Open File Envelope No. 8621

EROMANGA BASIN

GEOLOGICAL STUDIES

REPORTS

Submitted by

Delhi Petroleum Pty Ltd and Santos Ltd
1988

Enquiries: Customer Services
Ground Floor
101 Grenfell Street, Adelaide 5000

Telephone: (08) 8463 3000
Facsimile: (08) 8204 1880

PRIMARY INDUSTRIES AND RESOURCES SA

ENVELOPE 8621

TENEMENT: Not applicable

TENEMENT HOLDER: Not applicable

CONTENTS OF VOLUME ONE

PLAN		Scale	Company plan no.	MESA NO.	
Plate 3	**Magier, P., 1965.** Gamma ray correlation of the Mesozoic (enclosure to missing French Petroleum Company [Australia] Pty Ltd regional geology report no. 505, 9/2/65).	1:2 400	RG505/11	8621-1	*>A0*

REPORTS: **Swindon, V.G. and Moore, P.S., 1984.** Exploration and production, Eromanga Basin, Central Australia (August 1984). — **8621 R 1** Pgs 3-47

Gausden, J., 1979. Landsat interpretation [of the] western Great Artesian Basin (consultant's report for Delhi Petroleum Pty Ltd, June 1979). — **8621 R 2** Pgs 48-60

PLANS		Scale		
Encl. 1	Lineament map.	1:1 000 000	8621-2	*>A0*
Encl. 2	Interpreted structure map.	1:1 000 000	8621-3	*>A0*

CONTENTS OF VOLUME TWO

REPORT: **Moore, P.S., 1984.** Cretaceous stratigraphy of the southwestern Eromanga Basin. Part 1. General introduction, formation tops and log correlation diagrams for the interval Toolebuc Formation to 'C'-Horizon (Delhi Petroleum Pty Ltd, June 1982). — **8621 R 3** Pgs 61-105

PLANS		Scale	Company plan no.		
Encl. 1	Location of log correlation stratigraphic cross-sections (constructed between wells lying within the areas of PELs 5 and 6 and ATP259P).	1:1 000 000	82XG-1332	8621-4	*A0*
Encl. 2	Cross section A-B.	1:1 200	81XG-0747	8621-5	*>A0*
Encl. 3	Cross section C-D.	1:1 200	81XG-0746	8621-6	*>A0*
Encl. 4	Cross section E-F.	1:1 200	81XG-0744	8621-7	*B1*
Encl. 5	Cross section C-H.	1:1 200	81XG-0745	8621-8	*B1*
Encl. 6	Cross section G-J.	1:1 200	81XG-0748	8621-9	*A0*
Encl. 7	Cross section L-K.	1:1 200	81XG-0742	8621-10	*A1*
Encl. 8	Cross section K-N.	1:1 200	81XG-0743	8621-11	*B1*

REPORT: **Taylor S. and Redfearn, J., 1988.** Eromanga [oil exploration] potential of the Nappamerri Trough [Oil Project 88-3] (Santos Ltd, September 1988). — **8621 R 4** Pgs 106-146

CONTENTS OF VOLUME THREE

CONTENTS OF VOLUME FOUR

END OF CONTENTS

Open File Envelope

NUMBER 8621

EROMANGA BASIN

GEOLOGICAL STUDIES

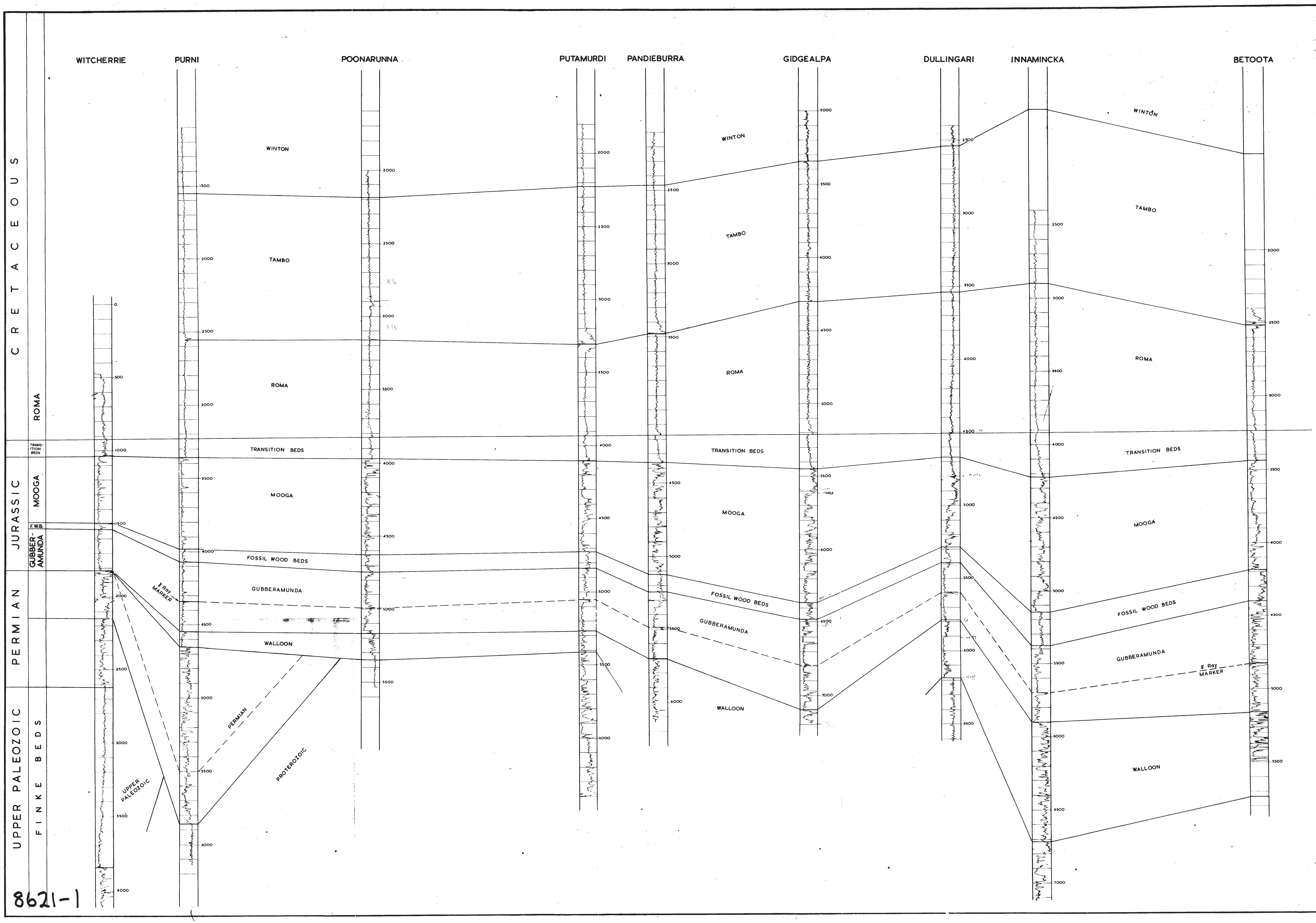
REPORTS

Submitted by

Delhi Petroleum Pty Ltd and Santos Ltd
1988

MINES and ENERGY RESOURCES SOUTH AUSTRALIA

Enquiries: Customer Services
Mines and Energy Resources South Australia
191 Greenhill Road, Parkside 5063
Library Telephone: (08) 8274 7522
General Enquiries Telephone: (08) 8274 7500
Facsimile: (08) 8272 7597



R.G. 505
PL. No. 3

GAMMA RAY CORRELATION OF THE MESOZOIC

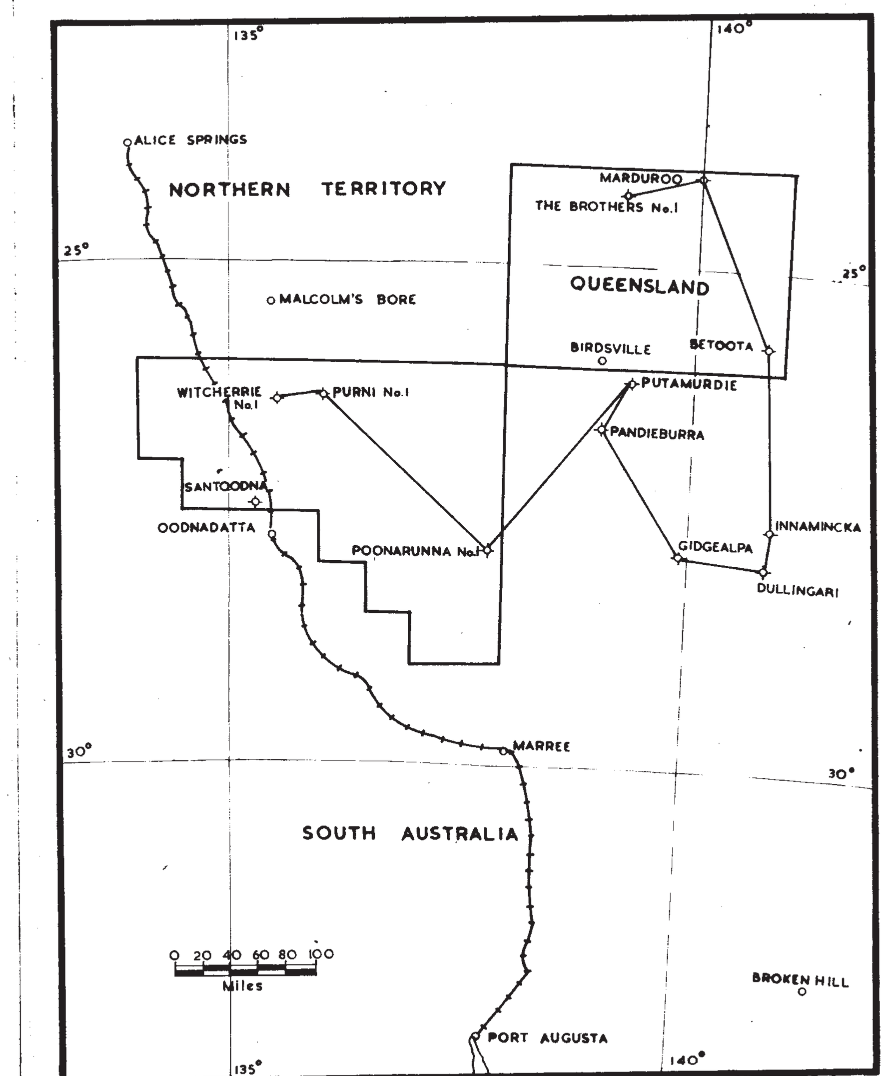
FROM THE DRILLINGS IN THE WESTERN ARTESIAN BASIN

8621-1

NOV. 1964 – JAN. 1965

Ph. M.

R.G. 505/11 9-2-1965 P.V.



0003

EXPLORATION AND PRODUCTION,

EROMANGA BASIN

CENTRAL AUSTRALIA

V.G. Swindon & P.S. Moore
CSR Oil & Gas Division
August 1984
DFL/111/7

Exploration and Production,

Eromanga Basin, Central Australia

by

V.G. Swindon[1] and P.S. Moore[2]

[1] Oil and Gas Division, CSR Limited, 1 O'Connell Street, Sydney NSW, 2000
[2] Delhi Petroleum Pty Ltd, 33 King William St, Adelaide, SA, 5000

ABSTRACT

The Eromanga Basin has an area of about 1 million square kilometres and is the largest of three sub-units of the Great Artesian Basin, which covers one fifth of the Australian continent. The basin contains an Early Jurassic to Late Cretaceous sequence up to 3000 metres thick. It is underlain by several older basins which have influenced Eromanga Basin deposition.

The central part of the Eromanga Basin overlying and adjacent to the Permo-Triassic Cooper Basin is productive of oil and gas. The Cooper Basin contains major gas reserves and some oil. The first Eromanga Basin discovery was made in 1976. This and subsequent discoveries, particularly since 1981, have led to an active exploration and development programme. Two liquids pipelines, totalling over 1700 kilometres, have been completed since October 1982. The region now produces crude oil, condensate, LPG and gas.

The Eromanga Basin contains mainly non-marine, fluviatile and lacustrine sequences. The major discoveries are structurally trapped at the top of thick, braided-fluviatile sandstone bodies (the Hutton and Namur reservoirs). However, some traps are stratigraphic, related to point-bar and lacustrine-delta sandstones. Future exploration is expected to shift increasingly towards the search for stratigraphic traps.

Eromanga Basin crude oils appear to have been generated from marginally mature to early-mature source rocks. High pour point oils typical of

Hutton reservoirs were derived from organic material in spores and resins. Low pour-point oils of the Murta and Namur reservoirs originated from lacustrine, algal-bacterial material. The high pour-point of the bulk of the crude (approximately 23^{o}C) has presented problems in piping the oil 1000 kilometres to the eastern coast refineries. Diluents of low pour-point oils and condensate as well as chemical pour point depressants are used to overcome pumping problems.

The location of the Eromanga Basin fields in a remote arid area, far from logistical services, has provided major engineering challenges. Development of the liquids reserves of the Eromanga Basin and the underlying Cooper Basin commenced in December 1981. To the end of 1986 approximately $2 billion will have been spent on this project.

