meandering, reworked Hutton in Queensland. Whether the VAD sediment wedge played a part in raising drainage base levels (as shown in Figure 6) is not certain and is unimportant in the context of our model. What is significant, however, is that deposition was controlled by base-level rise. Thus, the overall model for the deposition of the Birkhead Formation is one of provenance switching with associated onlap[4] across a major disconformity at the top of the Hutton Sandstone.

Regional seal evaluation

The most important aspect of seal evaluation is to establish which lithofacies within a formation is the weak link and thus the effective seal. Within a sand-rich, fluvial to shallow lacustrine sequence like the Birkhead Formation, where shales are not very thick,

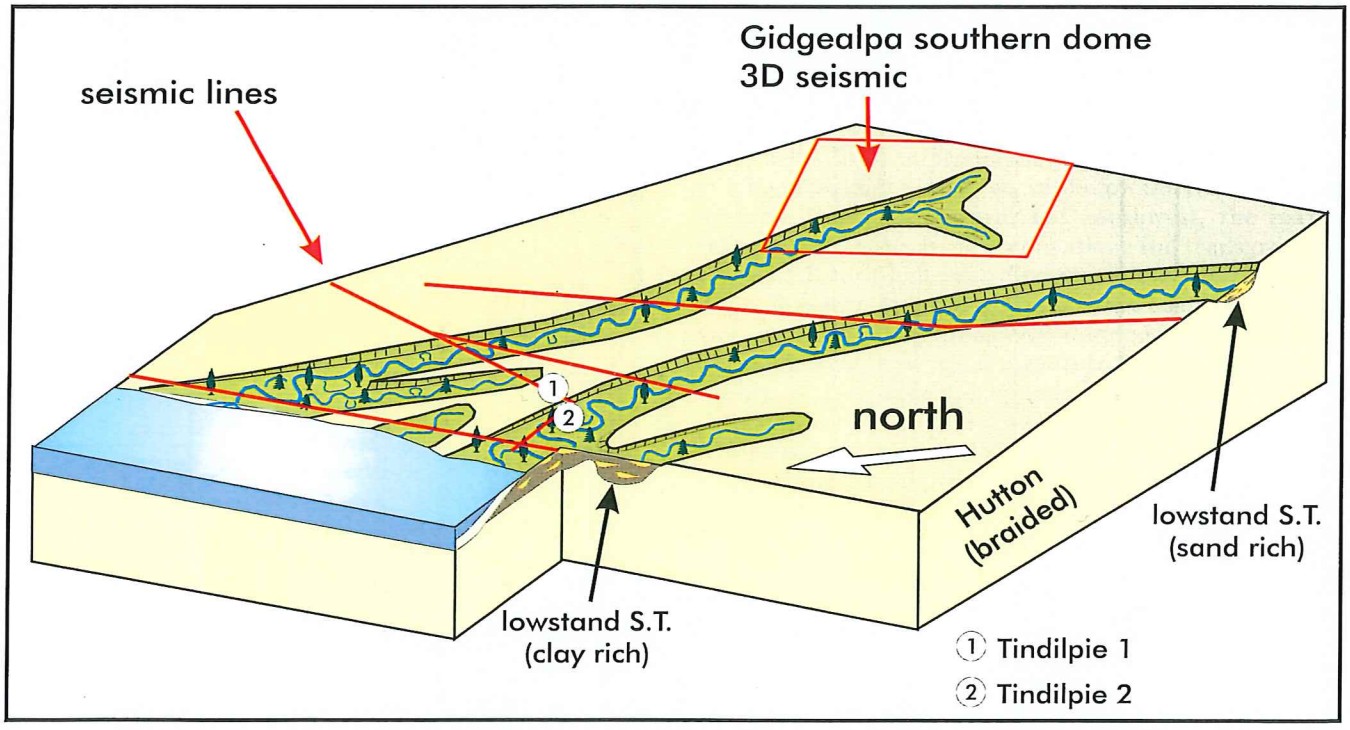

Figure 5. Schematic 3D reconstruction of the palaeo-geography during the deposition of the lowstand systems tract of the Birkhead Formation in the Gidgealpa/Tindilpie area.

they are not likely to be the effective seal to migrating hydrocarbons. The effective seal within such a unit will probably be the intervening sandy facies. This is especially true when fault offset or erosional surfaces juxtapose sandy interbeds. Thus the previously mentioned influx of VAD sediment is a good candidate for the formation of a widespread diagenetic seal (Boult, 1993).

The switch from easterly–derived, but reworked, Hutton Sandstone, to VAD sediment is sharp at Jackson and Kenmore but is more gradational at Bodalla South, Gidgealpa and Moorari. As expected, the percentage of volcanic material contained within more distal sediments is less than those which are more proximal. Thus, in the more distal southwestern areas, the base of the effective seal is coincident with the first flooding surface after the influx of VAD sediment. However, in the east, the base of the effective seal, which in places is a medium–grained arenite, often lies directly on the erosional surface at the top of the braided–fluvial Hutton Sandstone. Where the lowstand systems tract is well developed, sourced from a cratonic area and thus quartzose, and predominantly deposited in low energy depositional environments, it may contain poor reservoirs or even be considered as a waste zone.

At Moorari the influx of VAD sediment occurs between 150 and 220 ft (46 to 67 m) above the sequence boundary and the section comprising poor reservoirs or waste zone is well developed. Figure 7 shows the regional seal as occurring at the first flooding surface above an excursion of the neodymium model ages from about 1.61 to 1.07 Ga. Despite the moderate to high gamma–ray values for the seal, cores in wells 9 and 10 show that more than 50 per cent of the seal comprises fine sands, and that its shales are rarely greater than 1 foot thick. Structural closure, oil column buoyancy and capillary displacement pressures, which have been computed for the weak-link lithic sands of the seal in the Moorari field (Boult et al, 1993), indicate that the Hutton/Birkhead reservoir was charge–poor and is full neither to capillary seal capacity nor structural spill point. This is confirmed by the lack of significant shows within the seal and a lack of commercial accumulations higher in the section.

Figure 8 shows our interpretation of the stratigraphy at Gidgealpa where several cores have been cut in the lower Birkhead Formation. Here the transgressive surface and seal are well defined. The lowstand systems tract is more sandy than at Moorari, varies in thickness from 0 to 100 feet (30 m) and is readily observable in the core at Gidgealpa 17. The disconformity appears to follow the

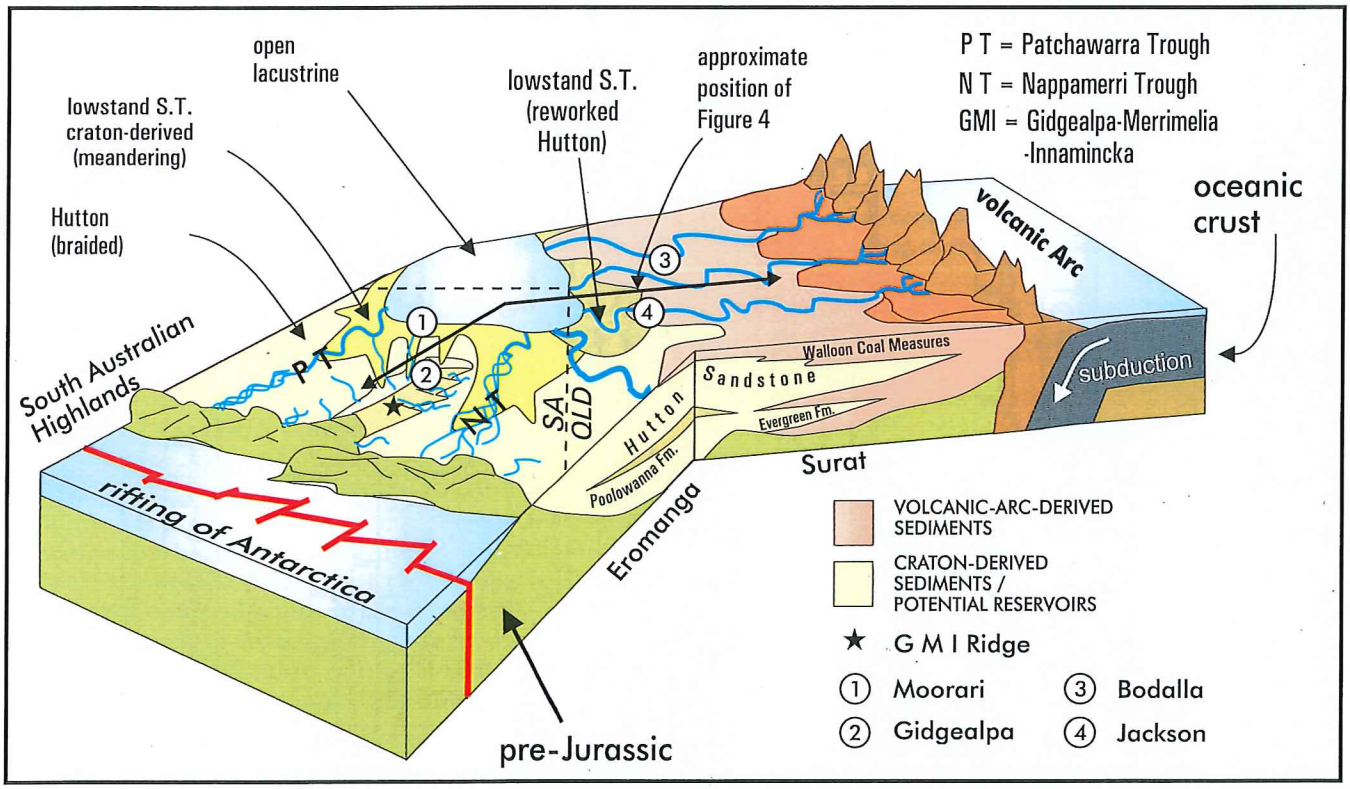

Figure 6. Schematic 3D diagram of palaeo-geography during the early phase of Birkhead Formation deposition. This shows the interleaving of volcanic-arc-derived seals and craton-derived reservoir-type sediments. The Gidgealpa-Merrimelia-Innamincka (GMI) trend is shown as temporarily exposed, shedding eroded material via braided fluvial channels into the Patchawarra Trough (PT) and Nappamerri Trough (NT). The positions of the Gidgealpa (G), Moorari (M), Jackson (J) and Bodalla South (B) fields are shown diagrammatically only relative to the South Australian (*SA*) and Queensland (*QLD*) border (after Boult et al, 1997b).

main seismic pick horizon but is offset above it by 10 to 30 feet (Fig. 9). Above the transgressive surface and within the transgressive systems tract, both delta front and upper delta facies are recognised, eventually giving way to a locally shallow, very sandy, open lacustrine facies containing common channel mouth–bar deposits. The dipmeter interpretation averaged for the Gidgealpa field (Fig. 8) confirms the switch at the transgressive surface from a southwest/southerly–sourced drainage pattern, to a more easterly–sourced drainage direction. The influx of VAD sediment is also observable mineralogically and is accompanied by a change to younger neodymium model ages. However, the main change from craton–derived to VAD material is gradational and begins higher up within the transgressive systems tract. Thus, at Gidgealpa the main seal for underlying accumulations occurs at the base of the first flooding surface above the influx of VAD material. Capillary displacement pressures, which have been interpreted (see later) for the weak–link lithic sands of the seal in the Gidgealpa southern dome, together with structural closure interpretation and computed buoyancies from the palaeo and live oil columns, indicate that the Hutton / Birkhead reservoir was initially charged close to both structural spill point and capillary seal capacity. However, after several million years, capillary displacement pressures within the seal were reduced by changing wettability and most of the estimated 300 million barrels of palaeo–oil leaked away. This model of filling and leakage is discussed later in the paper.

Control on source rock development within the Birkhead Formation

Geochemical analysis of source rocks and oils (Boult et al, 1997a; Michaelsen and McKirdy, 1996) indicate that coals within the Birkhead Formation are the major contributor to accumulations of oil occurring up–dip beneath the seal within the Birkhead Formation. It is our interpretation that the previously described disconformity has significantly controlled the location of thick coaly pods associated with major flooding surfaces within the Birkhead Formation. Wireline correlation (Fig. 10) and subtle 2D and 3D seismic interpretation show that palaeo–topography on the disconformity, in some marginal depocentre localities, was characterised by valleys with intervening residual peneplain ridges up to 97 m (320 ft) high. Thus, during the deposition of the transgressive and highstand systems tract, differential compaction of the underlying lowstand systems tract where it is relatively thick and shale–rich compared with the braided Hutton, allowed thick coal pods to develop over the pre–existing valleys. These coaly pods can be

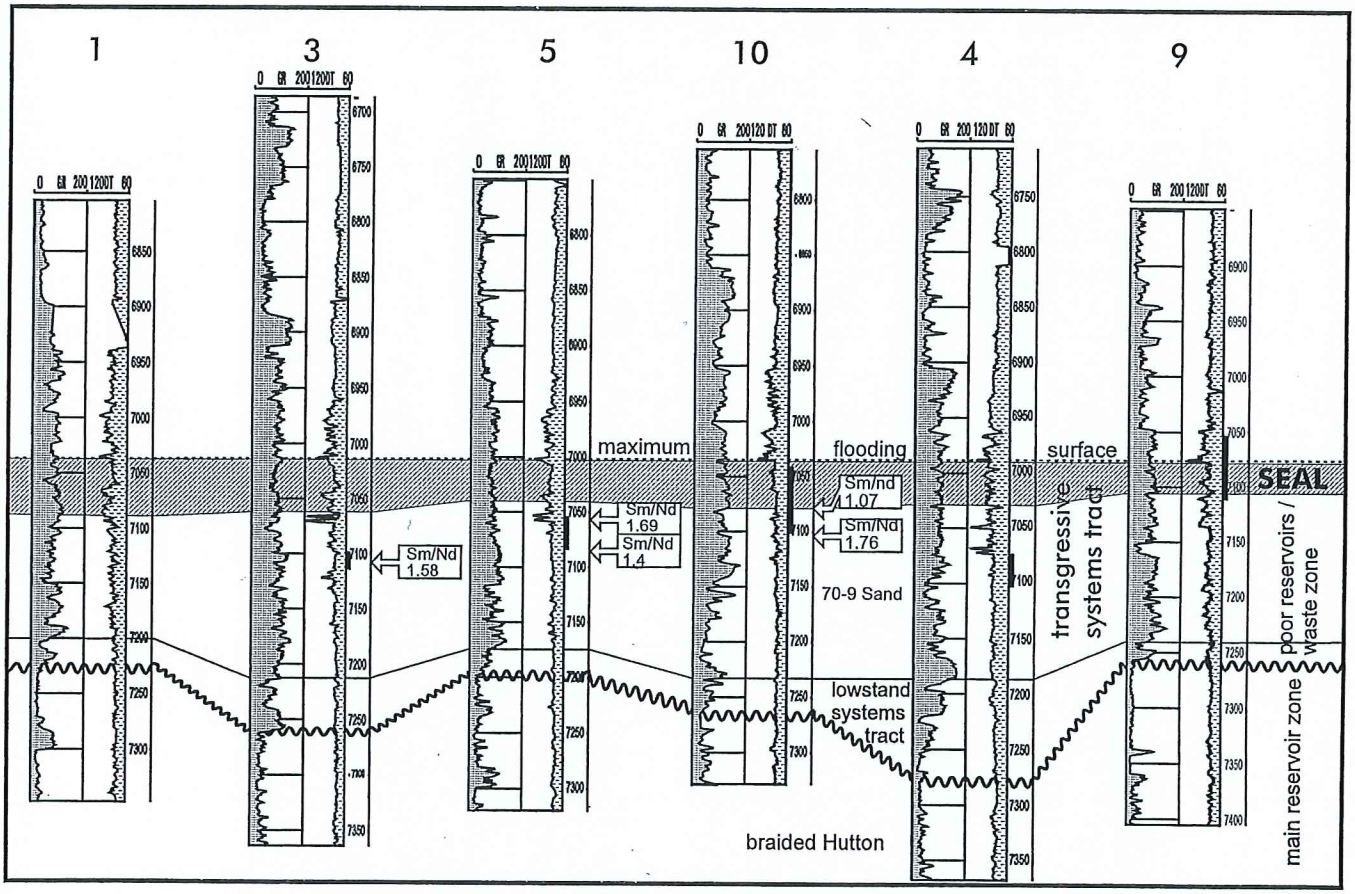

Figure 7. Stratigraphic correlation, hung on the maximum flooding surface of the Birkhead Formation in the Moorari field.

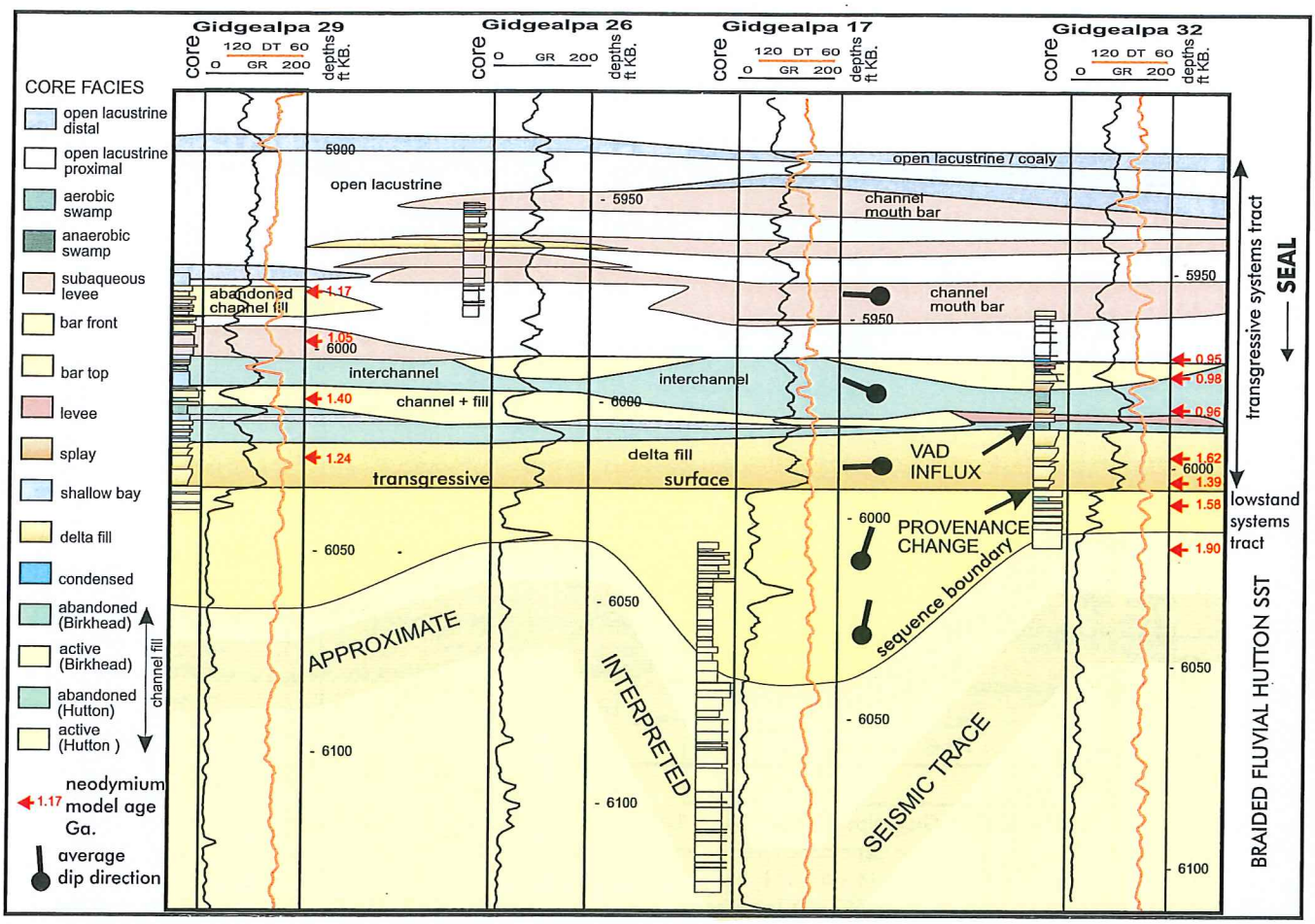

Figure 8. A detailed stratigraphic cross-section of the Gidgealpa southern dome based on core information. Dipmeter data are averaged for several wells at Gidgealpa. Neodymium model ages are shown in red. The datum is hung on the transgressive surface.

observed on 2D seismic and are known to be very oil prone, with a hydrogen index of almost 450 developed locally in the Tindilpie area (Michaelsen and McKirdy, 1996).

Control of secondary migration efficiency below the Birkhead Formation

Oil always takes the easiest route during secondary migration and this is not necessarily the stratigraphically highest pathway (i.e. underneath the regional seal). The previously described remnant peneplain ridges of very permeable, braided–fluvial Hutton Sandstone, which are flanked by less permeable valley–fill sediments of the lowstand systems tract, controlled and stratigraphically focussed migration, making long pathways possible. In this case, oil produced from the aforementioned coal pods easily found its way to structurally higher but stratigraphically lower intervening palaeo–ridges. Such ridges are very efficient conduits for oil migration and in this case were quite capable of directing migration across structural dip. The significance of this control is described below.

THE BIRKHEAD–HUTTON(!) PETROLEUM SYSTEM OF THE GIDGEALPA AREA

Introduction

For the purposes of this paper we have concentrated on the Hutton/Birkhead oil pool of the Gidgealpa southern dome in order to demonstrate the character of a significant Jurassic–sourced petroleum system along the GMI trend. However, it is likely that the same petroleum system is widespread throughout the Eromanga Basin. Our recognition of this petroleum system was made possible by an understanding of the regional palaeogeography and its significant control on sequence stratigraphy, source rock development, migration pathways and seal recognition.

In the following discussions we refer to the Hutton and Birkhead accumulations as the Hutton/Birkhead oil pool, rather than as separate reservoirs. We explain the reasons for this below.

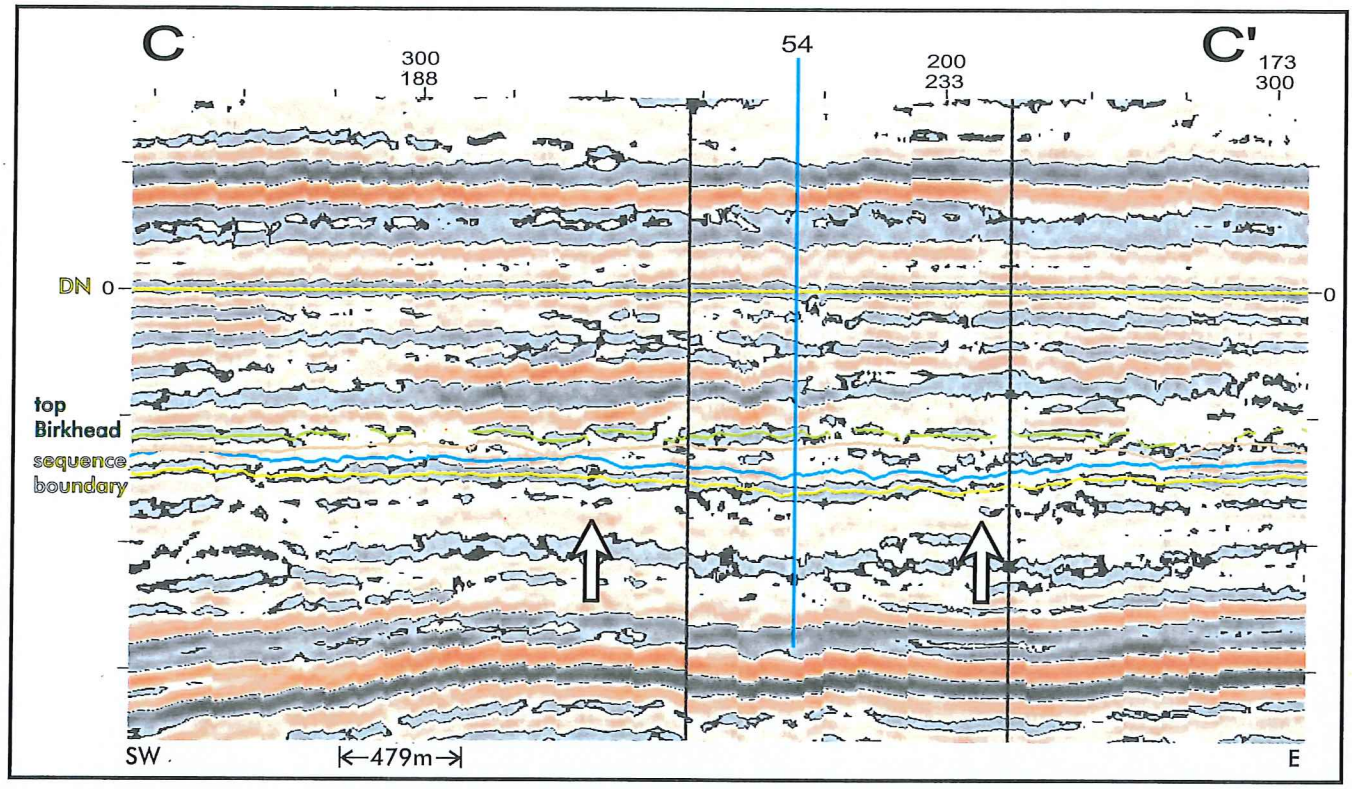

Figure 9. Cross-section of part of the Gidgealpa southern dome, flattened on the DN horizon (base Murta Formation - yellow) and showing the unconformity at the top of the Hutton Sandstone (yellow) with truncation of horizons underneath (black arrows).

The Gidgealpa Field

The Gidgealpa field is located towards the southern end of the Gidgealpa–Merrimelia–Innamincka Ridge, which at the top of the Hutton Sandstone is a northeast to southwest trending asymmetric anticline (Fig. 11). The ridge has an expression throughout the underlying and overlying sections of the Cooper and Eromanga Basins. In the Gidgealpa area, basement–related faults are generally confined to the Permian section, with structure in the overlying Jurassic section being mostly due to drape. The Gidgealpa field comprises northern and southern domes, which are separated by a relatively shallow saddle. The top Hutton Sandstone to top Winton Formation isopach map (D.R. Vinall, MESA, 1996, pers. comm.) indicates that at least 40 m (131 ft) of closure existed at the end of the Cretaceous. This is very similar to the present–day closure of 38.1 m (125 ft) mapped by Singh (1990). Analysis of shows within the palaeo–oil column indicates that closure may have been as much as 47.2 m (155 ft)[5].

The Gidgealpa field produces gas from the Permian Tirrawarra Sandstone, Patchawarra and Toolachee Formations of the Cooper Basin and oil from the Jurassic Poolowanna Formation, Hutton/Birkhead transition, and Namur Sandstone in the Eromanga Basin (McIntyre et al, 1989). A schematic cross–section, oblique to the main fold axis, is shown in Figure 12 and the reservoir boundaries in Figure 13. Gas is found only within the Permian sequence which onlaps a basement high, with the major accumulation being 7070 x 10^6 m^3 (250 billion cubic feet) in the Toolachee Formation of the northern dome. The seal for this gas pool is the Triassic Arrabury Formation. There is a thin 4 m (12 ft) oil leg beneath the gas accumulation in the Tirrawarra Sandstone of the southern dome and some oil occurs within the Patchawarra Formation of the northern dome.

The Triassic seal has been eroded away or was not deposited over part of the southern dome and the gas accumulation in the Toolachee Formation is limited here by a stratigraphic spill point related to the base–Jurassic unconformity (Fig. 12). It is the opinion of those workers that argue for a Permian source for Jurassic oil in this area, that oil and gas have probably migrated into the overlying Eromanga sequence above the southern dome (Heath et al, 1989; Low–Young et al, 1997). Because no gas is found in the Jurassic of the Gidgealpa southern dome and the oils have very low gas–to–oil ratios, water–washing by aquifer flow in the Eromanga Basin is assumed to have stripped all the gas away. However, this model denies two very important facts. The first is the lack of a significant amount of oil in the Permian at Gidgealpa; and the second is the fact that the Permian oil has a very different geochemical signature to that of the Jurassic oil (Boult et al, 1997).

An estimated 1.7 α 10^6 m^3 (10.9 million barrels) of oil

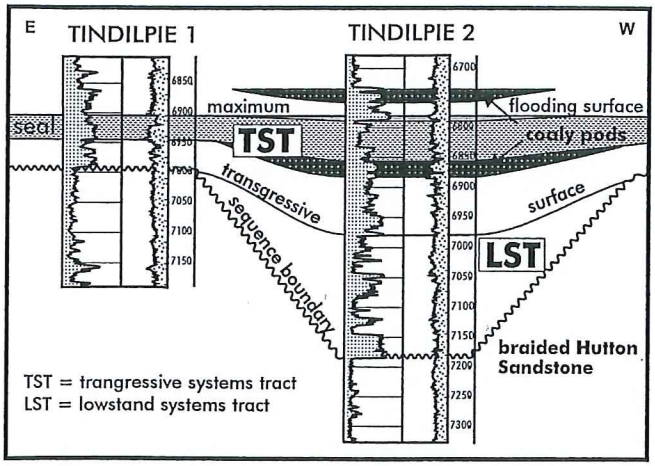

Figure 10. Cross-section in the Tindilpie area, showing: 1) relief on the disconformity at the top of the Hutton Sandstone; 2) in-fill of the palaeo-topography by the lowstand systems tract; and 3) the better development of coals/source rocks where they are underlain by a thick compactable lowstand systems tract.

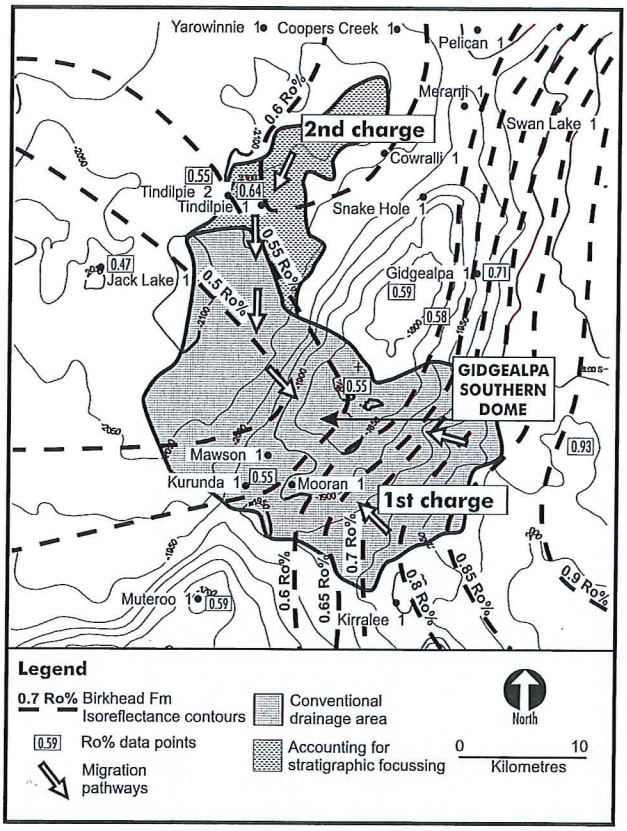

Figure 11. Top Hutton Sandstone depth map, showing the location of the Gidgealpa southern dome, possible present-day drainage areas and vitrinite isoreflectance contours. Depth contour interval is 50 m (after D.R.Vinal, MESA, pers. comm., 1996)

was trapped in the Hutton / Birkhead pool at the time of its discovery. The seal to this oil pool is a lithic arenite containing abundant volcanic rock fragments within the transgressive systems tract of the Birkhead Formation (Figure 14). We have calculated that a palaeo–oil pool of up to 50 x 10^6 m^3 (320 million barrels) may have existed within the Hutton / Birkhead oil pool prior to leakage through the Birkhead seal. Thus as much as 47 x 10^6 m^3 (300 million barrels) may have leaked through the Birkhead Formation seal. There is at least 0.6 x 10^6 m^3 (4.0 million barrels) of oil trapped beneath a local mid–Namur seal and near the base of the Murta Formation. However, as the Namur / Murta oils in this field have not yet been geochemical analysed, their affinity is presently unknown. Even if the oils from the Namur/Murta reservoirs are Birkhead sourced, there still remains 46.4 x 10^6 m^3 (296 million barrels) to be accounted for. Thus, we postulate that during its ascent through the Namur Sandstone aquifer it may have been stripped of its light ends by water–washing, thus loosing much of its buoyancy and causing it to be swept in a south–westerly direction by a strong groundwater flow.

Figure 15 is a structural cross–section of the Gidgealpa southern dome showing the regional seal, the location of the Hutton/Birkhead oil pool and the approximate location of the oil/water contact for the palaeo–oil pool. Also shown is the location of a drill stem test (Gidgealpa 17, DST 3) which sampled oil (from oil cut mud) that is leaking through the seal. On Figure 15 we show the location of the apparently separate live oil pools. We have deliberately not drawn in the present oil/water contact, but, instead we have shown the free water level. Thence it is observed that the free water levels for oil pooled within the lower Birkhead Formation, and within the Hutton Sandstone, are the same. Therefore,

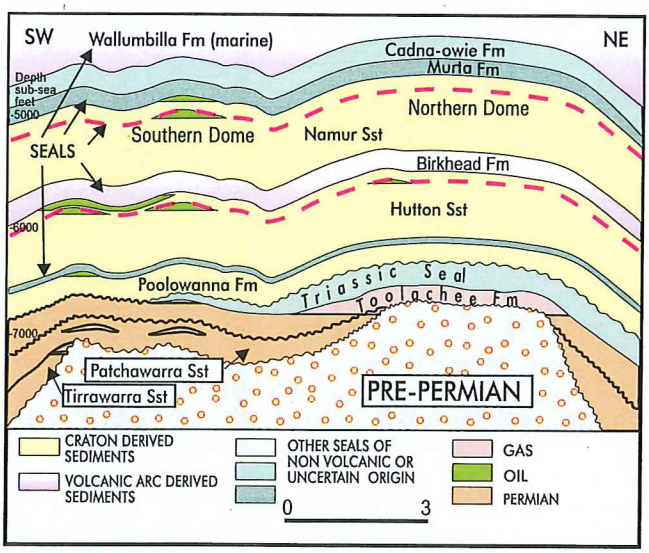

Figure 12. A schematic cross-section of the Gidgealpa field.