Exploration coverage in the Eromanga Basin is low. In the prospective central portion, drilling density is less than 6 wells per 1000 square kilometres. The nearest outcrops of the reservoir sections are several hundred kilometres away. Accordingly, exploration relies heavily on subsurface techniques including seismic surveys and regional and detailed structural and stratigraphic analyses. However, exploration activity is increasing. During 1984 approximately 20,000 line kilometres of seismic will have been recorded and 100 exploration wells will have been drilled. This activity reflects a common belief that the Eromanga Basin is the most prospective onshore region in Australia.

INTRODUCTION

The Eromanga Basin is a broad intracratonic downwarp, extending over 1 million square kilometres of central Australia (Fig. 1). The basin contains sediments of Early Jurassic to Late Cretaceous age and attains a maximum thickness of approximately 3 kilometres. Sandstone, siltstone, shale and minor coal were deposited in fluviatile and lacustrine settings, except during the Early Cretaceous when fine-grained marine sediment was deposited during an eustatic rise in sea level.

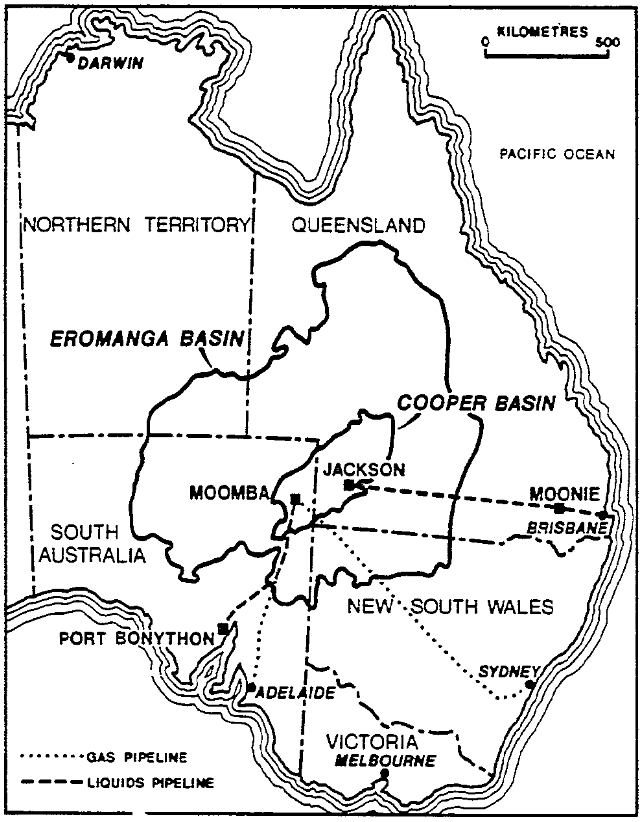


Fig. 1: Location of the Jurassic-Cretaceous Eromanga Basin, central eastern Australia. Moomba was originally constructed in 1968 for the gathering and processing of natural gas produced from the underlying Permo-Triassic Cooper Basin. Oil and natural gas liquids processing facilities were added in 1982-3, in order to produce liquid hydrocarbons from both the Cooper and Eromanga Basins. The liquids are transported from Moomba to Point Bonython via a 659 km pipeline. Only Eromanga Basin oil flows along the second, recently completed pipeline, from Jackson to Moonie. Moonie is the liquids collection centre for the Surat Basin, and has had a pipeline link with Brisbane since 1963.

The first major hydrocarbon discovery in the Eromanga Basin occurred in 1976, 13 years after hydrocarbons had been discovered in the underlying Cooper Basin. Indeed, by 1976, over 300 wells had been drilled in the Permo-Triassic Cooper Basin, resulting in the discovery of 3.5 TCF of gas and 300 million barrels of liquid hydrocarbons. A large gas processing plant had been built at Moomba and gas pipelines serviced the Adelaide and Sydney markets (Fig. 1).

Success followed rapidly once the initial discovery was made in the Eromanga Basin. To the end of August, 1984, 58 oil and 8 gas pools had been discovered, all within the non-marine, Jurassic to earliest Cretaceous part of the sequence. Recent success is attributed to improved exploration techniques and a better understanding of the geology of the basin.

Production of crude oil and condensate from the South Australia section of the Cooper and Eromanga Basins commenced in 1983 following completion of a 659 km pipeline from Moomba to the South Australian coast (Fig. 1). Collection, storage, treatment and wharf facilities also have been constructed at a cost to date of over $1.1 billion, making this project the largest single onshore development programme in Australia. Meanwhile, oil discoveries in the Eromanga Basin at Jackson in Queensland have resulted in the construction of a second oil pipeline which forms part of a 1087 km link from Jackson to Brisbane (Fig. 1). Development costs for the Jackson oilfield facilities and Jackson-Moonie pipeline was estimated at nearly $200 million in June 1984.

The history of exploration and production in the Eromanga Basin is an interesting one which has particular relevance to explorationists working in non-marine, clastic sequences. The discovery mainly of oil, rather than gas, has been of particular interest and the moderately shallow nature of some of the discoveries has promoted much discussion. Finally, the scope and magnitude of the development programme, when placed in an Australian context, is outstanding.

BASIN SETTING

The Eromanga Basin is part of the hydrogeological Great Artesian Basin (Habermehl, 1980). Other constituents are the Carpentaria and Surat Basins, which are linked to the Eromanga Basin across shallow basement ridges (Fig. 2). The Great Artesian Basin is underlain by a variety of rock types constituting older sedimentary basins and cratonised areas. It is overlain by a relatively thin veneer of fluviatile, lacustrine and aeolian sediment assigned principally to the Lake Eyre Basin (Wopfner and Twidale, 1976).

The Great Artesian Basin is one of the world's largest artesian systems, occupying an area of 1.7 million square kilometres or one-fifth of the Australian continent. Confined aquifers occur mainly in fluviatile sandstones of Jurassic and Early Cretaceous age. The basin forms a large synclinal structure, uplifted and exposed along its eastern margin and tilted southwest (Fig. 3). Recharge occurs mainly in the east, with discharge in the south and southwest (Habermehl, 1982a, b, c).

Underlying the Eromanga Basin are several smaller, more highly structured basins of Late Carboniferous to Late Triassic age. The most important of these with respect to petroleum exploration is the Cooper Basin, which consists of up to 2 km of non-marine Permian and Triassic sediment. The Cooper Basin is an important petroleum province and presently supplies about 40% of Australia's domestic gas requirements. Most of this production comes from the coal-rich, fluviatile and lacustrine Permian sequence. The Triassic sequence is dominated by fine-grained redbeds which generally act as a seal, preventing hydrocarbon migration from the Cooper Basin into the overlying Eromanga Basin.

Older, pre-Permian strata beneath the Cooper and Eromanga Basins consist of undeformed to strongly folded and overthrust sediment of Proterozoic, Cambrian, Ordovician and Devonian age. The structure and stratigraphy of these sediments are poorly understood, particularly in areas underlying the central Eromanga Basin (e.g. Wake-Dyster, 1982; Gatehouse, in press; Passmore and Sexton, 1984).

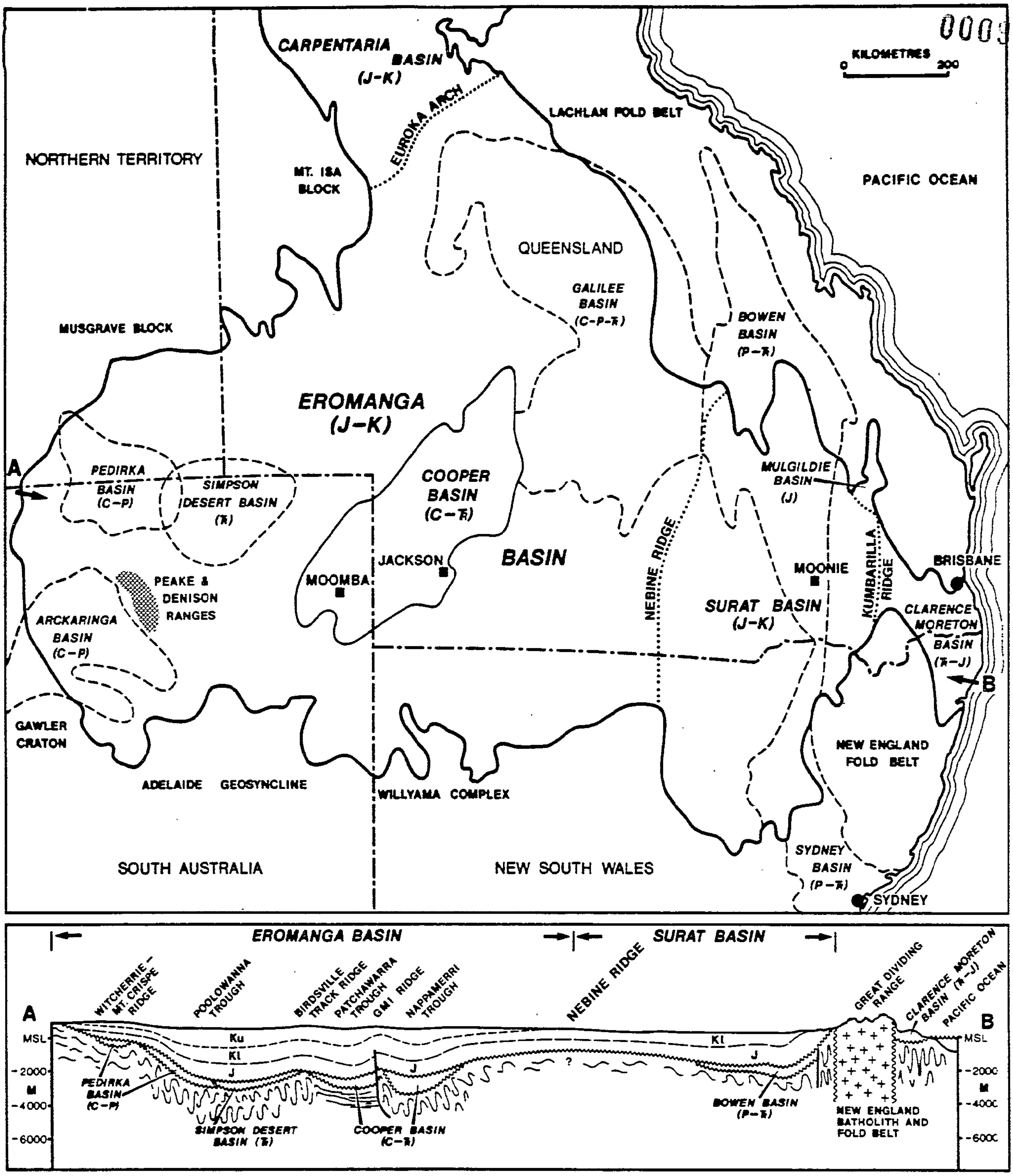


Fig. 2: Geological setting. The Eromanga Basin, together with the Carpentaria and Surat Basins, forms part of the hydrogeological Great Artesian Basin. Several Late Carboniferous to Late Triassic sedimentary basins underlie the Great Artesian Basin and partly control its distribution and sediment thickness. Shaded areas represent pre-Carboniferous outcrops or highly deformed, Permo-Triassic rocks. Cross-section AB is orientated roughly east-west and passes through the deepest parts of the Eromanga and Surat Basins.

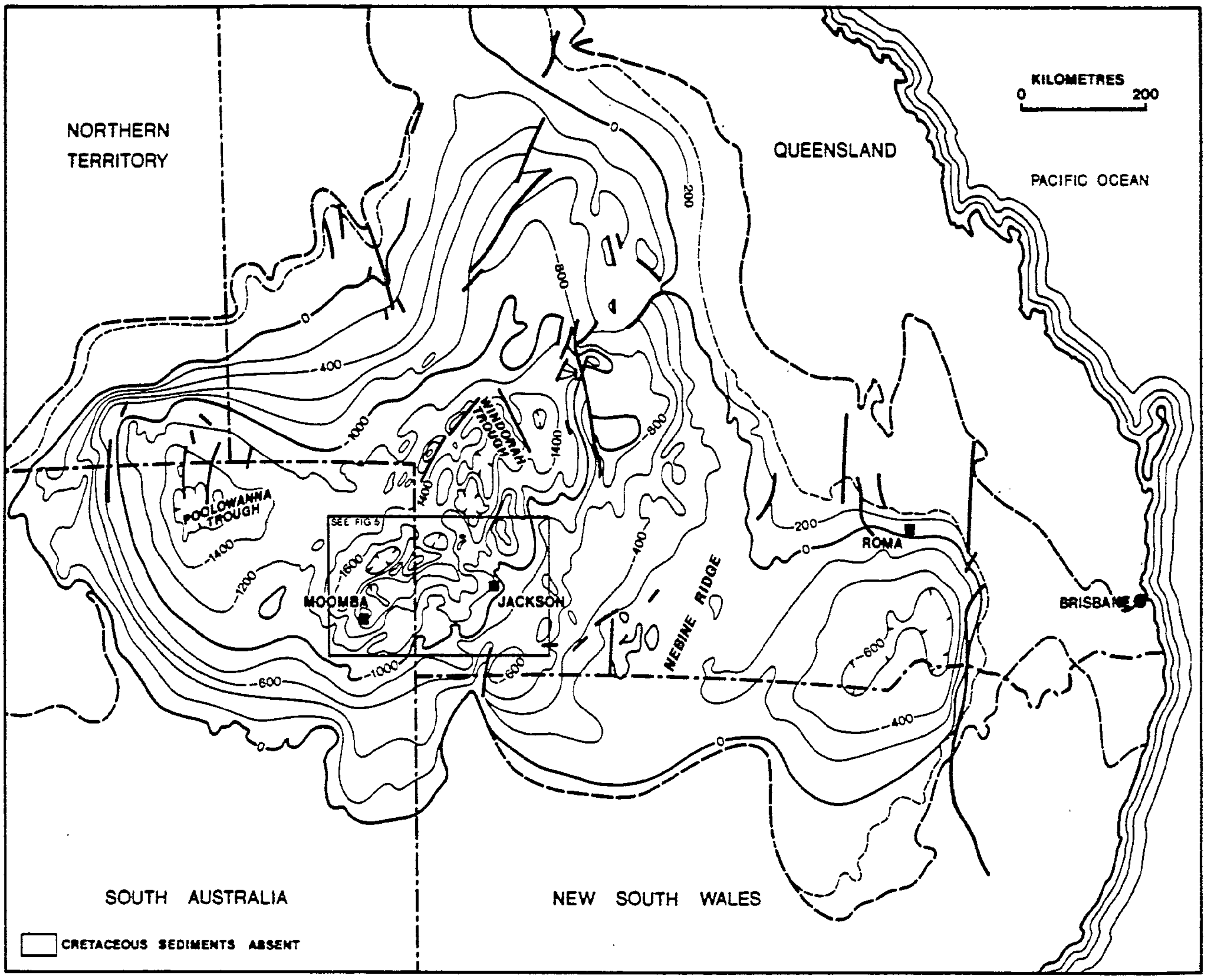


Fig. 3: Structure contour map of the 'C' seismic horizon (base of Bulldog Shale and Wallumbilla Formation) in the Eromanga, Surat and southern Carpentaria Basins.

STRATIGRAPHY AND DEPOSITIONAL ENVIRONMENTS

Stratigraphic relationships, as observed in the subsurface, are summarised in Figure 4. Only the most important formations are listed, since many local names are used to describe facies variations around the margins of the Eromanga Basin. In Figure 4 and in the following text, reference is also made to the Surat Basin, since it is there that many units crop out and have been studied in detail. Furthermore, facies variations between the Eromanga and Surat Basins throw considerable light on the tectonic evolution of the Great Artesian Basin as a whole.

Sedimentation in the Great Artesian Basin commenced roughly synchronously in the Surat and Eromanga Basins. In the Surat Basin the oldest deposit is the braided-fluviatile Precipice Sandstone. According to Martin (1981), cross-bedding orientations indicate transport from the west, while lithological characteristics suggest a metamorphosed Precambrian source which conceivably included the Willyama Complex (Fig. 2). Local desert conditions existed in the Early Jurassic in central Australia, as indicated by wind-faceted pebbles and aeolian quartz grains contained within basal conglomerates of the Algebuckina Sandstone (Wopfner et al., 1970).

The first sediment to be deposited in the Eromanga Basin was laid down in the Poolowanna Trough (Figs 2, 4). The basal unit, known as the Poolowanna Formation (Moore, 1982b, in press) consists of interbedded sandstone, siltstone, shale and thin coal beds, deposited in a moderate energy, meandering fluviatile environment with associated floodplains and swamps. Synchronously, in the Surat Basin the Evergreen Formation was being laid down under slightly more quiescent conditions (Porter, 1979; Wiltshire, 1982). Lacustrine deposits in the upper part of the Evergreen Formation contain acritarch swarms which may indicate a partial connection with the open sea, which lay further to the east (Evans, 1962).

In the late Early Jurassic, deposition expanded beyond the Poolowanna Trough and Surat Basin areas, as indicated by the sporadic development of

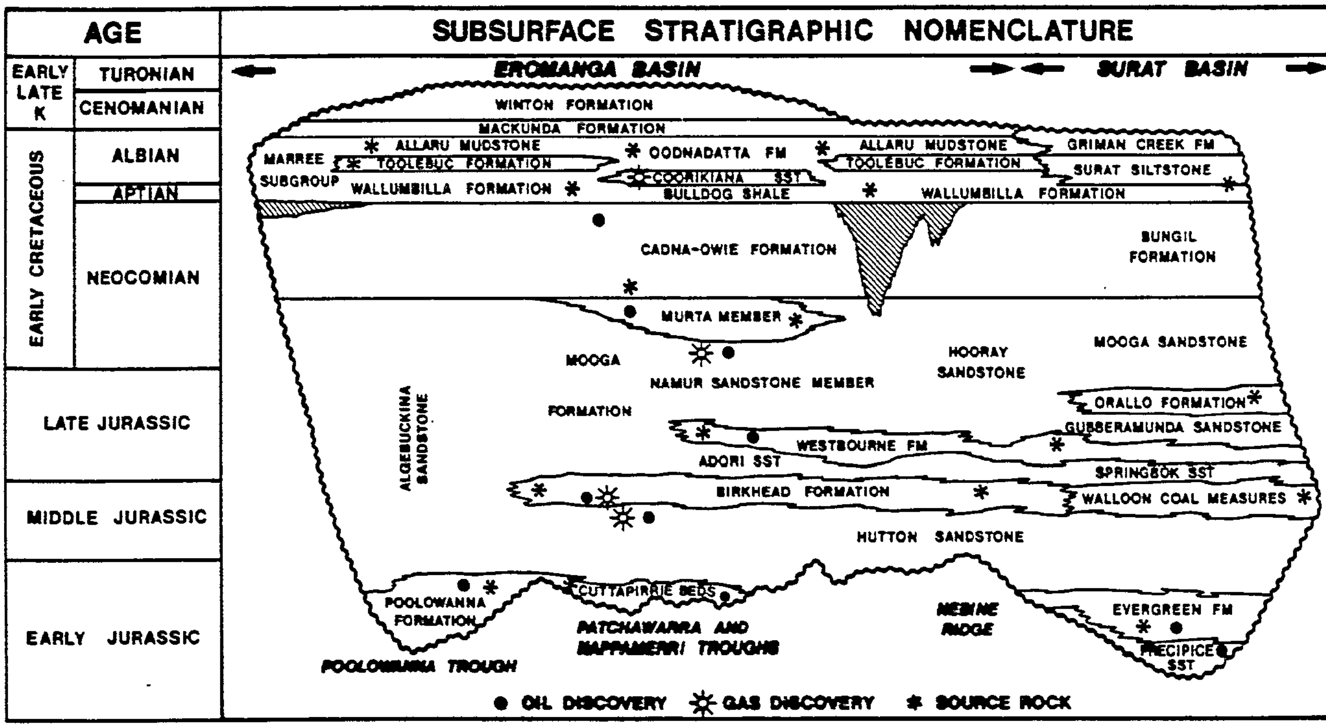


Fig. 4: Major stratigraphic units within the Eromanga and Surat Basins. Line of section (AB) shown in Fig. 2. Cross hatching indicates significant erosion.

low-energy, fluviatile deposits in the central Eromanga Basin ("Cuttapirrie beds", Fig. 4). The Eromanga, Surat and Carpentaria Basins finally were linked in the late Early Jurassic by the development of an extensive, bedload-dominated, sandy fluviatile system which spread over the entire region. Sediment was derived from a generally westerly direction, with the coarsest and mineralogically least mature deposits occurring within the Algebuckina Sandstone (Wopfner et al., 1970). The laterally equivalent Hutton Sandstone is better sorted and rounded, and contains calcrete and silcrete horizons in its upper portions (Gravestock et al., 1983), suggesting that deposition occurred sporadically under warm, probably humid conditions. Further east in the Surat Basin, the Hutton Sandstone consists of lacustrine delta-fill deposits at the base (Wiltshire, 1982) overlain by sandy, bedload-dominated fluviatile deposits (Power and Devine, 1970; Exon, 1976). Throughout the entire Eromanga-Surat Basin area, sediment transport was from the west, northwest and southwest (Exon, 1976; Martin, 1981; Moore, in press).

The great lateral extent of the Hutton Sandstone and other braided-fluviatile units within the Eromanga Basin has puzzled sedimentologists for decades. Exon (1976), studying sequences in the Surat Basin, suggested that their deposition was in response to a sharp, eustatic drop in sea level. He argued that this would cause a sudden change in the base level of erosion resulting in high-energy, braided-fluviatile deposition. Subsequent deposits, formed during periods of stability or rising sea level, would be increasingly finer grained, terminating in lacustrine or swamp conditions. According to Day et al. (1983) this suggestion has considerable merit, because of the tectonic stability of the Australian craton and inferred connection between the low-lying Great Artesian Basin and the open sea to the east. Alternatively, such cycles may be tectonic in origin, resulting from uplift and erosion beyond the basin margins (e.g. Gawler Craton, Wopfner et al., 1970), prior to the onset of rifting between Australia and Antarctica.

However, regardless of their origin, it is apparent that within the Jurassic and earliest Cretaceous sequences of the Great Artesian Basin, laterally extensive braided-fluviatile sandstones occur interbedded with floodplain, swamp and lacustrine deposits. Thus, the braided-fluviatile Hutton Sandstone is overlain by finer-grained floodplain deposits of the Birkhead Formation and swamp deposits of the Walloon Coal Measures. The climate at the time was temperate and moist (Gould, 1980). The succeeding cycles (Adori-Westbourne and Gubberamunda-Orallo; Fig. 4) are similar although less pronounced, with the latter being confined to the finer-grained Surat Basin sequence. The Murta Member has no lithological equivalent in the Surat Basin, and is lacustrine in origin (Nugent, 1969; Mount, 1981, 1982; Ambrose et al., 1982).

Non-marine sedimentation probably persisted until the end of the Neocomian, although a marine influence has been suggested for the upper sandy part of the Cadna-owie Formation and its lateral equivalent (the Bungil Formation) in the Surat Basin (Day et al., 1983; Moore and Pitt, in press). A major marine transgression occurred in the earliest Aptian and deposited mudstone throughout the area. Large channels incised into the Cadna-owie Formation at the end of the previous regressive phase also appear to have been filled with fine-grained marine sediment (Moore and Pitt, 1984).

The Aptian to Albian marine sequence is up to 700m thick in the Eromanga Basin and is relatively homogeneous, apart from the Toolebuc Formation which locally develops oil shale facies (Ozimic, 1982) and the Coorikiana Sandstone, which is a thin shoreface sandstone (Moore and Pitt, 1982). Overlying this sequence is the Mackunda Formation, which is a marginal marine, regressive sandy siltstone. Finally, non-marine sedimentation dominated in the Cenomanian, with the deposition of the 1000m thick coal-bearing, fluviatile Winton Formation.

EXPLORATION METHODS

The style of exploration in the Eromanga Basin is influenced by its large size and remote setting. Initially, areas are assessed using outcrop data, photogeology, Landsat imagery and gravity and aeromagnetic data. Resulting interpretations provide the basis for orientation of regional seismic lines, which in some cases are up to 25 km apart. Attractive structural leads are evaluated using a semi-detailed seismic grid. Drilling targets are normally defined by a detailed seismic grid, using a 1 km spacing. This tight grid is necessary to locate the characteristically small hydrocarbon pools of the Eromanga Basin.

Modern seismic surveys typically use the Vibroseis method, due to its competitive price and superior results. Geoflex cord, previously used extensively for regional surveys and in areas of large sand dunes, also is used to a minor extent, while dynamite data are recorded in areas where access is a problem, such as on the soft ephemeral saline lakes of the Australian interior.

Vibroseis data recorded by the major operator (Delhi Petroleum Pty Ltd) are typically 24-fold, 96 trace, with 37.5m geophone group interval spacing. Data acquisition and processing are aimed at delineating mainly structural targets at a depth corresponding to 1.0 to 2.0 seconds two-way time. Wavelet processing is generally not applied, although single sweeps are recorded for future use in more detailed structural and stratigraphic analysis. Twelve second sweeps are used, with 5 sweeps per vibration point. Due to the very gentle dips of much of the Eromanga Basin sequence, only about 40 - 50% of the data are migrated.

Static problems, related to the high variability of near-surface weathering, are a major concern in the delineation of subtle traps. At present, static control is provided by the use of multiple upholes at 1.5 km spacing on regional lines, and 1 km on detailed surveys. Recently introduced field processing units provide early warning of static problems and enable more efficient location of uphole surveys. The field processing units can also provide early indications of prospective exploration targets and allow an immediate response.

During 1984, up to 12 seismic crews were active within the Eromanga Basin, providing locations for a maximum of 19 drilling rigs. Most of this activity was concentrated over the most prospective Cooper Basin area where the sequence is thickest and most mature for oil generation. In these areas, where there are dual Permian and Jurassic objectives, wells may penetrate up to 12,000 feet of strata and take over two months to drill. More characteristically however, exploration wells in the Eromanga Basin are 5000 - 8000 feet deep, and take between 2 and 4 weeks. Typically, a 12 1/4 inch hole is drilled to 600 feet and cased with 9 5/8 inch surface casing. The remaining hole is 8 1/2 inch diameter, suitable for 7 inch production casing.