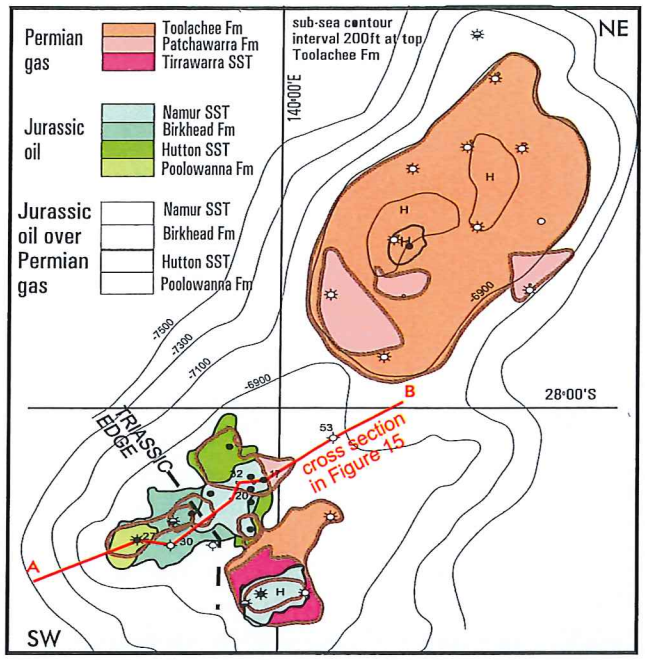

Figure 13. Oil pool map of the Gidgealpa field.

geologically speaking, both pools are part of the same accumulation. Our observations and analysis also show that there is good evidence to suggest both the palaeo– and present oil accumulations were trapped by the same seal as shown in Figure 15. Non–economic intervals, which occur below this, are merely capillary exclusion or waste zones. Our estimates are that the present oil column has a height of 20 m (66 ft) and that the palaeo–oil column had a height of 47.2m (155 ft), or 27.2 m greater than at present.

Geochemical evidence of a Jurassic source

Detailed analyses of the aromatic hydrocarbon fractions of the live–oil column and the palaeo–oil column at Gidgealpa by gas chromatography–mass spectrometry (GC–MS) (Boult et al, 1997a) reveal that the oils contained within the Hutton/Birkhead oil pool are unequivocally of Jurassic origin. Elevated concentrations of 1,2,5–trimethylnaphthalene, 1–methylphenanthrene, 1,7–dimethylphenanthrene and retene occur in the live and palaeo–oils and indicate an origin from Jurassic source rocks. When present in such high concentrations, these

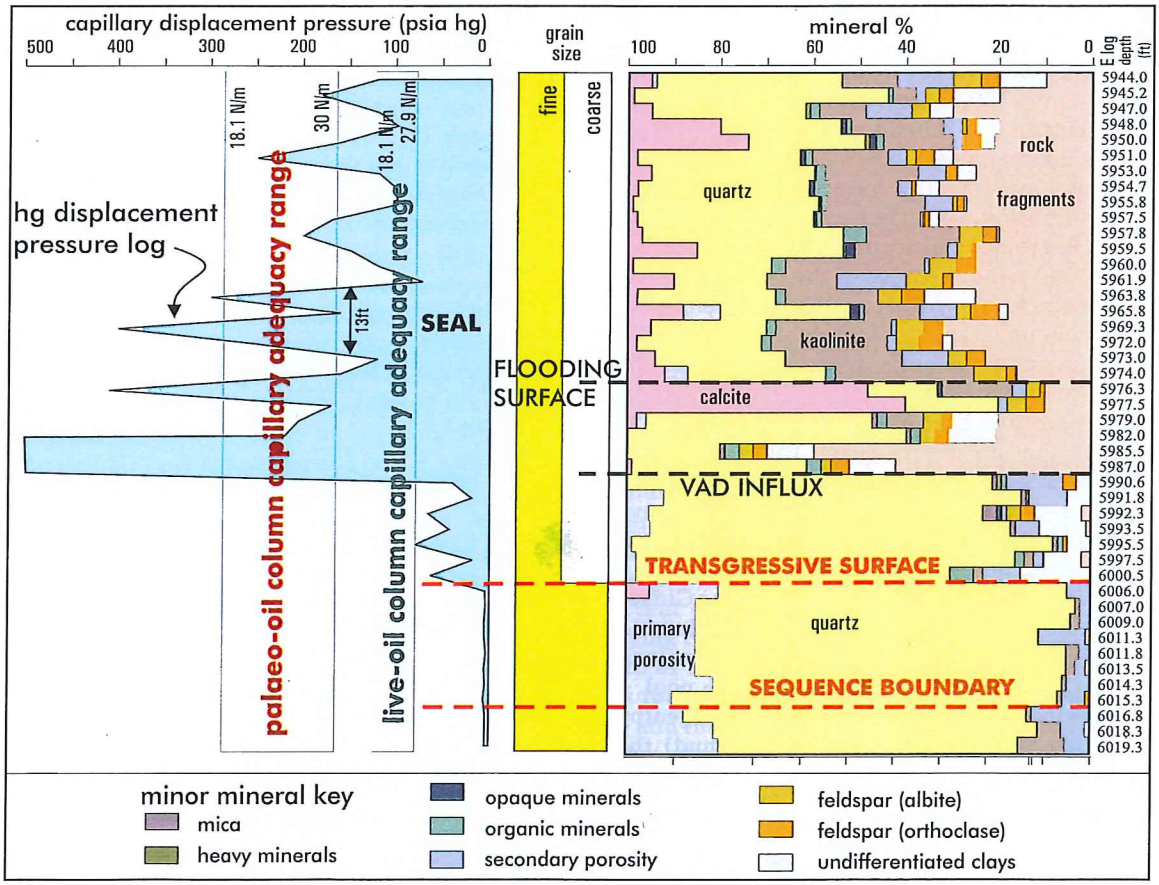

Figure 14. Gidgealpa 32 and 26, Hutton Sandstone/Birkhead Formation mineralogy and displacement pressure log. Showing the location of the Birkhead Formation seal with respect to the initial influx of VAD sediment and major systems tracts.

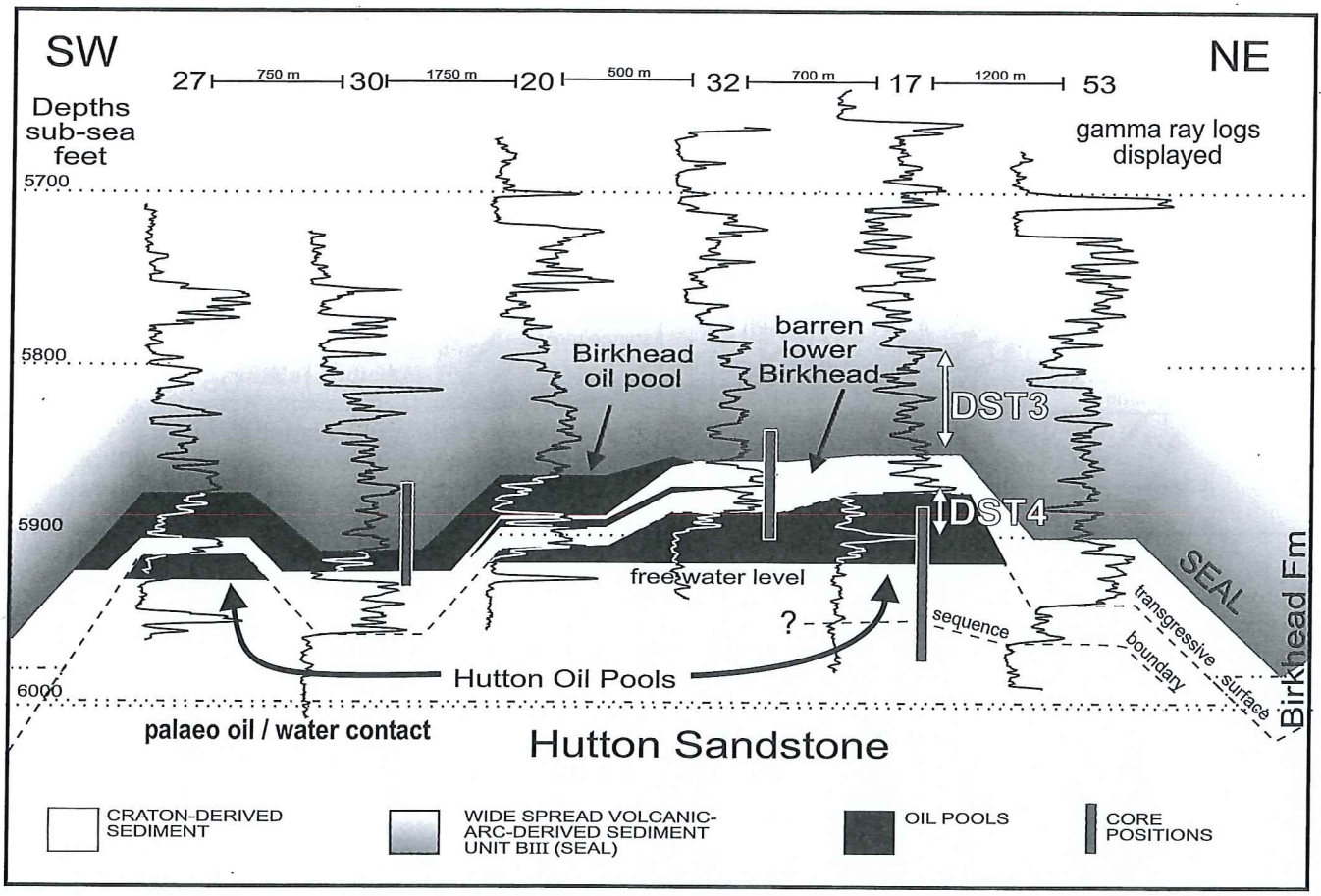

Figure 15. Gidgealpa southern dome structural cross-section (27-53) for the Hutton/Birkhead oil pool, showing pre-drill oil and palaeo-oil pool locations.

compounds are biomarkers for the Araucariaceae, conifers which first appeared during the Early Jurassic (mid–Poolowanna time), and were established members of the plant community during deposition of the Hutton Sandstone and Birkhead Formation (cf Alexander et al, 1988).

The shaded areas depicted in Figure 16 are established from the results of analyses of over 70 source rock samples from the Cooper/Eromanga area. On Figure 16 individual analyses of oils from the Birkhead/Hutton oil pool at Gidgealpa plot well within the Birkhead Formation source rock zone. If the biomarkers were just contaminants in an otherwise predominantly Permian–sourced oil, one would expect them to plot within, or very close to, the Permian source rock zone. By contrast, the Patchawarra oil from Gidgealpa–4 (DST 6) of the northern dome contains significantly lower concentrations of these aromatic compounds and is clearly derived from a pre–Jurassic (i.e. Cooper Basin) source rock.

A further constraint on the source of the live oil (Gidgealpa 17, DST 4) is provided by its content of a pseudohomologous series of 17β,21β–hopanes (Figure 17b) (Ryan, 1996). To the best of our knowledge, this is the only oil from the Cooper/Eromanga Basin in which this series of hopanes has been detected. The 17β,21β–hopanes are typical of coals and shales with maturities less than 0.5% R_o (i.e. rocks that have not entered the 'oil window' proper). Similarly, the predominance of 22R over 22S C_{31} 17α,21β–homohopane is uncharacteristic of an oil, but more typical of a low–rank coal. C_{27} 17β,21α–22,29,30–trisnorhopane (C_{27} moretane; labelled βα in the C_{27} trace: Fig. 17b) is also in relatively high concentration. This is another feature normally associated with immature source rocks, and one not expected to occur so prominently in an oil. By contrast, the Birkhead oil (Gidgealpa 17, DST 3 from within the seal) contains a conventional suite of hopanoids (Fig. 17a). In the Gippsland Basin, Philp and Gilbert (1982) likewise discovered 17β,21β–hopanes in a terrestrially sourced oil and assumed leaching or 'solubilisation' of the 22R C_{31} homohopane and the 17β,21β–hopanes from an immature coaly facies. We believe a similar scenario can explain the occurrence of the unusual hopanes in the live oil at Gidgealpa. The occurrence of these 'immature' biomarkers in the live oil means that it is highly unlikely that the live oil migrated into the Gidgealpa southern dome from what would almost certainly be hotter Permian rocks directly below. The lack of these 'immature' biomarkers within the oil

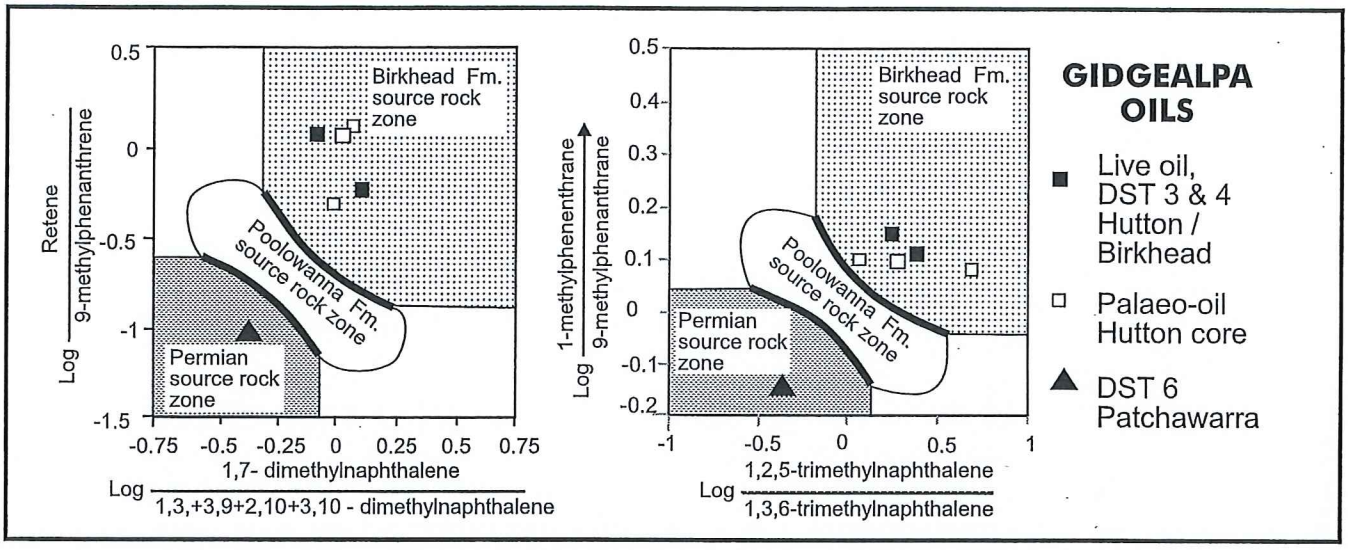

Figure 16. Cross-plots of aromatic hydrocarbon ratios: Araucariaceaen biomarkers (numerators) and non-Araucariaceaen biomarkers (denominators) (Style of plot modified after Alexander et al, 1988 and Ryan, 1996)

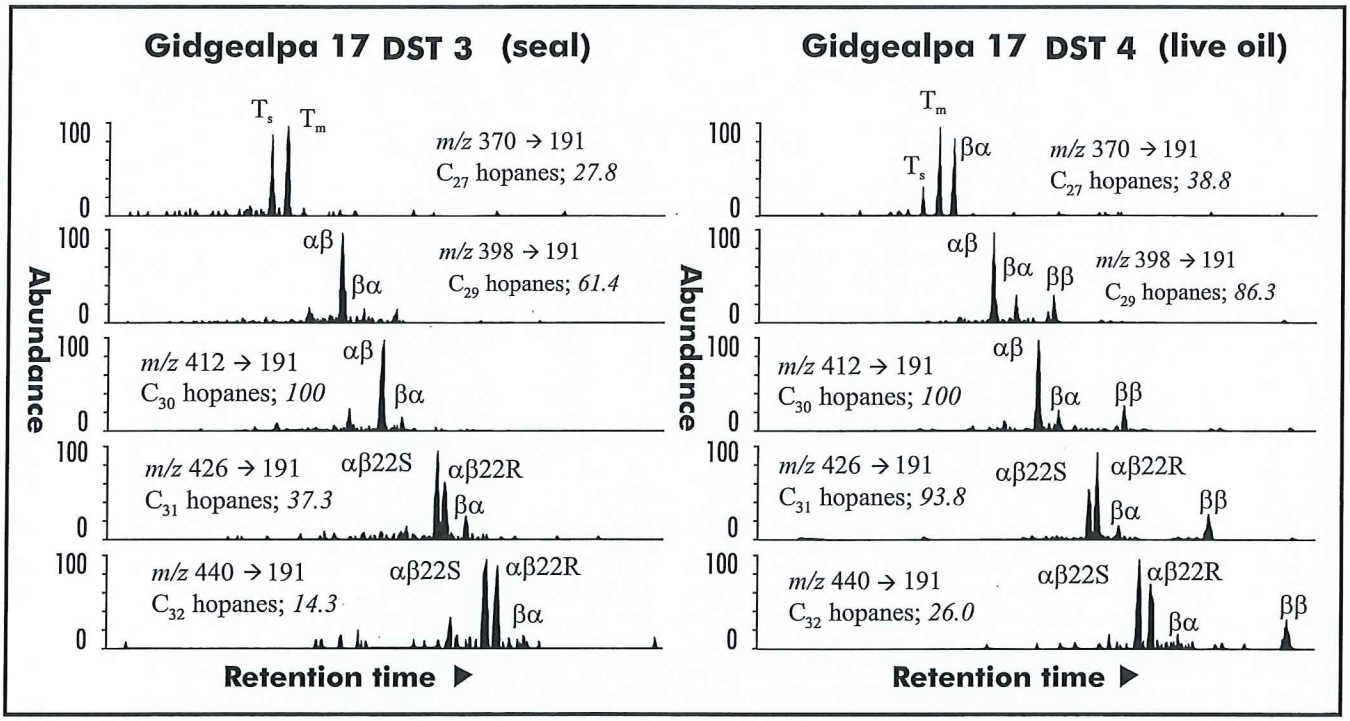

Figure 17. Partial selective reaction monitoring GC-MS-MS chromatograms (SRM); $M^+ \rightarrow 191$) for; a) DST3 oil (seal); and b) DST 4 oil (live oil) from Gidgealpa 17. The DST3 oil represents a more-or-less conventional crude. The DST4 oil contains high concentrations of C_{27} βα-hopane (17β,21α-22,29,30-trisnorhopane), a pseudohomologous series of C_{29} to C_{32} ββ-hopanes (17β,21β-hopanes), and a predominance of 22R over 22S C_{31} 17α,21β-homohopane. These features are normally not observed in oils or mature source rocks (see text for explanation) (after Boult et al, 1997a).

saturating the seal indicates that it is more representative of the palaeo–oil that leaked upward from within the Birkhead/Hutton palaeo–reservoir.

Maturation and migration of oil into the Gidgealpa southern dome

A double pulse of migration appears to have charged the Gidgealpa southern dome. This is indicated by biomarker analysis, seal studies and maturation modelling.

Maturation modelling within the Gidgealpa drainage area (Boult et al, 1997a) indicates that the Birkhead Formation of the Nappamerri Trough expelled the majority of its oil during the first pulse between 90 and 70 Ma. Then, at approximately 70 Ma, the Birkhead Formation in the Patchawarra Trough entered the oil window and possibly contributed hydrocarbons to the first pulse of oil which entered the Gidgealpa southern dome. More recently, in the last one million years, a significant increase in geothermal gradient for the Cooper/Eromanga region, as suggested by Pitt (1986), Gleadow (1988) and Boult et al (1997a), provided the second pulse of oil. However, as the Birkhead Formation of the Nappamerri Trough is now over–mature for oil generation, much of the second oil charge, which supplied the Gidgealpa southern dome, appears to have originated from the Birkhead Formation in the Patchawarra Trough.[6] In particular, the geochemical evidence suggests that much of this second charge may have come from the Tindilpie area.

Figure 11 shows the possible drainage area for the two oil charges generated from the Birkhead Formation and now trapped within the Gidgealpa southern dome. The drainage area to the north and west is divided into two parts. The first assumes a conventional smooth reservoir/seal interface (dark shading); and the second comprises an additional area (lighter shading) which takes into account stratigraphic focussing towards the south along palaeo–ridges developed at the unconformity near the top of the Hutton Sandstone. Figure 18 shows the northward trend of these ridges. The existence of these ridges extends the drainage area out beyond the Tindilpie structure where high quality mature source rocks occur within the Birkhead Formation (Michaelsen and McKirdy, 1996).

Included in Figure 11 is a possible migration pathway from the Tindilpie area to the Gidgealpa southern dome which passes through the 0.5 per cent vitrinite isoreflectance (R_o) contour line[7]. We believe that the 17β,21β–hopanes and 22R C_{31} homohopane, which were found in the Gidgealpa live oil, were picked up along this route, and hence the Tindilpie region has provided a significant part of the second oil charge to the Gidgealpa southern dome.

Further evidence of a double oil charge is provided by an investigation of the seal. A seal capacity sensitivity spread sheet for both the palaeo– and live oil columns is presented as Table 2. We have computed equivalent

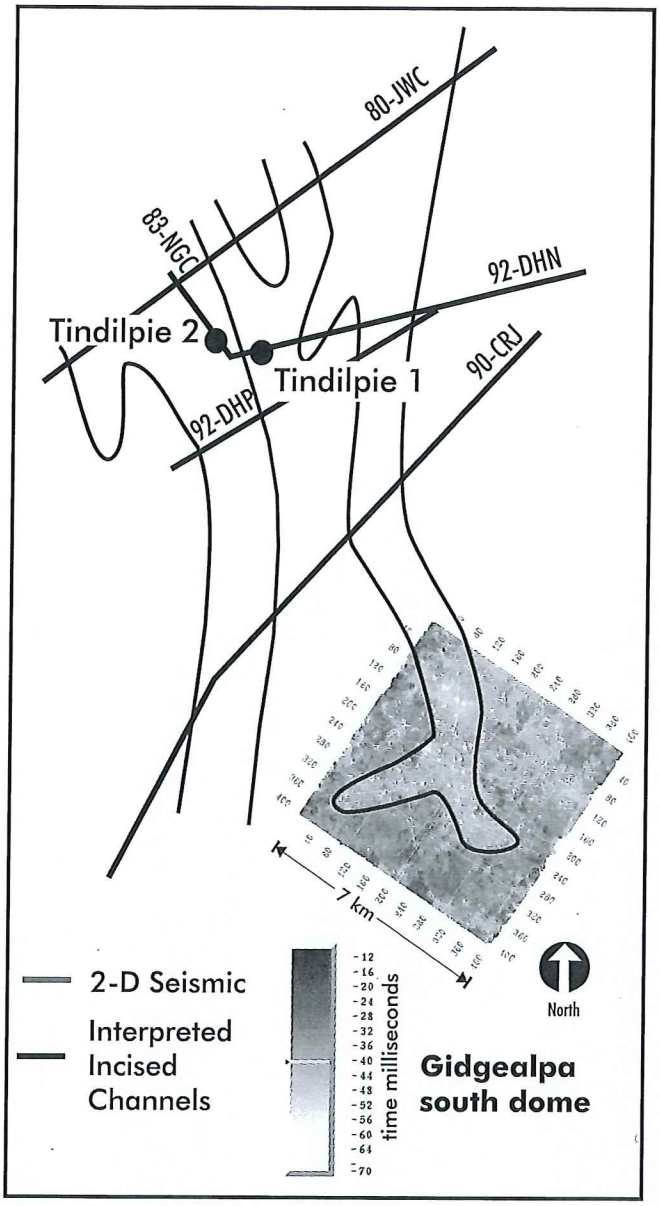

Figure 18. Map showing the incised channel trends in the Gidgealpa/Tindilpie area. Interpretation is done from several 2D seismic lines and from a Gidgealpa southern dome isochron map between the top Birkhead and the disconformity near the top of the Hutton Sandstone.

mercury/air displacement pressures (EMADP) for the effective sealing of a system with a range of adhesion tensions that may be applicable to the oil/water/rock system of the 'weak-link' in the seal. To do this we assumed that the 'weak-link' was, or is, in equilibrium with the buoyancy of the underlying oil column. The adhesion tension for the mercury/air system is well known, but the oil/water system in the subsurface is poorly understood. Thus, a sensitivity type of approach, using the maximum and minimum adhesion tension values as input into the seal capacity equation, is required in order to understand the sealing mechanism.

Table 2. Seal capacity sensitivity spread sheet for the Gidgealpa field, with the density of oil and water at 0.784 and 0.97 g/cm^3 respectively. The adhesion tension values of 27.9, 20.6 and 18.1 N/m are measured while that of 30 N/m is the maximum probable for the palaeo-oil column.

oil column height (ft)	adhesion tension N/m	equivalent mercury/air displacement pressure (psia)
155	30	171.1
155	27.9	183.9
155	20.6	249.1
155	18.1	283.5
66	27.9	78.3
66	20.6	106.1
66	18.1	120.7

For the live oil, we have measured an adhesion tension against a cleaned, and perfectly water–wet rock sample, as high as 27.9 N/m. In this case the live–oil column would have a EMADP of 78.3 psia. This value is plotted as the right side of the transparent green rectangle on Figure 14. For the palaeo–oil column an adhesion tension value as high as 30 N/m might be applicable, and the EMADP of 171 psia is plotted as the right side of the transparent orange rectangle on Figure 14. The lower adhesion tension values, which are covered by the rectangles to the left of the previously mentioned EMADP values, have been measured by other methods (Boult et al, 1993; Clinch, 1995; Hedegaard, 1995) on similar oils from elsewhere in the Eromanga Basin. Generally, a reduction in adhesion tension is caused by an increase in the wetting angle. Thus, as a seal changes through time, from totally water–wet (contact angle = zero degrees) through to less water–wet (contact angle > zero degrees), the calculated EMADP value will become higher.

From Figure 14 it can be seen that if the 'weak-link' theory holds and the lithic arenites are responsible for entrapment of hydrocarbons of the Gidgealpa southern dome, then a zone only 13 ft thick is the effective seal. This is apparent where the locus of mercury/air displacement pressure points is higher than the calculated EMADP line for the initial palaeo–oil column. Leakage from the palaeo–oil column occurred as oil/water/rock adhesion tension became lower and the EMADP values moved towards the left side of the orange rectangle of Figure 14. Table 2 also shows that none of the computed EMADP values for the live oil column are as great as the minimum EMADP for the palaeo–oil column. Thus, if the palaeo–oil was trapped by a water–wet capillary seal, it is highly unlikely that the present oil column still is. Therefore it appears that the VAD arenites are presently acting as a dynamic permeability seal. Oil exists beneath the seal because it is presently migrating. This is supported by the available geochemical evidence and maturation modelling.

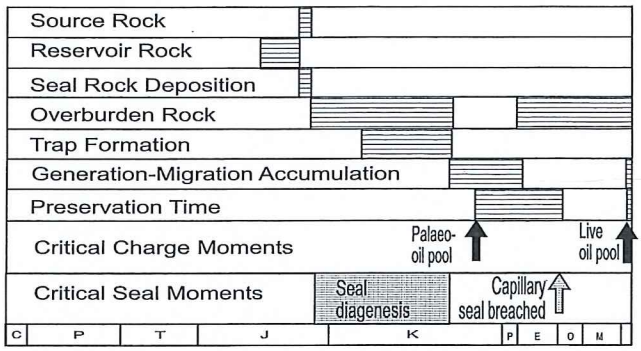

Figure 19. Birkhead-Hutton(!) petroleum system events chart for the Gidgealpa area.

DISCUSSION AND CONCLUSIONS

Figure 19 summaries important events of the Birkhead–Hutton(!) petroleum system. Events are classified into source, reservoir, seal and overburden deposition. Trap formation occurred soon after deposition, essentially reflecting drape over the underlying Permian structure. The two hydrocarbon charges are shown on this events chart as bars covering an interval of time. This is in contrast to the critical charge moments (black arrows) which represent peak generation times. Seal events are also shown in this diagram such that seal diagenesis occurs over a period of time and is necessary for entrapment[8]. The preservation time for the first charge, and the critical seal moment (grey arrow), which indicates when the capillary seal was broken, are not well constrained. However, it can be assumed that seal leakage must have occurred sometime between the two charge events.

Many authors depict capillary seals as automatic valves (Schowalter, 1979; J. Kaldi, ARCO, pers. comm., 1995; and R.M. Sneider, pers. comm., 1992), with snap–off occurring after leakage. They embrace the notion of a capillary seal which is not affected by leakage. In this paper we have shown that this may not always be the case and that through time, contact of a seal rock with oil is likely to change its wettability. Certainly it is difficult to imagine that the heavily oil-soaked seal of the Gidgealpa southern dome is as good as it was before leakage occurred. Thus a change of wettability of the Birkhead seal allowed huge quantities of oil to leak away. All that is left is presently migrating oil temporarily (on the geological time scale) backed up behind a permeability seal.

This study demonstrates 1) a model for the location of a regional seal within the Birkhead Formation, and 2) that large volumes of oil have been generated from within the Birkhead Formation. Our model has enabled the identification of source rocks suitable for oil generation. These are related to the palaeo–topography on an unconformity at the top of the Hutton Sandstone. Migration from the Tindilpie oil kitchen was focussed towards the Gidgealpa southern dome by the same palaeo–topography. The existence of large volumes of oil

generated from Jurassic coals refutes the notion that significant oil accumlations in the Eromanga Basin require a Cooper Basin source This in turn should lead to new exploration strategies.

ACKNOWLEDGEMENTS

We would like to thank J. Jago, P. Theologou and D. Gravestock for their geological input. The Boral drafting team for bringing the diagrams up to publication standard. J. Kaldi who provided vital discussion on the understanding and classification of seals and SANTOS and MESA for the provision of data.

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NOTES

1. The '!' symbol is accepted notation for a known petroleum system.

2. The prefix 'G' has been given to Units 1, 2 and 3 referred to by Gravestock et al (1983) within the their Hutton Sandstone.

3. The prefix 'P' has been given to Units 1 2 and 3 referred to by Paton (1986) within their Birkhead Formation.

4. The absolute age range of the Birkhead Formation is debatable, with the Department of Mines and Energy South Australia (MESA) assigning it a span of 17 Ma and SANTOS Ltd. only 7 Ma (G. Wood, pers. comm., 1995). However, both organisations agree that the base of the Birkhead Formation is older, in terms of palynological boundaries, in the northeast of the basin along the axis of the Birkhead depocentre. But, they disagree where those boundaries are in terms of absolute age. To the east Newton (1986) stated that 'the top Hutton Sandstone at Tintaburra is time equivalent with the mid-Birkhead Formation in the basin depocentre to the northwest'. This indicates that the transgressive nature of the Birkhead Formation not only occurs from northeast to southwest but out of the basin depocentre as a whole and to the southeast.

5. Three consecutive cores, 90 feet in total, were taken in well 17 . This was the first well to be drilled on the southern dome which encountered oil in the Hutton Sandstone. The reason that coring continued below what was later found to be the oil/water contact, was because when the core was brought to the surface, the shows were so good that the well-site geologist thought he was still within the reservoir and continued coring. Given that the shows occur in both coarse and fine grained rocks, and that right across the field just below this core level there is a significant reduction in shows recorded on the mud-log, it is our interpretation that this represents a palaeo-oil column. We believe these shows must represent pooled oil, rather than migrating oil because migrating oil would not have sufficient buoyancy to enter the fine grained rocks in which shows occur. Furthermore, as oil is known to migrate in conduits, it is highly unlikely that shows would persist down to this level right across the field. There is no evidence of a similar large palaeo-oil column in the northern dome.

6. The Birkhead Formation in the Nappamerri Trough has a present-day maturity of Ro ≥ 0.9% (Figure 11). This does not preclude it as a source for the first charge of the Hutton/Birkhead oil pool in the Gidgealpa southern dome as the Birkhead Formation in the Nappamerri Trough would have been much less mature at the time it was expelling oil.

7. These cool areas may be zones of increased aquifer flow as suggested by Toupin et al (1997).

8. Seal diagenesis is also an important aspect to consider in this case (Figure 19) as it is only after the diagenesis of the labile sands within the Birkhead Formation that it became an effective seal.

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SOURCE ROCK DISTRIBUTION and HYDROCARBON GEOCHEMISTRY

B.H. Michaelsen* and
D.M. McKirdy*

Chapter 7

INTRODUCTION

Numerous commercial and non-commercial hydrocarbon discoveries have been made in the Eromanga Basin. One question which continues to perplex explorers is whether these hydrocarbons are indigenous or have migrated from kitchens in the underlying Permo-Triassic Cooper Basin. Over the last two decades, explorationists have come to the realisation that oil-prone and effective source rocks are developed within the Eromanga Basin itself. Some oil and gas has almost certainly migrated from the Cooper Basin and has been trapped in the overlying Eromanga sequence. However, geochemical evidence suggests that a large proportion of the Eromanga crudes are indigenous and are derived from source beds in the Eromanga Basin. The most prolific source rock horizons are the Poolowanna, Birkhead and Murta Formations. This chapter reviews the source rock distribution and hydrocarbon geochemistry of the Eromanga Basin. Its aims are twofold: to collate the large body of Rock-Eval pyrolysis and vitrinite reflectance data on the South Australian sector of the Eromanga Basin, with a view to identifying potential and probable hydrocarbon source rocks; and to briefly summarise the biomarker geochemistry database for oils and source rocks and, where possible, to establish genetic relationships between potential source rocks and hydrocarbon accumulations.

To facilitate discussion of the large volume of data, we have chosen to present the South Australian database in two parts: data on the basin east of the Birdsville Track Ridge (i.e. the Eromanga Basin immediately overlying the Cooper Basin and adjacent areas) which we refer to as the 'eastern' sector; and the Eromanga Basin west of the Birdsville Track Ridge, which we describe as the 'western' sector. For the purposes of this chapter, the western Eromanga Basin includes the Jurassic and Cretaceous strata overlying the Pedirka and Simpson Basins. These data are compiled mostly from Amdel, Analabs, and University of Adelaide reports, or from respective well completion reports. Some new data from the western Eromanga Basin in the Eringa Trough area and from the Pandieburra 1, Poonarunna 1 and Putamurdie 1 wells west of the Birdsville Track Ridge are presented in Table 7.1.

POOLOWANNA FORMATION

Western sector

The fluviolacustrine Poolowanna Formation is the basal unit of the Eromanga Basin and is its first important potential source rock. Rock-Eval data for the western sector are plotted in Figure 7.1a. As the samples analysed are predominantly coals and carbonaceous shales or siltstones, source richness is generally very high. For example, for the Poolowanna 1, 2 and 3 wells in the Poolowanna Trough, total organic carbon (TOC) ranges from 5.1 to 42.1%. Potential yield ($S_1 + S_2$) ranges from 11 to 160 kg hydrocarbons per tonne, indicating good to excellent source richness.