The Eromanga Basin sequence yields relatively few drilling problems. The sequence is, in general, normally pressured and can be drilled using a gel-lignosulphate mud system. More expensive KCL-polymer muds are used mainly in shallow wells or areas of lower geothermal gradient, where they help control swelling and caving of shaly marine Cretaceous units. The Tertiary and marine Cretaceous sequence is drilled using journal-bearing tooth bits and the rest of the sequence using roller-bearing, tungsten-carbide insert bits. Strata-pax bits are not widely used, due to the lithological variability of the sequence.

Onsite geological monitoring is conducted from surface casing shoe to total depth, using a standard, two-person mudlogging unit. Formation evaluation is by open hole, straddle or cased-hole testing. The repeat-formation-tester (RFT) provides useful pressure data, but is not often used because of sample-chamber contamination by mud filtrate in the porous Jurassic reservoirs.

Full-hole cores (30 to 60 feet in length) are normally taken after a successful open hole drill-stem test. On completion of the hole, a 10 foot basement core is usually cut. The standard logging suite includes gamma ray (GR), sonic (SLS), resistivity (DLL-MSFL), lithodensity (LDT), neutron (CNL), spontaneous potential (SP) and caliper logs. Sidewall cores are collected for palynological and other evaluation purposes. Other logs, such as the microlog (ML), dipmeter (HDT, SHDT), natural-gamma-ray spectroscopy tool (NGS) and electromagnetic propagation tool (EPT) may also be run, depending upon special circumstances and problems. The main problems affecting wireline-log interpretations are the poor resistivity contrasts between oil and fresh-water-bearing zones, and the difficulties of evaluating thin and shaly sandstones. Another significant problem lies in the high gamma-ray response of some sandstones due to local concentrations of potash feldspar, muscovite and, in some cases, zircon (Halyburton and Robertson, 1984).

Overall, the 1984 cost of data acquisition in the Eromanga Basin is approximately \$2700 - \$3000 per kilometre of seismic survey and between \$600,000 and \$1,500,000 for an average-depth exploration well. Interpretation costs are additional and involve the employment of over 200 geoscientists in nearly 50 companies.

HYDROCARBON DISCOVERIES

Hydrocarbon discoveries have been made at eight stratigraphic horizons within the Eromanga Basin (Fig. 5; Table 1). All commercial discoveries are located within the non-marine, Jurassic to earliest Cretaceous part of the sequence (Fig. 2). Most of the traps are anticlinal although some are stratigraphic.

The first Eromanga Basin discovery was in 1976, when gas flowed to surface at the rate of 13.9 million cubic feet per day (MMCFD) from the Namur Sandstone Member in the Namur 1 well. At the time, it was believed that the gas has a Permian source and has migrated to its present site up a

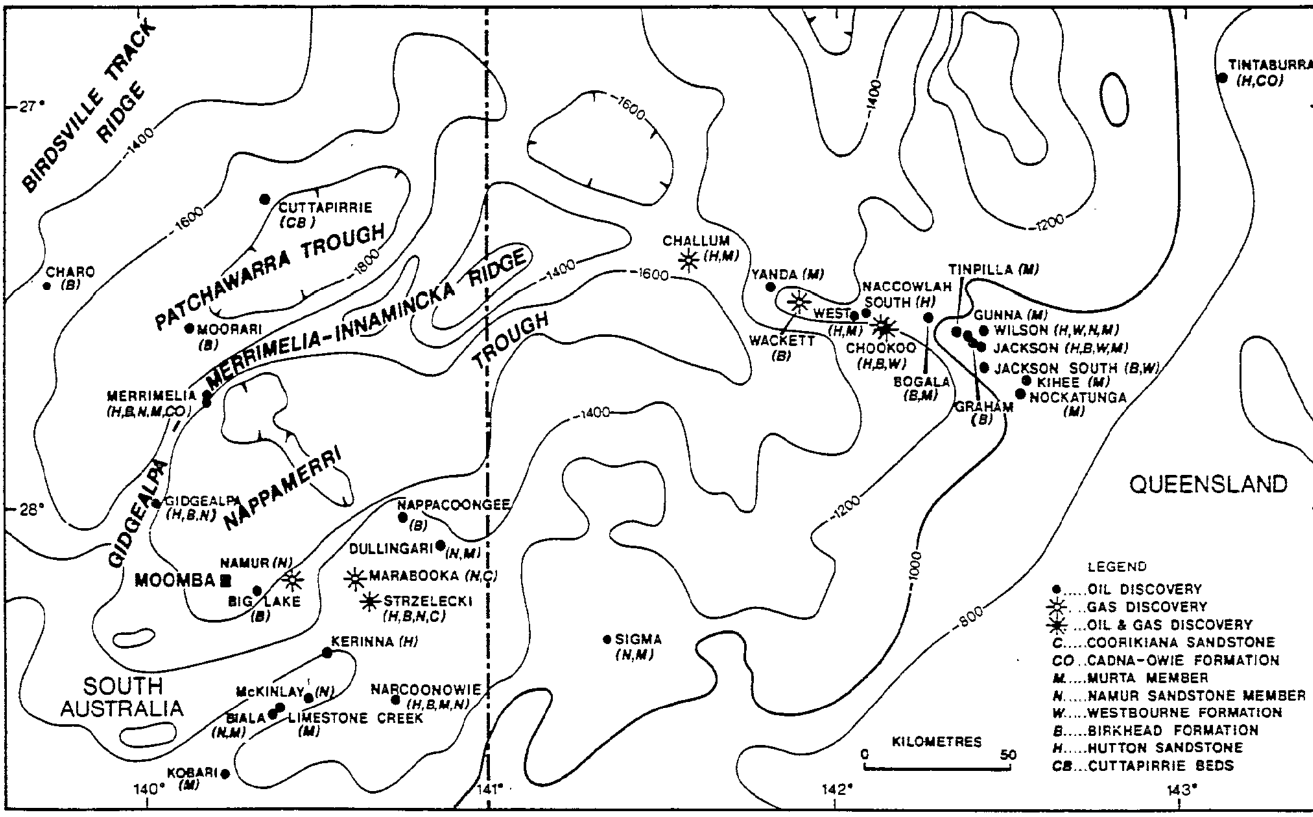


Fig. 5: Location of Eromanga Basin hydrocarbon discoveries. The Poolowanna oil discovery (Poolowanna Trough) is shown in Fig. 11. Oil discoveries are defined as a flow to surface or a measurable recovery of oil in the drillpipe following a drill-stem test (Table 1). Not all discoveries are presently economically producible and some have yet to be evaluated by appraisal drilling.

TABLE 1: EROMANGA BASIN HYDROCARBON DISCOVERIES

Discovery Well	Discovery Date	Hydrocarbon Type	Oil Character: Gravity (°API)	Oil Character: Pour Point (°C)	Gas Character: CO_2 (%)	Gas Character: C_{3+} (%)	Flow Rate or Recovery
A. Poolowanna Formation							
Poolowanna 1	1977	oil	37	41	-	-	Rec 840m O; 840m W
B. Cuttapirrie Beds or 'basal Hutton'							
Cuttapirrie 1	1980	oil	50	- 2	-	-	160 BOPD
Bodalla South 1	1984	oil	47	n.a.	-	-	2000 BOPD
C. Hutton Sandstone							
Strzelecki 4	1978	oil	44	14	-	-	3170 BOPD
Merrimelia 6	1981	oil	55	- 5	-	-	2738 BOPD
Jackson 1	1981	oil	40	20	-	-	2375 BOPD
Chookoo 1	1983	gas;oil	50	-25	2	14	7.4 MMCFD; 483 BOPD
Narcoonowie 2	1983	oil	52	-12	-	-	not tested
Naccowlah South 1	1983	oil	48	16	-	-	1395 BOPD
Wilson 1	1983	oil	40	18	-	-	163 BOPD
Naccowlah West 1	1983	oil	41	18	-	-	144 BOPD
Challum 1	1984	gas	-	-	3	4	8.9 MMCFD
Tintaburra 1	1984	oil	n.a.	n.a.	-	-	1750 BOPD
Bodalla South 1	1984	oil	n.a.	n.a.	-	-	883 BOPD
Kerinna 1	1984	oil	42	30	-	-	Rec 751m O
Gidgealpa 17	1984	oil	48	n.a.	-	-	3200 BOPD
D. Birkhead Formation							
Wackett 1	1978	gas	-	-	2	6	2.2 MMCFD
Strzelecki 3	1978	oil	45	8	-	-	Rec 64m O
Nappacoongee 2	1979	oil	45	11	-	-	Rec 61m O, 1005m W
Moorari 3	1981	oil	51	n.a.	-	-	Rec 13 bbl O
Jackson South 1	1982	oil	41	23	-	-	Rec 137m O, 396m MW
Big Lake 26	1982	oil	48	9	-	-	150 BOPD
Merrimelia 9	1982	oil	53	- 5	-	-	Rec 15 bbl O
Narcoonowie 2	1983	oil	n.a.	n.a.	-	-	not tested
Chookoo 2	1983	gas	-	-	2.4	6	1.1 MMCFD
Jackson 18	1983	oil	40	22	-	-	Rec 6m O
Mudera 2	1984	oil	47	3	-	-	Rec 178m O
Charo 1	1984	oil	48	6	-	-	Rec 317m O, 204m W
Bogala 1	1984	oil	47	9	-	-	Rec 283m O, 125m MO
Graham 1	1984	oil	37	n.a.	-	-	Rec 138m O
Gidgealpa 17	1984	oil	53	n.a.	-	-	Rec 83m O, 120m M
E. Westbourne Formation							
Jackson 1	1981	oil	41	19	-	-	1165 BOPD
Jackson South 1	1981	oil	41	18	-	-	750 BOPD
Wilson 1	1983	oil	42	16	-	-	707 BOPD
Chookoo 1	1983	oil	47	- 3	-	-	5 BOPD
F. Namur Sandstone Member							
Namur 1	1976	gas	-	-	5	2	13.9 MMCFD
Strzelecki 4	1981	oil	48	17	-	-	200 BOPD
McKinlay 1	1981	oil	41	15	-	-	9 BOPD
Dullingari 22	1982	oil	57	n.a.	-	-	1994 BOPD
Marabooka 2	1982	gas	-	-	4	6	7 MMCFD
Merrimelia 8	1982	oil	51	- 5	-	-	440 BOPD
Narcoonowie 2	1983	oil	53	-15	-	-	1275 BOPD
Wilson 1	1983	oil	54	-22	-	-	Rec 1132m O
Sigma 1	1983	oil	45	10	-	-	Rec 350m O
Biala 1	1984	oil	41	18	-	-	201 BOPD, 1205 BWPD
Gidgealpa 17	1984	oil	43	n.a.	-	-	260 BOPD, 720 BWPD

TABLE 1: EROMANGA BASIN HYDROCARBON DISCOVERIES (Cont.)

Discovery Well	Discovery Date	Hydrocarbon Type	Oil Character: Gravity (°API)	Oil Character: Pour Point (°C)	Gas Character: CO_2 (%)	Gas Character: C_{3+} (%)	Flow Rate or Recovery
Murta Member							
Dullingari North 1	1979	oil	57	- 3	-	-	450 BOPD
Merrimelia 6	1981	oil	51	- 5	-	-	443 BOPD; 679 BWPD
Jackson 1	1981	oil	51	0	-	-	338 BOPD
Kihee 1	1982	oil	n.a.	n.a.	-	-	Rec. oil
Nockatunga 1	1983	oil	n.a.	n.a.	-	-	Flowed OTS
Gunna 1	1983	oil	47	- 8	-	-	Rec 219m O
Sigma 1	1983	oil	45	9	-	-	Rec 722m O
Wilson 1	1983	oil	47	-12	-	-	Rec 546m O
Tinpilla 1	1983	oil	48	n.a.	-	-	Rec 415m O
Naccowlah West 1	1983	oil	48	- 9	-	-	120 BOPD
Challum 1	1983	oil	60	-22	-	-	Rec 15m O, 91m OM
Yanda 1	1984	oil	44	8	-	-	Rec 18m MO
Bogala 1	1984	oil	48	0	-	-	Rec 694m O, 415m OM
Limestone Creek 1	1984	oil	42	18	-	-	332 BOPD
Biala 1	1984	oil	42	18	-	-	Rec 15.5 bbl O
Narcoonowie 3	1984	oil	56	n.a.	-	-	Rec 666m O, 35m [illegible]
Kobari 1	1984	oil	43	n.a.	-	-	53 BOPD
H. Cadna-owie Formation							
Merrimelia 15	1983	oil	46	4	-	-	Rec 9m O, 12m OM
Tintaburra 1	1984	oil	n.a.	n.a.	-	-	Rec 12m O, 18m W
Coorikiana Sandstone							
Strzelecki 8	1982	gas	-	-	0.7	7	0.38 MMCFD
Marabooka 3	1984	gas	-	-	n.a.	n.a.	0.65 MMCFD

Abbreviations:

n.a. is not available
Bbl is barrels
Cond. is condensate
BOPD is barrels of oil per day
BWPD is barrels of water per day

MMCFD is million cubic feet of gas per day
Rec is recovered
O is oil
W is water

MO is muddy oil
MW is muddy water
OM is oily mud
OTS is oil to surface

fault. In 1977, Poolowanna 1 flowed a small amount of viscous, waxy oil from the Poolowanna Formation in the Simpson Desert region. Both discoveries aroused interest in the Jurassic sequence, although they were not representative of the discoveries which followed.

The first major oil discovery occurred in 1981, when the Strzelecki 3 well flowed at the rate of 2400 barrels of oil per day (BOPD) from the Hutton Sandstone (Fig. 6A). By then, it was realised that oil could be sourced from within the Jurassic sequence and trapped at several different horizons. Also, it was becoming apparent that Jurassic reservoirs were areally quite small (average 1000-3000 acres), requiring a tight (1 km) seismic grid to accurately locate the crest of the anticlines.

Exploration in the period 1978-1981 resulted in several successes, the most notable of which was the discovery of a stratigraphic accumulation of oil in the Murta Member in Dullingari (Mount, 1981). The reservoir sand is a lacustrine-beach deposit less than 1m thick (Fig. 6B). However, the sandstone has excellent reservoir properties, with porosities of about 16%, permeabilities of up to 3 darcies and flow rates in excess of 2000 BOPD (Mount, 1982).

In December 1981, the Jackson oilfield was discovered in southwestern Queensland (Halyburton and Robertson, 1984). Oil was found at three stratigraphic horizons, although the largest accumulation occurred in the Hutton Sandstone (Fig. 6C). This was the first oil discovery in the Queensland portion of the Eromanga Basin and the largest discovery to date. At 31st March 1984, total proved and probable reserves in the Jackson Field were estimated by Delhi Petroleum Pty Ltd at 42 million barrels of oil, of which 38 million barrels were contained in the Hutton Sandstone. The Jackson discovery was particularly significant since it established the potential of the Jackson-Naccowlah trend, which flanks the northeastern end of the Nappamerri Trough. Seventeen oil and 3 gas pools have since been discovered along this trend (Table 1), with exploration still in progress.

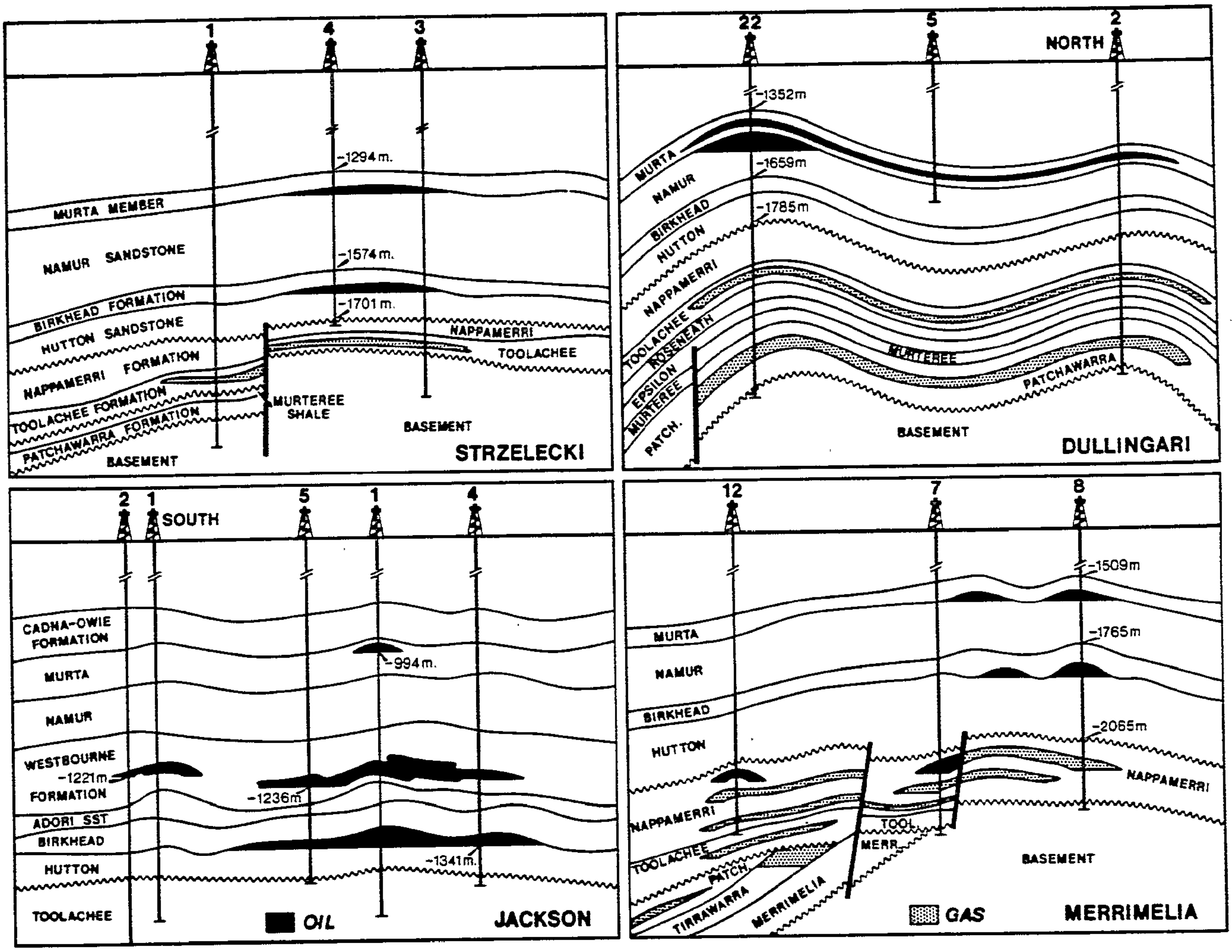


Fig. 6: Geological cross-sections of the Strzelecki, Dullingari, Jackson and Merrimelia Fields. Field locations shown in Fig. 5.

Meanwhile, in South Australia additional wells were being drilled to intersect the crests of structures which previously had been drilled down-dip and had either proved to be dry or were established Permian gas fields. Thus, small pools of oil were discovered in Dullingari 22, Merrimelia 6, 8 and 9, Strzelecki 3 and 4, Big Lake 26, and Narcoonowie 2.

At August 1984, 58 oil and 8 gas pools had been discovered in the Eromanga Basin, with proved and probable in-place hydrocarbons totalling over 250 million barrels of oil and 75 BCF of gas. Most of the the hydrocarbons are contained within structural traps at the top of the Hutton Sandstone, particularly along the Jackson-Naccowlah trend. While the majority of the discoveries are located around the flanks of the mature Nappamerri Trough, recent oil discoveries in Tintaburra 1, Charo 1 and Bodalla South 1 (Fig. 5) have led to a reappraisal of the potential of the Eromanga Basin.

PETROLEUM TYPE

To date, there have been 66 hydrocarbon discoveries within the Eromanga Basin (Table 1). The discovery ratio of oil to gas is approximately 8 to 1.

Eromanga Basin oil is typically light (41° to 51° API) and paraffinic (Fig. 7). Oils in the Poolowanna, Hutton, Birkhead and Westbourne Formation reservoirs tend to have a variable and sometimes high wax content, as indicated by their moderate to high pour point (commonly about $20^{\circ}C$). These oils also tend to be rich in C_{21-27} alkanes (Fig. 8b). In contrast, oils from the Namur Sandstone Member and Murta Member tend to be condensate-like, with a very low pour point ($-5^{\circ}C$ to $0^{\circ}C$), light colour and mild petroliferous odour. These oils have a low wax content and are rich in C_{6-12} alkanes (Fig. 8a).

Gas in Eromanga Basin reservoirs has a modest content of higher hydrocarbons (typically less than 10% C_{3+}), and a low CO_2 content. Carbon isotopic compositions of methane fall within the narrow range of $\delta^{13}C$ = -31 to -34%, and are thus indistinguishable from underlying Permian gases.

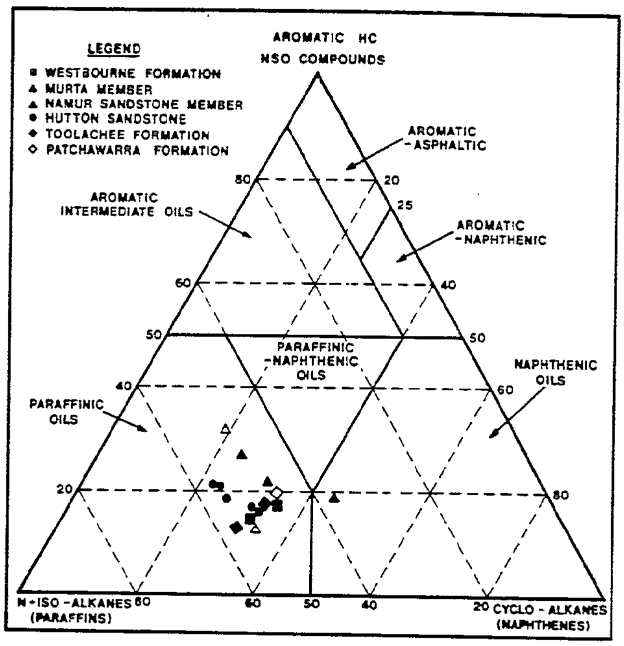


Fig. 7: Gross composition of some Eromanga Basin oils. The oils are typically paraffinic, with Murta oils being the least mature. Cooper Basin (Toolachee and Patchawarra Formation) oils and condensates (plotted for comparison) have a similar composition).

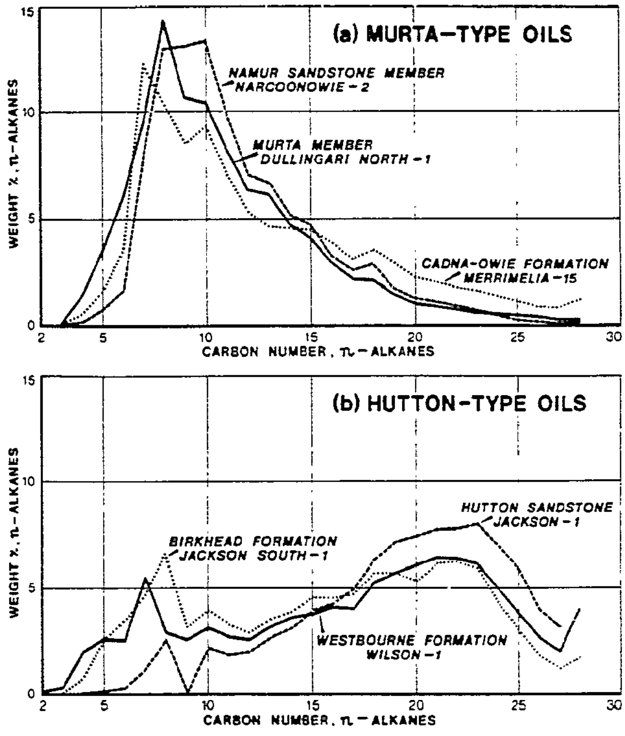


Fig. 8: Alkane abundance distributions of some Eromanga Basin oils. Murta-type oils (Fig. 8a) are rich in C_{6-12} n-alkanes, due to their microbial origin. Hutton-type oils (Fig. 8b) are rich in C_{20-24} n-alkanes, due to their woody-herbaceous origin.

PETROLEUM ORIGIN

Detailed geochemical studies have been carried out on hydrocarbons and source rocks from the Eromanga Basin. Source-rock studies include total-organic-carbon determinations, Rock-Eval pyrolysis, liquid chromatography of extractable organic matter, gas chromatography of alkanes, and GC-MS analysis of rock-extract naphthenes. Hydrocarbon analyses include determination of physical properties, bulk compositional studies, n-alkane analysis, carbon-isotope determinations and GC-MS analysis of oil naphthenes. The results of some of the studies have been published by McKirdy (1982), Moore (1982a) and Kantsler et al. (1983).

Analysis has revealed that the Murta-type oils (present in the Cadna-owie Formation, Murta Member and Namur Sandstone Member) were generated from predominantly algal-bacterial and degraded terrestrial organic matter, at maturation levels as low as 0.4% VR (vitrinite reflectance). The source of the oil is thus believed to be lacustrine shales which characterise the Murta Member, particularly in the lower portion (Fig. 9; Mount, 1981, 1982). Other horizons which have the potential to generate this type of oil are the basal portions of the Cadna-owie Formation and an organic-rich shale immediately overlying the Cadna-owie Formation (Moore and Pitt, 1984; McKirdy et al., in press). The relatively low maturation levels of the Murta oils, as revealed by GC-MS analysis (McKirdy, written comm. 1984) is consistent with the fact that the oil accumulations are located in marginally mature to early mature (VR = 0.45 - 0.65%) sequences. Negligible migration is indicated by stratigraphic entrapment of oil at Dullingari (Mount, 1981, 1982) and is supported by GC-MS results.