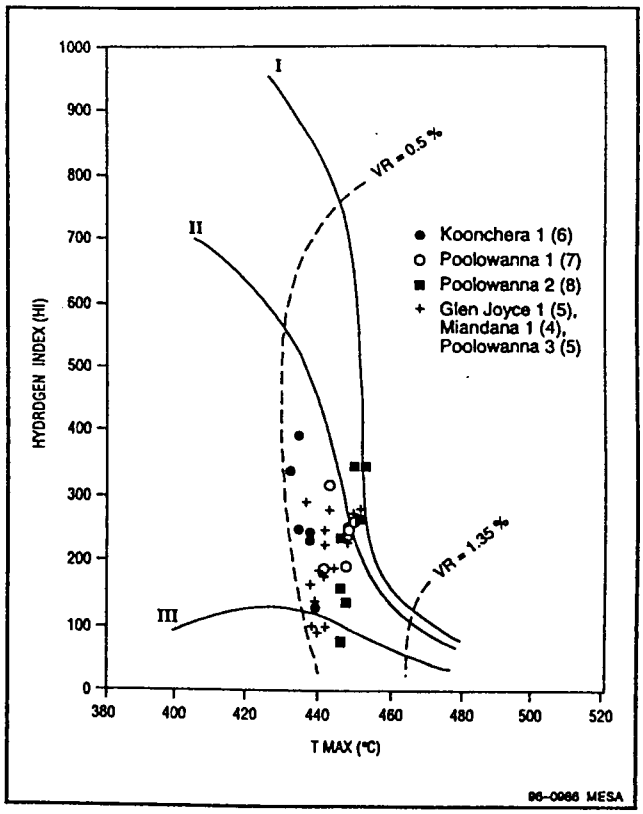

Fig. 7.1a HI versus T_{max} plot, Poolowanna Formation, Eromanga Basin, South Australia (western sector).

Kerogen composition for the Poolowanna samples ranges from Type III (gas-prone) to Type II (oil-prone). Although there is considerable variability, a total of five samples out of the 35 analysed have hydrogen indices (HI) >300 (Fig. 7.1a). These samples are from Koonchera 1, Poolowanna 1 and Poolowanna 2 and have good oil-generative potential. Organic petrography shows that in the Poolowanna area liptinite ≥ vitrinite > inertinite. Elevated HI values (i.e. Type II kerogen) occur when the coals and shaley coals are resinite-enriched (Kagya *et al.*, 1996).

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As indicated by measured vitrinite reflectance (R_o) and maturities estimated from T_{max}, the maturity of the Poolowanna Formation in the Poolowanna Trough reaches about 0.9% R_o which corresponds to peak hydrocarbon generation for Type II organic matter. However, where it is intersected by Koonchera 1 in the Birdsville Track area, or by Glen Joyce 1 and Miandana 1 in the Pedirka Basin, the Poolowanna Formation is only marginally mature for liquid hydrocarbon generation (0.5–0.6% R_o).

Eastern sector

Rock-Eval data from 44 wells (88 samples) in the Cooper region are plotted in Figure 7.1b. As expected for such a large database, source richness and quality are highly variable. However, some of the best source rocks are developed at Kobari 1, Leleptian 1, Toolachee East 2, Tantanna 1 and Titan 1. When considering data from only these wells source quality ranges from fair to very good. Eight of the samples from these wells, and 10 samples from other wells, have HI values greater than 250 indicating good (Type II/III kerogen) to very good oil source potential (Type II kerogen).

The organic petrography of the Poolowanna facies in the Sturt–Tantanna area south of the Patchawarra Trough is similar to that described for the Poolowanna Trough, except that in many samples inertinite is dominant over vitrinite suggesting a greater variety of sub-oxic to oxic terrestrial depositional environments (M. Kagya, University of Adelaide, pers. comm., 1996). In some samples *Botryococcus*-type telalginite is relatively abundant, and is occasionally associated with framboidal pyrite, signifying local anoxic lacustrine conditions (Kagya and McKirdy, 1996).

The Poolowanna facies has attained only marginal maturity (0.5–0.6% R_o) in the Sturt–Tantanna area, but is of slightly higher maturity (0.6–0.7% R_o) in the Leleptian and Toolachee East areas.

Table 7.1 New Rock-Eval pyrolysis data from the western Eromanga Basin.

Well	Depth (m)	TOC (%)	Genetic Potential ($S_1 + S_2$)	Hydrogen Index	Oxygen Index
Birkhead equivalent					
Cur 3	251.6	34.30	135.08	359	38
	251.9	39.00	168.29	388	36
	259.5	47.20	279.41	542	37
Cur 5	209.2	52.90	49.41	87	47
	210.1	50.50	175.72	312	39
	249.4	58.70	248.59	368	46
Pandieburra 1	1567.4	1.01	1.66	158	51
	1753.3	0.84	1.43	165	91
Poonarunna 1	1583.2	9.34	43.15	417	11
	1587.8	3.56	21.07	553	13
	1601.3	1.72	5.12	277	19
	1602.0	1.61	4.94	288	39
	1621.1	1.96	11.03	509	26
	1622.8	1.96	8.31	378	21
	1625.0	9.19	40.89	398	9
	1625.4	8.88	37.88	367	5
	1627.1	19.70	97.64	438	7
Putamurdie 1	1456.6	5.98	24.45	391	8
	1458.5	1.11	3.44	297	30
	1458.6	1.74	6.35	354	31
Namur Sandstone					
Poonarunna 1	1519.7	6.04	27.97	437	8
	1522.4	2.86	12.28	397	9
	1524.3	1.44	8.03	538	22
	1529.6	0.77	2.03	255	37
	1529.8	1.03	2.70	251	13

TOC: total organic carbon

$S_1 + S_2$: kg hydrocarbons per tonne rock

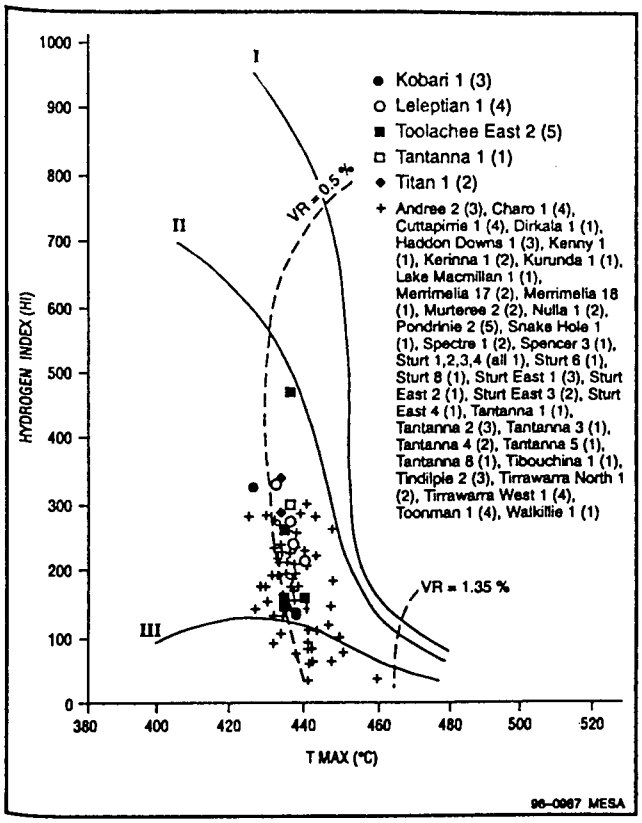

Fig. 7.1b HI versus T_{max} plot, Poolowanna facies, Eromanga Basin, South Australia (eastern sector).

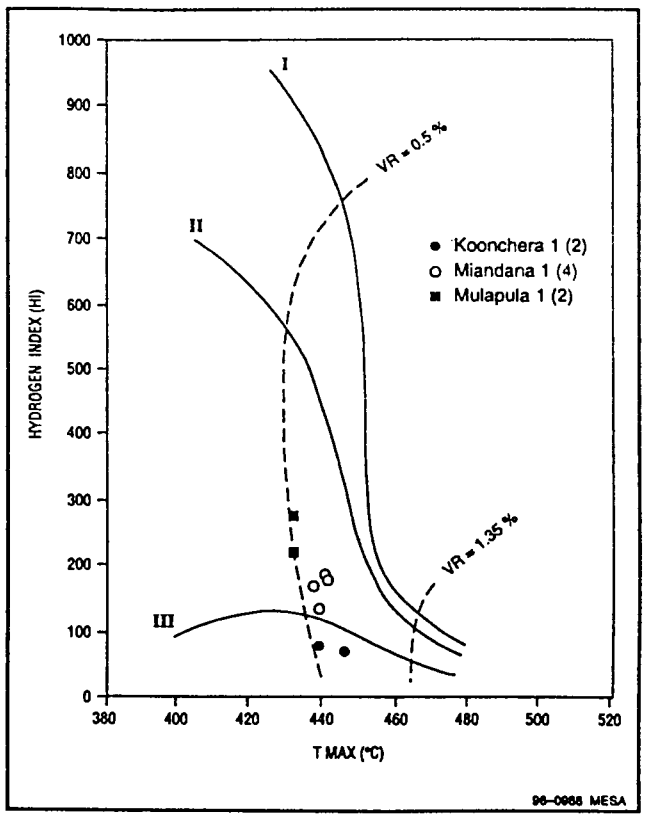

Fig. 7.2a HI versus T_{max} plot, Hutton Sandstone, Eromanga Basin, South Australia (western sector).

HUTTON SANDSTONE

Source rock data for the Hutton Sandstone in the western and eastern sectors are presented in Figures 7.2a and 7.2b, respectively. Note that data from the western sector are sparse. Despite low shale/sand ratios, some thin source beds were encountered at 1359.7 and 1362.8 m in Mulapula 1 (TOC = 1.6 and 2.3%; HI = 220 and 273; $R_o \approx 0.5\%$). These are immature and moderately oil prone. More data are available from the eastern sector where it appears that an immature, moderately oil-prone source facies (Type II/III kerogen) is developed at Murteree 2 on the Murteree Ridge (TOC = 1.2–3.4%; HI = 229–336; $R_o \approx 0.5\%$). A single sample at Merrimelia 18 also displays good oil source potential (TOC = 16.8%; HI = 284) and is initially mature ($R_o \approx 0.65$–0.7%). The source quality of some moderately oil-prone shales at Munkarie 4 and Tirrawarra West 1 (amongst other localities) is diluted by inferior Type III kerogen in other samples from the same Hutton section.

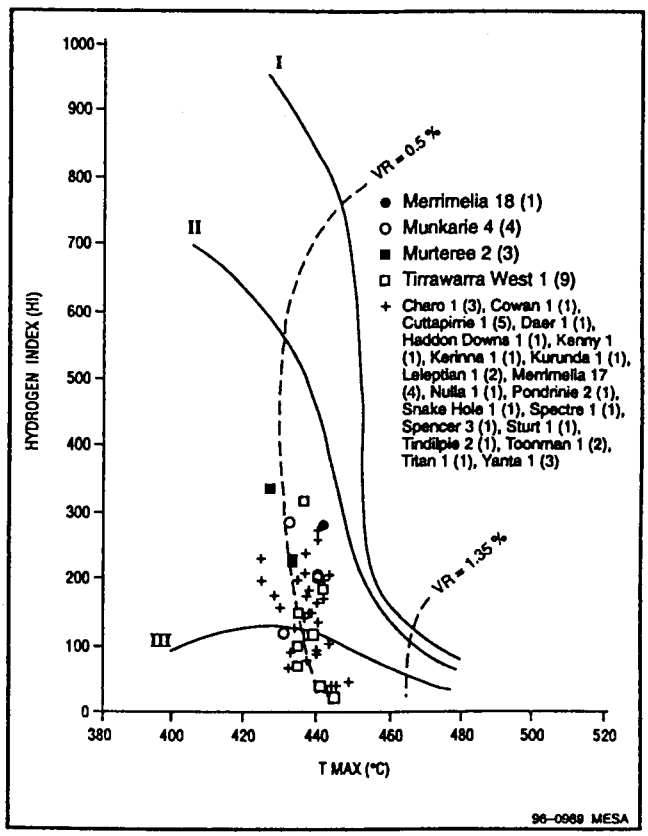

Fig. 7.2b HI versus T_{max} plot, Hutton Sandstone, Eromanga Basin, South Australia (eastern sector).

BIRKHEAD FORMATION

Western sector

The Birkhead Formation of the western Eromanga Basin is the second important unit for hydrocarbon generation. The Rock-Eval plot of Figure 7.3a summarises these data. Source richness parameters are highly variable in the Birkhead Formation. For example, in Pandieburra 1, Poonarunna 1 and Putamurdie 1, where core was selectively sampled for dark argillaceous lithologies, source richness is generally high but ranges from fair to excellent (TOC = 0.84–19.7%; S_1+S_2 = 1–98 kg hydrocarbons per tonne). TOC values and potential yields are even higher in the Algebuckina Sandstone (the Birkhead equivalent) at Cur 3 and Cur 5 (TOC = 34.3–58.7%; $S_1 + S_2$ = 49–279 kg

hydrocarbons per tonne). Twenty-nine of the 31 samples from Cur 3, Cur 5, Mulapula 1, Poonarunna 1 and Putamurdie 1 display good to excellent source quality (HI = 199–553). The spatial distribution of these wells implies that high quality (Type II) source rocks are developed over wide areas of the western Eromanga Basin. Even samples with lesser generative-potential (i.e. those where HI <200) are notably better than the least oil-prone samples in other Eromanga formations.

T_{max} values between 435 and 444°C for the Birkhead at Poonarunna 1 and Putamurdie 1 suggest that its level of maturity is between 0.65 and 0.85% R_o. This is in conflict with directly measured vitrinite reflectance which indicates a maturity of <0.6% R_o. Michaelsen and McKirdy (1996) reported suppression of directly measured R_o at these localities. Petrographic observations suggest that such suppression is the result of natural impregnation of vitrinite by plant resins and essential oils. Thus R_o values closer to 0.80–0.85% are the preferred maturity estimates. Since Type II kerogen enters the oil window ahead of Type III kerogen (Type II at ≈ 0.5% R_o; Type III at ≈ 0.7% R_o), it is highly likely that the Birkhead sequence intersected at Poonarunna 1 and Putamurdie 1 is presently an effective source rock. Moreover, a maturity of around 0.80 to 0.85% R_o suggests the Birkhead Formation at these localities may be approaching the peak of oil generation.

The Birkhead equivalent of the Algebuckina Sandstone at Cur 3 and Cur 5 on the western margin of the Eringa Trough also contains high quality source facies (Type II/III and Type II kerogen) although at a lower thermal maturity (0.41–0.45% R_o: Staples *et al.*, 1995). The best quality samples from the Cur wells are telovitrinite-rich coals which contain abundant resinite and fluorinite (plant oils). Gas chromatography–mass spectrometry (GC–MS) of their saturated hydrocarbons demonstrates that the same samples have an enriched microbial biomarker signature (Alexander *et al.*, 1996). In Cook's (1986) opinion, hydrocarbon generation from resinite can commence as early as 0.40 to 0.45% R_o. Powell (1985) also put forward a hydrocarbon generation model wherein resinite-enriched and bacterially-modified source rocks (comprising predominantly vitrinite and inertinite) can begin generating hydrocarbons at 0.45% R_o. Therefore, it is conceivable that the Birkhead equivalent in this area has entered the oil window, especially towards the centre of the Eringa Trough where maturity levels are expected to be higher.

Eastern sector

Figure 7.3b summarises the HI and T_{max} data for 115 samples from 31 well localities. Although much of the Birkhead Formation appears favourable for liquid hydrocarbon generation, its source potential is clearly less than in the western Eromanga Basin. Of the 134 samples analysed, only 18 (or 13%) have HI values of 300 or greater (i.e. Type II/III or II kerogen). This compares to 52% of samples analysed (23 out of 44) in the western sector. High quality source facies are developed at Cuttapirrie 1, Lake Macmillan 1, Snake Hole 1, Tirrawarra North 1, Tirrawarra West 1 and Wancoocha 4. One sample from Snake Hole 1 has an exceptionally high HI of 568 and represents very oil-prone Type II kerogen. Although these localities contain reasonably high quality source material (Type II/III kerogen), many of the coals and shales are diluted with equal amounts of inferior Type III kerogen.

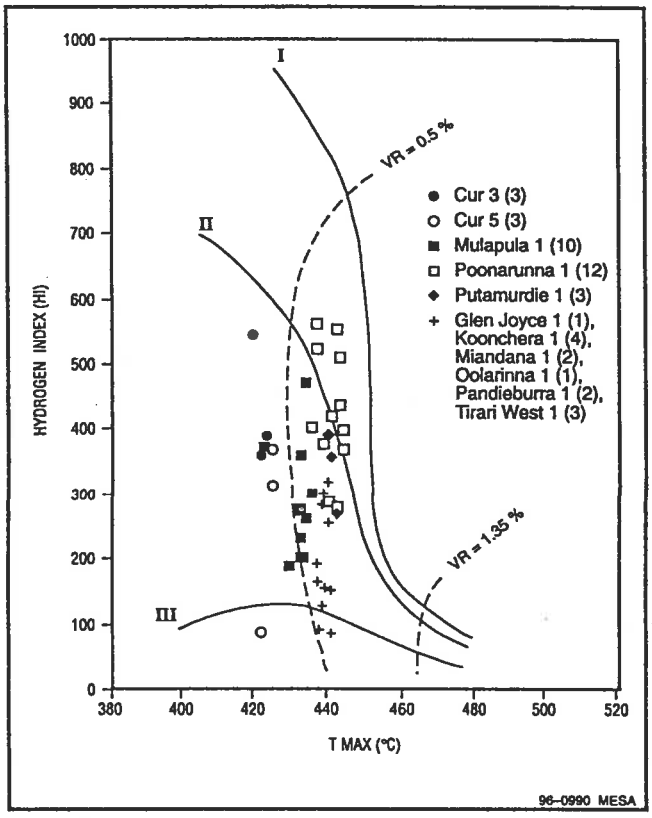

Fig. 7.3a HI versus T_{max} plot, Birkhead Formation, Eromanga Basin, South Australia (western sector).

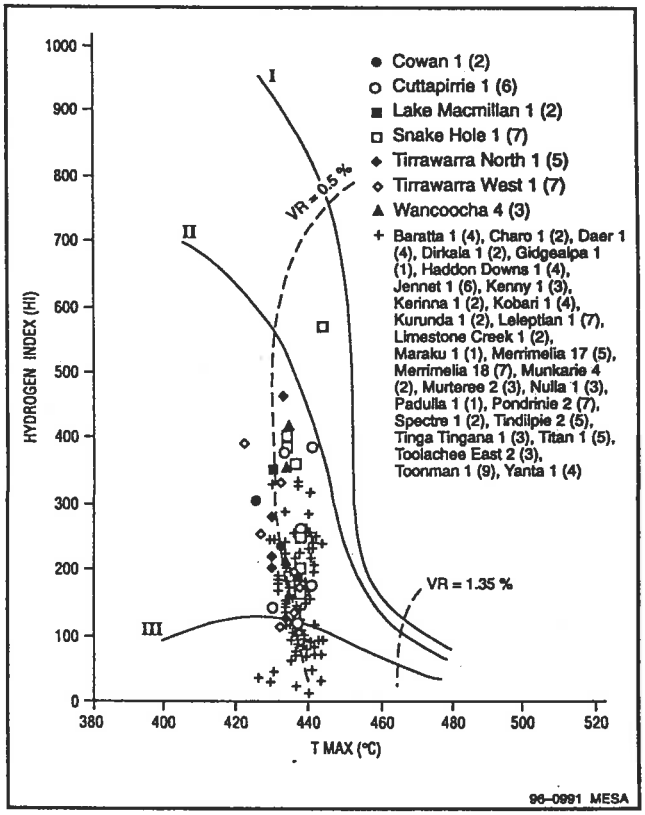

Fig. 7.3b HI versus T_{max} plot, Birkhead Formation, Eromanga Basin, South Australia (eastern sector).

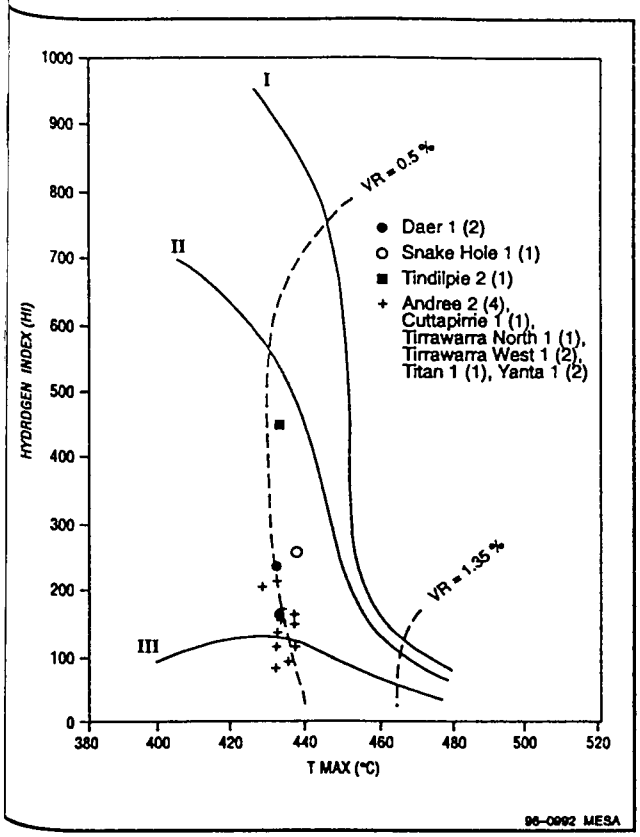

Fig. 7.4 HI versus T_{max} plot, Adori Sandstone, Eromanga Basin, South Australia (eastern sector).

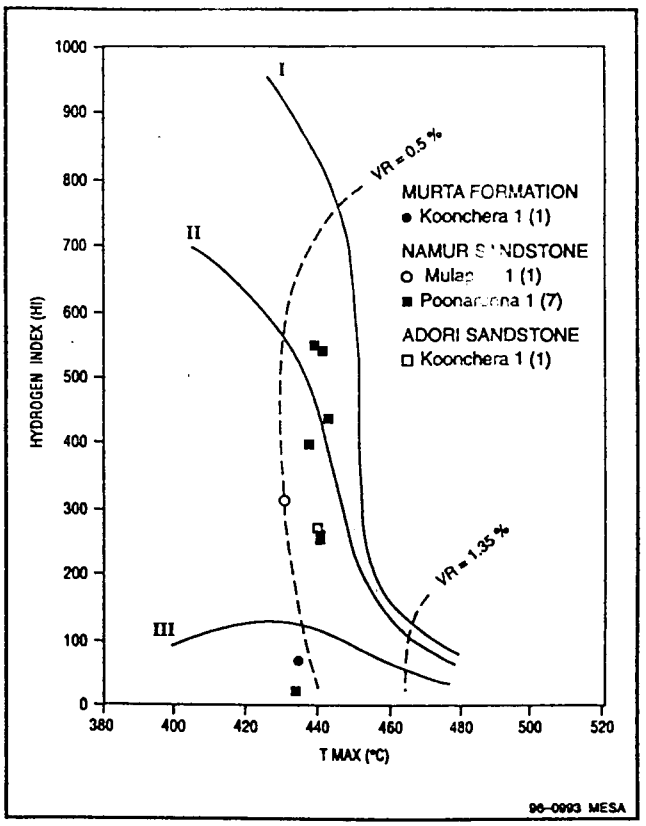

Fig. 7.5 HI versus T_{max} plot, Murta Formation, Namur Sandstone and Adori Sandstone, Eromanga Basin, South Australia (eastern sector).

ADORI SANDSTONE

In both the western and eastern sectors of the Eromanga Basin, the Adori Sandstone is a poor source for liquid hydrocarbons. Only one cuttings sample (2048.3–2057.4 m) from Tindilpie 2 has any noteworthy source potential (TOC = 3.7%; HI = 449; Type II kerogen; $R_o \approx 0.6\%$). Cross-plots of Rock-Eval data for the Adori Sandstone are provided in Figures 7.4 and 7.5.

WESTBOURNE FORMATION

The Westbourne Formation, which is restricted to the eastern sector of the Eromanga Basin in South Australia, has poor source potential for liquid hydrocarbons (Fig. 7.6). Most of the 27 rock samples from 12 wells analysed by Rock-Eval pyrolysis plot beneath the Type III kerogen evolution curve, indicating very poor oil potential. Based on one cuttings sample (2020.8–2039.1 m) from Leleptian 1 (TOC = 0.77%; HI = 210; $R_o \approx 0.55\%$), the Westbourne Formation at best exhibits only minor development of a moderately oil-prone source facies.

NAMUR SANDSTONE

Rock-Eval pyrolysis data for the Namur Sandstone in the western and eastern sectors of the South Australian Eromanga Basin are presented in Figures 7.5 and 7.7, respectively. In the western sector, based on only 8 shale samples from Mulapula 1 and Poonarunna 1, the Namur Sandstone contains, on average, excellent quality Type II/III and oil-prone Type II kerogen. If one excludes an atypically poor sample from Poonarunna 1 (1523.7 m; TOC = 0.36%;

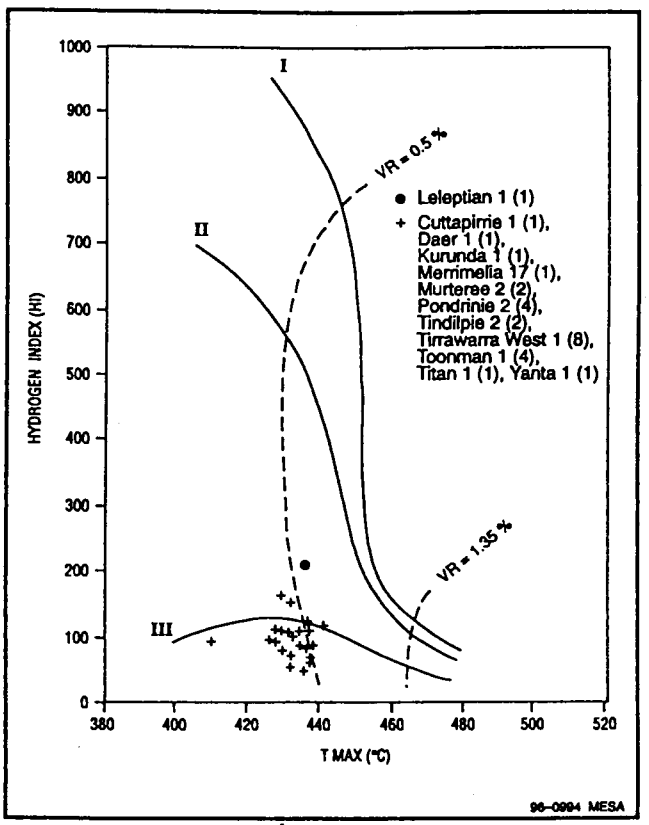

Fig. 7.6 HI versus T_{max} plot, Westbourne Formation, Eromanga Basin, South Australia (eastern sector).

HI = 22), the sample suite from Mulapula 1 and Poonarunna 1 displays fair to excellent source richness (TOC = 0.8–6.0%; $S_1 + S_2$ = 7–28 kg hydrocarbons per tonne) and good to excellent source quality (HI range = 251–548; average = 391). Dispersed organic matter (DOM) in these oil-prone samples is dominated by vitrinite with subordinate liptinite, and only minor inertinite (Michaelsen and McKirdy, 1996). However, in the exceptionally oil-prone samples with HI above 500, liptinite is the dominant maceral group. The liptinites in all samples are chiefly sporinite and sporinite-derived liptodetrinite. Measured vitrinite reflectances suggest a maturity between 0.4 and 0.5% R_o, at variance with T_{max} data which indicate a significantly higher maturity (0.65–0.80% R_o). The T_{max}-derived maturity estimates are probably more realistic, since it is evident from petrographic observations that R_o suppression has lowered the measured reflectance values.

Thin shale intervals of the Namur Sandstone in the eastern sector appear to have potential only for gas generation. HI values are at best around 200, but most samples plot below the Type II evolution pathway, suggesting the presence of Type III (gas-prone) or Type IV (inert) kerogen.

McKINLAY MEMBER

Where developed at the base of the Murta Formation, shaley facies of the McKinlay Member appear to have generally poor source potential. Ten of the 13 samples analysed by Rock-Eval pyrolysis plot around or below the Type III evolution curve (Fig. 7.8) which is typical of gas-prone organic matter. Only three samples from Buckinna 1 have any liquids-generating capacity. However, this potential has been significantly downgraded by dilution with poorer quality Type III/IV source material.

MURTA FORMATION

The lacustrine Murta Formation is stratigraphically the highest unit of importance for hydrocarbon generation. Its hydrocarbon geochemistry was studied in detail by Michaelsen and McKirdy (1989) and Powell *et al.* (1989) who concluded it had potential to generate light paraffinic crude oils, even at maturity levels as low as 0.50–0.55% R_o. Rock-Eval data on 136 samples from 37 wells are summarised in Figure 7.9. The data fall into three broad groupings, as follows:

- Thirty-three core samples analysed from the Biala 1, Buckinna 1, Limestone Creek 6 and McKinlay 2 wells on the Murteree Ridge have by far the best source potential. Here TOC values in the range 0.8 to 2.6% and potential hydrocarbon yields of 3–12 kg per tonne indicate fair to good source richness. HI values between 175 and 541 are characteristic of Type II/III (oil/gas prone) to Type II (oil prone) organic matter. Optical microscopy reveals that the main macerals present are inertinite (40–80% of DOM) and liptinite (15–60% of DOM). Vitrinite is a minor component of the maceral assemblage. Many of the Murteree Ridge samples contain high concentrations of *Botryococcus*-type telalginite, and a positive correlation has been observed between telalginite and elevated HI, especially at Limestone Creek 6, where two samples containing 25% and 26% telalginite (as a percentage of total DOM) possess HI values of 351 and 541, respectively. Intense autofluorescence of the

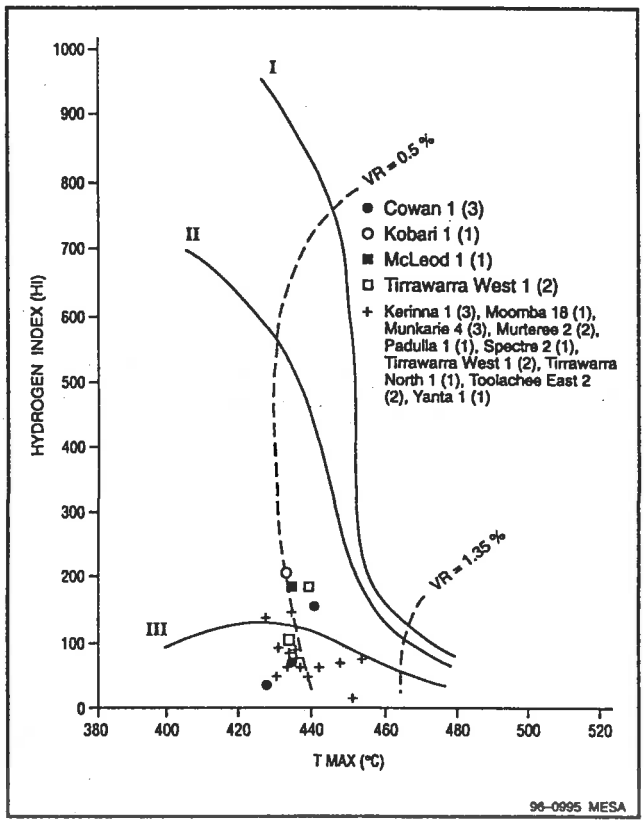

Fig. 7.7 HI versus T_{max} plot, Namur Sandstone, Eromanga Basin, South Australia (eastern sector).

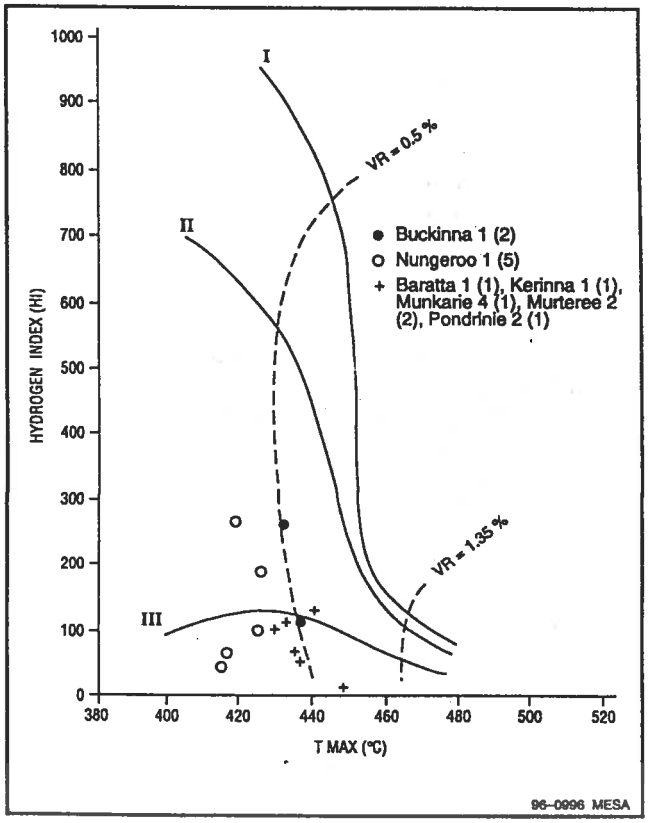

Fig. 7.8 HI versus T_{max} plot, McKinlay Member, Eromanga Basin, South Australia (eastern sector).

liptinite fraction in the Murteree Ridge samples suggests it has been little altered by oxidation, probably because of relatively rapid burial.

- Data from 15 core samples at Moomba 18 in the Nappamerri Trough form a second discrete cluster of points in Figure 7.9. For all but one sample, TOC values range between 0.6 and 2.1% and genetic potentials are between 1 to 6 kg hydrocarbons per tonne. All but two of the 15 samples analysed have HI values between 125 and 200, and therefore contain essentially gas-prone Type III kerogen. Although the maceral composition of the Moomba 18 samples is broadly similar to that of the samples from the Murteree Ridge, muted fluorescence of the liptinite fraction hints that the organic matter was subjected to enough oxidation prior to burial to result in significant loss of oil generating potential.
- The bulk of the remaining 88 samples from 32 wells have HI values <200 and represent Type III to Type IV kerogen. It is possible that many of these samples have diminished source potential because they comprise cuttings which may have contained mixtures of sandy and argillaceous lithologies. However, it is clear that the Murta Formation has poor source potential outside the Murteree Ridge, although oil-prone facies are developed in the Queensland sector (cf. Michaelsen and McKirdy, 1989; Powell *et al.*, 1989).

The maturity of the Murta along the Murteree Horst (0.55–0.60% R_o) places it at the incipient stage of hydrocarbon generation for conventional terrestrial organic matter. Powell *et al.* (1989) provided biomarker evidence that the best Murta source facies contains abundant alkanes derived from bacterial precursors. Bacterial organic matter is more labile than woody (terrestrial) material. Therefore, it is likely that the shales and siltstones of the Murta Formation along, and immediately adjacent to, the Murteree Ridge have been effective source rocks, given their current level of maturity. Powell *et al.* (1989) demonstrated that Rock-Eval pyrolysis of powdered whole rock samples provide an unduly pessimistic assessment of source quality in organically lean (i.e. TOC <2%) units like the Murta Formation, due to the absorption of hydrocarbons by the mineral matrix. Experiments on demineralised samples (kerogens) from Limestone Creek 6 and Biala 1 by Powell *et al.* (1989) revealed that even the Murta shales from the Murteree Ridge have significantly better source potential than conventional Rock-Eval indicates. Finally, the intercalation of these thin oil-prone source facies with reservoir quality sandstones has provided a highly efficient mechanism for the drainage of hydrocarbons into carrier and reservoir lithologies.