Hutton-type oils (from the Westbourne and Birkhead Formations and Hutton Sandstone) have a mixed source, with a minor algal-bacterial contribution and a predominant land plant origin. The higher wax content of some of the oils is due to their terrigenous source affinity and may be emphasised by depletion of light, gasoline-range hydrocarbons by in-situ water

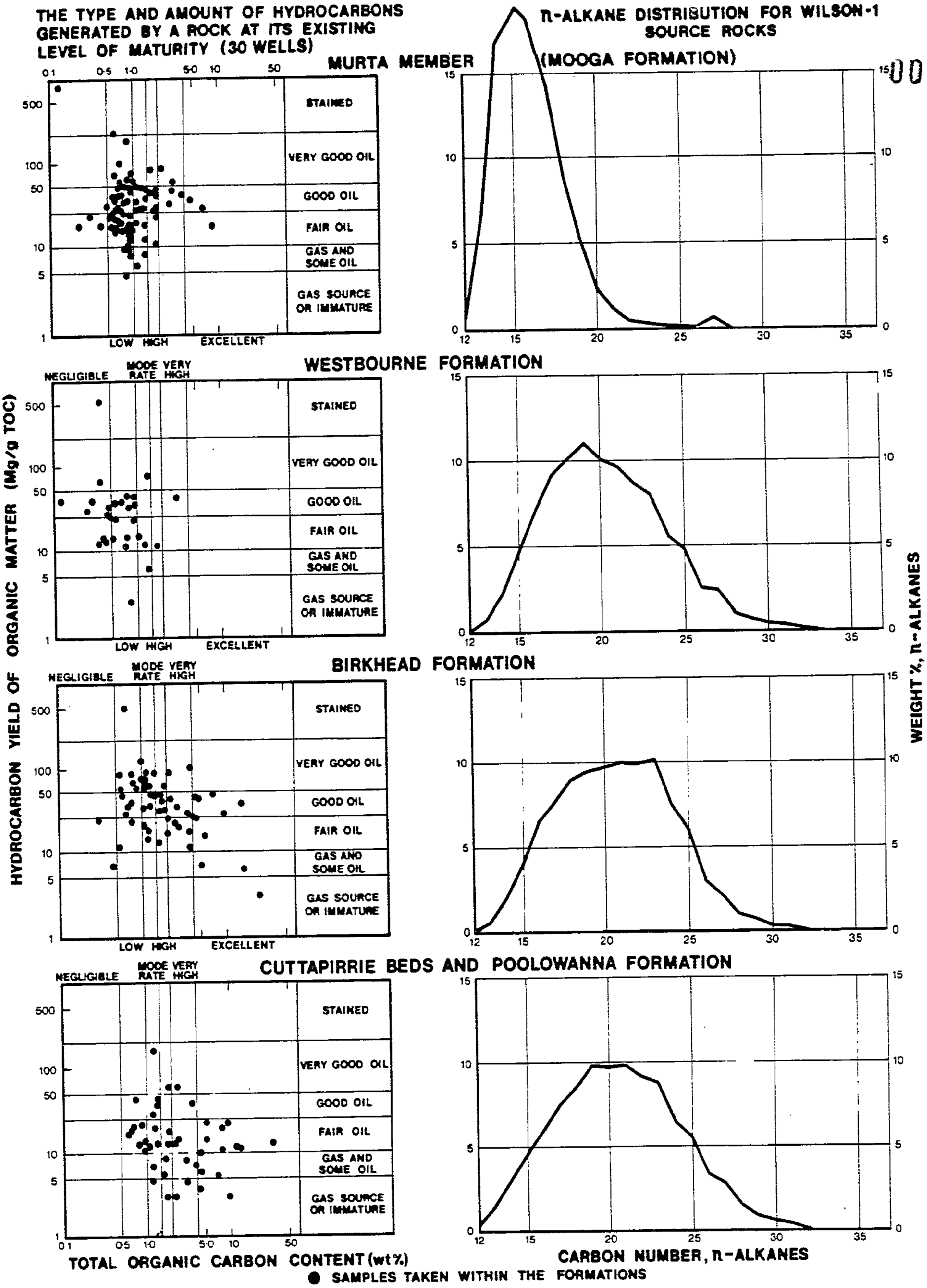


Fig. 9: Characterisation of source rocks from the Murta Member, Westbourne Formation, and Birkhead Formation, Cuttapirrie Beds and Poolowanna Formation. Plots on the left hand side summarise results from 30 wells in the Eromanga Basin. The cross-plot of total-organic-carbon (TOC) with hydrocarbon yield gives and indication of the type and amount of hydrocarbons likely to be generated from the source rocks. Graphs on the right hand side are

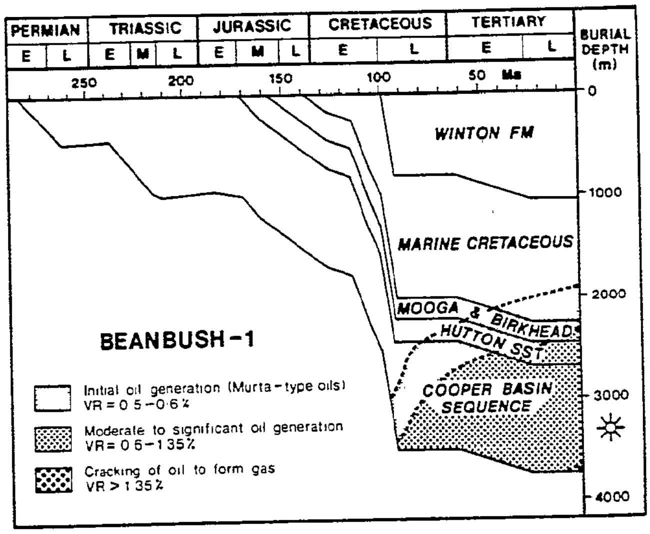
washing. Mixed source types occur both within the Jurassic sequence and in the underlying Permian Cooper Basin sediments (Fig. 9) and thus the source of the oil (Permian or Jurassic) is uncertain. GC-MS work has so far failed to adequately resolve the problem. According to McKirdy (written comm. 1984) "the remarkably uniform sterane and hopane distributions of the oils and rock-extracts makes precise oil source correlations difficult, if not impossible...using these particular biomarkers."

Gas in Jurassic reservoirs at Namur (Namur Sandstone), Wackett (Birkhead Formation), Packsaddle (Murta Member), Chookoo and Challum (Hutton Sandstone) contains methane which is isotopically similar to that of Permian-sourced methane found elsewhere in the Cooper Basin (Rigby and Smith, 1981). On this basis, Kantsler et al. (1983) and McKirdy (written comm. 1984) have argued that the gas has a Permian source. However, the gas is low in CO_2 and relatively rich in higher hydrocarbons (Table 1) and, in this respect, has a character of its own. On present evidence, it is still uncertain whether the gas has a Permian of Jurassic source.

HYDROCARBON GENERATION, MIGRATION AND ENTRAPMENT

Murta-type oils are assumed to have been generated mainly from lacustrine shales of the Murta Member at levels of maturation equal or greater than 0.5% vitrinite reflectance. As stated above, uncertainty exists regarding the main source of the Hutton, Birkhead and Westbourne oils. However, it is likely that the Birkhead and Westbourne Formations contain source rocks, with the underlying Permian sequence also contributing gas and at least some oil to the Hutton Sandstone accumulations.

The timing of hydrocarbon generation in the Eromanga Basin is largely controlled by variations in depth of burial and palaeogeothermal gradient. For example, in the central Nappamerri Trough where conditions for generation were most favourable, the lower part of the Jurassic sequence reached the stage of initial maturation in the early Late Cretaceous, about 90-100 million years ago (Fig. 10). Elsewhere, maturation levels sufficient for



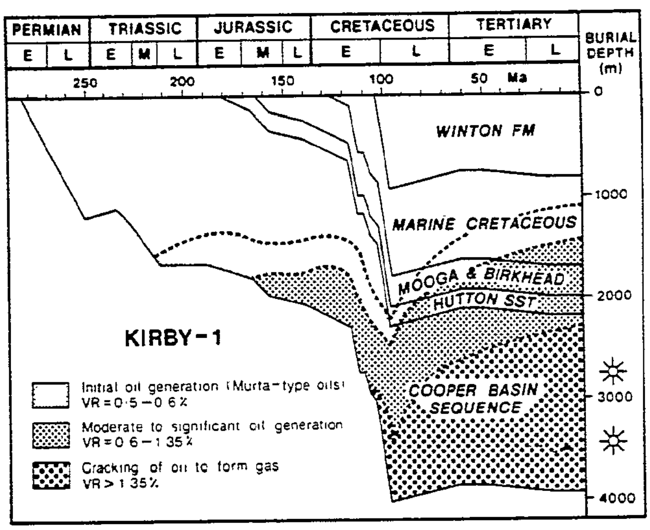


Fig. 10: Burial and maturation histories for 2 wells in the Cooper and Eromanga Basins. Beanbush 1 is located in a relatively low geothermal gradient area, in the central Patchawarra Trough. Kirby 1 is located in a high geothermal gradient area, towards the centre of the Nappamerri Trough.

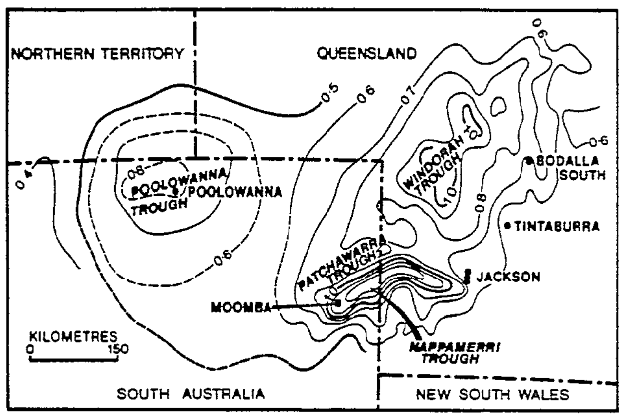


Fig. 11: Maturation levels at the base of the Eromanga Basin sequence, as determined by vitrinite reflectance data. Note the high values associated with the Nappamerri Trough, northeast of Moomba. The elevated values are due mainly to high geothermal gradient, and partly explain the concentration of oil fields around the margins of the trough.

oil generation were obtained during the Late Cretaceous or Tertiary. Present maturation levels at the base of the Eromanga Basin sequence reflect these trends (Fig. 11).

Hydrocarbon migration pathways in the Eromanga Basin are still poorly understood. Originally, it was thought that the westward-directed artesian water drive had flushed hydrocarbons from the basin. However, there is no evidence to support this claim. Recent theoretical studies (Bowering, 1982; Moriarty and Williams, 1982) have shown that the artesian water drive should impart only a 0.1 degree slope to any oil-water contact, and is therefore in capable of flushing liquid hydrocarbons from most structural closures. The absence of any detectable dip to oil-water contacts in the Eromanga Basin and the fact that many structures along the Jackson-Naccowlah trend are filled approximately to spill point, support the view that the artesian water system has had little flushing effect on trapped hydrocarbons.

Prior to 1984, most hydrocarbon discoveries were located around the margins of the Nappamerri Trough. This led Kantsler et al. (1983) and others to argue that the trough was the source of Eromanga Basin hydrocarbons, with short distance migration to flanking structures. However, recent discoveries at Tintaburra, Charo and Bodalla South (Figs 5, 11) suggest that much larger areas of the Eromanga Basin or underlying Cooper Basin are capable of generating oil. A better understanding of the migration pathways involved ultimately will depend on better oil to source-rock correlations, which are still in progress.

Most Eromanga Basin hydrocarbon accumulations occur in structural traps. Thus, the timing and style of structural deformation are very important. Various phases of structuring have occurred within the basin, and structural style varies considerably from area to area. For example, in southwestern Queensland where the most recent hydrocarbon discoveries have been made, wrenching plays an important role. Structural movements have recurred throughout the Late Palaeozoic and Mesozoic, with the most recent post-dating deposition of the Eromanga Basin sequence. Moore and Pitt

(1984) argued that this last, major phase of tectonism probably began in the latest Cretaceous or Paleocene and persisted until at least the Oligocene (Fig. 12). Structures which largely owe their origin to this deformation contain hydrocarbons, and may be filled to spill point. Thus, it is not wise to downgrade structures because of their superficially youthful appearance, as evidenced by oil in Jackson, which has dipping Tertiary silcrete on the flanks of the structure.

DEVELOPMENT AND PRODUCTION: THE LIQUIDS PROJECT

The concept of selling crude oil and natural gas liquids from the Cooper Basin was first suggested in 1970 following discovery of the Early Permian Tirrawarra Oilfield (Fig. 13). However, the remote location of the fields, their relatively small sizes and large interfield distances made development uneconomical. In the late 1970s, circumstances altered with a significant worldwide increase in the price of crude oil. This stimulated exploration, which in turn led to the discovery of more oil and wet-gas fields in the Cooper Basin and the discovery of the Strzelecki and Dullingari Oilfields in the overlying Eromanga Basin.

Early in 1980, a consortium of eleven companies announced its decision to proceed with the "Liquids Project". These companies are party to the Cooper Basin Unit Agreement, which was established in 1976 to control the orderly development of the Cooper Basin gas reserves. The companies are Alliance Petroleum Australia Pty Ltd, Basin Oil N.L., Bridge Oil Developments Pty Ltd, Bridge Oil Ltd, Crusader Resources N.L., Delhi Petroleum Pty Ltd (part of the CSR Group), Reef Oil N.L., Santos Ltd, South Australian Oil and Gas Corporation Pty Ltd, Total Exploration Australia Pty Ltd and Vamgas Ltd.