CADNA-OWIE FORMATION

Figures 7.10a and 7.10b summarise Rock-Eval data for the Cadna-owie Formation. In the western sector, only one sample from Mulapula 1 stands out as having any oil-source potential. Although this sample is organically lean (TOC = 0.26%), it exhibits fair to good source quality (HI = 280; Type II/III kerogen). The remaining samples have very poor source potential for liquid hydrocarbons. In the eastern sector, a similarly pessimistic picture emerges, except perhaps for samples from Buckinna 1, McLeod 1 and Nulla 1 (HI = 180–250).

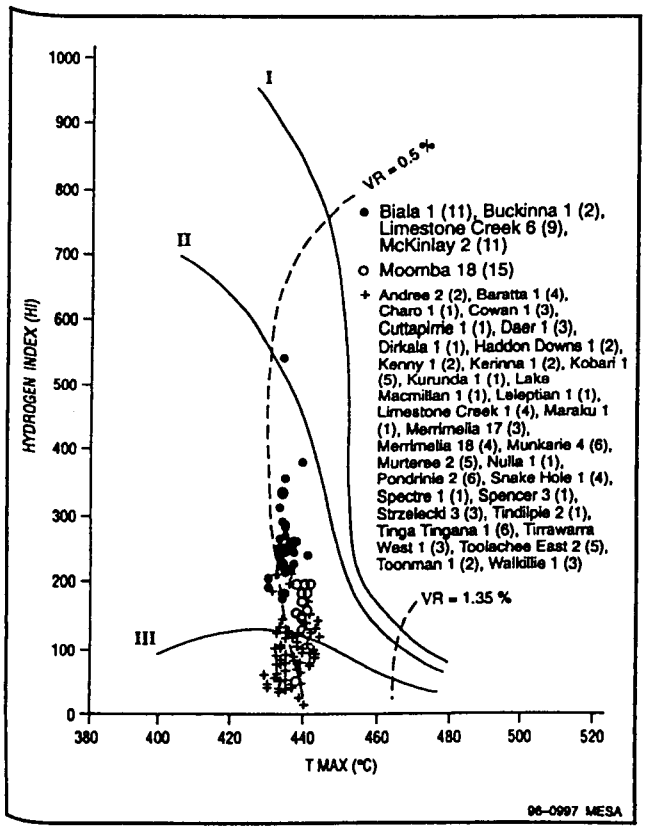

Fig. 7.9 HI versus T_{max} plot, Murta Formation, Eromanga Basin, South Australia (eastern sector).

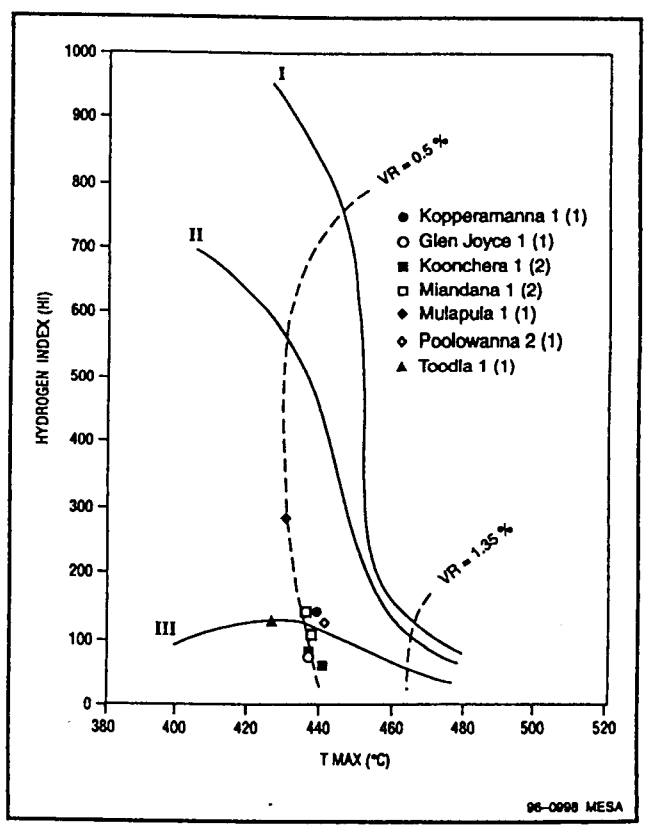

Fig. 7.10a HI versus T_{max} plot, Cadna-owie Formation, Eromanga Basin, South Australia (western sector).

BULLDOG SHALE

Western sector

The available data for the Bulldog Shale in the area west of the Birdsville Track Ridge come entirely from Toodla 1. Core samples from this well were studied extensively by McKirdy *et al.* (1986). TOC values are in the range 0.8–1.9% and potential yields <1 kg hydrocarbons per tonne. Figure 7.11a demonstrates that the Bulldog Shale contains inert (Type IV) kerogen with no liquid hydrocarbon-generative potential. McKirdy *et al.* (1986) reported that the maceral assemblage is dominated by inertinite, although a minority of samples studied contain mostly liptinite (chiefly phytoplankton and sporinite). Vitrinite is only a minor component in all samples. Suppressed fluorescence of the liptinitic fraction is evidence of partial oxidation and loss of hydrocarbon potential. The thermal immaturity of the Toodla 1 samples is evident from their low T_{max} values (423–436°C) which equate to measured vitrinite reflectances of <0.4% R_o.

Eastern sector

The Bulldog Shale in the eastern sector exhibits similarly poor oil source potential (Fig. 7.11b). Notable exceptions are three samples from Buckinna 1 on the Murteree Ridge which have TOC values of 1.2–1.7% and HI values of 224–248. These samples contain Type II/III kerogen with a modest liquids-generating potential. Petrographic examination of cuttings and sidewall cores in Strzelecki 3 by McKirdy *et al.* (1986) confirmed that the Bulldog Shale contains an abundance of inertinite and subordinate vitrinite and liptinite. The present low maturity of the Bulldog Shale at such localities (<0.45% R_o) precludes hydrocarbon generation. What appear to be unduly high T_{max} values for the Buckinna samples may be a function of organic matter type and so may not accurately represent the true thermal maturity (cf. McKirdy *et al.*, 1986).

HYDROCARBON GEOCHEMISTRY

Considerable efforts have been made to establish robust correlations between reservoired oils and potential source rocks within the Cooper–Eromanga petroleum system. This problem has been tackled using three different approaches.

Aromatic hydrocarbons can be useful in determining the maturity of an oil at the time of its expulsion from the source rock. Michaelsen and McKirdy (1989), Powell *et al.* (1989) and Tupper and Burckhardt (1990) used calculated vitrinite reflectance (R_c) derived from the methylphenanthrene index (MPI) to type a large number of oils for comparison with the maturity of potential source rocks. These studies reveal that most Murta–Namur oils migrated from their source rocks at the very threshhold of the conventional oil window (R_c = 0.54–0.61%). Murta oils with low R_c values include those along the Murteree Ridge (e.g. Biala, Limestone Creek and McKinlay) and at Dullingari. Among the few exceptions are Murta crudes at Merrimelia for which higher source maturities are indicated (R_c = 0.73–0.84%). Oils in Jurassic reservoirs generally have MPI values that indicate they were expelled from their respective source rocks at somewhat higher maturity levels (R_c = 0.64–1.04%). This is in broad agreement with present maturation levels of the Birkhead Formation. Calculated vitrinite reflectance values of the Murta and Jurassic oils differentiate them from many Cooper Basin oils which underwent primary migration between 0.95

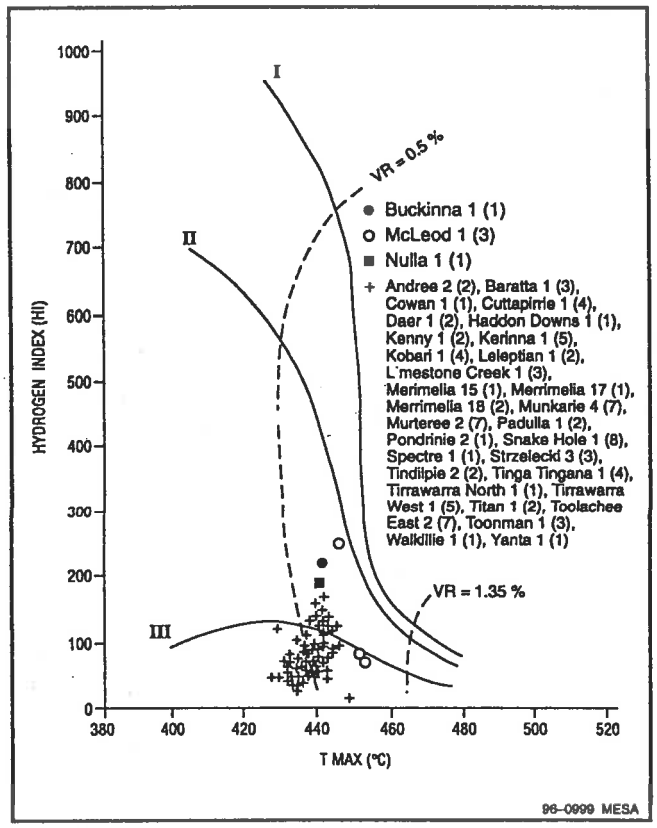

Fig. 7.10b HI versus T_{max} plot, Cadna-owie Formation, Eromanga Basin, South Australia (eastern sector).

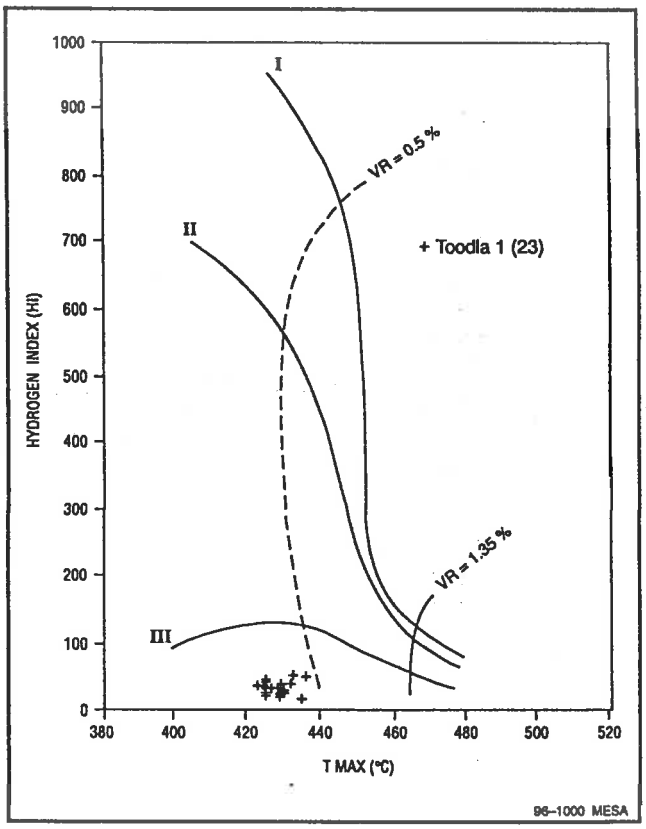

Fig. 7.11a HI versus T_{max} plot, Bulldog Shale, Eromanga Basin, South Australia (western sector).

and 1.10% R_o. The values of other maturity parameters based on saturated hydrocarbon biomarkers (e.g. C_{29} sterane 20S/20R and C_{30} moretane/hopane) are consistent with the inferred thermal immaturity of the Murta and Jurassic-hosted crudes (cf. Michaelsen and McKirdy, 1989).

Alexander *et al.* (1988) employed aromatic biomarkers derived from the conifer family Araucariaceae to differentiate between oils sourced from Permian and Jurassic kitchens in the Cooper–Eromanga Basins. Araucariaceae did not become important members of the plant kingdom until the Early–Middle Jurassic, and therefore their biomarkers should be abundant in rocks and oils of the Eromanga Basin. Conversely, the relative abundance of the araucariacean biomarkers can be expected to be low in Cooper Basin source rocks and their derived oils. Figure 7.12 plots log 1,2,5-trimethylnaphthalene/1,3,6-trimethylnaphthalene against log 1-methylphenanthrene/9-methylphenanthrene for a selection of oils and source rocks in the western Cooper region. The following can be inferred from these data:

- Permian sediments have low concentrations of 1-methylphenanthrene (an araucariacean biomarker) relative to 9-methylphenanthrene when compared to Jurassic and Cretaceous sediments. However, the ratio of 1,2,5-trimethylnaphthalene (another araucariacean biomarker) to 1,3,6-trimethylnaphthalene alone is insufficient to discriminate between Permian and Jurassic rocks.
- Permian and Jurassic-reservoired oils can be distinguished on the basis of their 1,2,5-trimethylnaphthalene/1,3,6-trimethylnaphthalene and 1-methylphenanthrene/9-methylphenanthrene ratios. Both parameters are markedly higher in oils from Jurassic reservoirs. Based on this premise, the following oils can be assigned a Cretaceous or Jurassic source affinity: Bookabourdie 1, Callabonna 1, Charo 1 (all Birkhead reservoirs), Cuttapirrie 1 (basal Jurassic reservoir), Gidgealpa 20 (Namur and Birkhead reservoirs), Kenny 1 (Birkhead), Merrimelia 9 (Birkhead), Merrimelia 15 (Murta) Moolion 1 (Poolowanna), Mulapula 1 (Namur), Strzelecki 19 (Namur and Birkhead) and Wancoocha 2 (Murta, Birkhead and Hutton; cf. Michaelsen *et al.*, 1995). Its aromatic biomarker distribution and low maturity (R_c = 0.61%) also suggest an intra-Poolowanna source for the Poolowanna 1 oil.

Other biomarker studies have utilised saturated hydrocarbons to distinguish between Cooper and Eromanga-sourced oils. Jenkins (1989) attempted to assign source affinity on the basis of differences in the concentration of the demethylated hopanes, 25,28,30-trisnorhopane (25,28,30-TNH) and 28,30-bisnorhopane (28,30-BNH). Both 25,28,30-TNH and 28,30-BNH are biomarkers for anaerobic bacteria. Jenkins concluded that 25,28,30-TNH was restricted to rocks of Jurassic age or younger, and their genetically related crude oils. However, we disagree with

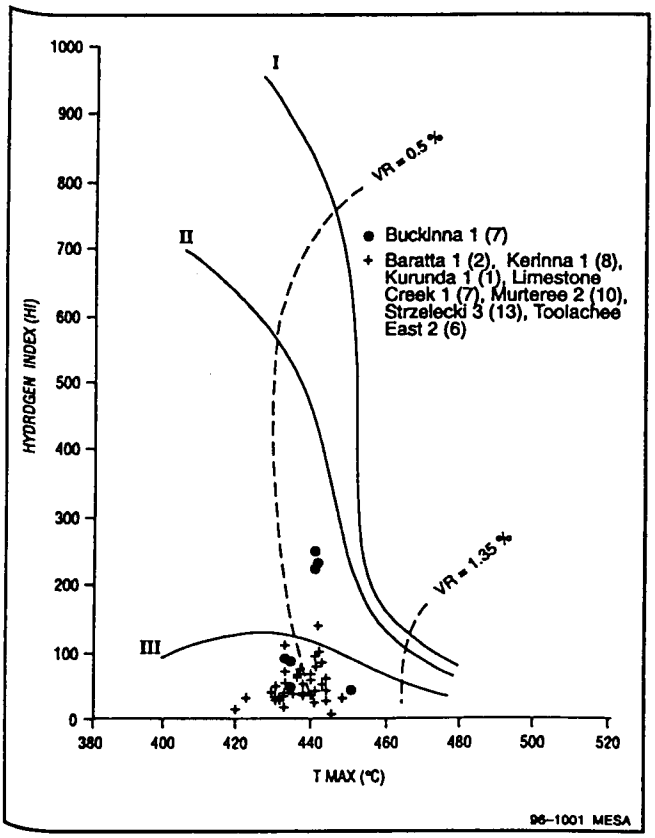

Fig. 7.11b HI versus T_{max} plot, Bulldog Shale, Eromanga Basin, South Australia (eastern sector).

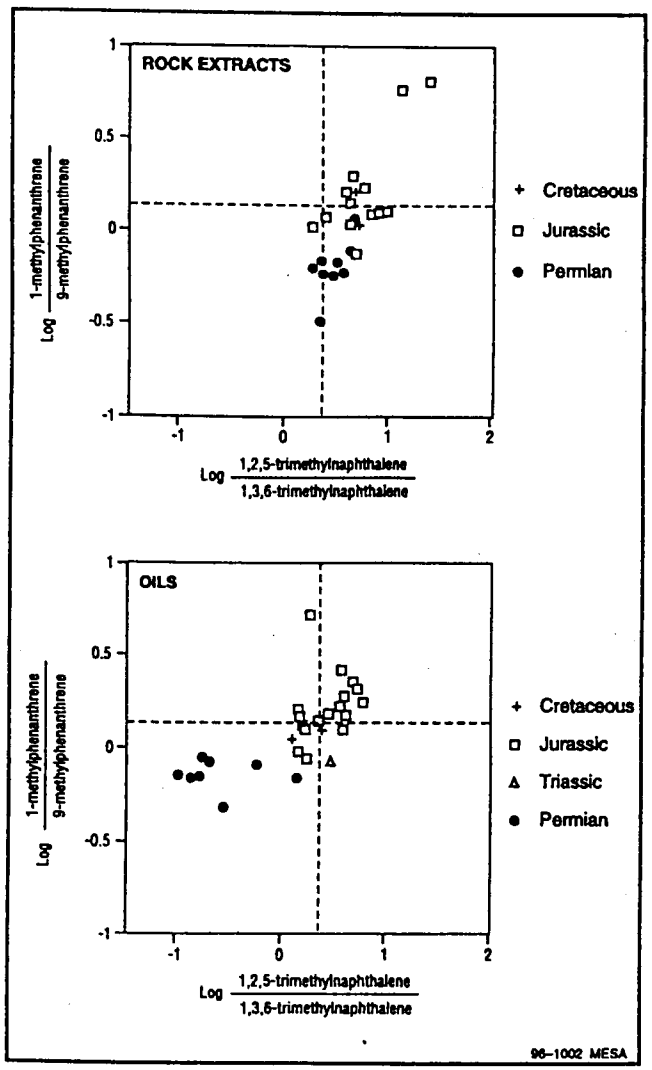

Fig. 7.12 Plot of log 1,2,5-trimethylnaphthalene/1,3,6-trimethylnaphthalene versus log 1-methylphenanthrene/9-methylphenenthrene for rock extracts and oils from the western Cooper region.

this premise because 25,28,30-TNH (± 25,28,30-trisnormoretane) occurs in high abundance in Triassic shales of the Mungaroo Formation, Northern Carnarvon Basin, Western Australia (B.H. Michaelsen, University of Adelaide, unpub. data; Noble *et al.*, 1985; Peters and Moldowan, 1993). Nevertheless, we agree with Jenkins (1989) to the extent that 25,28,30-TNH is virtually absent from the geological record during the Palaeozoic. Thus, the presence or absence of 25,28,30-TNH may be indicative, but not necessarily definitive, of source affinity in the case of oils from the Cooper and Eromanga Basins.

Until recently very little biomarker information was available for oils and rock extracts from the western sector of the study area. Alexander *et al.* (1996) used the ratios 28,30-BNH/17α-hopane and retene/phenanthrene to geochemically characterise Permian coals and Jurassic coals in the Eringa Trough. Figure 7.13 summarises their data on logarithmic axes. All Permian samples (n = 7) have retene/phenanthrene ratios lower than those of the Jurassic samples (n = 3). Concentrations of the demethylated hopane 28,30-bisnorhopane are consistently higher, relative to 17α-hopane, in Permian rocks (Purni, Crown Point Formations) than they are in the Jurassic (Birkhead Formation) samples. High concentrations of 28,30-bisnorhopane are indicative of rocks deposited under suboxic and anoxic conditions (especially the latter: cf. Peters and Moldowan, 1993). There is no obvious reason why the concentration of 28,30-BNH in Permian coals should be higher than in Jurassic coals. Nevertheless, it appears that the observed variation in 28,30-BNH content can be readily exploited in oil-source rock correlation studies. This finding presents explorers of the western Eromanga Basin with another means of distinguishing Permian and Jurassic hydrocarbons.

Future oil discoveries with elevated 28,30-bisnorhopane/17α-hopane ratios are likely to be sourced from the Permian, whereas those with low 28,30-bisnorhopane contents could be expulsion products of Jurassic source rocks.

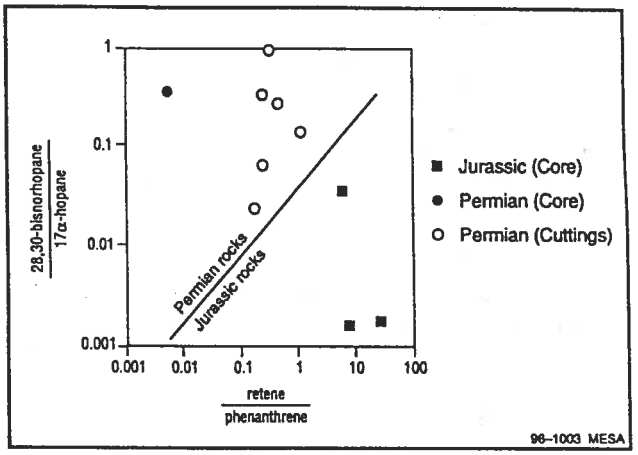

Fig. 7.13 Plot on logarithmic axes of retene/phenanthrene versus 28,30-bisnorhopane/17α-hopane for Permian (Crown Point and Purni Formations) and Jurassic (Birkhead equivalent of Algebuckina Sandstone) rock extracts, Eringa Trough (after Alexander et al., 1996).

CONCLUSIONS

Ranked in order of decreasing potential as measured by Rock-Eval pyrolysis, the best source rocks in the western Eromanga Basin are the coals and carbonaceous shales of the Birkhead Formation, followed by the organic-rich shales and siltstones of the Murta Formation, and the highly carbonaceous shales of the Poolowanna Formation. These units display a wide range of source richness and quality, but all contain varying quantities of Type II/III (oil/gas-prone) and Type II (oil-prone) organic matter. Other units have negligible source potential. The calculated vitrinite reflectance of most Eromanga oils indicates they were expelled from their source rocks at maturation levels which closely match the present-day maturities of the adjacent intra-Eromanga source rocks.

The aromatic hydrocarbon geochemistry of oils from Jurassic reservoirs in the Eromanga Basin, where it overlies the southern Cooper Basin, closely resembles that of potential Jurassic source rocks. Likewise, the chemistry of the Permian oils matches that of potential source rocks in the Cooper Basin. These findings suggest that migration from Permian source kitchens into the superjacent Eromanga sequence has not occurred to any appreciable extent in the southern Cooper Basin region. Therefore, many of the oils which are reservoired in the Eromanga Basin have been generated *in situ*, and have not migrated from deeper source rocks in the Cooper Basin.

PD25

Aromatic hydrocarbon signatures of oils from the Cooper and Eromanga Basins, central Australia: Evidence of multiple sources and in-reservoir mixing

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This survey of aromatic hydrocarbon distributions in crude oils from the Cooper and Eromanga Basins (central Australia) was promped by our recent discovery of two families of oil in Early Permian reservoirs. Family 1 oils, such as those in the Fly Lake, Tirrawara, Moorari and Woolkina fields of the Patchawarra Trough, are exceptionally mature (MPI-derived R_c=0.99-1.19%; rearranged hopanes >> 17α-hopanes; Σ steranes >> Σ hopanes). Matching rearranged hopane distributions in coals of the Patchawarra Formation are evidence that these high maturity oils were derived from coals, rather than shales which have more conventional hopane distributions (McKirdy et al., 1997). The latter are a feature of Family 2 Permian oils in fields such as Daralingie, Gidgealpa, Malgoona and Sturt (MPI-derived R_c=0.93-0.99%; rearranged hopanes < 17α-hopanes; Σ steranes < Σ hopanes).

The aromatic hydrocarbon contents of 62 oils from Soouth Australia and Queensland were screened using whole-oil GC-MS in order to more fully characterize each Permian family, and to distinquish them from oils of Jurassic (intra-Eromanga) origin. A novel combination of aromatic source and maturity parameters has enabled the recognition of multiple petroleum systems; instances of migration from Permian kitchens into Jurassic reservoirs; and Eromanga traps which have received charges from both Permian and Jurassic source rocks. The principal findings of the present study are summarized in Figures 1 and 2. They indicate the following:

The relative abundance of methylphenanthrene isomers defines a single mixing curve in Queensland and two mixing curves in South Australia (Fig. 1). Thus oils from the Naccowland-Jackson Trend (NJT; Queensland) have had variable inputs from the Cooper Basin and can be classified accordingly: 1. Oils in Jurassic (Hutton Sst) reservoirs at Chookoo and Naccowlah South (north-west NJT) appear to be derived entirely from a Permian source kitchen; 2. Eromanga oil at Jackson and Gunna (central NJT) represents Permian hydrocarbons which have breached the Cooper Basin regional seal and invaded the Jurassic reservoirs to comingle with indigenous Eromanga oil; and 3. Eromanga oils from Koora, Winna and Thungo (south-east NJT) are wholely Jurassic in origin.

The best criteria to distinquish Family 1 and 2 oils using aromatic hydrocarbons are the conventional maturity parameters DNR and TNR (Fig. 2). These data confirm that the Eromanga oils in Queensland have a greater affinity with the Cooper Basin than do those in South Australia.

In the South Australian sector, significant volumes of high-maturity oil have not migrated from the Cooper Basin into the overlying Eromanga Basin. For example, the stacked reservoirs of the Tirrawarra Sandstone and Birkhead Formation at Moorari contain oils with distinct end-member chemistries. The Tirrawarra oil (Family 1) is of high maturity and pre-Araucariacean (i.e. pre-Jurassic: *cf.* Alexander *et al.*, 1992) in its source affinity, whereas the Birkhead oil is an archetypical Eromanga-sourced oil. The Moorari-4 (DST-3, Birkhead Formation) oil contains the highest concentrations of Araucariacean biomarkers encountered in this study.

Alexander R., Larcher A. V., Kagi R.I. and Price P.L. (1992) An oil-source correlation study using age-specific plant-derived aromatic biomarkers. In *Biological Markers in Sediments and Petroleum*, eds. J.M. Moldowan, P. Albrecht and R.P. Philp, pp. 201 –221. Prentice-Hall, Englewood Cliffs, NJ.

McKirdy D.M., Michaelsen B.H., Kagya M.L.N. and Ryan M.J. (1997) Biomarker signatures of oils from the Patchawarra Trough, Cooper/Eromanga Basin, South Australia. *18th International Meeting on Organic Geochemistry, 22–26 September 1997, Maastricht, The Netherlands. Abstracts Part I*, pp. 415–416.

Figure 1

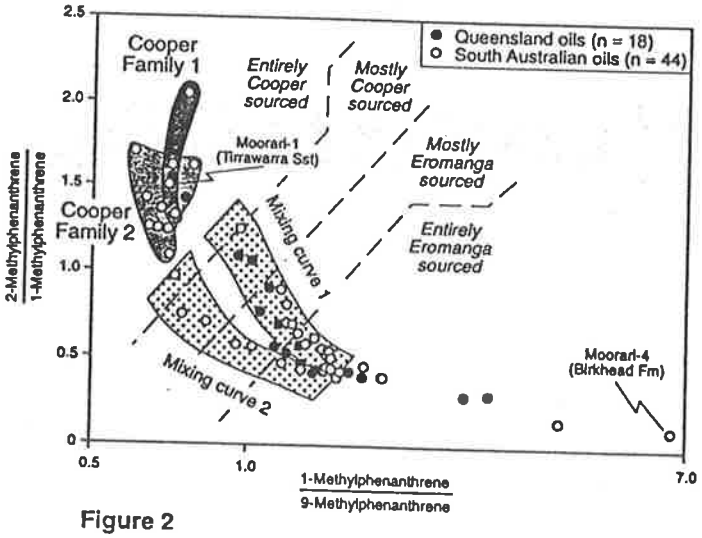
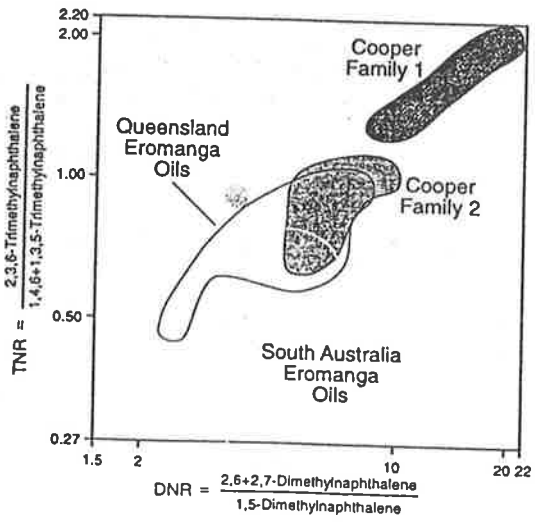


Figure 2



Migration and mixing of oils in the Cooper/Eromanga Basin

Bernd H. Michaelsen and David M. McKirdy

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The University of Adelaide, SA 5005, Australia

This survey of aromatic hydrocarbon distributions in crude oils from the Cooper and Eromanga Basins (central Australia) was prompted by our discovery of two families of oil in Early Permian reservoirs. The condensate-like Family 1 oils (46 – 50° API) appear to be restricted to the Fly Lake, Tirrawarra, Moorari and Woolkina fields of the Patchawarra Trough and are exceptionally mature (MPI-derived R_c = 0.99 – 1.19%; rearranged hopanes >> 17α-hopanes; steranes >> hopanes). Matching rearranged hopane distributions in coals of the Patchawarra Formation are evidence that these high-maturity oils were predominantly derived from local coals (via short-range migration), rather than shales which have more conventional hopane distributions (McKirdy *et al.*, 1997). The latter are a feature of the heavier Family 2 oils (34 – 36° API) which are geographically more widespread (and more migrated) and are found in fields such as Daralingie, Gidgealpa, Malgoona and Sturt (MPI-derived R_c = 0.94 – 0.99%; rearranged hopanes < 17α-hopanes ; steranes < hopanes).

The aromatic hydrocarbon contents of 62 oils from South Australia and Queensland were screened using whole-oil GC-MS in order to more fully characterise each Permian family, and to distinguish them from oils of Jurassic (intra-Eromanga) origin. A novel combination of aromatic source and maturity parameters has enabled the recognition of multiple petroleum systems; instances of migration from Permian kitchens into Jurassic reservoirs; and Eromanga traps which have received charges from both Permian and Jurassic source rocks. The principal findings of the present study are summarised in Figure 1 and elaborated below:

The relative abundance of methylphenanthrene isomers defines a single mixing curve in Queensland and two mixing curves in South Australia. Thus oils from the Naccowlah-Jackson Trend (NJT; Queensland) have had variable inputs from the Cooper Basin and can be classified into three groups. Oils in Jurassic (Hutton Sandstone) reservoirs at Chookoo and Naccowlah South (north-west NJT) appear to be derived entirely from a Permian source kitchen. Eromanga oils at Jackson and Gunna (central NJT) represent Permian hydrocarbons which have breached the Cooper Basin regional seal and invaded the Jurassic reservoirs to comingle with indigenous Eromanga oil. Finally, Eromanga oils from Koora, Winna, Thungo and Maxwell (south-east NJT) are wholely Jurassic/Cretaceous in origin.

The best criteria to distinguish Family 1 and Family 2 oils using aromatic hydrocarbons are the conventional maturity parameters DNR and TNR. These data confirm that the Eromanga oils in Queensland have a greater affinity with the Cooper Basin than do those in South Australia. In contrast to the scenario in Queensland, significant volumes of high-maturity oil have not migrated from the Cooper Basin into the overlying Eromanga Basin in the South Australian sector. For example, the stacked reservoirs of the Tirrawarra Sandstone and Birkhead Formation at Moorari contain oils with distinct end-member chemistries. The Tirrawarra oil (Family 1) is of high maturity and pre-araucariacean (i.e. pre-Jurassic: *cf.* Alexander *et al.*, 1992) in its source affinity, whereas the Birkhead oil is an archetypical Eromanga-sourced oil. The Moorari-4 (DST-3, Birkhead Formation) oil contains the highest concentrations of araucariacean biomarkers encountered in this study. Nevertheless, Permian-derived hydrocarbons have contributed towards Eromanga oil pools at *inter alia* Kobari (Murta Formation: *ca* 80%), Strzelecki (Hutton & Namur Sandstones: 40 – 60%) and Merrimelia (Hutton Sandstone: 40 – 60%; Namur Sandstone: *ca* 20%).

References:

Alexander R., Larcher A. V., Kagi R.I. and Price P.L. (1992) An oil-source correlation study using age-specific plant-derived aromatic biomarkers. In *Biological Markers in Sediments and Petroleum*, eds. J.M. Moldowan, P. Albrecht and R.P. Philp, pp. 201–221. Prentice-Hall, Englewood Cliffs, NJ.

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NOTE: This publication is included in the print copy of the thesis held in the University of Adelaide Library.

Michaelsen, B.H. Kamali, M.R. and McKirdy, D.M. (1995). Unexpected molecular fossils from Early Cambrian marine carbonates of the Officer Basin, South Australia. In J.O. Grimalt and C. Dorronsoro (Eds.), *Organic Geochemistry: developments and applications to energy, climate, environment and human history: selected papers from the 17th International Meeting on Organic Geochemistry*, 4-8 September, 1995, Donostia-San Sebastian, The Basque Country, Spain.

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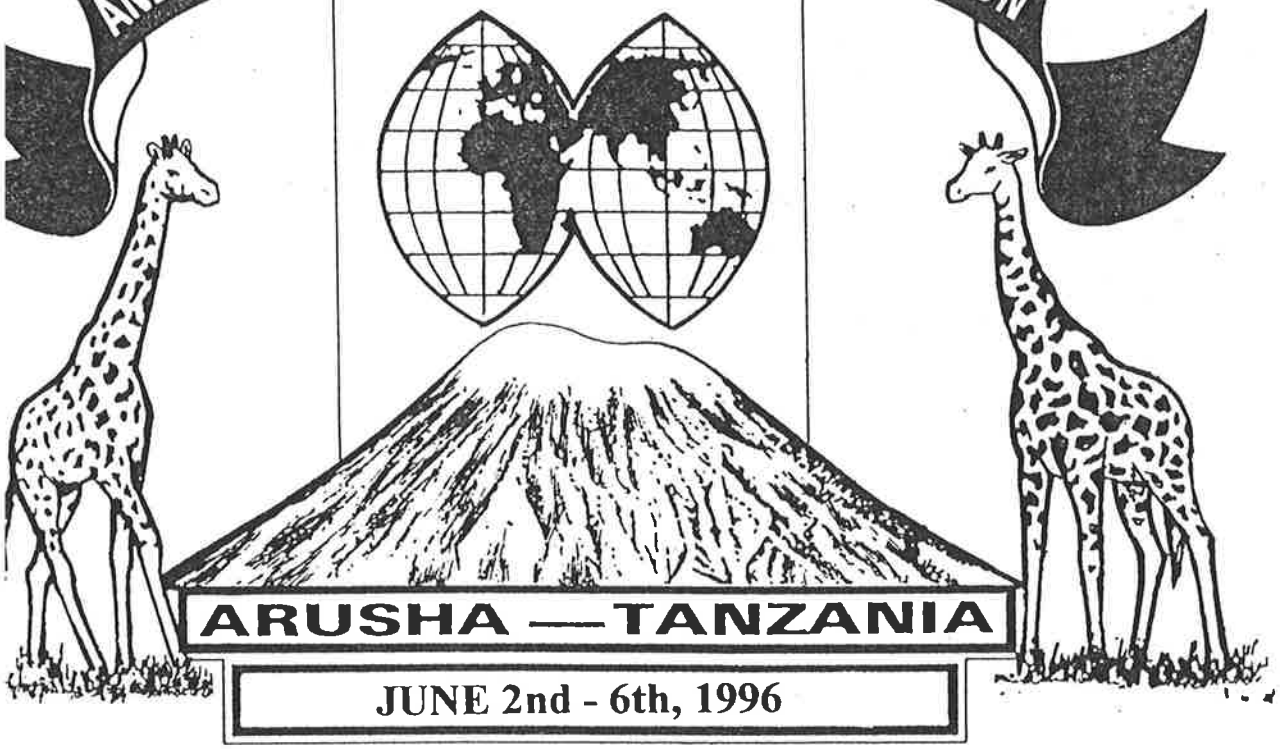
4TH CONFERENCE ON PETROLEUM GEOCHEMISTRY AND EXPLORATION IN THE AFRO-ASIAN REGION



ARUSHA — TANZANIA

JUNE 2nd - 6th, 1996

PROGRAMME AND ABSTRACTS

PETROLEUM DEVELOPMENT CORPORATION
TANZANIA

Michaelsen, B.H., Paull, R., McKirdy, D.M., Nytoft, P. and Kamali, M.R. (1996). GC-MS-MS characterization and possible origins of a C_{30} rearranged hopane and coeluting C_{29} fernane. In *4th Conference on Petroleum Geochemistry and Exploration in the Afro-Asian Region*, 2nd-6th June, 1996, Arusha, Tanzania. Programme and Abstracts.

NOTE: This publication is included in the print copy of the thesis held in the University of Adelaide Library.

Paull, R., Michaelsen, B.H. and McKirdy, D.M. (1997). Fernenes and fernanes in Dicroidium-bearing Triassic mudstones and coals from South Australia. In *18th International Meeting on Organic Geochemistry*, 22-26 September, 1997, Maastricht, The Netherlands. Abstracts.

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Pergamon

PII: S0146-6380(98)00088-6

Org. Geochem. Vol. 29, No. 5–7, pp. 1331–1343, 1998
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Printed in Great Britain
0146-6380/98 $ - see front matter

Fernenes and other triterpenoid hydrocarbons in *Dicroidium*-bearing Triassic mudstones and coals from South Australia

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Abstract—Tandem sector mass spectrometry of the aliphatic hydrocarbon fraction of selected Late Triassic sub-bituminous coals, mudstones and plant fossils from the Leigh Creek coalfield, Telford Basin, South Australia, has revealed three pseudohomologous series of triterpenoid hydrocarbons. Two of these series have been identified as fern-8-enes (C_{29}–C_{31}) and fern-9(11)-enes (C_{29}–C_{30}). The third series (C_{29}–C_{31}) comprises saturated hydrocarbons tentatively identified as fernanes. These hydrocarbons appear to be related to pteridosperms (seed ferns) of the genus *Dicroidium*, fronds of which are preserved throughout the sedimentary sequence. © 1998 Elsevier Science Ltd. All rights reserved

Key words—pteridosperms, *Dicroidium*, fernenes, fernanes, hopenes, hopanes

INTRODUCTION

As part of a recent study of Triassic coals and mudstones from Leigh Creek, South Australia (Paull, 1995), two macrofossils of *Dicroidium zuberi* (pteridosperms or seed ferns) found within the sedimentary sequence were geochemically analysed in an attempt to find plant-specific biological marker compounds characteristic of southern hemisphere Triassic sediments. A *Dicroidium* flora dominated the terrestrial habitats of Gondwana during the Triassic (Thomas, 1982; Hobday, 1987). Its triterpenoid biomarkers, if characteristic, could be useful for oil–oil and oil–source rock correlations in Mesozoic southern hemisphere basins.

Evolution of ferns and seed ferns

Palaeozoic fern-like plants, the Cladoxales, first appeared in the Early Devonian but were extinct by the Early Carboniferous (Stewart and Rothwell, 1993). Whilst a few true ferns (Filicales) evolved during the mid-Palaeozoic, most did not appear until after the Carboniferous (Taylor and Taylor, 1993). The Pteridospermophyta (or seed ferns) are an extinct group of vascular plants, transitional between ferns and seed plants, which arose during the late Palaeozoic (Taylor, 1981). Generally resembling small tree ferns in habit, these plants bore microsporangia and seeds on their leaves. The Palaeozoic pteridosperms belong to five orders and include the Glossopteridales (Permian-Triassic; Fig. 1). Three new orders of pteridosperms evolved during the Triassic: the Caytoniales, the Corystospermales and the Peltaspermales. The Caytoniales (Triassic to Cretaceous) are confined to the northern hemisphere. The less diverse Corystospermales group are found only in Gondwana (Thomas and Spicer, 1987). The Corystosperms are believed to have produced several foliage types, of which *Dicroidium* fronds, characterised by bifurcation of the rachis, are dominant (Taylor and Taylor, 1993). *Dicroidium* megafossils have been used to delimit biostratigraphic zones (Anderson and Anderson, 1983). Some members of the Corystospermales may have extended into the Cretaceous and coexisted with early flowering plants (Taylor and Archangelsky, 1985).

Major environmental changes at the end of the Palaeozoic were responsible for the demise (after 80 million years) of the resilient Glossopteris flora and the rise to dominance of plants with *Dicroidium*-type fronds during the Mesozoic (Pigg and Taylor, 1990). The success of the *Dicroidium* flora was due to its ability to adapt to widely divergent topographic and climatic conditions, at latitudes of 30–80° south. These plants grew on inland plains, plateaus, coasts and mountainous regions as part of floral ecosystems ranging from temperate rain forest and deciduous woodland, to fringe vegetation in the arid interior of Gondwana. The latter setting is exemplified by the Leigh Creek region of South Australia (Fig. 2). Here *Dicroidium* grew around small lacustrine basins scattered across an inland plateau where summers were warm to hot, and winters cold to very cold (Anderson and Anderson,

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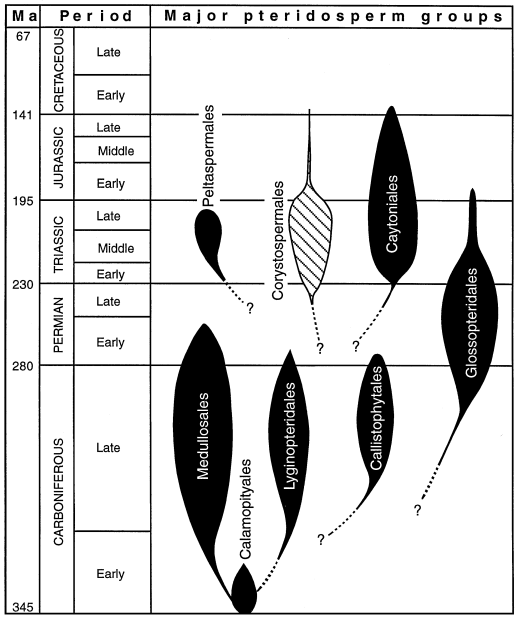


Fig. 1. Possible origins and relationships of major pteridosperm groups (modified from Stewart and Rothwell, 1993).

1983). In the wetter, warm to hot climates of the Jurassic *Dicroidium* became less significant (White, 1993), and was extinct by the earliest Cretaceous.

Origins of hopenes and fernenes

Hopanoid hydrocarbons are widespread in petroleum source rocks, coals and crude oils. Their biological precursors include diplopterol (Fig. 3, structure **I**), bacteriohopanetetrol (**II**) and diploptene (hop-22(29)-ene: **V**), the rigidity-imparting pentacyclic constituents of the cell membranes of most prokaryotes (eubacteria, cyanobacteria) (Rohmer *et al.*, 1992). In sediments which predate the emergence of higher plants, C_{30} hopenes, namely diploptene, hop-17(21)-ene (**III**), hop-21-ene (**IV**) and neohop-13(18)-ene (**VII**) are attributed to bacteria (Brassell and Eglinton, 1983). However, some ferns also have hopanoid constituents (Bottari *et al.*, 1972; Ageta and Arai, 1983). Conversely, the fernenes [viz fern-7-ene (**X**), fern-8-ene (**XI**), and fern-9(11)-ene (**XII**)] once thought to be derived only from ferns, may also have bacterial origins (Brassell and Eglinton, 1983). In some Recent saline lacustrine sediments of Antarctica, fern-7-ene is associated with methanogenic biomarkers and anoxic depositional environments, and is thought to have been derived from purple non-sulphur bacteria (Volkman *et al.*, 1986).

Isomerisation of fern-7-ene gives rise to the more stable fern-8-ene (Volkman *et al.*, 1986). Hop-21-ene, hop-17(21)-ene and neohop-13(18)-ene may also arise from acid-catalysed isomerization of diploptene or dehydration of diplopterol during diagenesis (Brassell *et al.*, 1980; Summons and Jahnke, 1992). Ageta *et al.* (1987) describe the acid-catalysed isomerization of fernenes into a mixture of neohop-13(18)-ene and hop-17(21)-ene. The C_{30} triterpenoid, neohop-12-ene (**VI**) is of uncertain origin (Brassell and Eglinton, 1983).

Lipids isolated from cultures of the anaerobic, photosynthetic bacterium *Rhodomicrobium vanniellii* were reported to contain fernenes (Howard *et al.*, 1984), and there is compelling circumstantial evidence that aromatised compounds with arborane/fernane skeletons found in lacustrine sediments of Permian to Recent age are microbial in origin (e.g. Hauke *et al.*, 1992, 1995; Jaffé and Hausmann, 1995; Borrego *et al.*, 1997). Aerobic bacteria have been suggested as the source of intact isoarobrinol in some recent sediments (Ourisson and Rohmer, 1982). However, *de novo* synthesis of arborane/fernane skeletons by microorganisms has yet to be conclusively demonstrated (M. Vliex, personal communication to D. M. McKirdy, 1997).

The formation of C_3-oxygenated triterpenes (e.g. isoarborinol, **IX**; fern-9(11)-en-3β-ol, **VIII**) requires molecular oxygen (Hauke *et al.*, 1992) and these compounds occur predominantly in higher plants including extant angiosperms (Hauke *et al.*, 1992; Hauke *et al.*, 1995 and references cited therein). Vliex *et al.* (1994) attribute the origin of aromatic arboranes/fernanes in Upper Carboniferous and Early Permian coals ($R_o = 0.5$–1.5%) from the Saar-Nahe Basin (Germany) to higher plants, namely pteridosperms. The lack of saturated arborane/fernane compounds in these coals was attributed to B-ring aromatisation. Vliex and his coworkers noted that one of the samples examined by Hauke *et al.* (1992), from the Permian Kupferschiefer, was deposited in anoxic nearshore conditions and contains abundant terrestrial matter which could be the source of aromatic arborane/fernane derivatives. Thus, the origin of arborane/fernane-related compounds remains obscure. It is likely that these compounds have multiple sources.

GEOLOGICAL SETTING AND SAMPLES

The Late Triassic succession of the Telford Basin at Leigh Creek (Fig. 2) comprises *ca* 1 km of mostly fine-grained strata, including three distinct series of low rank (sub-bituminous) coal seams (Springbett *et al.*, 1995). Individual seams are 0.5–20 m thick. The coal-bearing intervals are separated by up to 660 m of lacustrine mudstone (Fig. 4). Abundant carbonised plant remains occur throughout the sequence. This assemblage of fossil plants is dominated by several species of *Dicroidium*. The rock and fossil specimens analysed (Table 1) were collected from fresh exposures within the open-cut mine at Leigh Creek. They include representative coals from each of the coal series; and mudstones and mudstone-*Dicroidium zuberi* fossil pairs (Fig. 5)

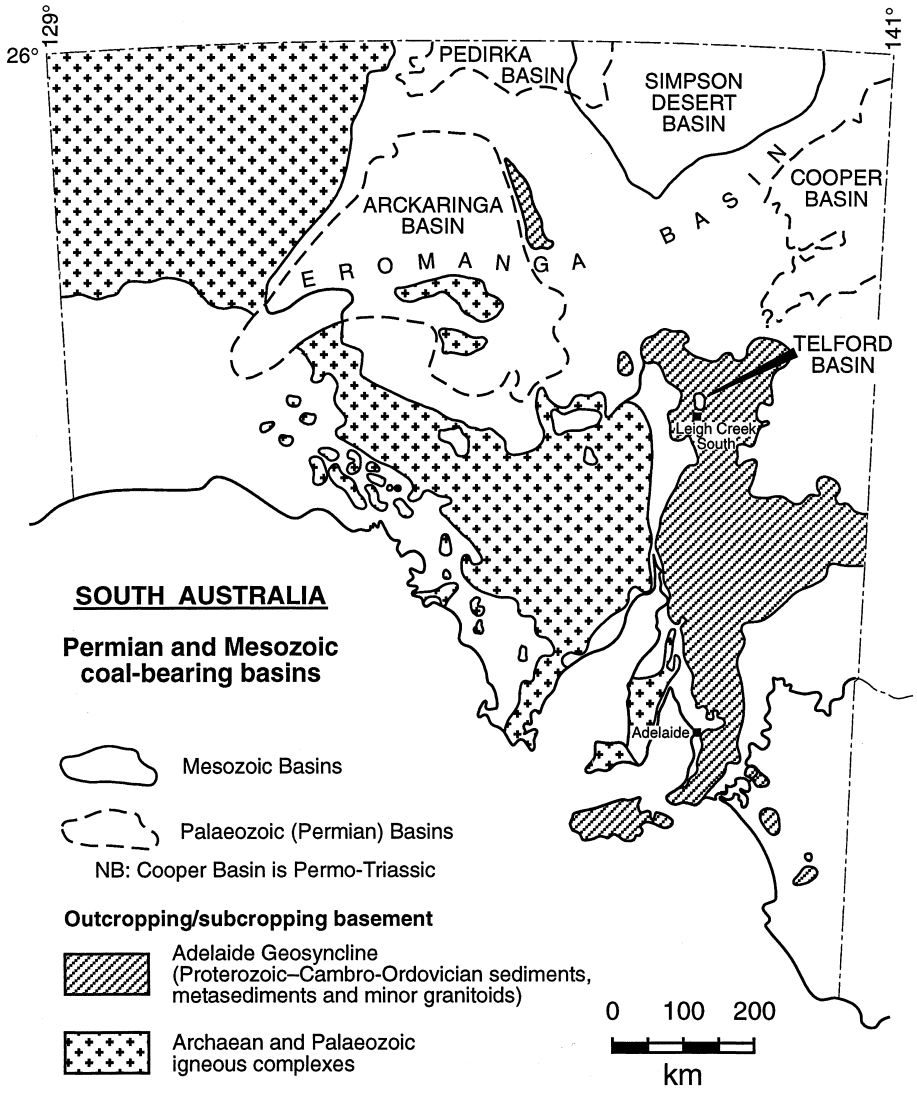


Fig. 2. Locality map, Telford Basin, Leigh Creek, South Australia.

from the lacustrine sequence between the Main and Upper Series coals.

Sample preparation

Each coal was carefully handpicked to obtain sub-samples of its bright and dull lithotypes. The two mudstone/fossil pairs comprised intact *Dicroidium zuberi* fossil remains (removed from their mudstone matrix by careful separation using a solvent-washed scalpel blade) and a few millimetres of the mudstone immediately adjacent to the fossil. The other mudstones in Table 1 were not associated with intact pteridosperm fronds.

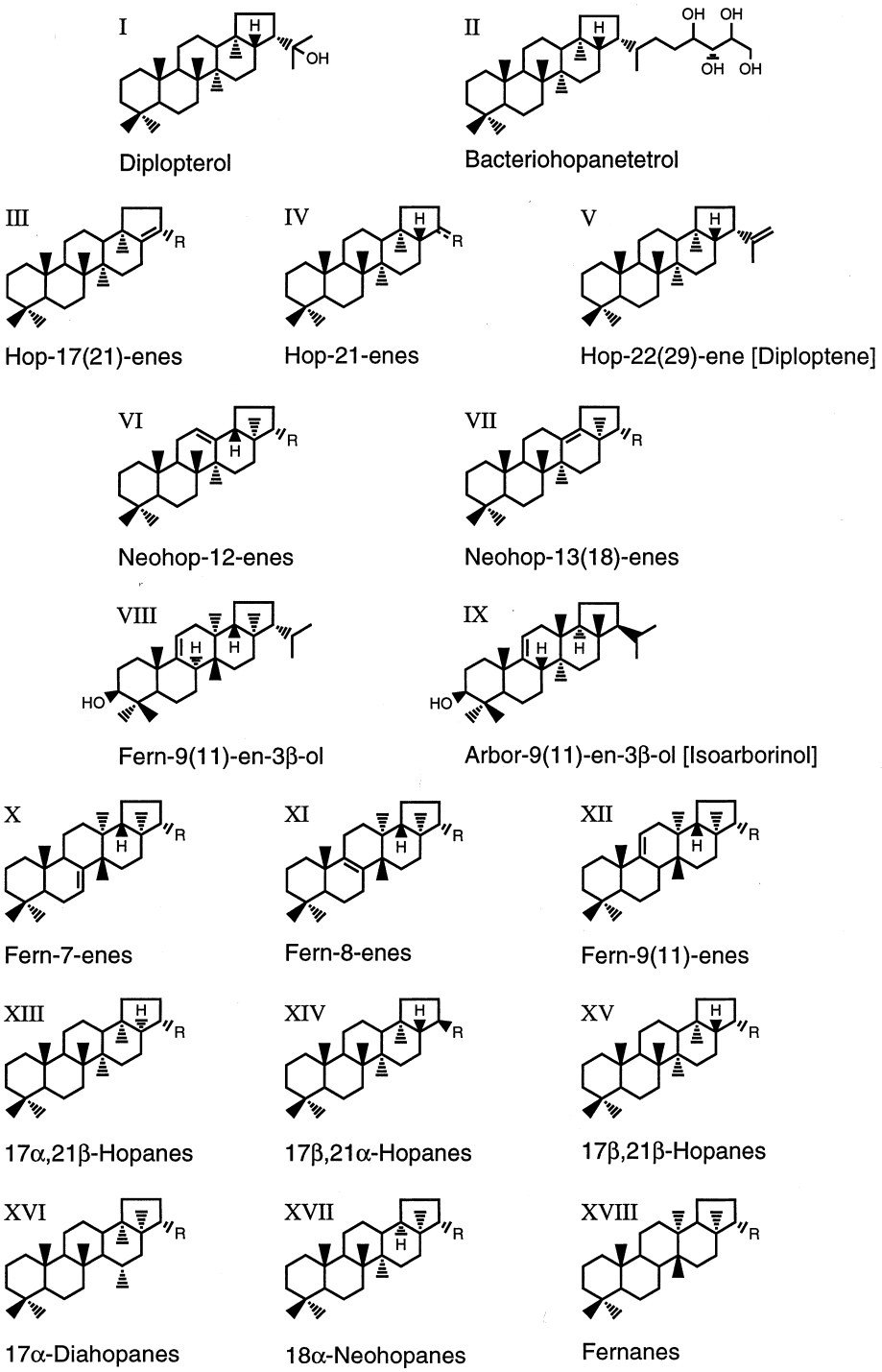
EXPERIMENTAL PROCEDURES

Extraction and fractionation

All samples were crushed and subjected to solvent extraction with azeotropic dichloromethane (DCM)/methanol (93:7, 72 h) in Soxhlet apparatus. Copper turnings were added to the solvent to remove elemental sulphur. The resulting geolipid extract from each sample was fractionated into aliphatic hydrocarbons, aromatic hydrocarbons and polar compounds by sequential elution on silica (Merck 40, 70–230 mesh) with petroleum ether, petroleum ether/DCM (40:60) and DCM/methanol (35:65) followed by methanol.

Gas chromatography (GC)

The aliphatic hydrocarbons were dissolved in *n*-hexane and injected into a Varian 3400 gas chromatograph (fitted with a 25 m × 0.22 mm i.d. fused silica column, BP-1, 0.25 μm film thickness; SGE Australia), operating in split mode (ratio 1:50). The carrier gas was hydrogen (velocity of 30 ms^{-1}). Injector and detector (FID) temperatures were 300°C. The oven temperature was held at



C_{27} compounds, R = H; C_{29} compounds, R = *n*-C_2H_5; C_{30} compounds, R = *i*-C_3H_7;
C_{31} compounds, R = *s*-C_4H_9; C_{32} compounds, R = *s*-C_5H_{11}.

Fig. 3. Structures of triterpenoid compounds described in text and/or identified by GC-MS.

40°C for 5 min and then increased at 4°C per minute to 300°C where it was held for 30 min. A MacLab analogue to digital convertor linked to a Macintosh SE computer running the software program *Chart* 3.2.8 was used to record and process the data.

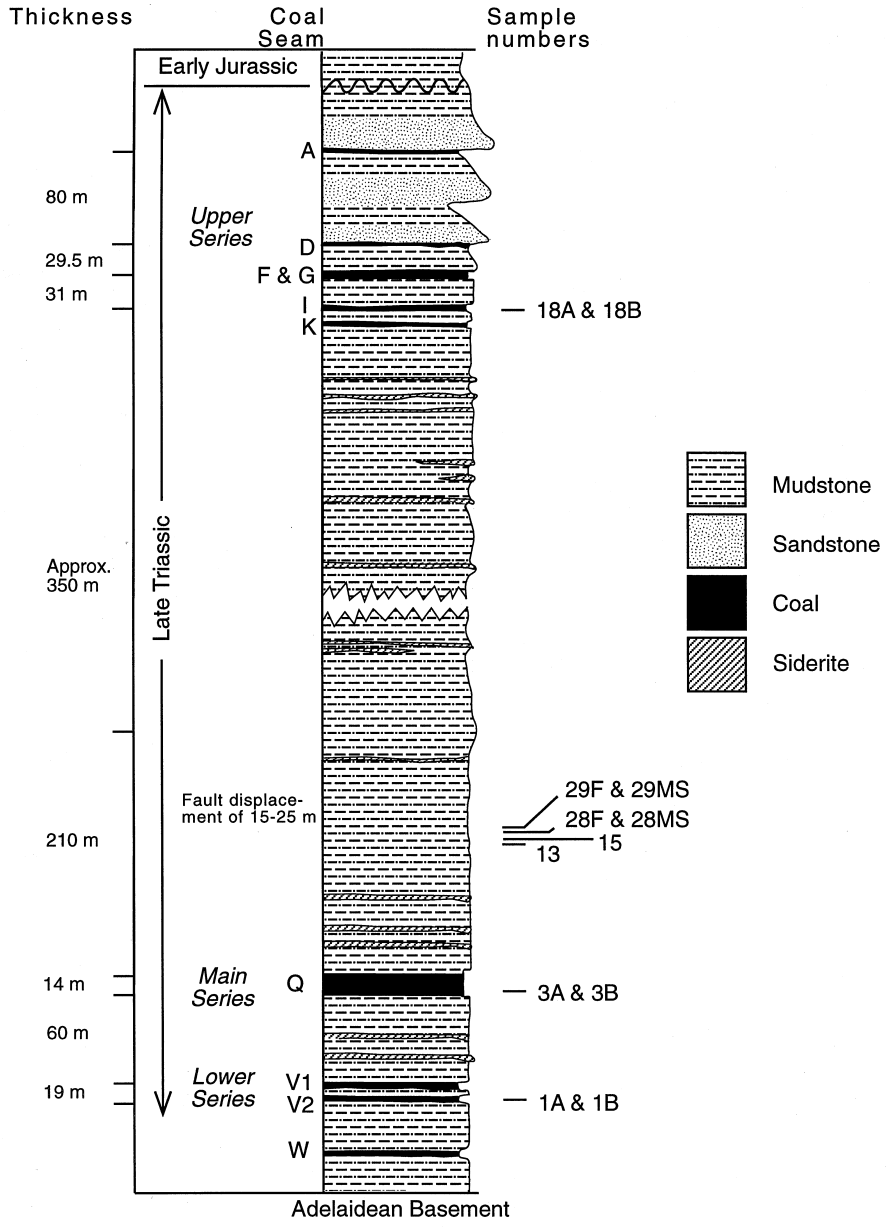


Fig. 4. Generalised stratigraphic column of the Telford Basin, showing location of samples analysed in this study.

Gas chromatography-mass spectrometry (GC-MS)

The aliphatic hydrocarbon fractions, dissolved in *n*-hexane were injected (on-column) into a Varian 3400 gas chromatograph connected to a Finnigan MAT TSQ 70 triple quadrupole mass spectrometer. A 60 m × 0.25 mm i.d. fused silica column (DB-1, 0.25 μm film thickness; J & W Scientific) was fitted to the gas chromatograph. The filament current and ionization voltage used for mass spectrometry were 200 μA and 70 eV, respectively. Helium was used as the carrier gas (inlet pressure approx. 100 kPa). The oven was programmed at 50°C for 2 min, 50–120°C at 8°C min^{-1}, 120–300°C at 4°C min^{-1} and finally held at 300°C for 35 min.

Because interpretation and structural assignment of saturated hydrocarbons in low rank sediments is often complicated by the presence of alkenes, the triple quadrupole mass spectrometer was operated in GC-MS-MS mode. The parent ion quadrupole of the mass spectrometer (Q1MS) acted as a mass filter allowing only those parent ions of specific mass to charge ratios (m/z) to pass to the next stage, the collision cell quadrupole (Q2MS), where the parent ions underwent argon-induced, collision-activated decomposition. The resulting fragment ions then passed to the daughter ion quadrupole (Q3MS)

Table 1. Geochemical data on samples analysed

Samples	TOC	R_r	*n*	EOM (ppm)	Saturated hydrocarbons (%)	Aromatic hydrocarbons (%)	NSO compounds (%)	Pr/Ph	Pr/*n*-C_{17}	Ph/*n*-C_{18}
Upper Series coals										
18B	54.8	0.35	26	17900	3.5	3.8	92.7	0.99	0.32	0.27
18A	52.7	0.29	25	28100	1.3	1.4	97.3	0.83	0.39	0.43
Mudstones and mudstone — fossil pairs										
29F				25900	2.2	1.1	96.7	0.90	0.26	0.42
29MS				50300	3.6	1.7*	94.7	0.97	0.24	0.45
28F				16700	7.1	3.4	89.5	0.76	0.27	0.46
28MS				3350	14.1	5.4*	80.5	0.78	0.28	0.45
15MS		0.20	6	1150	7.8	4.7	87.5	1.36	0.11	0.13
13MS†	6.08	0.26	6	847	10.6	7.5*	81.9	0.87	0.18	0.33
Main Series coals										
3B	49.5	0.33	6	18000	1.0	1.9	97.1	1.29	0.82	0.71
3A	53.2	0.36	25	25800	1.1	2.1	96.8	1.27	0.86	0.49
Lower Series coals										
1B		0.38	25	4380	5.7	6.0	88.6	2.00	0.61	0.26
1A		0.39	25	10800	2.2	3.4	94.4	1.09	0.61	0.68

Key: A = bright coal, B = dull coal, F = fossil, MS = mudstone; TOC = total organic carbon (wt%); R_r = mean of random vitrinite reflectance (%), *n* = number of reflectance determinations; EOM = extractable organic matter; Pr = pristane, Ph = phytane, *n*-C_{17} = *n*-heptadecane, *n*-C_{18} = *n*-octadecane; * = porphyrins present in aromatic fraction; † = contains fragmented pteridosperm fronds.

where they were selectively monitored and recorded with a photomultiplier set to 1900 V. Table 2 shows the monitored *m*/*z* 191 and *m*/*z* 243 decomposition reactions. Examples of the resulting selective reaction monitoring (SRM) chromatograms are illustrated in Figs 6–9. Selected samples were also analysed by full-scan GC-MS (Q3MS, scanning *m*/*z* 50–500 every 0.5 s). The structures of the key triterpenoid compounds mentioned in the text and/or identified by GC-MS are shown in Fig. 3.

For calibration purposes, a fernene standard [comprising fern-7,9(11)-diene, fern-8-ene, neohop-13(18)-ene, fern-9(11)-ene, fern-12-ene and fern-7-ene] was also analysed by the aforementioned methods. To establish where the various fernenes elute in relation to the *n*-alkanes a mudstone sample (13) was also spiked with the fernene standard. Recognition of hopane and hopene peaks was aided by comparison with published mass chromatograms.

Petrography

Random vitrinite (huminite) reflectance (R_r) measurements from polished sections of coals and mudstones were made using a Leitz ORTHOLUX II Pol BK microscope. The photomultiplier was

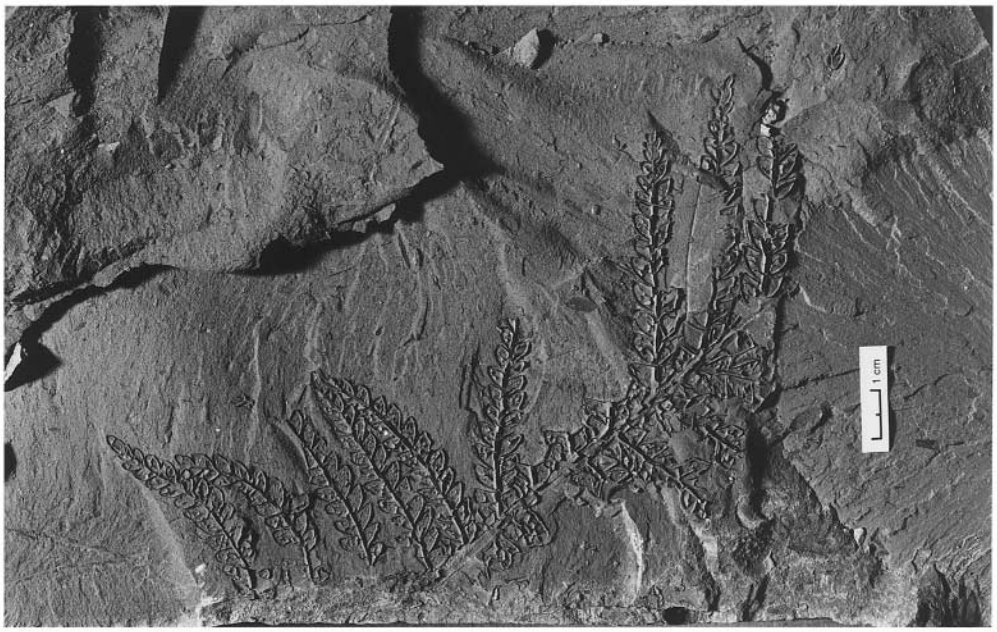


Fig. 5. *Dicroidium zuberi* fossil frond on mudstone matrix. Scale bar is 1 cm.

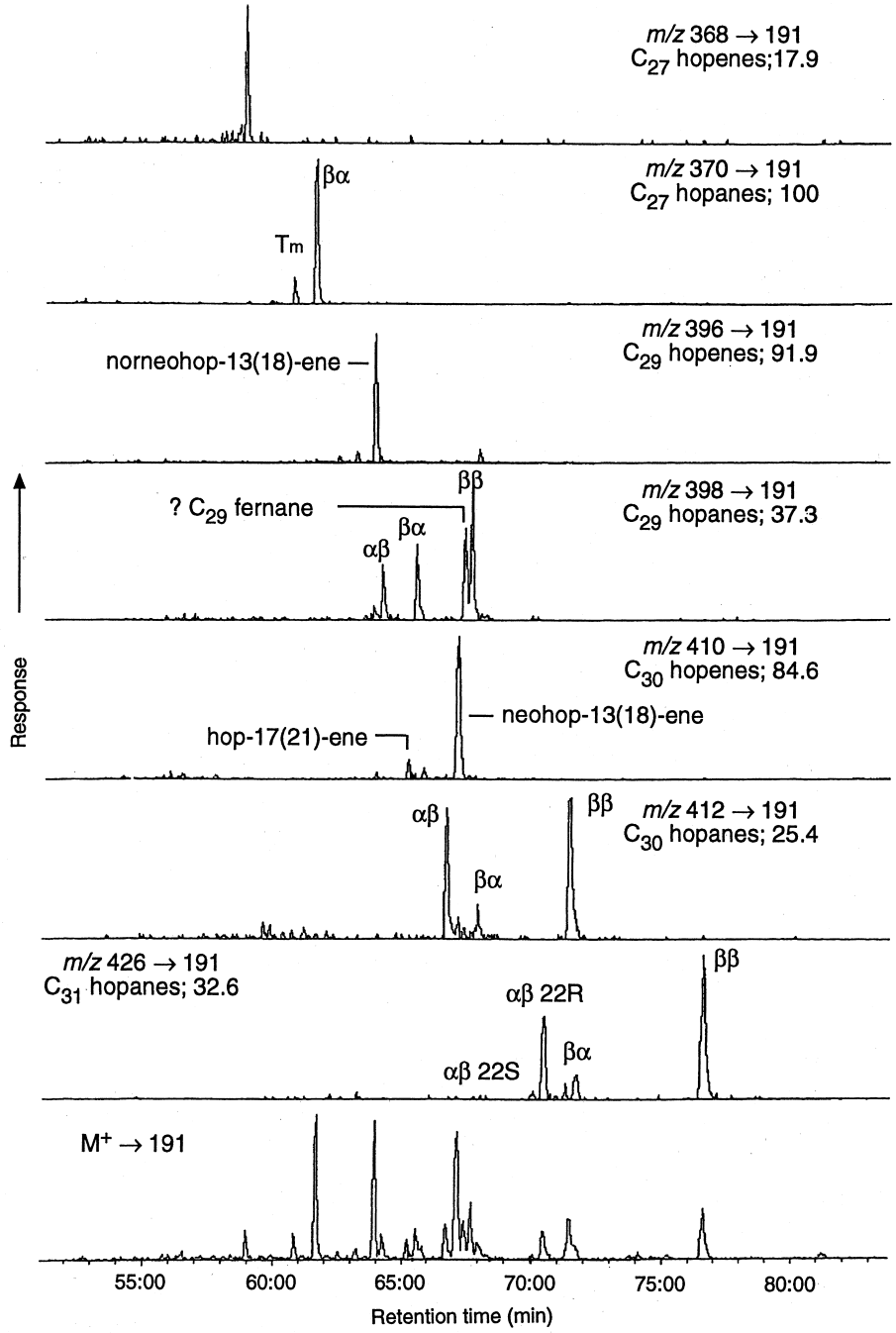


Fig. 6. Partial SRM chromatograms of hopenes and hopanes in the aliphatic fraction of a Lower Series dull coal lithotype (1B).

calibrated with a synthetic spinel standard (0.420% reflectance).