Throughout 1981, events occurred in rapid succession. A site for the liquids terminal was selected, a route for the liquids pipeline chosen, environmental impact studies completed and approved by Government and an Indenture Agreement ratified by Parliament. Final terms of agreement

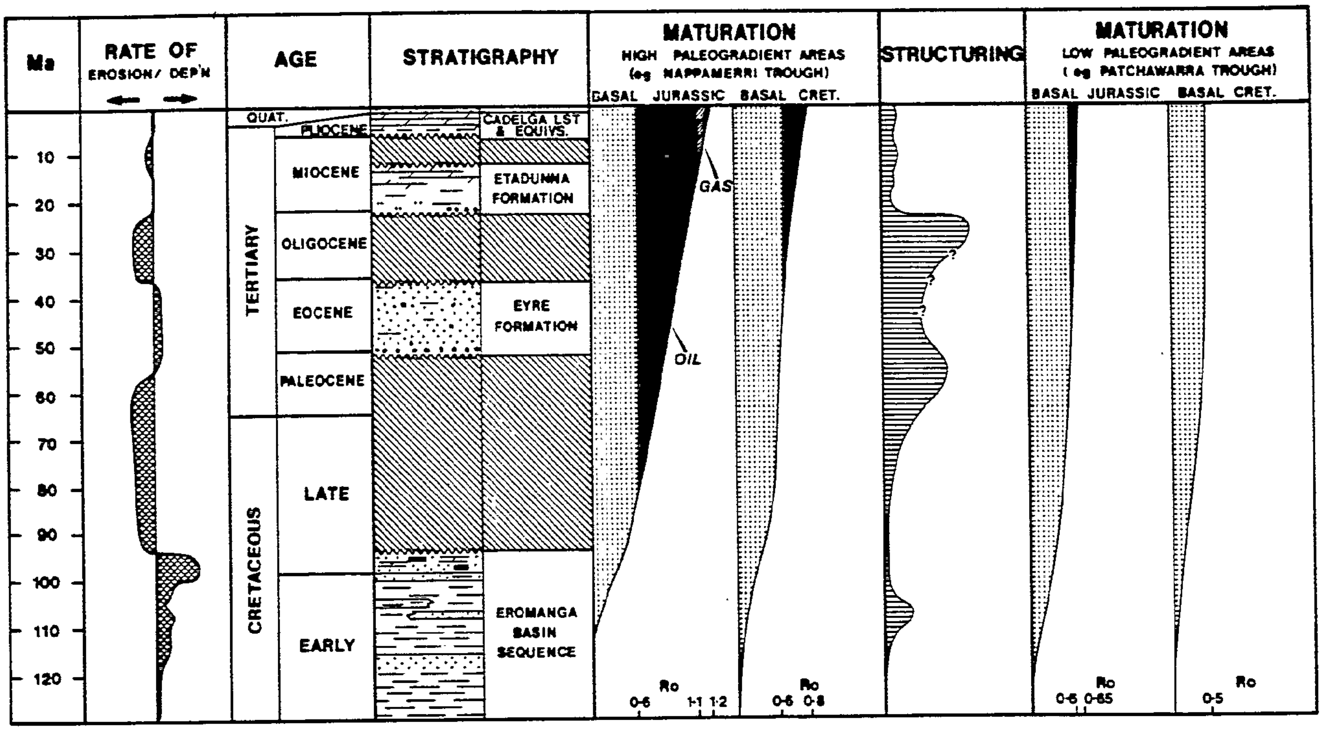


Fig. 12: Summary of structuring and maturation history for the Eromanga Basin during the Cretaceous and Tertiary. Base of oil window is taken at 0.6% vitrinite reflectance, although Murta-type oils may be generated at vitrinite reflectivities as low as 0.5% (after Moore and Pitt, 1984, Fig. 21).

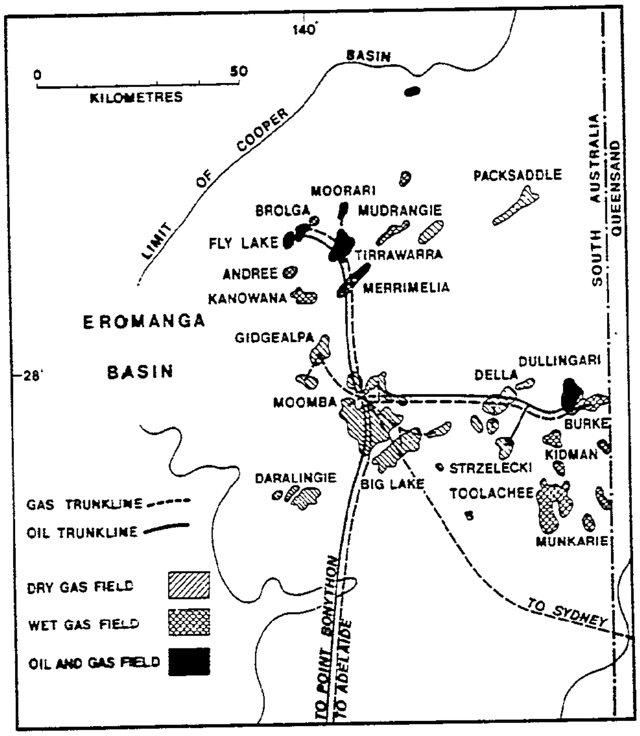


Fig. 13: Location of wet gas fields and oil fields associated with the 'Liquids Project' in South Australia. This $1.5 billion development is complementary to the production of methane (extracted from wet gas and produced from dry gas fields), which supplies the Sydney and Adelaide markets.

amongst the eleven participating companies was signed on 31 December 1981. Of great benefit was the bi-partisan support of the major political parties. Their acceptance of the Indenture Agreement, which set the terms and conditions under which the project could proceed, gave producers the security needed to negotiate loans to finance their respective shares of the project, the total of which is $1.5 billion between 1982 and 1986.

The Liquids Project is an integral part of continuing petroleum development in both the Cooper and Eromanga Basins. As well as the production of crude oil, the Liquids Project involves the separation of natural gas liquids (ethane, propane, butane and condensate) from gas bound for the Sydney and Adelaide markets (Fig. 14). The rate of production of natural gas liquids therefore depends in part upon the rate of consumption of natural gas.

Prior to liquids development, only five dry gas fields were in production (Gidgealpa, Moomba, Big Lake, Namur and Della; Fig. 13). In its initial phase, the Liquids Project involves the development of an additional 14 Cooper Basin gas fields, and 6 oil fields. Of the 6 oil fields, Tirrawarra, Moorari and Fly Lake produce from the Cooper Basin whereas Strzelecki and Dullingari produce from the Eromanga Basin. The sixth field is Merrimelia, which produces oil from both Cooper and Eromanga Basin sequences (Fig. 13).

The Strzelecki, Dullingari and Merrimelia Oilfields produce from several horizons within the Eromanga Basin sequence (Fig. 6). For example, Dullingari produces from twelve wells, eight from the Murta Member and four from the Namur Sandstone Member. For the Murta Member these wells are currently utilising rod pumps for artificial lift. One Namur producer has a downhole electric pump. For the Murta accumulation, which is thin and stratigraphically controlled, pressure maintenance will be by water flood. For the structurally controlled Namur accumulation, further downhole electric pumps may be installed.

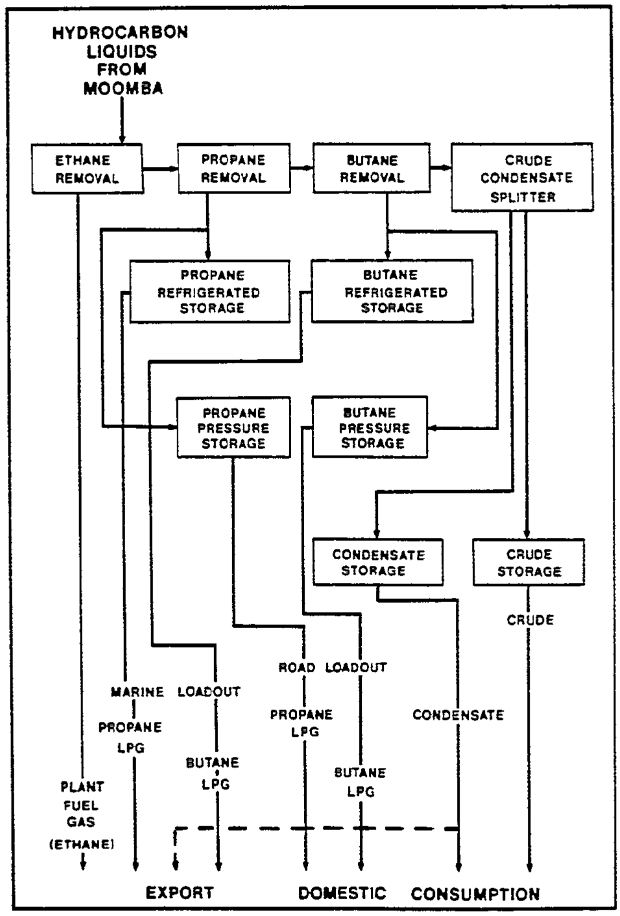


Fig. 14: Flow chart of hydrocarbon liquids treatment at Point Bonython, South Australia (see Fig. 1 for location).

For the Eromanga Basin fields, treatment stations at Dullingari, Strzelecki and Merrimelia cool and separate the produced fluid into oil, water and gas. At Dullingari for example, the oil is stored in two 5000 barrel capacity tanks prior to being pumped to Moomba via a 150 mm diameter trunkline. A team of about 8 people are employed to operate the Dullingari Oilfield, and are replaced fortnightly under a roster system. The personnel are housed in a permanent camp consisting of single quarters accommodation. Other field collection and processing facilities are similar.

The main treatment plant for the Liquids Project is situated at Moomba, in the Strzelecki Desert, 800 km northeast of Adelaide. Moomba is a company-operated single quarters camp, originally constructed in 1968 for the treatment of natural gas bound for the Adelaide market. The Liquids Project has had a major impact on the camp, with the addition of a liquids recovery plant, a crude oil stabilisation plant, additional CO_2 processing facilities and other equipment. The Moomba complex has been designed to process 25.4 million cubic metres of raw natural gas per day, 7250 kilolitres of natural gas liquids per day and 30,000 barrels of crude oil per day. Surface storage facilities consist of a 300,000 barrel crude-oil storage tank and a 100,000 barrel condensate storage tank. A new camp providing accommodation for an additional 304 staff has been constructed, bringing the camp's capacity to over 500 people. During 1983, over 30,000 passengers travelled to Moomba, making the airport the second busiest in South Australia. However, most supplies reach Moomba by road; a 900 km trip that takes 12 hours from Adelaide and includes 350 km of unsealed road.

Ethane, extracted from natural gas, is being stored underground at Moomba in partially depleted gas wells while its marketability is investigated. The rest of the natural gas liquids are commingled with the stabilised crude oil and piped 659 km to Port Bonython along a 355 mm diameter underground pipeline. The pipeline, with 4 pump stations installed, has a throughput capacity of 80,000 barrels of hydrocarbon liquids per day.

Construction of the pipeline commenced in January 1982 and was completed in nine months.

The Point Bonython complex incorporated fractionation, storage and loading facilities. The fractionation process separates ethane, propane and butane from the heavier hydrocarbons. Onshore storage is available for propane (500,000 barrels), butane (350,000 barrels), crude oil (750,000 barrels) and condensate (500,000 barrels). These products are pumped along a 2.4 km jetty, to tankers at deep-water anchorage. LPG (propane and butane) is pumped as a refrigerated liquid while heavier hydrocarbons (condensate and crude) are delivered to the tankers at atmospheric pressure in a separate line. Production of crude oil and condensate began early in 1983 and LPG production commenced in mid 1984. It is anticipated that by late 1984 total liquids production via Point Bonython will have been 53,000 barrels per day. When facilities are fully operational the initial production of crude oil and condensate will amount to about 10 million barrels per annum, while LPG will be produced at the rate of about 550,000 tonnes per annum. The crude oil and most of the condensate is sold to Australian refineries. The LPG supplies a small domestic market and is also exported. Ethane is used as plant fuel at Port Bonython but eventually may be used as a feedstock for a petrochemical plant.

DEVELOPMENT AND PRODUCTION: THE JACKSON PROJECT

The size of the Jackson Oilfield, discovered in southwestern Queensland in 1981, led to a decision to quickly put the field into production. The nearby Jackson South Field, discovered in February 1982, was included in this development programme. Some of the more recent discoveries in the area are also being linked to the production facilities. Others will have separate facilities, depending upon the economics of the development, which will include the size of the discoveries and their distance from Jackson.

Meanwhile, as exploration continues in the Naccowlah Block and adjacent licence areas, field facilities at Jackson and a pipeline from Jackson to

Moonie (Fig. 1) have been constructed to enable the oil to be transported to Brisbane for refining. The six companies responsible for field development are Ampol Exploration Ltd (7.5%), Claremont Petroleum NL (10%), Delhi Petroleum Pty Ltd (upstream operator; 32%), Oil Company of Australia NL (2.5%), Santos Ltd (downstream operator; 40%) and Vamgas Ltd (8%). The cost of development is presently estimated at $62 million, and has included the drilling and completion of 31 development wells and installation of gathering treating, storage and infrastructure facilities.