RESULTS AND DISCUSSION

The bulk geochemical characteristics of the rock and fossil samples from Leigh Creek coalfield are summarised in Table 1.

Maturity

Vitrinite reflectance (R_r) values for the coal measures increase with depth from 0.29–0.35% in the Upper Series to 0.38–0.39% in the Lower Series and are consistent with a sub-bituminous rank. The R_r values of 0.26% and 0.20% obtained for mudstones 13 and 15 are anomalously low due to the el-

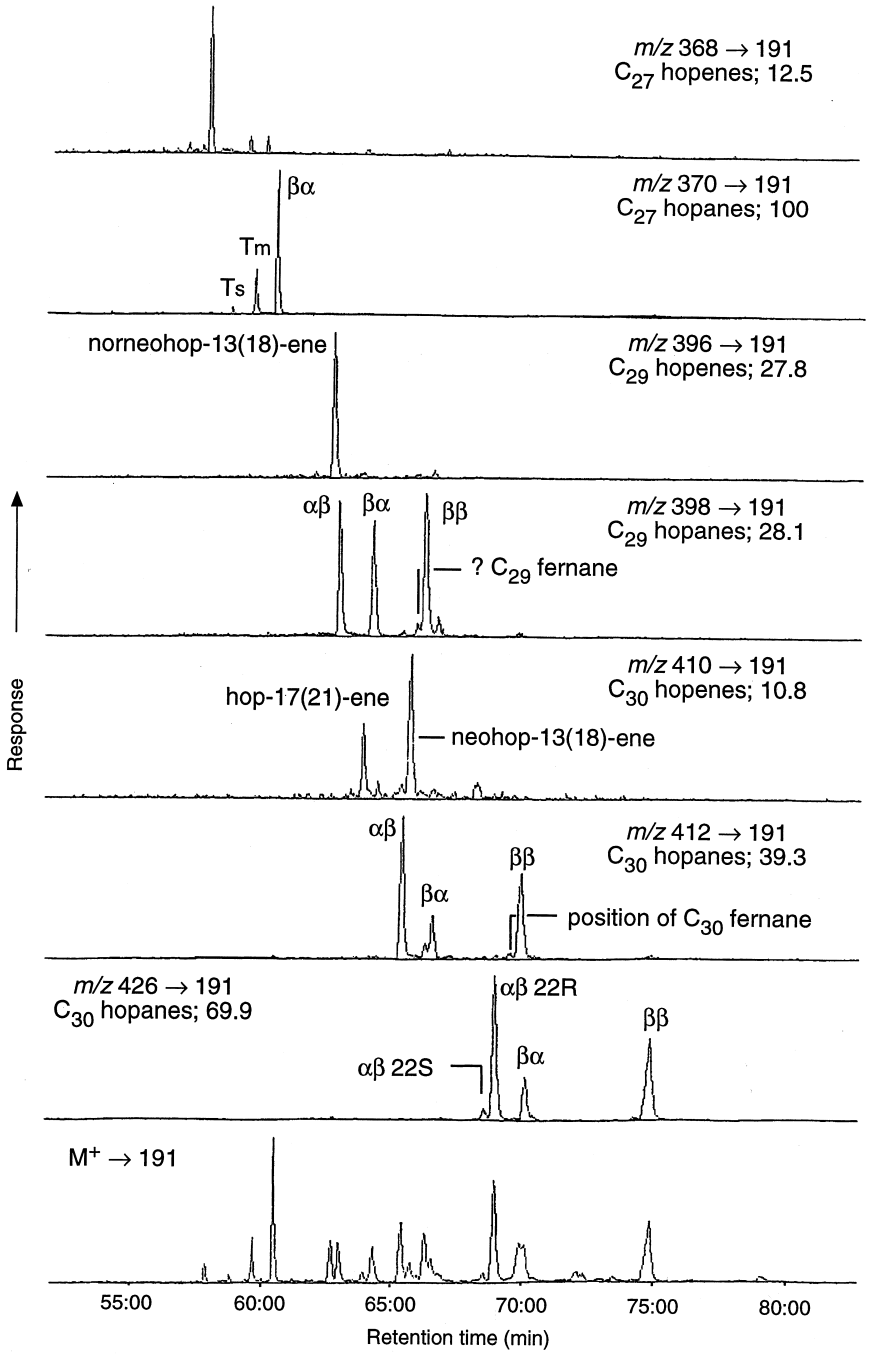


Fig. 7. Partial SRM chromatograms of hopenes and hopanes in the aliphatic fraction of a mudstone (29 MS) containing *Dicroidium* sp.

evated concentrations of telalginite and liptodetrinite and the degraded state of their huminite macerals.

Biological markers

Isoprenoid alkanes. The two acyclic isoprenoids pristane and phytane are minor components of all samples but are least abundant in the coals. Pristane to phytane (Pr/Ph) ratios of the coals increase from 0.8–1.0 in the Upper Series to 1.1–2.0 in the Main and Lower Series (Table 1), a trend attributable to the slightly higher rank of the deeper samples. For each bright and dull coal pair, the Pr/Ph ratio is higher in the latter lithotype where a greater inertinite content reflects more intense oxidation of woody detritus. The fossils and mudstones (with one exception) have Pr/Ph values < 1, perhaps indicating deposition under less oxic conditions than the coals. The low thermal maturity of these sediments renders uncertain such inferences

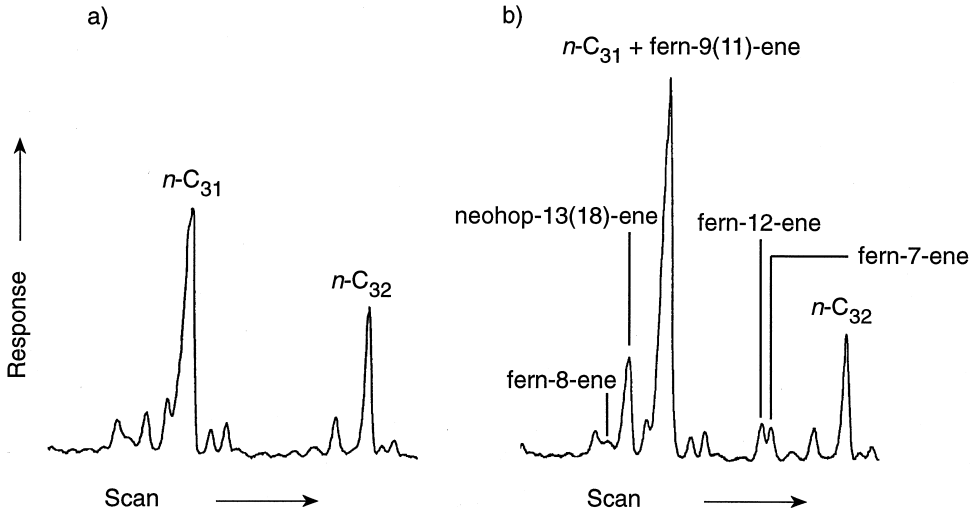


Fig. 8. Partial GC-FID traces of a) aliphatic hydrocarbons in mudstone 13, and b) same sample spiked with the C_{30} fernene standard.

on the redox potential (E_h) of their depositional setting. However, as elemental sulphur and porphyrins are both notably present in the mudstones, it would appear that their lacustrine environment was indeed anoxic (*cf.* Peters and Moldowan, 1993, pp. 149–150).

Steranes. In both bright and dull coal lithotypes $C_{29} > C_{28} > C_{27}$ steranes and, with the exception of the dull coal from the Main Coal seam, 5α,14α,17α-20R (abbreviated ααα-20R) and 5β,14α,17α-20R (βαα-20R) steranes dominate the series. Low concentrations of ααα-20S steranes and low diasterane/sterane ratios are consistent with the sub-bituminous rank of the coals. Although diasteranes are relatively minor components in all the coals, they are generally more abundant in the dull lithotype for which a higher depositional E_h may be inferred. Steranes in the mudstone and fossil samples are dominated by the ααα-20R and βαα-20R isomers. Mudstone 15 is an exception wherein $C_{27} > C_{29} > C_{28}$ steranes. Here the enhanced proportion of cholestane is attributed to the relatively high concentration of alginite observed in the dispersed organic matter of this mudstone. The argillaceous mudstones, like the coals, display very low relative abundances of diasteranes. Thus, the non-formation of diasteranes in this suite of samples appears to be related more to E_h and thermal immaturity than to the absence of clays (*cf.* Michaelsen *et al.*, 1995).

Table 2. Mass spectrometer decomposition reactions

Q1MS (*m*/*z*)		Q3MS (*m*/*z*)	Target compounds
		Triterpenes	
368	→	191	C_{27} hopenes
396	→	191	C_{29} hopenes
410	→	191	C_{30} hopenes
424, 438, 452	→	191	C_{31}, C_{32}, C_{33} hopenes
368	→	243	C_{27} fernenes
396	→	243	C_{29} fernenes
410	→	243	C_{30} fernenes
424, 438, 452	→	243	C_{31}, C_{32}, C_{33} fernenes
		Triterpanes	
370	→	191	C_{27} hopanes (e.g. T_s, T_m)
398	→	191	C_{29} hopanes/?fernanes
412	→	191	C_{30} hopanes/?fernanes
426, 440, 452	→	191	C_{31}, C_{32}, C_{33} hopanes/?fernanes
		Steranes	
372	→	217	C_{27} steranes
386	→	217	C_{28} steranes
400	→	217	C_{29} steranes

Hopenes. Figures 6 and 7 include the hopene distributions of the aforementioned samples. In the coals, the most abundant biomarkers are the neohop-13(18)-ene series. Bright coal lithotypes exhibit a similar abundance of the C_{29} and C_{30} homologues. In the dull coals of the Lower and Main Series $C_{30} > C_{29}$ neohop-13(18)-ene, whereas in the Upper Series dull lithotype $C_{29} > C_{30}$. For the mudstones and fossils $C_{29} > C_{30} > C_{31} > C_{32}$ neohop-13(18)-ene. All coals have minor hop-17(21)-ene (C_{30}: **III**) and some contain homohop-17(21)-ene (22S and 22R). The mudstones and fossils all contain the $\Delta^{17,21}$ hopene series ($C_{30} > C_{31} > C_{32}$) but these are generally much less abundant than the corresponding $\Delta^{13,18}$ neohopanes. Two exceptions are the mudstone samples 15 and 28 wherein C_{30} hop-17(21)-ene $\geq C_{30}$ neohop-13(18)-ene.

Hopanes. Hopane distributions for the Lower Series dull coal (1B) and a fossiliferous mudstone (29MS) are shown as part of Figs 6 and 7, respectively. The three pseudohomologous series of hopanes normally associated with low rank sediments, 17β,21β-hopanes (abbreviated as ββ), 17β,21α-hopanes (βα, moretanes) and the thermodynamically favoured 17α,21β-hopanes (αβ) (Peters and Moldowan, 1993), are present in all samples. The ββ homologues comprise around 50% (or more) of the C_{29}–C_{31} hopanes for most coal

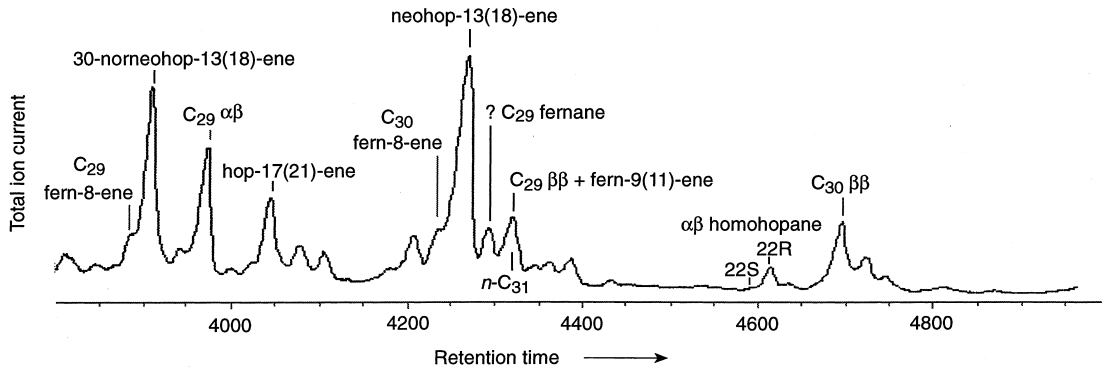


Fig. 9. Partial full-scan RIC of the aliphatic fraction of a Lower Series dull coal lithotype (1B).

samples (except in the Main Series where C_{31} $\alpha\beta > \beta\beta > \beta\alpha$), with the $\beta\alpha$ isomer dominating the C_{27} hopanes. Generally *within* each coal seam the distributions of $\alpha\beta$, $\beta\alpha$ and $\beta\beta$-hopanes are similar for both coal lithotypes. In the mudstone and fossil/mudstone pairs $\alpha\beta \geq \beta\beta > > \beta\alpha$-hopanes at C_{30} and C_{31}. At C_{29}, however, these isomers are of almost equal abundance. Thus the relative concentration of the $\alpha\beta$-hopanes is clearly facies dependent. Likewise, the C_{27} $\alpha\beta$-hopane (T_m: **XIII**) is more abundant in the mudstones and fossils than in the coals.

Rearranged hopanes. The minor presence of the C_{27} 18α-neohopane (T_s: **XVII**) in all mudstones and one fossil sample can be attributed to clay-catalysed reactions of 17α-hopanoids. T_s is absent from the coals. The other rearranged hopanoid common to source rocks and petroleum, C_{30} 17α-diahopane

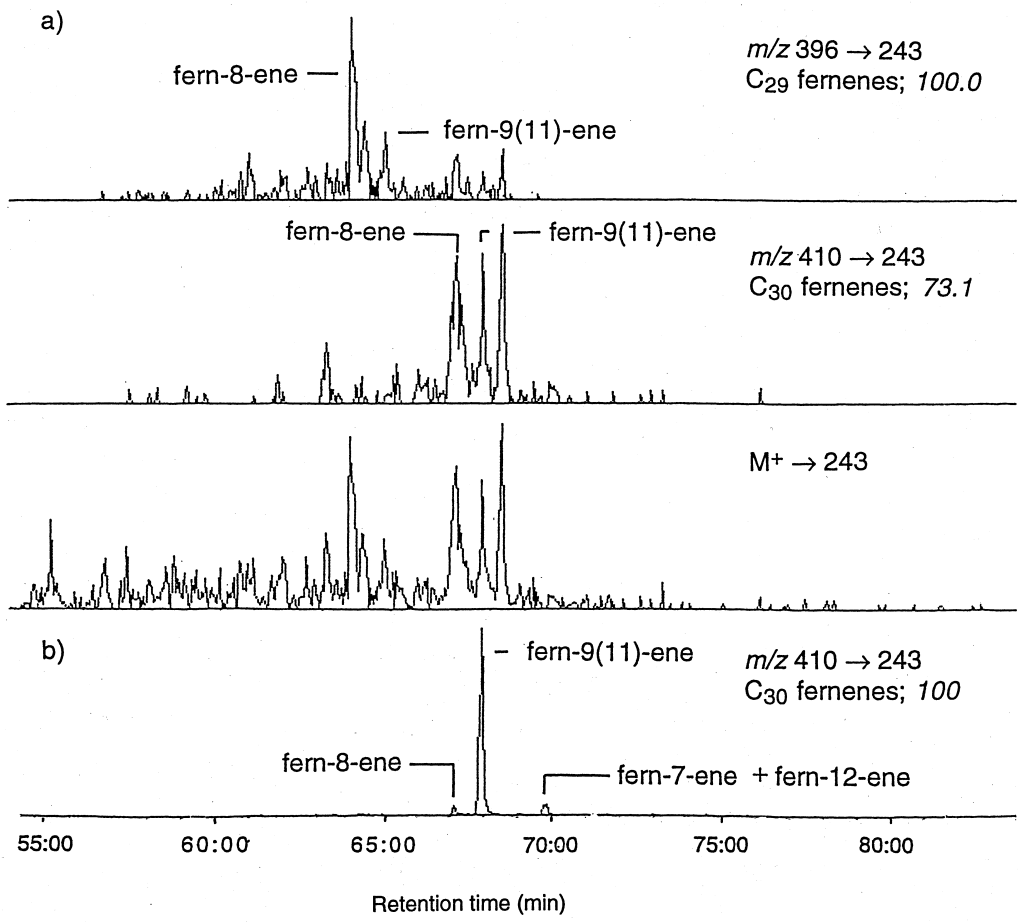


Fig. 10. Partial SRM chromatograms of: (a) fernenes in the aliphatic fraction of a Lower Series dull coal lithotype (1B) and (b) the C_{30} fernene standard.

(**XVI**), is absent or in very low concentration in all samples.

Fernenes. Peak assignment using mass spectra proved difficult because of the co-elution of fernenes with other compounds. GC analysis of the aliphatic fraction of mudstone 13, co-injected with the C_{30} fernene/neohopene standard, showed that (1) fern-9(11)-ene (**XII**) co-elutes with the C_{31} *n*-alkane and (2) fern-8-ene (**XI**) elutes on the leading edge of neohop-13(18)-ene (**VII**) (Fig. 8). Other instances of co-elution were confirmed by comparison of diagnostic SRM chromatograms (Table 2) for a given sample and inspection of the major fragment ions in the mass spectra of individual fernene peaks in the corresponding full-scan RIC (Fig. 9). Thus, for example, it was established that fern-9(11)-ene also co-elutes with the C_{29} $\beta\beta$-hopane (**XV**); and that, in a similar fashion to their C_{30} counterparts, C_{29} fern-8-ene elutes as a shoulder on the leading edge of the 30-norneohop-13(18)-ene peak.

Fernene identification was made possible only by comparing the m/z $396 \rightarrow 243$ (C_{29}) and m/z $410 \rightarrow 243$ (C_{30}) chromatograms of coals (e.g. Fig. 10(a)), mudstones (e.g. Fig. 11) and fossils with that of the C_{30} fernene standard (Fig. 10(b)). All samples are shown to contain fern-8-enes (abundance of C_{29} relative to C_{30} is variable) and lesser amounts of fern-9(11)-enes ($C_{30} > C_{29}$). C_{30} fern-7-ene (**X**) ($\pm$fern-12-ene) occurs as a very minor component in coals from the Lower and Upper Series. The m/z $368 \rightarrow 243$ chromatogram (Fig. 11) suggests that C_{27} fernenes (position of double bond unknown) may also be present.

Pseudohomologous series of possible fernanes. Chromatographic data presented by Volkman *et al.* (1986) show co-elution of C_{30} fernane (**XVIII**) and C_{30} $\beta\beta$-hopane (**XV**). In the present study, the m/z $412 \rightarrow 191$ chromatograms of the aliphatic fractions from some Leigh Creek coals and a fossil/mudstone pair (29) show a small peak (tentatively identified as C_{30} fernane) eluting immediately before C_{30} $\beta\beta$-hopane (Fig. 7). Likewise, with the exception of mudstone 15, the m/z $398 \rightarrow 191$ chromatograms of all samples have a compound eluting in the same position before C_{29} $\beta\beta$-hopane. This peak (? C_{29} fernane) is most pronounced in the chromatograms of coals from the Lower and Main Series (both bright and dull lithotypes: Fig. 6). Some samples appear to contain trace amounts of the C_{31} fernane.

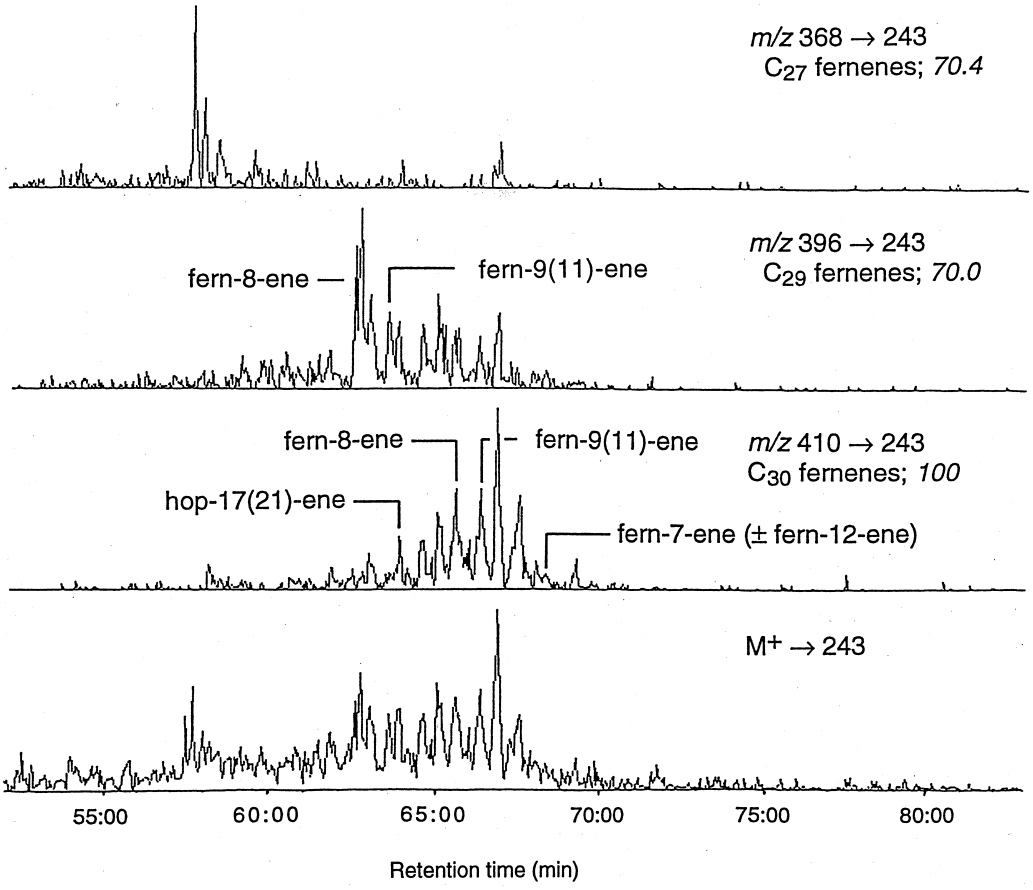


Fig. 11. Partial SRM chromatograms of fernenes in the aliphatic fraction of a mudstone (29 MS) containing *Dicroidium* sp.

The putative C_{29} fernane has been observed in a number of Australian sediments and oils but is particularly abundant in thermally immature terrestrial sediments of Mesozoic age. Molecular modelling of the fernane series (B. H. Michaelsen and M. Buntine, unpublished data) reveals that the C_{29} pseudohomologue is the most stable. In the Telford Basin, sub-bituminous Lower and Main Series coals contain this compound in greatest abundance. This may be a reflection of a different primary pteridosperm input to the peat swamp. Palaeobotanical observations (Paull, 1995) suggest that the Upper Series coal is floristically different from those in the Main and Lower Series.

CONCLUSIONS

Analysis of the free aliphatic hydrocarbons in a suite of low-rank Triassic coals and fossiliferous mudstones from the Telford Basin by tandem sector GC-MS has revealed C_{29} and C_{30} fern-8-enes and fern-9(11)-enes and, in much lesser abundance, C_{30} fern-7-ene to be significant components of the triterpenoid fraction. The general dominance in all samples of the $\Delta^{13,18}$ series of neohopenes over the $\Delta^{17,21}$ hopenes, and the low abundance of fern-7-ene relative to fern-9(11)-ene and fern-8-ene, is suggestive of acid-catalysed rearrangement of the precursor triterpenoids. The origin of the fernenes present in the Leigh Creek samples is uncertain. While they may quite reasonably be attributed to the fossil seed fern *Dicroidium* sp., their derivation from bacteria cannot be ruled out. The high abundance of neohopenes could be due to isomerisation of fernenes of pteridosperm origin; or, alternatively, they and the $\Delta^{17,21}$ hopenes may have been original components of pteridosperms.

The absence of fernane from the saturated hydrocarbon fractions of the German coals analysed by Vliex *et al.* (1994) was attributed to advanced aromatisation at ranks of $R_o > 0.5\%$. Likewise, incipient aromatisation possibly explains the reduced abundance of fernanes in the low-rank Leigh Creek samples. With the exception of the putative C_{29} fernane, the potential usefulness of these triterpanes as Triassic biomarkers in oil–oil and oil source–rock correlations is essentially nil. However, aromatic fernene derivatives may yet prove to be helpful in distingishing oils of Permian and Mesozoic origin in both southern and northern hemisphere basins. The survival of the ? C_{29} fernane (and the virtual absence of the C_{30} homologue) in the Leigh Creek coals is consistent with their sub-bituminous rank and the calculated heats of formation of these two biomarkers.

Acknowledgements—We thank Geoffrey Brick and Edek Choros (ETSA) for assistance in the collection of samples at Leigh Creek. Dr Chris Boreham (Australian Geological Survey Organization) kindly provided the fernene standard. Drs M. Radke, R. E. Summons, H. L. ten Haven and M. Vliex are thanked for detailed reviews of the original manuscript. R. Paull was supported by an Australian Postgraduate Award. D. M. McKirdy acknowledges an Australian Research Council small grant.

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PETROLEUM GEOCHEMISTRY OF THE MURTA MEMBER, MOOGA FORMATION, AND ASSOCIATED OILS, EROMANGA BASIN

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ABSTRACT

An investigation has been made of the source potential, degree of maturation and hydrocarbon composition of selected oils and sediments in the Murta Member in ATP 267P and the Moomba and Napacoongee–Murteree Blocks (PEL 5 and 6), Eromanga Basin. Shales in the Murta Member contain low amounts (up to 2.5% TOC) of terrestrial oil-prone organic matter (Types II–III) which consists predominantly of sporinite, liptodetrinite and inertinite with lower amounts of vitrinite, although some samples contain relatively abundant telalginite. Extractable hydrocarbon yields demonstrate that parts of the Murta Member are effective source rocks at present maturation levels, which are at the threshold of the conventional oil window (vitrinite reflectance = 0.5–0.6% Ro).

Oils from Murta reservoirs in ATP 267P (Kihee, Nockatunga and Thungo) all show the characteristics found by previous analyses of many Murta oils, namely paraffinic, low wax, and high pristane-to-phytane ratios. In contrast Murta oils from Limestone Creek and Biala are waxy. All oils show chemical evidence of generation at relatively low maturation levels. Gas chromatograms of the saturate fractions from the best source facies show the same characteristics noted for the low-wax oils. Samples with lower source potential in contrast contain relatively abundant waxy n-alkanes. Methylphenanthrene Indices and biomarker maturation indicators obtained from the oils show the same values as were measured on sediment samples from the Murta. Hence the oils could not have been derived from deeper, more mature source rocks. The distribution of biomarkers in the low-wax oils is also consistent with an origin from the Murta Member. A corresponding source facies for the high-wax oils has not yet been located. However, chemical maturation indices also suggest a source in the Murta Member or in immediately adjacent strata.

The unusual circumstances represented by the Murta oils (low maturity, low-wax terrestrial oils) provide evidence for bacterial contribution to the source material for non-marine oils. Both the low-wax oils and the best source facies contain abundant hydrocarbons derived from bacterial precursors. This bacterial organic matter appears to yield hydrocarbons at an earlier stage of maturation than the predominantly terrestrial plant and algal organic matter with which it is associated. In the case of the Murta Member there are sufficient hydrocarbons generated at relatively low maturity to allow migration to occur. Chemical evidence suggests a low contribution from algal organic matter to the generated hydrocarbons.

INTRODUCTION

The discovery of oil at Dullingari North 1 in 1979 provided a new focus for petroleum exploration in the southern Eromanga Basin (Fig. 1). Flow rates in excess of 2000 BOPD from thin sands of the Murta Member, Mooga Formation (Fig. 2) (Mount, 1981), highlighted the potential for commercial hydrocarbon accumulations in Early Cretaceous sediments (Fig. 2) which hitherto had been considered unprospective. Over the last decade this potential has been confirmed by numerous Murta (and several Cadna-owie) oil discoveries in both the South Australian and Queensland sectors of the Eromanga Basin (Fig. 1) where it overlies the southern Cooper Basin.

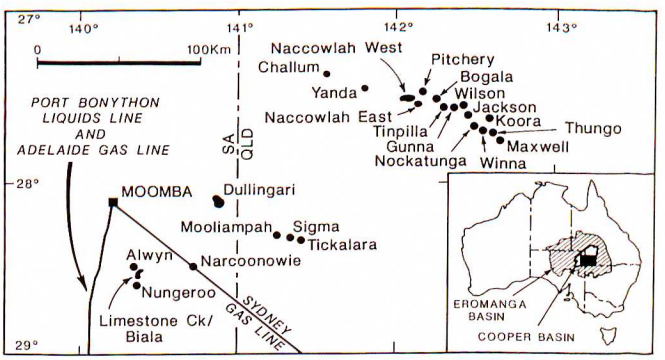

Figure 1. Location map showing study area, Eromanga Basin.

Notable discovery wells in southwest Queensland (Fig. 1) include Jackson 1, Wilson 1, Gunna 1, Tinpilla 1, Bogala 1, Naccowlah West 1, Yanda 1, Kercumurra 1, Sigma 1 and

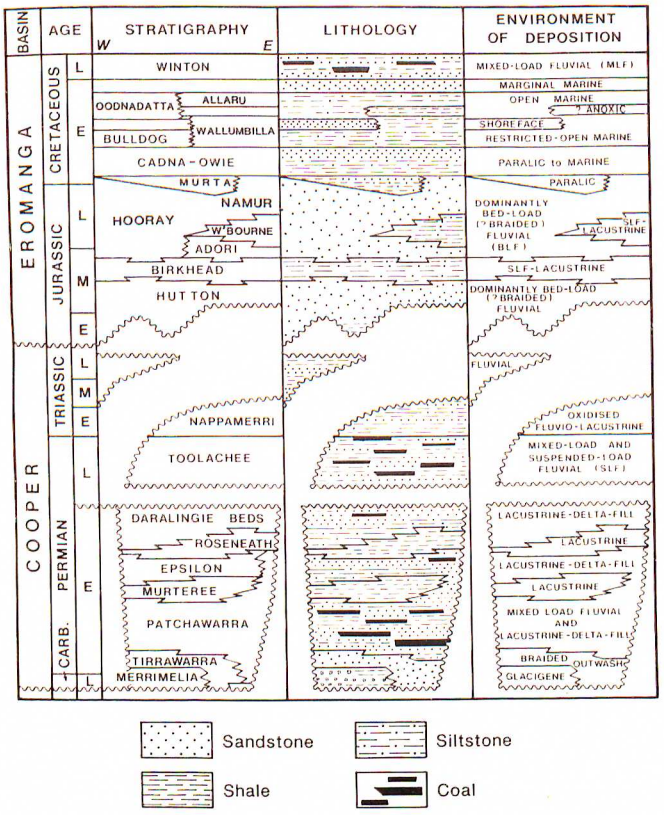

Figure 2. Generalised stratigraphy, lithology and environments of deposition of the Cooper–Eromonga Basin (Kuang, 1985).

Mooliampah 1 (ATP 259P), and Tintaburra 1 and Talgeberry 1 (ATP 299P(A)) and Nockatunga 1, Winna 1, Thungo 1 and Maxwell 1 (ATP 267P).

In South Australia (Fig. 1) (PEL 5, 6) significant oil flows from these Neocomian units were recorded at Limestone Creek 1, Biala 1, Alwyn 1, Ulandi 1, Kobari 1, Wancoocha 1, Narcoonowie 1, Merrimelia 6, 15, and Meranji 1. The underlying Namur Sandstone Member (Late Jurassic – Early Cretaceous) of the Mooga Formation has proved to be far less prospective than the Murta Member, although Namur oil pools are not uncommon, particularly along the Murteree–Nappacoongee and Gidgealpa–Merrimelia Trends.

Although its upper part displays some evidence of a marine influence (Zoellner, 1988), the Murta Member (Fig. 2) was deposited mostly in a shallow fresh-water lacustrine system (Lake Murta: Mount, 1982) which developed in Early Neocomian time near the centre of the Eromanga Basin. This unit is of particular interest because it contains interbedded reservoir and source facies (Mount, 1982; Ambrose et al., 1986), and therefore represents an ideal test case for the hypothesis that certain hydrocarbons pooled in the Eromanga Basin sequence originated in Jurassic and Cretaceous source beds (McKirdy, 1982, 1985; Kantsler et al., 1983; Vincent et al., 1985). Alexander et al. (1988) confirmed earlier suggestions (Kantsler et al., 1983) that while some of the Eromanga oils were sourced in Jurassic and Cretaceous sediments, some also appear to have been sourced from Permian sediments (Fig. 2). Thus each case has to be considered on its merits.

GEOLOGICAL SETTING

The Murta Member was first described by Nugent (1969) as a lacustrine facies of the Mooga Formation. It is a predominantly fine grained Neocomian unit of great lateral continuity which in places interfingers with the underlying coarse-grained, braided fluvial sediments of the Namur Sandstone Member of the same formation.

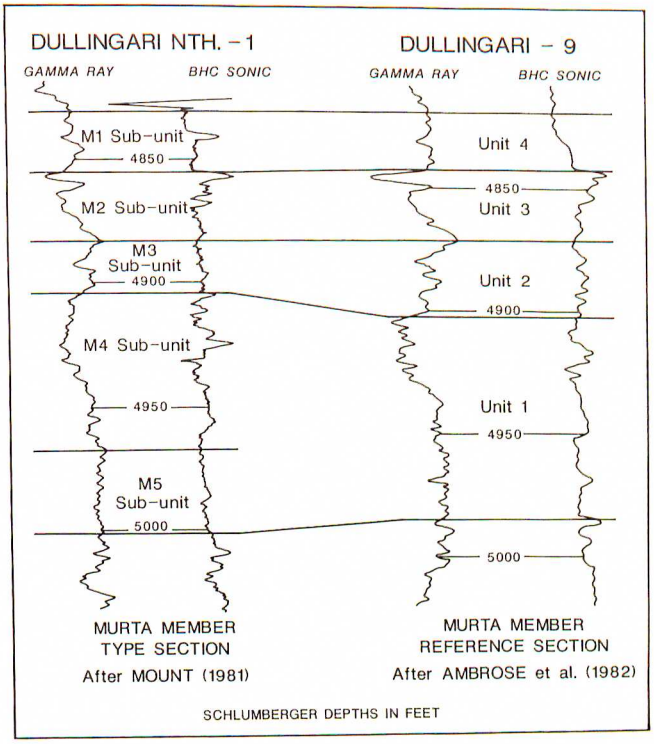

Figure 3. Subdivision of Murta Member, in type and reference sections (Mount, 1981; Ambrose et al., 1986).