In the Jackson Field, oil is produced from the Murta Member, Westbourne Formation and Hutton Sandstone. The Hutton Sandstone contains the majority of reserves and typically flows at rates in excess of 1000 BOPD per well. The Westbourne Formation contains thinner, shalier sandstones which generally flow at rates of up to 200 BOPD per well. Wells producing from the Westbourne Formation are typically dual completions, with production also coming from the Hutton Sandstone. Only four wells are utilised to produce the small Murta accumulation. In the Jackson South Field, three wells produce oil from the Westbourne Formation; these are linked to the Jackson facilities by a 5.5 km pipeline.

The treatment and dispatch facilities at Jackson consist of separation facilities (oil, water and gas), oil storage and measurement facilities, pour point treatment, blending facilities and water disposal (Fig. 15). Support infrastructure will include a permanent camp for up to 60 people as well as office accommodation, a store and workshop. The area is serviced by road and air.

Construction of a 323 mm diameter, 780 km underground pipeline from Jackson to Moonie commenced in April 1983 and was completed in February 1984 at a cost of approximately $120 million. Owners and operators of the pipeline are the six Naccowlah Block exploration companies (50%), Moonie Pipeline Company Pty Ltd (25%) and Bridgefield Pty Ltd (25%). Initial design capacity was 16,000 barrels of oil per day. However, this can be increased to 55,000 barrels of oil per day with the installation of extra

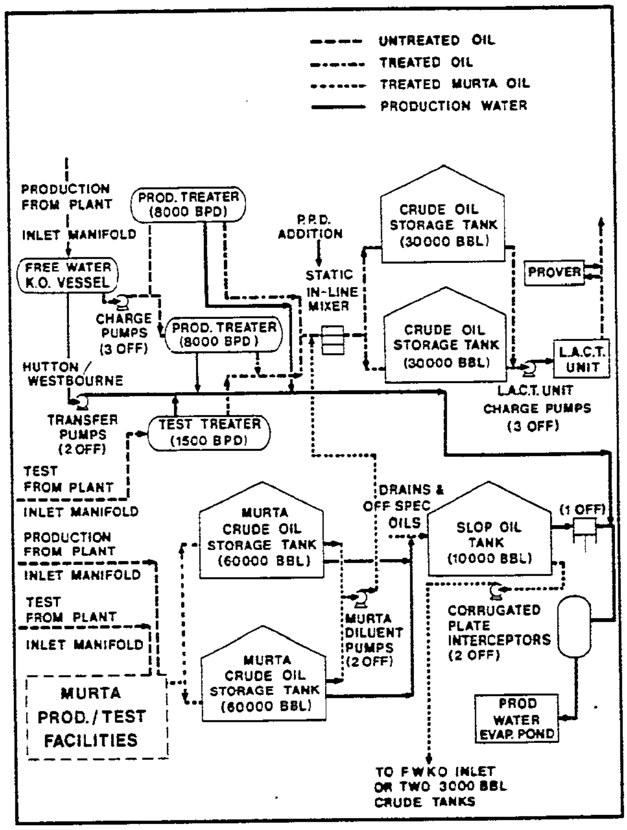


Fig. 15: Flow diagram for hydrocarbons passing through the Jackson production facilities, southwestern Queensland.

pumps. Two 30,000 barrel tanks are located at Moonie to provide buffer storage. The existing 307 km long, 250 mm diameter Moonie-to-Brisbane pipeline has the capacity to transport Jackson crude at the rate of 25,000 barrels per day. However, the capacity of this line can also be upgraded with the installation of extra pumping facilities.

The high pour points of Hutton and Westbourne oils (25^{o}C and 20^{o}C respectively) and their waxy nature provide significant pumpability problems. Although no treatment is needed during the hot Australian summer, pour point depressants are added in spring, autumn and winter. This increases the production cost of Jackson crude by about $0.50 per barrel. During winter, air temperatures in the Australian desert can drop to 0^{o}C at night and, although the pipeline is buried, additional modification of the flow properties of the oil is necessary. This is achieved by producing low pour point (0 ^{o}C) oil from the Murta reservoir and adding it as a 10% diluent.

During the pipeline construction period, early production involved trucking crude oil to Moonie, then piping it to Brisbane. To the end of 1983 approximately 46,000 barrels had been transported in this way. At June 1984, the Jackson to Moonie pipeline had filled, and Jackson crude was en route to Brisbane. It is expected that during 1984, 4 million barrels of oil will have been produced for sale on the Australian market.

CONCLUSIONS

Significant progress has been made since 1977, when Poolowanna 1 flowed oil from the Eromanga Basin sequence. In the last seven years, over 350 petroleum wells have been drilled in the basin and several tens of thousands of kilometres of seismic data have been recorded. The exploration effort has led to the discovery of over 50 hydrocarbon pools. Two major development programmes (the 'Liquids Project' in South Australia and the Jackson Project in Queensland) are operational, with an expenditure to date of over $1.6 billion.

Despite this progress, exploration in the Eromanga Basin is still at a very early stage. For example, less than 600 petroleum wells penetrate the sequence, with large areas almost totally unexplored. Outcrops on the basin margins yield only limited data because the thin, gently dipping and deeply weathered strata bear little resemblance to the more complete subsurface sections. Even in the most prospective central portion of the Eromanga Basin, drilling density is low, with less than 6 wells per thousand square kilometres.

However, exploration activity is increasing. During 1984 approximately 20,000 kilometres of seismic data will have been recorded and 100 exploration wells will have been drilled. This activity reflects a common belief that the Eromanga Basin is the most prospective onshore area in Australia for petroleum. Future exploration is likely to be concentrated to the northeastern South Australia and particularly southwestern Queensland, where success has been greatest. The presence of the two oil pipelines will also promote exploration in these areas, making it more attractive to explore for the small to medium-sized (1-30 million barrels) oil fields typical of the basin. Based on successes to date and on petroleum potential outlined by geological studies, many more discoveries can be expected.

REFERENCES

Ambrose, G., R. Suttill, and I. Lavering, 1982, A review of the Early Cretaceous Murta Member in the southern Eromanga Basin, in P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

Armstrong, J.D. and T.M. Barr, 1982, The Eromanga Basin, in P.S. Moore and T.J. Mount, eds, Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

Bowering, O.J.W., 1982, Hydrodynamics and hydrocarbon migration - a model for the Eromanga Basin: Australian Petroleum Exploration Association Journal, 22(1), 227-236.

Day, R.W., W.G. Whitaker, C.G. Murray, I.H. Wilson, and K.G. Grimes, 1983, Queensland geology. A companion volume to the 1:2,500,000 scale geological map (1975): Geological Survey of Queensland, Publication, v. 383.

Evans, P.R., 1962, Microfossils associated with the "Bundamba Group" of the Surat Basin, Queensland: Australian Bureau of Mineral Resources, Geology and Geophysics, Records, v. 1962/115 (unpublished).

Exon, N.F., 1976, Geology of the Surat Basin in Queensland: Australian Bureau of Mineral Resources, Geology and Geophysics, Bulletin, v. 16.

Gatehouse, C., in press, Geology of the Warburton Basin in South Australia: Australian Journal of Earth Sciences.

Gould, R., 1980, The coal-forming flora of the Walloon Coal Measures: Coal Geology, v. 1, p. 83-105.

Gravestock, D., M. Griffiths, and A. Hill, 1983, The Hutton Sandstone - two separate reservoirs in the Eromanga Basin, South Australia: Australian Petroleum Exploration Association Journal, v. 23(1), p. 109-119.

Halyburton, R.V., and A.L. Robertson, 1984, Geology of the Jackson oil field: Australian Petroleum Exploration Association Journal, v. 24(1), p. 259-265.

Habermehl, M.A., 1980, The Artesian Basin, Australia: Australian Bureau of Mineral Resources, Geology and Geophysics, Journal, v. 1, p. 33-50.

______ 1982a, Investigations of the geology and hydrology of the Great Artesian Basin 1879-1980: Australian Bureau of Mineral Resources, Geology and Geophysics, Report, v. 234.

______ 1982b, Springs in the Great Artesian Basin, Australia - their origin and nature: Australian Bureau of Mineral Resources, Geology and Geophysics, Report, v. 235.

______ 1982c, The Eromanga Basin within the Great Artesian Basin, <u>in</u> P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium, summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

Kantsler, A.J., T.J.C. Prudence, A.C. Cook, and M. Zwigulis, 1983, Hydrocarbon habitat of the Cooper/Eromanga Basin, Australia: Australian Petroleum Exploration Association Journal, v. 23(1), p. 75-92.

McKirdy, D.M., 1982, Aspects of the source rock and petroleum geochemistry of the Eromanga Basin, <u>in</u> P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

______ J.K. Emmett, B.A. Mooney, R.E. Cox, and B.L. Watson, in press, Organic geochemical facies of the Cretaceous Bulldog Shale, western Eromanga Basin, South Australia, <u>in</u> D.I. Gravestock, P.S. Moore, T.J. Mount and G.M. Pitt, eds, Contributions to the geology and petroleum potential of the Eromanga Basin: Geological Society of Australia, Special Publication.

Martin, K.R., 1981, Deposition of the Precipice Sandstone and evolution of the Surat Basin in the Early Jurassic: Australian Petroleum Exploration Association, Journal, v. 21(1), p. 16-23.

Moore, P.S., 1982a, Hydrocarbon potential of the Arckaringa region, central South Australia: Australian Petroleum Exploration Association Journal, v. 22(1), p. 237-253.

______ 1982b, Mesozoic geology of the Simpson Desert region, northern South Australia, in P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium, summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

______ in press, Jurassic and Triassic stratigraphy and hydrocarbon potential of the Poolowanna Trough (Simpson Desert region) northern South Australia, in D.I. Gravestock, P.S. Moore, T.J. Mount and G.M. Pitt, eds, Contributions to the geology and hydrocarbon potential of the Eromanga Basin: Geological Society of Australia, Special Publication.

______ and T.J. Mount, eds, 1982: Eromanga Basin Symposium summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

______ and G.M. Pitt, 1982, Cretaceous of the southwestern Eromanga Basin: stratigraphy, facies variations and petroleum potential, in P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

______ ______ 1984, Cretaceous of the Eromanga Basin - implications for hydrocarbon exploration: Australian Petroleum Exploration Association Journal, v. 24(1), p. 358-376.

______ ______ in press, Cretaceous subsurface stratigraphy of the southwestern Eromanga Basin: a review, in M.J. Lindsay, ed., Essays in honour of N.H. Ludbrook: Geological Survey of South Australia, Special Publication.

Moriarty, K.C., and Williams A.F., 1982, Hydrocarbon flushing in the Eromanga Basin - fact or fallacy: in P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

Mount, T.J., 1981, Dullingari North 1, an oil discovery in the Murta Member of the Eromanga Basin: Australian Petroleum Exploration Association Journal, v. 21(1), p. 71-77.

______ 1982, Geology of the Dullingari Murta Oilfield, in P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium Summary Papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

Nugent, O.W., 1969, Sedimentation and petroleum potential of the Jurassic sequence in the southwestern Great Artesian Basin: Australian Petroleum Exploration Association Journal, v. 9(2), 97-107.

Ozimic, S., 1982, Depositional environment of the Toolebuc Formation and its equivalents, Eromanga Basin, Australia, in P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

Passmore, V.L., and M.J. Sexton, 1984, The structural development and hydrocarbon potential of Palaeozoic source rocks in the Adavale Basin region: Australian Petroleum Exploration Association Journal, v. 24(1), p. 393-411.

Porter, C.R., 1979, Fluvio-deltaic deposition in Lower Jurassic sediments of the Surat Basin, Queensland: Australian Petroleum Exploration Association, Journal, v. 19(2), p. 37-50.

Power, P.E., and S.B. Devine, 1970, Surat Basin - Australia - subsurface stratigraphy, history and petroleum: American Association of Petroleum Geologists, Bulletin, v. 54, p. 2410-2437.

Rigby, D., and J.W. Smith, 1983, An isotopic study of gases and hydrocarbons in the Cooper Basin: Australian Petroleum Exploration Association Journal, v. 21(1), p. 222-229.

Wake-Dyster, K.D., 1982, The relationship between the Thomson Syncline and underlying Barcoo Trough, _in_ P.S. Moore and T.J. Mount, eds, Eromanga Basin Symposium, summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

Wiltshire, M.J., 1982, Late Triassic and Early Jurassic sedimentation in the Great Artesian Basin, _in_ P.S. Moore and T.J. Mount, compilers, Eromanga Basin Symposium, summary papers: Geological Society of Australia and Petroleum Exploration Society of Australia, Adelaide, 415p.

Wopfner, H., and C.R. Twidale, 1967, Geomorphological history of the Lake Eyre Basin, _in_ J.N. Jennings and A. Harbutt, eds, Landform studies from Australia and New Guinea: Australian National University Press, Canberra, ... p.

______ I.B. Freytag, and G.R. Heath, 1970, Basal Jurassic-Cretaceous rocks of western Great Artesian Basin, South Australia: stratigraphy and environment: American Association of Petroleum Geologists, Bulletin, v. 54, p. 383-416.