The stratigraphy, lithofacies and interpreted depositional environment of the Murta Member have been discussed in detail by Mount (1982) and Ambrose et al. (1986). Their respective type and reference sections are summarised in Figure 3. The five-fold stratigraphic subdivision of Mount provides the basis for the following brief summary.

The lowermost M5 unit comprises organic-rich, laminated to thinly bedded, argillaceous siltstone, which represents distal, open lacustrine sedimentation. The M4 unit contains finely laminated, poorly sorted sandstones interbedded with dark carbonaceous siltstones. These sediments represent a series of vertically stacked, lobate, low-relief, subaqueous, clastic fans. The presence of Bouma sequences indicates deposition by density currents. Carbonaceous siltstone dominates the M3 unit, which was deposited in a deeper water lacustrine environment. The M2 unit appears as a prominent upward-coarsening

arenaceous cycle, probably deposited in a prograding deltaic fan, with distal laminated, dark, silty shale at its base. Shoreline bar sands at the top of the unit comprise the principal reservoirs of the Dullingari oil field. The uppermost M1 unit consists of a low-energy, fining-upwards sequence of laminated grey siltstones with subordinate sandy interbeds.

Zoellner (1988) reports the presence of fluorapatite nodules, glauconite and possible calcisphere microfossils in the M3 through M1 units. Together with boron trace element data, these features suggest a brackish to marine environment for this part of the Murta sequence. Erosional incisions of the Murta Member can be recognised on seismic sections. However, the size and frequency of the channel-fill sandstones decreases upsection from the basal M4 (thick channels) to the M3 and M2 (thin channels). Synthesis of the previously mentioned sedimentological, geochemical and seismic evidence led Zoellner (1988, p. 83) to propose a revised depositional model for the Mooga Formation. Initially the environment ranged 'from fluvio-deltaic (Namur Sandstone Member) to freshwater lacustrine (M5). A rapidly prograding delta sequence (M4) was followed by a slowly retreating delta and a transgressive shale sequence (M3 to M1)... Alternatively, sands were fed into the eastern study area through a large estuarine channel, and sediments were transported into the basin by underflow rather than by delta progression'. Deposition of the shaly M1 unit, together with shales of the basal Cadna-owie Formation, represents a maximum transgressive phase and is consistent with the connection of the central and western Eromanga Basin to marine waters during the Early Neocomian.

PREVIOUS STUDIES

On the basis of rock extract data, McKirdy (1982) considered the oil-source potential of the Murta Member to be moderately high. Petrological studies by McIntyre (1980) and Mudge (1980) highlighted the presence of exinite-rich dispersed organic matter (DOM up to 3 per cent by volume) in parts of the Murta Member. At Dullingari North 1, the highest concentrations of DOM occur in the more distal and argillaceous M1, M3 and M5 units (Mount, 1982). Across the Dullingari oil field the Murta Member is marginally mature (vitrinite reflectance = 0.60–0.66% Ro; Ambrose et al., 1986). Along the Naccowlah–Jackson Trend, the Murta Member contains enough terrestrial organic matter (0.7–2.0% TOC) and is sufficiently mature for early oil generation (Vincent et al., 1985). Here and elsewhere in the Eromanga Basin (McKirdy, 1985; Moore et al., 1986) kerogen is predominantly of Type III composition, although Rock Eval Hydrogen Index values in the range HI = 150–200 have been recorded. All these source-rock studies were based largely on cuttings samples. Therefore they are a less reliable indicator because of likely contamination by cavings and the inevitable mixing of thinly interbedded fine-grained (source) and coarse-grained (reservoir) lithofacies.

Previous studies of oils from the Murta and Namur Sandstone Members of the Mooga Formation have shown them to possess physical and chemical characteristics that differ from those of oils reservoired in older stratigraphic units of the Eromanga–Cooper Basin (Swindon & Moore, 1984; McKirdy, 1985; Vincent et al. 1985). Many of these paraffinic oils are light (45–54° API), lack the high content of waxy n-alkanes that typifies the older Mesozoic oils, and yet have high pristane-to-phytane ratios (*c.* 8.0) indicative of a predominantly terrestrial origin (Vincent et al., 1985). Furthermore, maturity indicators derived from combined gas chromatography – mass spectrometry analysis of their biomarker hydrocarbons suggest that these oils were generated at the threshold of the conventional oil window (vitrinite reflectance *c.* 0.5% Ro; Vincent et al., 1985; Jenkins, 1987). Thus, in composition and maturity, they do not conform with the established concepts of hydrocarbon genesis from non-marine source rocks whereby generation of waxy oil occurs at maturation levels characteristic of the main phase of oil formation (vitrinite reflectance >0.7% Ro; Tissot & Welte, 1984). Alternatively, they could represent the effects of fractionation during migration from a deeper source (Connan & Cassou, 1980).

Currently available geological and geochemical data have been used to infer that the Murta Member itself is the source of the oils found within its reservoir facies (Vincent et al., 1985; Ambrose et al., 1986). There is, however, no definitive evidence for this correlation nor for the existence of effective source rocks in the Murta Member at the relatively low maturation levels observed. If, on the other hand, this scenario could be confirmed, then it would have considerable impact on exploration strategies employed in the search for other Murta accumulations, since migration paths from deeper and more mature source rocks would not be required.

THE PRESENT STUDY

The present geochemical investigation was prompted by the availability of oil samples and continuously cored sections from the Murta Member in the Nockatunga area (ATP 267P) and along the Murteree Horst (PEL 5, 6) (Table 1). This sample suite, supplemented by Murta and Namur oils from elsewhere in the Eromanga Basin, offered the opportunity to obtain definitive evidence which would confirm or refute the intra-Murta source hypothesis. The objectives of the study were as follows:

— evaluate the source-rock potential and maturation level of the Murta Member within or adjacent to oil fields with Cretaceous production;
— document the geochemical characteristics of oils recovered from the Murta Member;
— determine whether the Murta Member has sourced the oils reservoired within it and the subjacent Namur Sandstone Member;
— examine the wider implications of a definitive Murta oil-source correlation for hydrocarbon generation scenarios in lacustrine sequences.

SAMPLES AND PROCEDURES

Eighty mudstone and siltstone samples were selected from cores of the Murta Member from the following wells: Koora 1, Nockatunga 1, 2, 3, and Winna 1, in ATP 267P, and Biala 1, Limestone Creek 6, Moomba 18 and McKinlay 2, from the Moomba and Napacoongee–Murteree Blocks of PEL 5

Area/Well	Depth Range (m)	Tmax (°C)	PI	VR (R_o%)	MPI-1	VR (R_c%)
ATP 267P						
Nockatunga 1	1004-1009	440	0.14-0.20	0.42	0.51	
Nockatunga 2	1005-1010.0	439	0.11-0.20		0.48	0.55
Nockatunga 3	1004-1011	441	0.12-0.22		0.43	0.52
Koora 1	968-987	442	0.07-0.22		0.40	0.50
Winna 1	998-1016	438	0.20-0.23	0.50	0.46	0.54
Nappacoongee-Murteree and Moomba Blocks						
Biala 1	1200-1216	432	0.11-0.17			
Limestone Creek 6	1212-1220	434	0.10-0.16	0.57		
McKinlay 2	1237-1248	433	0.07-0.12	0.53		
Moomba 18	1732-1778	438	0.05-0.11	0.62		

PI = Production Index of unstained samples (PI < 3); VR = Vitrinite reflectance; R_o% = measured reflectance; R_c% = calculated reflectance from MPI-1; MPI-1 = Methylphenanthrene Index.

Table 1. Average maturation levels, Murta Member.

and 6 (Fig. 1). Samples from the wells in ATP 267P were mostly from the uppermost shale unit (M1; Zoellner, 1988) whereas samples from the wells in PEL 5 and 6 were distributed throughout the Murta Member (M1–M5) (Fig. 2). Murta oils examined as part of this study are from Kihee, Thungo, Nockatunga, Biala and Limestone Creek and are compared with a further seven samples from Murta and Namur reservoirs and 22 Permian and 24 Jurassic oils and condensates from the Cooper–Eromanga Basin.

All rock samples were screened by measurement of organic carbon content and Rock Eval pyrolysis. On the basis of these results, 23 samples were extracted and 58 whole rock samples were polished and examined petrographically under normal and ultra-violet reflected light.

Twelve samples were selected for kerogen isolation, and the resulting kerogen isolates were analysed by pyrolysis gas chromatography (Larter & Sentfle, 1985) and for their elemental composition. Hydrous pyrolysis experiments were conducted in evacuated, sealed quartz tubes by heating 100 mg of kerogen with 50 μL of water at 330°C for 3 days.

The oil samples were distilled to remove the fraction boiling below 210°C. The oils and the extracts were fractionated into saturate hydrocarbons, aromatic hydrocarbons and ONS compounds using standard techniques (Powell, 1978). Saturated hydrocarbon fractions were analysed by capillary gas chromatography. Selected aromatic fractions were fractionated into mono-, di- and triaromatic fractions, using a combination of thin-layer chromatography and high-pressure liquid chromatography (Boreham et al., 1988). The triaromatic fractions were analysed for phenanthrene and methylphenanthrene isomers in order to determine the Methylphenanthrene Index (MPI-1), a maturation parameter that has been calibrated against vitrinite reflectance (Radke & Welte, 1983). MPI-1 is defined as follows:

$$\text{MPI-1} = 1.5 * (2\text{MP} + 3\text{MP})/(\text{P} + 1\text{MP} + 9\text{MP})$$

where *P* is the concentration of phenanthrene and *2MP, 3MP, 1MP* and *9MP* are the concentrations of 2-, 3-, 1- and 9-methylphenanthrene respectively. Boreham et al. (1988) have provided an alternative calibration of vitrinite reflectance against MPI-1 using Australian coals and carbonaceous shales. The preferred relationship in the reflectance range 0.3-1.7% Ro is

$$\text{Rc} = 0.7\ (\pm\ 0.05)\ \text{MPI-1} + 0.22\ (\pm\ 0.04)$$

where *Rc* is the calculated reflectance and the standard error is given in brackets. It should be noted that the relationship is valid only for terrestrial sediments (Boreham et al., 1988) and to samples in which there are no unusual concentrations of 1-methylphenanthrene derived from plant resins (Alexander et al., 1988) — namely the ratio of 1-methylphenanthrene to 9-methylphenanthrene does not exceed 2. Selected saturated hydrocarbon fractions from both oils and sediments were analysed by gas chromatography - mass spectrometry to determine biomarker distributions, using the metastable reaction-monitoring techniques described by Summons and Powell (1987).

RESULTS AND DISCUSSION

ORGANIC CONTENT AND KEROGEN COMPOSITION

Total organic carbon (TOC) contents in the Murta Member in ATP 267P are relatively low (TOC = 0.99 ± 0.25) compared with many source rocks. Higher values were

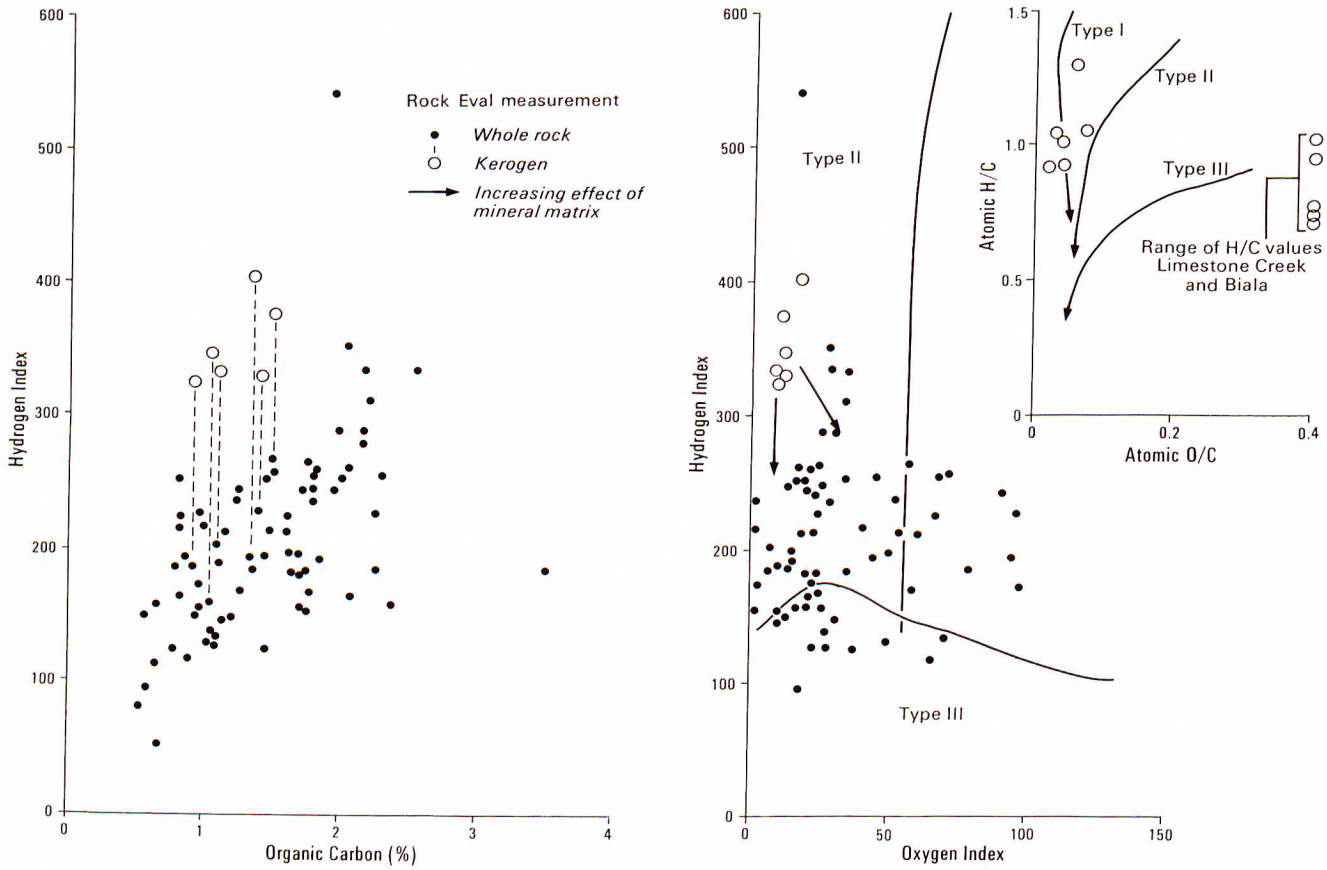

Figure 4. Organic carbon content, Rock Eval data and elemental analyses of kerogens.

encountered in PEL 5 and 6, ranging up to 2.5 per cent TOC (Fig. 4). A carbon content of 0.5 per cent (Tissot & Welte, 1984) is the generally accepted lower limit for an effective source rock, although documented cases of effective shale source-rocks with organic carbon contents below 1 per cent TOC are rare. In the Murta samples, yields of total pyrolysable hydrocarbons (S1 + S2) from Rock Eval analysis are generally less than 5.0 kg/t and are lower than most documented source rocks. Hydrogen Indices fall in the range 100–300, with occasional values up to 541 (Fig. 4). The Hydrogen Indices are clearly affected by the mineral matrix. In samples with less than 3 per cent TOC, suppression of pyrolysis yields results from absorption of the pyrolysate by the mineral matrix (Espitalie et al., 1980; Orr, 1983). Rock Eval analysis on isolated kerogens from the Murta Member gave Hydrogen Indices (300–400) significantly higher than values measured on the whole rock (150–270) (Fig. 4). A limited number of elemental analyses also demonstrate that the kerogen quality is higher than indicated by Rock Eval data. Atomic H/C ratios fall in the range 0.75–1.2. The atomic O/C ratios are lower than is commonly found in immature Type II and III kerogens, but the atomic H/C ratios are not as high as are found in Type I kerogens of comparable maturity.

Petrographic examination of selected samples under reflected light shows that the main variation in composition

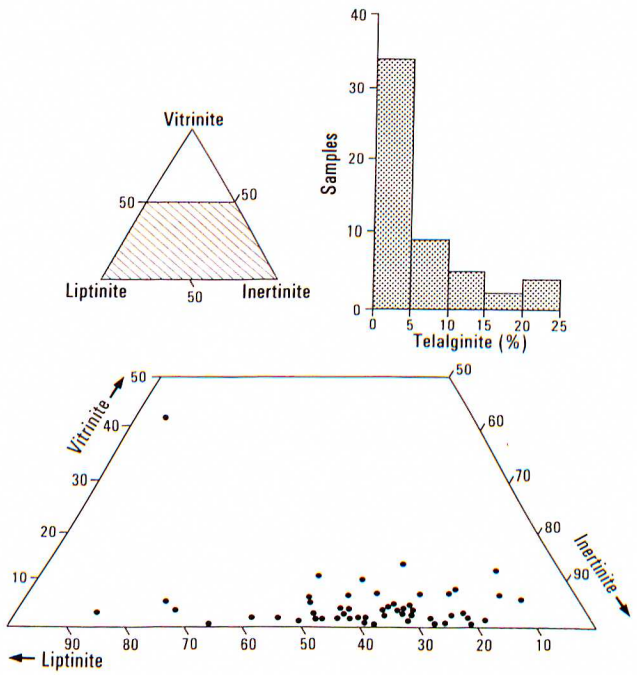

Figure 5. Variations in organic petrographic composition, Murta Member.

relates to the relative proportions of inertinite and liptinite (Fig. 5). Vitrinite is slightly fluorescing and is in low abundance in most samples. Sporinite and liptodetrinite are by far the most abundant liptinite macerals, although telalginite is relatively abundant (up to 25 per cent of organic matter) in certain samples from the Napacoongee–Murteree Block. When the samples are prepared as kerogen slides and examined under transmitted light, a minor but significant component of the organic matter is amorphous in appearance. Extensive degradation of the organic matter during deposition is also inferred from the highly comminuted nature of the liptinitic component.

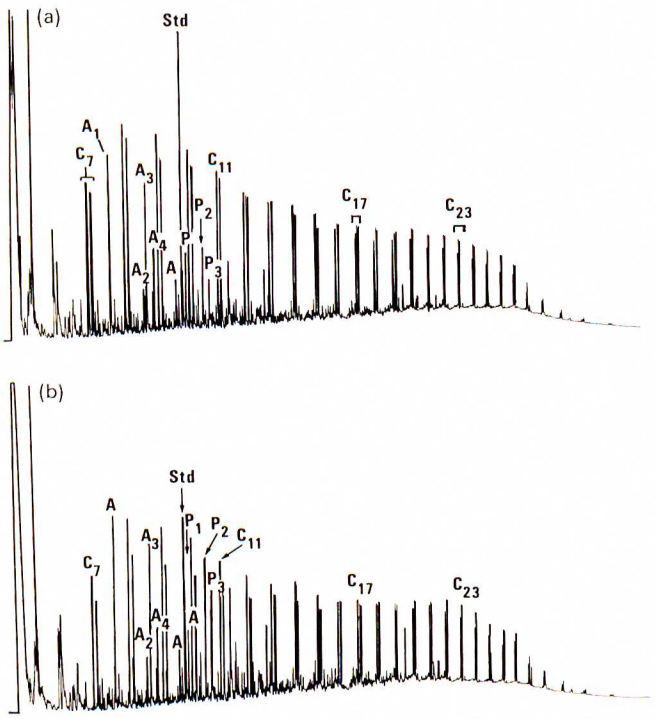

Figure 6. Selected pyrolysis–gas chromatograms of Murta kerogens.
(a) Non-source facies Nockatunga 2, 1008.3 m.
(b) Source facies Winna 1, 1016.3 m.
Numbered peaks refer to carbon number of alkene–alkane pairs; A–A4 denote aromatic hydrocarbons; P_1–P_3 denotes phenols; Std denotes standard.

Further evidence for the nature of the organic matter in the Murta Member can be obtained from the results of pyrolysis gas chromatography (Fig. 6). N-alkanes comprise a large proportion of the hydrocarbons in non-marine oils and it has been argued that the ability of organic matter to yield n-alkanes is the critical factor in the determination of source-rock potential in non-marine sequences (Smith et al., 1987). This can be assessed by quantitative pyrolysis gas chromatography of kerogens (Larter & Sentfle, 1985). On pyrolysis, humic coals yield largely aromatic and phenolic compounds and relatively few normal hydrocarbons (n-alkanes and n-alkenes) (Larter & Sentfle, 1985). In contrast, oil-prone terrestrial organic matter yields abundant normal hydrocarbons, the amounts being comparable to or greater than marine source materials (Powell et al., in preparation), although the latter give larger amounts of pyrolysate because of the greater yield of naphthenic and naphthenic-aromatic hydrocarbons (Larter & Sentfle, 1985). On pyrolysis, the Murta kerogens yield relatively abundant normal hydrocarbons (Fig. 6), ranging from 20 to 40 mg/g organic carbon, and represent the remaining hydrocarbon potential. This is lower than might be expected at the observed maturation levels, given the relatively high proportion of the organic matter that is liptinite (Fig. 5). The yields are lower than those obtained from many Jurassic and Tertiary coals and kerogens at comparable maturation levels (Powell et al., 1989). In addition, despite the largely terrigenous origin of the liptinites, the yield of normal hydrocarbons in the wax range ($>nC_{17}$) is rather low (20–40 per cent). This characteristic has been observed by the authors in coals where sporinite and liptodetrinite are also the dominant liptinite macerals. They contrast with samples where suberinite and cutinite are the dominant liptinite macerals when a relatively high proportion of waxes (>50 per cent) are observed in the pyrolysable normal hydrocarbons.

MATURATION, HYDROCARBON YIELDS AND COMPOSITION

The Murta rock samples were obtained from relatively narrow depth intervals, so that compositional differences attributable to maturation would not be expected. Tmax values from Rock Eval analysis typically show differences of 3°C between adjacent samples due to varying mineral matrix effects and varying organic matter concentrations; both of these mildly affect the timing of pyrolysate release during analysis. Average Tmax values for the Murta Member in the various wells (Table 1) correspond to small variations in maturation and range from 432 to 442°C. They indicate that the Murta Member is at the threshold of oil generation. Despite the narrow range of values, the wells from PEL 5 and 6 show consistently lower Tmax values (Table 1). Vitrinite is relatively sparse in samples obtained from ATP 267P and the single vitrinite reflectance measurement was supplemented by measurement of Methylphenanthrene Indices (MPI-1) (Table 1). Calculated vitrinite reflectance values have been obtained from MPI-1 using the calibration of vitrinite reflectance to MPI-1 obtained for Australian coals (Boreham et al., 1988; see 'Samples and Procedures'). The calculated vitrinite reflectances fall within the range 0.51–0.55 per cent (Table 1) and are in agreement with the measured reflectance value and the Tmax values obtained by Rock Eval analyses. Vitrinite reflectance values obtained from the Murta Member in the Nappacoongee–Murteree and Moomba blocks fall in the range 0.57–0.62% Ro (Table 1). The maturation levels obtained for the Murta Member are consistent with those obtained in previous studies (Kantsler et al., 1983; Vincent et al., 1985).

Despite the relatively low maturation levels, the Production Indices (PI) from the Rock Eval analyses showed wide variations, from 0.05 to 0.65. Values in excess of 0.3 are

typical of samples stained with migrated hydrocarbons. Neglecting samples obviously stained by oil, other samples had PI values typical of mature petroleum source rocks (PI >0.2) (Table 1). Extraction and analysis of free hydrocarbons were performed on samples selected to cover the full range of observed Production and Hydrogen Indices. Hydrocarbon yields vary from 200 ppm and less than 20 mg/g organic carbon to 3500 ppm and 271 mg/g organic carbon (Fig. 7). The highest yielding samples have very high proportions of hydrocarbons in their extracts (>50 per cent) and very high saturate-to-aromatic ratios (>4), and clearly represent staining by migrated hydrocarbons. Four samples with indigenous hydrocarbons have sufficient hydrocarbon yields to be rated as fair to good oil sources at present maturation levels (Fig. 7). The source quality as defined by extractable hydrocarbon yield fluctuates rapidly over a matter of metres within the Murta Member and no single unit gives consistently better hydrocarbon yields at the maturation levels encountered.

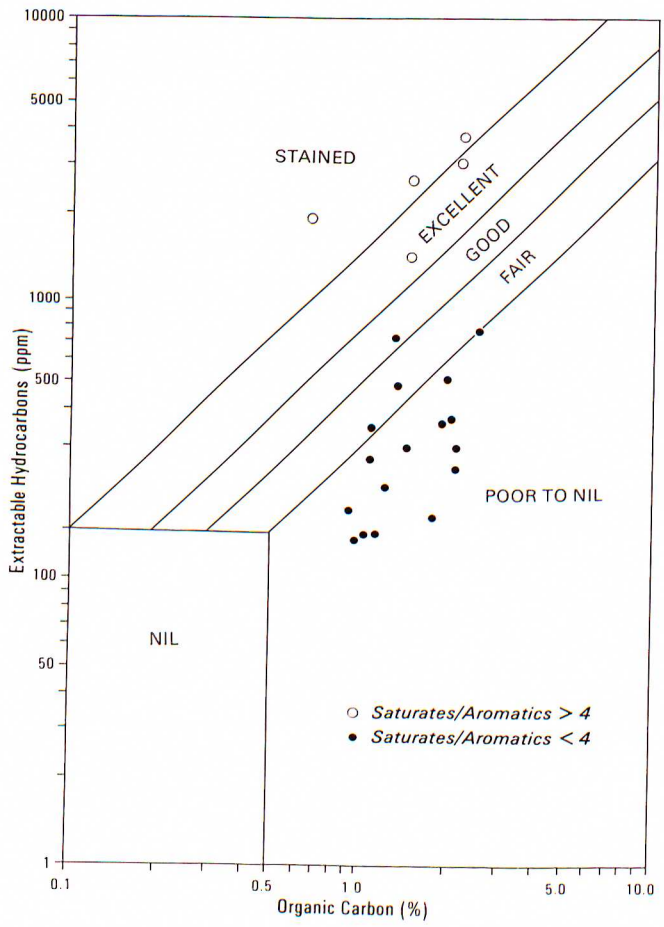

Figure 7. Source-rock quality of selected samples based on extractable hydrocarbon yields and organic carbon content; boundaries between source types are after Powell (1978). Thus <30 mg/g organic C — Nil; 30–50 mg/g organic C — fair; 50–80 mg/g organic C — good; 80–160 mg/g organic C — excellent; >160 mg/g organic C — stained. Sat/Arom denotes ratio of saturated to aromatic hydrocarbons.

The gas chromatograms of the saturated hydrocarbons from samples with fair to good hydrocarbon source potential (e.g. Winna 1 and Limestone Creek 6; Fig. 8) show that they are dominated by lower molecular weight n-alkanes with high pristane-to-phytane ratios, but relatively low proportions of pristane relative to n-heptadecane. Their low saturate-to-aromatic ratios (<4) indicate that the hydrocarbons are in place and that these samples do not represent staining by migrated oil (Fig. 7). Migration of oil results in enrichment of hydrocarbons and particularly of saturates in the oil compared with the parent source-rock (Tissot & Welte, 1984). The stained samples (Fig. 7) are characterised by high PI values, anomalously high hydrocarbon yields with a very high proportion of hydrocarbons (>60 per cent) and very high saturate to aromatic ratios (>7). The gas chromatograms of the stained samples (e.g. Biala 1; Fig. 8) resemble the samples with fair to good source potential. The gas chromatograms of saturate hydrocarbons from some samples with poor source potential (e.g. Koora 1; Fig. 8) is similar to that expected from marginally mature, non-marine organic matter — namely relatively abundant long-chain n-alkanes, with an odd to even predominance, high pristane-to-phytane ratios and a high proportion of pristane relative to n-heptadecane. Other samples (Nockatunga 3 and McKinlay 2; Fig. 8) have saturated hydrocarbon distributions between the two extremes.

It is worth noting that there is no difference in the Methylphenanthrene Indices and hence maturity level of hydrocarbons obtained from samples with varying extract yields. This is confirmed by the biomarker maturation parameters obtained from the sediments (Table 2). Maturation parameters derived from biomarkers are based on the progressive isomerisation of the biomarkers, from biological configurations to equilibrium mixtures of biological and geological isomers, under the influence of increasing temperature (Mackenzie, 1984). Several of these parameters achieve their equilibrium values prior to the onset of hydrocarbon generation. Thus the percentage of the 22S component in the C_{32} 17α(H), 21β(H) hopanes (parameter 2, Table 2) is at the equilibrium value of 60 per cent in ATP 267P (Nockatunga, Winna, Koora) but are below equilibrium values from wells (Biala, Limestone Creek and McKinlay) from PEL 5 and 6 (Table 2). The ratios of the C_{30} 17β(H), 21α(H) to C_{30} 17α(H), 21β(H)-hopanes (parameter 3, Table 2) approach the equilibrium values of below 0.10. In contrast other biomarker parameters achieve equilibrium in the oil window and none of the sediments of this study have reached these values. Thus, the equilibrium value for the percentage of the C_{29} 5α(H), 14α(H), 17α(H) sterane with a 20S stereochemistry (parameter 1, Table 2) is about 55 per cent, whereas values in this data set range between 30 and 40 per cent in ATP 267P and are even lower (<30 per cent) in the Limestone Creek – Biala area. The lower values are surprising, given the similarity in measured and calculated vitrinite reflectance values (0.53–0.57% Ro) obtained for the Murta Member in the two areas. Only detailed consideration of thermal and burial history and kinetics of the organic transformations would allow the significance of these differences to be determined.

These results indicate that the hydrocarbons showing

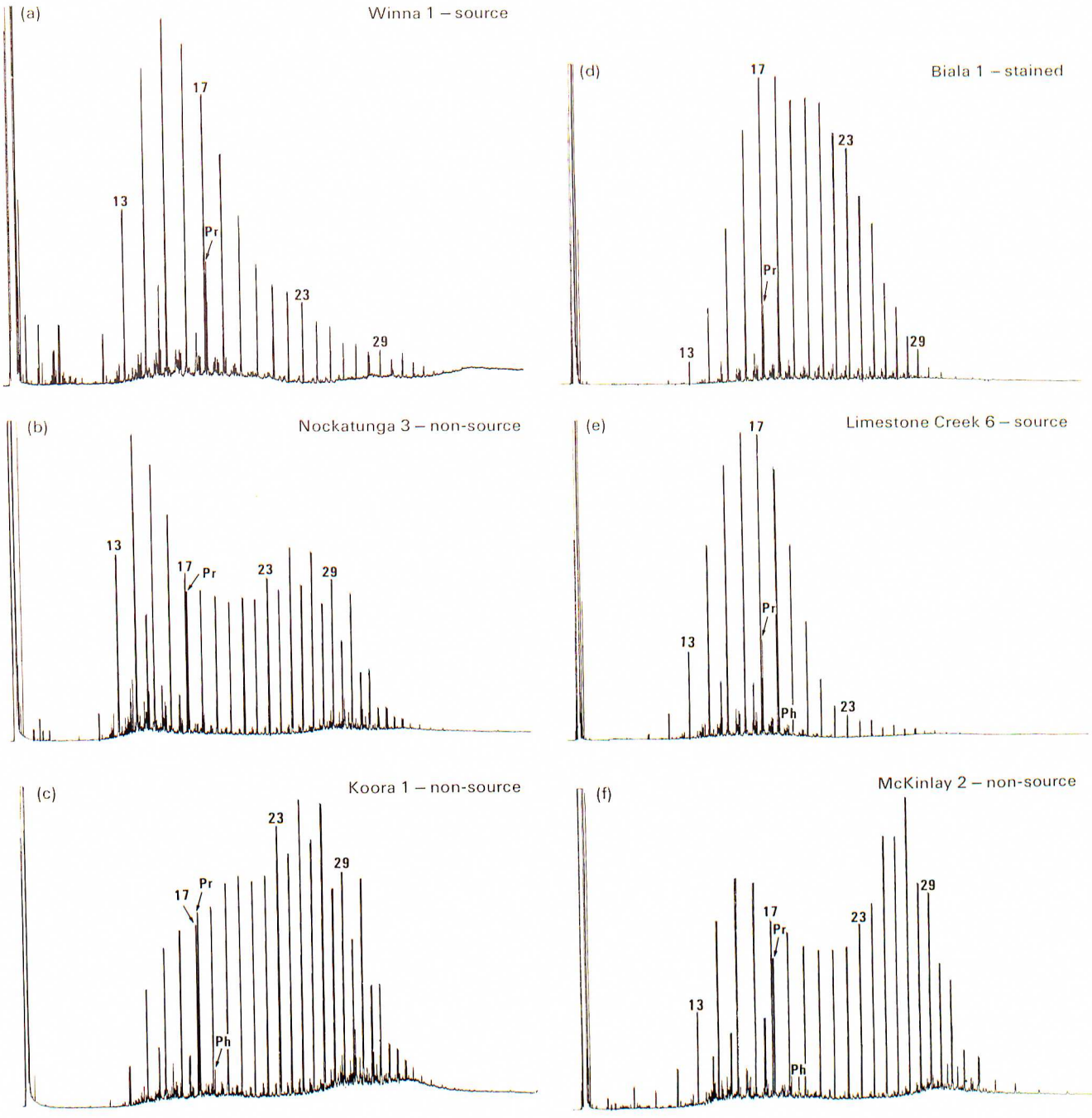

Figure 8. Gas chromatograms of extractable saturated hydrocarbons from selected samples with varying extractable hydrocarbon yields. (a) Winna 1, 1061.3 m; (b) Nockatunga 3, 1004.1 m; (c) Koora 1, 974.5 m; (d) Biala 1, 1200.7 m; (e) Limestone Creek 6, 1221.8 m; (f) McKinlay 2, 1239.2 m. Numbered peaks refer to carbon number of n-paraffins; Pr denotes pristane; Ph denotes phytane. Source denotes fair to good source potential (Fig. 7).

different gas chromatographic distributions are indigenous to the Murta Member. Variations in yield and hydrocarbon distribution in the sediments are related to variations in source facies in the Murta Member and are not due to migration of hydrocarbons into the unit from elsewhere. Furthermore, the variation in source-rock quality observed at these relatively low maturation levels is surprising, given the overall similarity of the organic matter. Rock Eval pyrolysis and pyrolysis-GC analysis of kerogens from samples which fall in the source and non-source facies at present maturation levels show basically similar results (Figs 4, 6). In other words, their total hydrocarbon potential is the

SAMPLE m - Unit	MATURATION PARAMETERS %[1] 20S	 %[2] 22S	 $\beta\alpha$[3] $\alpha\beta$	SOURCE PARAMETERS Dia[4] St	 M-St[5] St	 Hop[6] St	 H28[7] H29
			Murta Oils				
Nockatunga 4	29.6	n.d.	0.05	1.8	0.04	1.88	0.17
Thungo 1	34.8	60.6	0.06	3.4	n.d.	2.15	0.09
Dullingari 29	39.6	63.0	0.08	1.5	n.d.	3.14	0.05
Jackson 1	33.7	61.8	0.08	2.2	n.d.	2.46	0.08
Biala 1	35.0	51.4	0.05	4.3	n.d.	3.19	0.06
			Source Facies (Fair to Good)				
Nockatunga 2 1010.0-M1	30.6	61.1	0.10	0.94	0.11	1.66	n.d.
Winna 1 1016.3-M2/M3?	37.3	60.0	0.10	1.7	0.06	3.22	1.19
Limestone Creek 6 1218.1-M2	22.1	56.2	0.13	0.45	0.27	3.42	0.15
1221.8-M3	21.4	52.9	0.10	0.50	n.d.	3.32	0.11
			Non-Source Facies				
Nockatunga 2 1008.3-M1	30.4	60.6	0.10	0.62	0.68	2.23	0.02
Nockatunga 3 1009.1-M1	40.8	62.6	0.15	0.55	0.20	2.36	0.04
Koora 1 970.6-M1	32.7	60.5	0.11	0.73	0.45	1.95	0.11
Biala 1 1215.5-M4	28.6	59.1	0.20	0.64	0.14	3.85	0.14
Limestone Creek 6 1215.4-M2	24.2	55.3	0.16	0.42	0.12	2.96	0.15
1217.4-M2	23.6	57.9	0.15	0.42	0.24	3.89	0.13
McKinlay 2 1241.6-M5	28.3	55.1	0.15	0.73	0.26	3.08	0.07

1. 100 * (20S-) / (20S-) + (20R-) 24-ethyl-5α(H), 14α(H), 17α(H)-cholestane
2. 100 * (22S-) / (22S-) + (22R-) 17α(H), 21β(H)-bishopane
3. 17β(H), 21(H)- / 17α(H), 21β(H)-hopane (C_{30})
4. ΣC_{29} diasteranes / ΣC_{29} steranes
5. ΣC_{30} 2OR-methyl-5α(H), 14α(H), 17α(H)-steranes / 2OR-24-ethyl-5α(H), 14α(H), 17α(H)-cholestane
6. ΣC_{30} hopanes / ΣC_{29} steranes
7. 28,30-bisnorhopane /norhopane

n.d. = not determined due to low concentrations.

Table 2. Source- and maturation-dependent biomarker parameters in Murta oils and sediments of varying source potential, based on extractable hydrocarbon yield.

same. This was confirmed by hydrous pyrolysis of isolated kerogens from the source and non-source facies (Fig. 9). The yields of hydrocarbons and their distribution patterns are basically similar. The distinction between the source and non-source facies therefore appears to relate to a component of the organic matter which is maturing earlier in the former and this is discussed further below.

OIL COMPOSITION AND OIL SOURCE CORRELATION

Many oils reservoired in the Murta Member and the adjacent Namur Sandstone in the Eromanga Basin are very

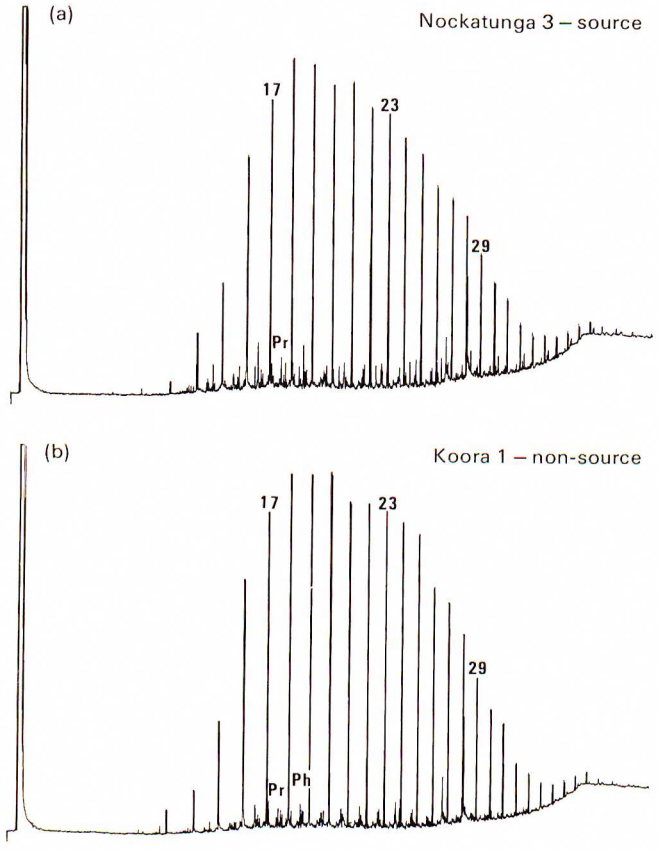

Figure 9. Gas chromatograms of saturated hydrocarbons obtained by hydrous pyrolysis of kerogens isolated from (a) source (Nockatunga 3, 1010 m) and (b) non-source (Koora 1, 970.6 m) samples. Refer to Fig. 8 for key to peak labelling.)

light (48–52°API) and are characterised by abundant light fractions (approximately 50 per cent boiling below 210°C), the absence of waxy n-alkanes, high pristane-to-phytane ratios and a low proportion of pristane to n-heptadecane (e.g. Jackson 1, DST2; Fig. 10) (Swindon & Moore, 1984; Vincent et al., 1985). Oils reservoired in the Murta Member in ATP 267P and examined in this study fall into this category (e.g. Thungo; Fig. 10). However, oils from the Murta reservoirs at Limestone Creek and Biala differ in having abundant waxy n-alkanes (Fig. 10) and as such they resemble oils reservoired in Jurassic reservoirs in the Eromanga Basin (Swindon & Moore, 1984; Vincent et al., 1985).

From the point of view of overall composition of the saturated hydrocarbons, there is a strong similarity between the n-alkane distributions, pristane-to-phytane ratios, the abundance of iso- and anteiso-alkanes, and isoprenoid to n-alkane ratios between the low-wax oils and the sediments of source-rock quality in the Murta Member (Figs 8, 10). In particular the relative proportions of iso- and anteiso-alkanes and pristane compared with the n-alkanes in the oils and the source facies are virtually identical (Figs 11, 12), whereas the samples with fair to nil source potential exhibit a range of values. There is not a unique correlation of the oils with the observed source facies because of the transition in composition from the source to non-source facies (Fig. 8).

Additional evidence of a local source for all Murta oils comes from the MPI values, which are identical in oils, source and non-source sediments in the Murta Member (Fig. 13) and are generally much lower than values recorded from Jurassic and Permian oils and condensates. Since the Methylphenanthrene Index is a maturation parameter, the close similarity of the sediment values to Murta oil values is consistent with the oils having been generated at the general maturation levels observed in the Murta Member.

The biomarker distributions of the oils and source sediments have been examined by gas chromatography – mass spectrometry. The general application of biological markers in petroleum geochemistry has been reviewed by Mackenzie (1984). Selected metastable reaction chromatograms from oils and sediments are illustrated in Figures 14 and 15 and the relevant source and maturation parameters are given in Table 2. The abundance of biomarkers in the oils is substantially lower than in all of the sediment samples, reflecting preferential enrichment of the lighter hydrocarbons during migration. The biomarker maturation parameters obtained for the oils are similar to those obtained from the Murta sediments (Table 2). They are consistent with previous observations that the oils were formed at the incipient stages of maturation (Vincent et al., 1985; Jenkins, 1987) and demonstrate that they have the same general maturation level as the sediments of the Murta Member. A slight maturation difference does exist between the sediments from Limestone Creek 6, Biala 1 and McKinlay 2 and the oils (parameter 1, Table 2).

The distribution of biomarkers also reflects variations in the nature of the source material. Thus C_{27}-C_{29} desmethyl steranes are particularly abundant in marine source rocks and oils and reflect an ultimate source from algae and the various metazoan inputs from the marine foodchain. In marine sources the steranes usually predominate over the hopanes of bacterial origin. In oils and source material derived from land plants the C_{29} steranes commonly predominate and the hopanes occur in greater abundance than in the steranes. The latter scenario holds in the case of the Murta sediments and oils. The C_{29} steranes predominate over the C_{28} and C_{27} isomers (Figs 14, 15). The ratio of C_{29} to C_{27} steranes approximates 3.5, and the ratio of the C_{30} hopanes to the C_{29} steranes ranges from 2 to 4 (parameter 6, Table 2). In the marine Toolebuc Formation, for example, the ratio of C_{30} hopanes to C_{27}-C_{29} steranes is typically 0.1 (Boreham & Powell, 1987). The overall similarity of these source parameters for both oils and sediments supports a Murta source for the oils.

Three other source parameters show significant variations between the samples. C_{30} 4-methyl steranes are biomarkers for dinoflagellates (Summons et al., 1987). They are relatively abundant (Fig. 15) in all but one of the sediment samples, but are not abundant in the oils (Fig. 14). These variations are shown in Table 2 by the ratio of the C_{30} methyl steranes to the C_{29} regular sterane (parameter 5, Table 2). With the exception of the Winna sample this ratio varies from 0.11 to 0.68 for the sediment sample, but is below 0.1 for the Winna sample and for the oils. Both

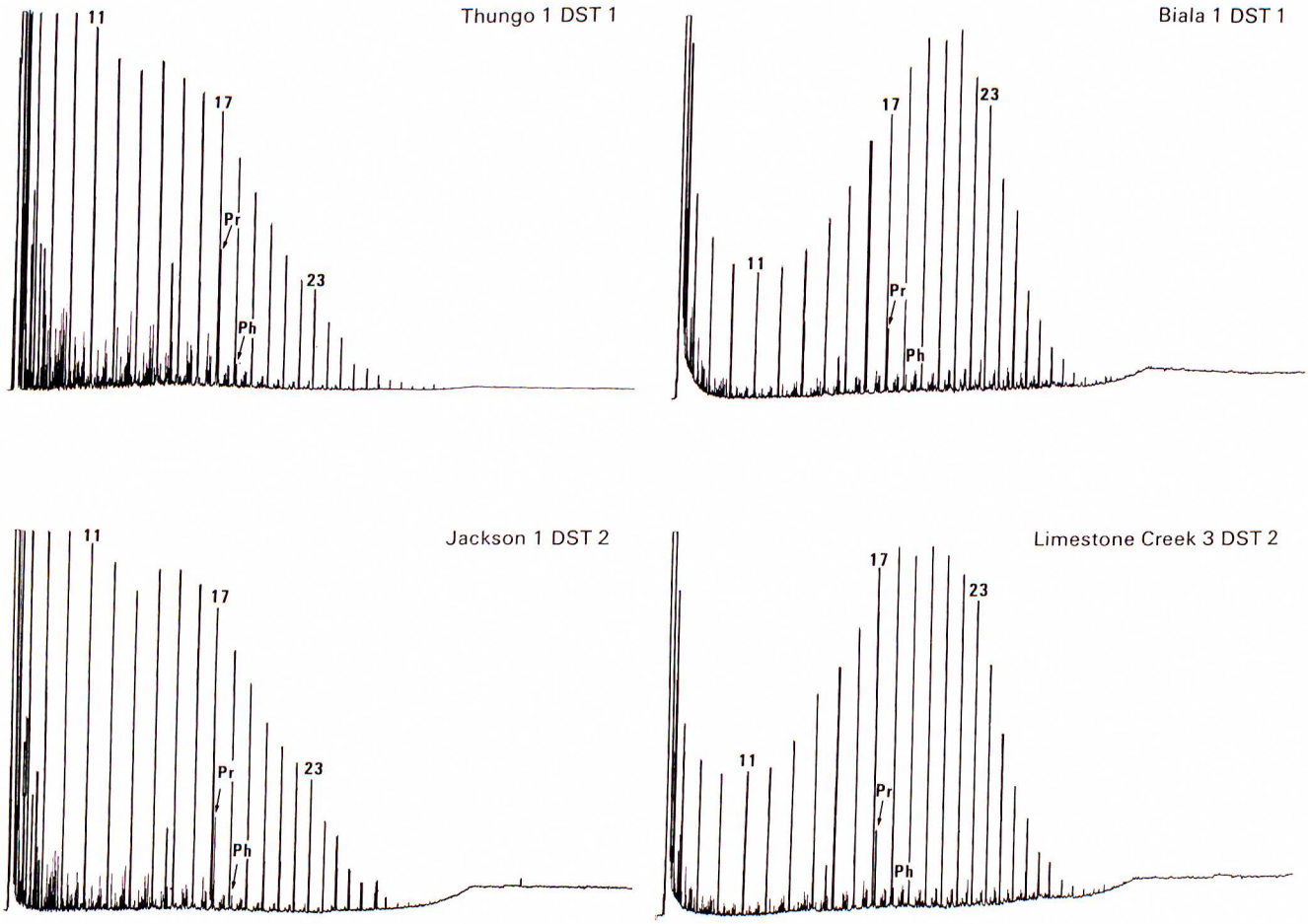

Figure 10. Whole oil–gas chromatograms of selected oils reservoired in the Murta Member. (Refer to Fig. 8 for key to peak labelling.)

24-ethyl-4-methylcholestane isomers and dinosterane isomers (Summons et al., 1987) are present. This is unexpected, given the predominantly lacustrine environment previously attributed to the Murta Member. Recent work (Summons et al., 1987; Goodwin et al., 1988) suggests that dinosterane is generally confined to sediments and oils of marine derivation.

The oils and some sediment samples also contain variable amounts of 28,30-bisnorhopane (Figs 14, 15) and this is reflected in the varying ratio of this C_{28} hopane to the C_{29} hopane (parameter 7, Table 2). This compound is abundant in many marine sediments and oils (Seifert et al., 1978; Grantham et al., 1980; Rullkotter et al., 1982) and is thought to have a bacterial origin (Katz & Elrod, 1983), although a specific source organism has not been identified. In conjunction with the occurrence of low amounts of dinosterane (Summons et al., 1987), the presence of this biomarker lends further credence to the proposition of a marine influence in the deposition of the upper part of the Murta Member (Zoellner, 1988). The ratio of the C_{29} diasteranes to steranes (parameter 4, Table 2) also shows markedly different values for the oils and the Winna sample — the best source sample — compared with the remainder of the sediment samples (Table 2). The variability in this ratio may be attributable to migration. It has been suggested that diasteranes migrate faster than 5α(H)-steranes through surface-active sediments such as clays (Seifert & Moldowan, 1978).

Although there is a general correspondence between the maturation levels and biomarker distribution patterns of the oils and the identified source facies within the Murta Member, the biomarker distribution patterns are not identical (Table 2). This is perhaps not surprising given the variability of source quality over short distances within the Murta Member. In addition a source rock with the characteristic high-wax content of the Limestone Creek and Biala oils has not been found. Certainly waxy hydrocarbons are generated from Murta kerogens on hydrous pyrolysis (Fig. 9) and the maturation level of the oils suggests that they were derived from source rocks close to the maturation levels observed in the Murta Member in this area. Migration from much deeper zones can be eliminated.

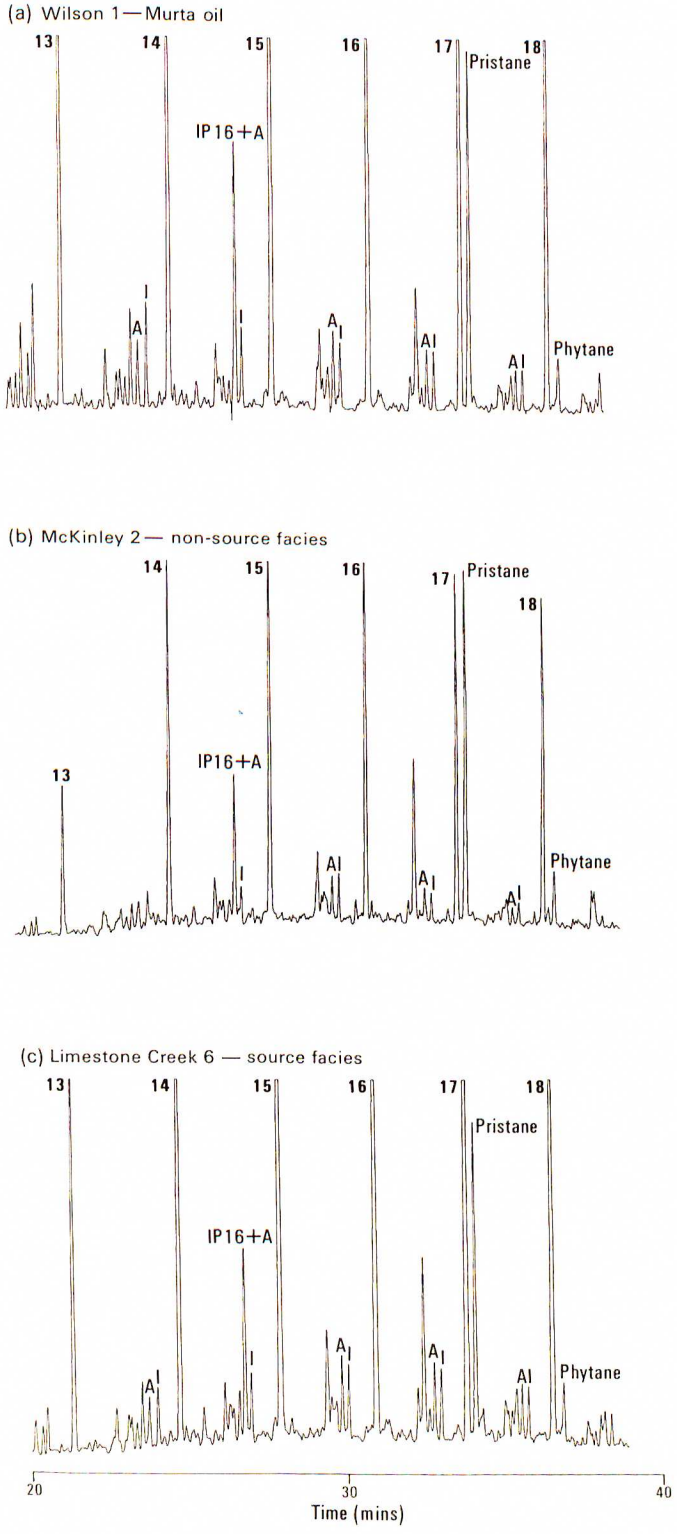

Figure 11. Expanded gas chromatograms of saturated hydrocarbons showing the relative concentrations of anteiso- (A) and iso- (I) alkanes relative to pristane in a Murta oil and source and non-source samples (a) Wilson 1; (b) McKinlay 2, 1241.4 m; (c) Limestone Creek 6, 1216.4 m. Numbered peaks refer to carbon number of n-alkanes (offscale). Ipr 16 = C_{16} acyclic isoprenoid.

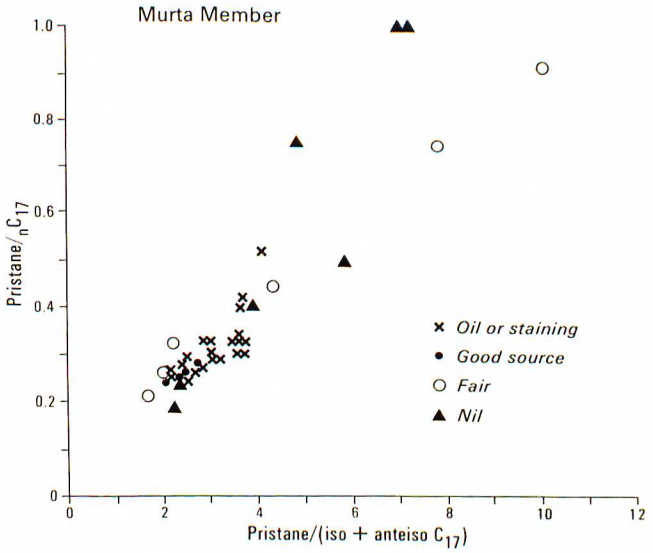

Figure 12. Cross-plot of pristane to n-heptadecane ratio and pristane to iso- plus anteiso-heptadecane ratio for oils and rock extracts. Classification of source quality is derived from Figure 7.

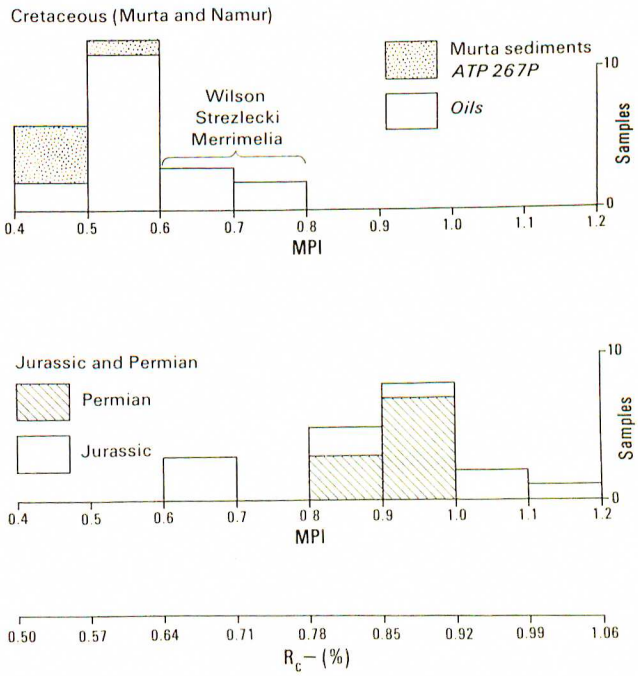

Figure 13. Distribution of Methylphenanthene Indices (MPI-1) in Murta sediments and oils and condensates from the Cooper–Eromanga Basins. Calculated reflectance scale is based on formula of Boreham et al. (1988). (See 'Samples and Procedures'.)

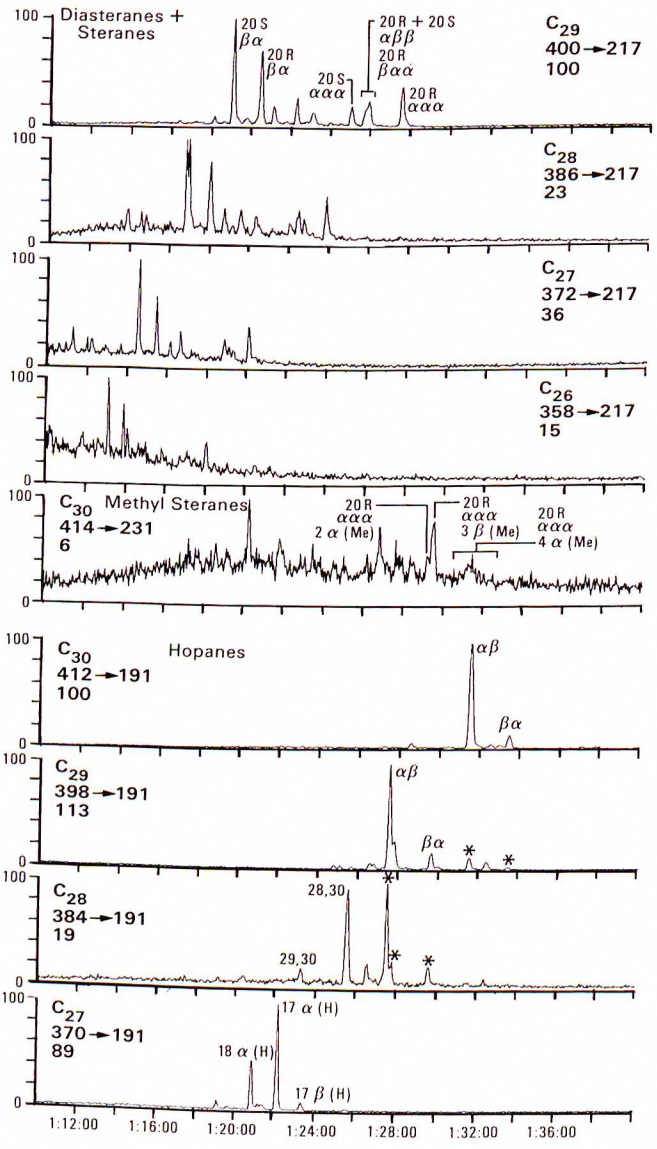

Figure 14. Sterane and pentacyclic hydrocarbon distributions in Nockatunga oil. The data were obtained by metastable reaction monitoring GC-MS of molecular ions fragmenting to daughter ions at m/z 217, 231 and 191 for desmethylsteranes, methylsteranes and pentacyclic triterpanes respectively. Chromatograms are identified by carbon number, reaction transition and relative abundance of the most-intense peak in the trace. Asterisk denotes contribution from hopanes of higher carbon number than the designated transition. Peak assignments for the steranes define the stereochemistry at C-20 (R and S), and $\alpha\,\beta$, $\alpha\alpha\alpha$ and $\alpha\beta\beta$ denote 13β(H), 17α(H) diasteranes; 5α(H), 14α(H), 17α(H) and 5α(H), 14β(H), 17β(H)-steranes respectively. For the hopanes, $\alpha\beta$ and $\beta\alpha$ denote 17α(H), 21β(H)-hopanes and 17β(H), 14α(H)-hopanes (i.e. moretanes) respectively. 18α(H) is 18α(H)-trisnorhopane; 17α(H) is 17α(H)-trisnorhopane, and 17β(H) is 17β(H)-trisnorhopane. 28, 30 and 29, 30 signify 28, 30-bisnorhopane and 29, 30-bisnorhopane respectively.

RELEVANCE TO CONCEPTS OF HYDROCARBON GENERATION

There are two maturation levels which are critical for oil generation in source rocks. The first represents the onset of hydrocarbon generation at a vitrinite reflectance of around 0.5% Ro, and the second represents the onset of the main phase of oil generation at 0.7% Ro. In general, non-marine sources only become effective above reflectance levels of 0.7% Ro (Snowdon & Powell, 1982). Some sources can yield oil for migration at maturation levels below 0.7% Ro. Typically these are from marine environments and they contain a high proportion of thermally labile C–S (carbon–sulphur) bonds, which cleave more readily than C–C bonds and can yield enough hydrocarbons at low levels of maturation for migration to occur (Tissot & Welte, 1984). In the terrestrial environment resinite-enriched terrestrial organic matter has been shown to yield enough hydrocarbons to allow migration to occur at low levels of maturation (Snowdon & Powell, 1982). Typically these oils have a high proportion of naphthenic and aromatic components, reflecting the structure of the parent resinite. There are no previously documented cases of low-maturity paraffinic oils, although there are reported cases of low-maturity paraffinic condensates (Connan & Cassou, 1980).

The Methylphenanthrene Indices and biomarker maturation parameters (Fig. 13; Table 2) demonstrate that the Murta oils were generated at relatively low maturity (0.5–0.6% Ro). Further, many of the Murta oils lack the long-chain, waxy n-alkanes characteristic of other oils in the Eromanga Basin. They do have some features in common with the high-wax oils, namely high pristane-to-phytane ratios and abundant alkanes derived from bacterial precursors (Powell 1984). It is this latter aspect which may provide a clue to the formation of these oils. Iso- and anteiso-alkanes are probably derived from bacterial precursors and are relatively abundant in the source facies and the oils compared with the non-source facies (Fig. 11). If pristane is considered to represent hydrocarbons derived from the primary photosynthetic biomass, then the transition in composition from the non-source facies to the source facies can be considered to be due to reworking of the primary photosynthetic biomass and replacement or addition in part by bacterial biomass during deposition. This results in a decrease in pristane content and an increase in the content of low-molecular-weight n-alkanes and iso- and anteiso-alkanes (Figs 11, 12). This process appears to be ubiquitous in non-marine systems and to be particularly effective in laustrine environments (Powell, 1984, 1986). The isotopic composition of hydrocarbon fractions and abundance of branched alkanes in the gasoline-range fraction of Murta oils are also consistent with a microbial source (McKirdy, 1982, 1985).

The thermal lability of bacterial organic matter in this situation is unknown, but the data presented herein suggest that this bacterial organic matter begins to generate hydrocarbons at a lower level of maturity than the terrestrial organic matter with which it is associated. If sufficient hydrocarbons are generated, as in this case, then these hydrocarbons may begin to migrate as a discrete phase. This will be facilitated by intimate interbedding of source and

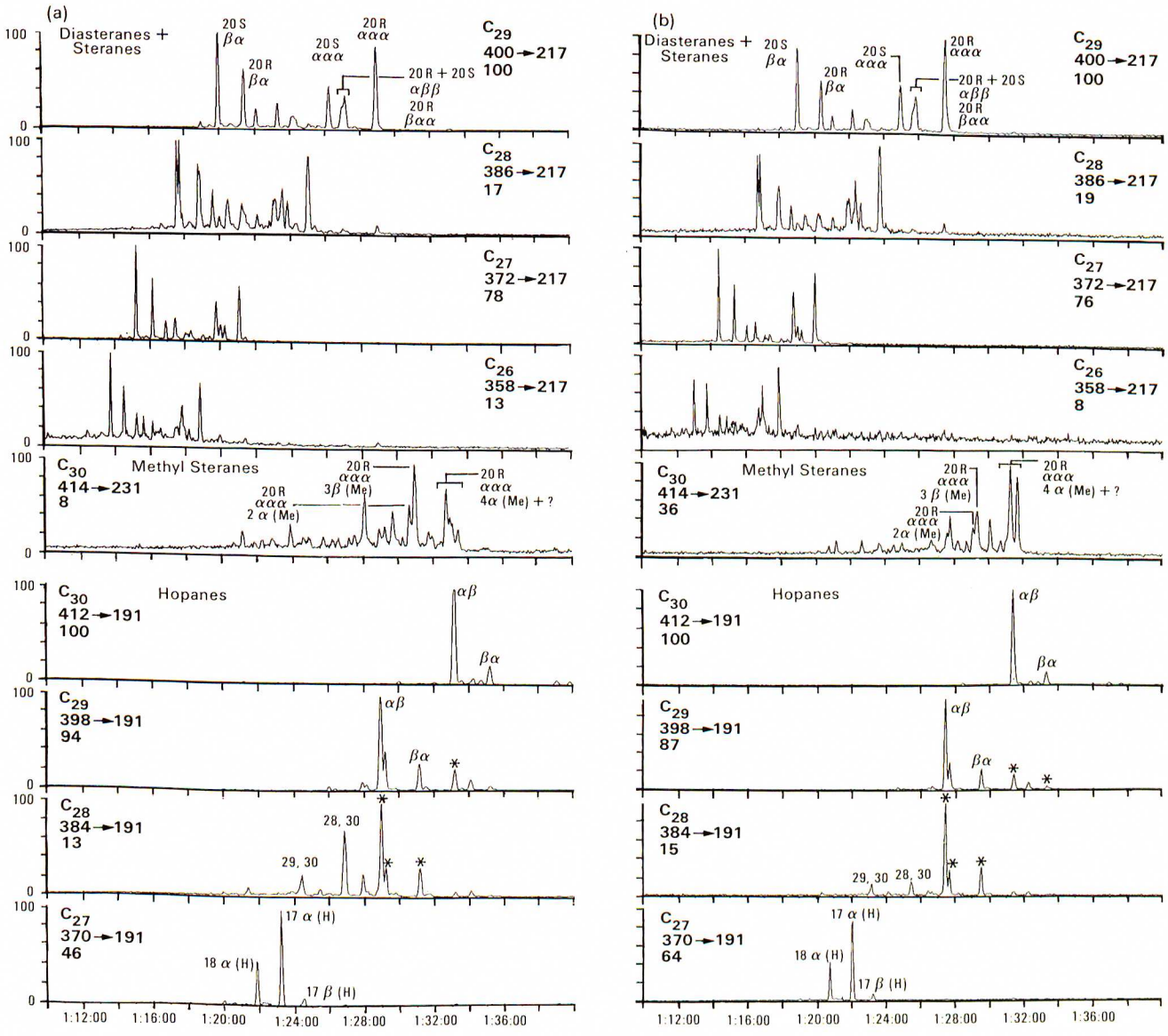

Figure 15. Sterane and pentacyclic hydrocarbon distributions in (a) source facies (Nockatunga 2, 1010.0 m) and (b) non-source facies (Nockatunga 2, 1008.3 m). (Refer to Fig. 14 for explanation.)

reservoir facies, allowing effective drainage of these generally lower quality source beds. As maturation proceeds oil generation will subsequently occur from the associated terrestrial organic matter. Certainly there is no significant difference in pyrolysable hydrocarbon yield and composition between source and non-source samples at present levels of maturation. Similarly the results of hydrous pyrolysis of source and non-source samples shown in Figure 9 indicate basically similar hydrocarbon yields and distribution patterns at higher maturation levels. This scenario would explain the general association of bacterial biomarkers with non-marine oils (Powell, 1984). The Murta oils may therefore represent the earliest maturation products of a more or less conventional non-marine source bed in which the concentration of bacterial organic matter is greater than usual.

CONCLUSIONS

Organic carbon contents of the Murta shales range from 0.54 to 2.51 per cent and are close to the lower limit for effective source rocks. The organic matter is mainly terrestrial in origin but is oil prone, as indicated by elemental analyses, pyrolysis-GC and petrographic study. Source-rock quality is better than Rock Eval data indicate, because of the mineral matrix effect. Several types of maturity data (Tmax, Methylphenanthrene Indices, vitrinite reflectance and biomarker parameters) indicate the

Murta Member is at the threshold of the conventional oil window (vitrinite reflectance *c.* 0.5% Ro). Extractable hydrocarbon yields up to 54 mg/g organic carbon have been obtained on unstained samples, indicating parts of the Murta have fair to good source potential at current maturation levels. Differences between source and non-source facies are attributed to the relative amount of bacterial organic matter preserved in the sediment and are reflected in the proportions of pristane, waxy versus non-waxy n-alkanes and iso- and anteiso-alkanes.

The oils from ATP 267P all show the characteristics shown by previous analyses of Murta oils — namely paraffinic, low wax, and high pristane-to-phytane ratios. Oils from Biala and Limestone Creek differ in having abundant waxy n-alkanes. The distribution of biomarkers, chemical maturation indicators, and overall composition of the saturate fractions all suggest an origin of the low-wax oils from within the Murta Formation at relatively low levels of maturation. Migration from deeper and more mature sources is not required to account for their occurrences. The high-wax oils in the Murta Member have many of the characteristics of the low-wax oils, but a precise source facies for these oils within the Murta Member has not been located at the maturation levels encountered in the Biala - Limestone Creek area. However, the results of hydrous pyrolysis experiments suggest the Murta Member could have been the source at slightly higher maturation levels.

ACKNOWLEDGMENTS

T.G. Powell, R.E. Summons and C.J. Boreham publish with the permission of the Director, Bureau of Mineral Resources, Geology and Geophysics. P. Fletcher, Z. Horvath, A. Juadvalkis, E. Bleys and A. Mussared are thanked for their technical assistance. Z. Roksandic conducted GCMS analyses. Pancontinental Petroleum and partners kindly allowed access to cores and oil samples from ATP 267P. Delhi Petroleum Pty Ltd, Santos Ltd and the South Australian Department of Mines and Energy are thanked for providing samples and data from PEL 5 and 6.

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